Working to Perfect the Flow of Energy

PJM Manual 11:

Energy & Ancillary Services Market Operations

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Prepared by

Forward Market Operations

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- Sections 2.5; 2.9 and 2.9.1 Edits associated with FERC Order No. 825 to implement the transient shortage rule changes effective May 11, 2017

Introduction

Welcome to the ***PJM Manual for Energy & Ancillary Services Market 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. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and Billing
- PJM administrative services

For a complete list of all PJM Manuals, go to the Library section on PJM.com.

About This Manual

The ***PJM Manual for Energy & Ancillary Services Market 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 Energy & Ancillary Services Market Operations*** consists of ten sections. The sections are listed in the table of contents beginning on page ii.

Intended Audience

The intended audience of the PJM Manual for Energy & Ancillary Services Market Operations is:

- *PJM Members* - Any participants requesting to purchase or sell energy to or from the PJM Interchange Energy Market or Ancillary Service Markets 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 and real-time information requirements.

References

The References to other documents that provide background or additional detail directly related to the ***PJM Manual for Energy & Ancillary Services Market Operations*** are:

- PJM ExSchedule User Guide
- PJM Manual for Transmission Operations(M-03)
- PJM Manual for Pre-Scheduling Operations (M-10)
- PJM Manual for Balancing Operations (M-12)
- PJM Manual for Emergency Operations (M-13)
- PJM Manual for Operating Agreement Accounting (M-28)

Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then, we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections
- An approval page that lists the required approvals and a brief outline of the current revision
- 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
- A section at the end detailing all previous revisions of the PJM Manual

Section 1: Overview of Energy & Ancillary Services Market Operations

Welcome to the Overview of Energy & Ancillary Services Market Operations of the PJM Manual for Energy & Ancillary Services Market Operations. In this section you will find the following information:

- A description of the scope and purpose of scheduling (see "*Scope & Purpose of* Energy & Ancillary Services Market Operations").
- A list of the PJM responsibilities (see "*PJM Responsibilities*").
- A list of the market participants' scheduling responsibilities (see "*PJM Market Participant Responsibilities*").

Scope & Purpose of Energy & Ancillary Services Market Operations

Operation of the PJM RTO markets 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 Energy & Ancillary Services Market 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 and in real-time associated with the Real-time Energy Market and Ancillary Service Markets. Exhibit 1 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, regardless of fuel type, fall into one of two categories, Capacity Resources or Energy Resources. If available, All Generation Capacity Resources that have an RPM Resource Commitment 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 closed. 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 1030 on the day before the Operating Day and the Day-ahead Market results are posted by 1330 or as soon as practicable thereafter 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 and Day-ahead Scheduling Reserve Market based using least-cost security constrained resource commitment and dispatch that simultaneously optimizes energy and reserves.

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.

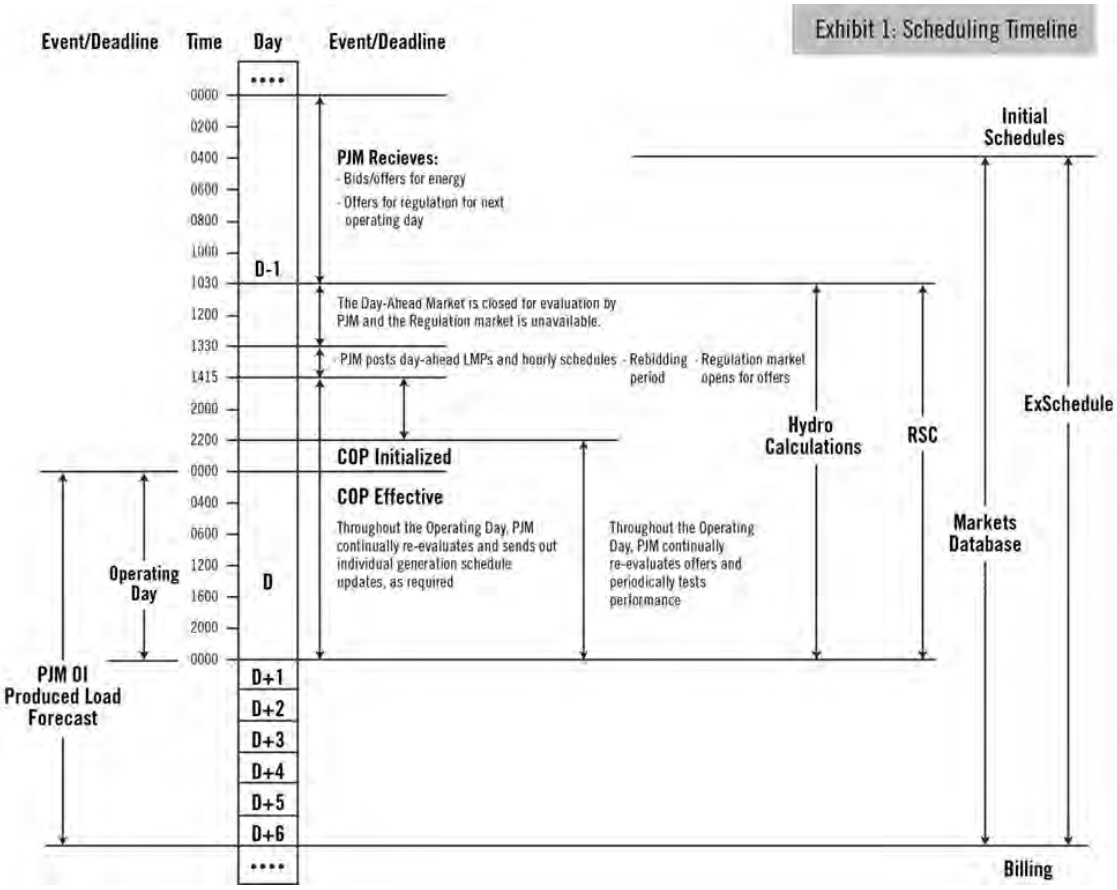


Exhibit 1: Scheduling Timeline

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.

In this manual, Locational Marginal Price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received. For accounting purposes, LMP is expressed in dollars per megawatt-hour ($/MWh). In performing this LMP calculation, the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer is calculated as the sum of the following three components of Locational Marginal Price: System Energy Price, Congestion Price, and Loss Price. In this manual, unless otherwise specified, the terms “LMP” or “Locational Marginal Price” refer to the total LMP value including all three components. For information on the concept of Locational Marginal Prices, please refer to Section 2 of this manual.

1.1 PJM Responsibilities

In the Day-ahead Market, PJM determines the minimum production cost 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 schedules 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:
- PJM develops the Day-ahead Market financial schedules based upon participant-supplied bids, offers and bilateral transaction schedules using least-cost security constrained resource commitment and dispatch analysis.
- The following information is posted after the Day-ahead Market clears by 1330:
  - Schedules for Next Day by participant (generation & demand),
  - Transaction Schedules,
  - Day-ahead LMPs, Day-ahead Congestion Prices, & Day-ahead Loss Prices
  - 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 Day-ahead Scheduling Reserve (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
- 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 resources to reflect updated projections of load, changing Bulk Electric System conditions, availability of and constraints of limited energy and other resources

Notification to PJM stakeholders of any new closed loop interface implementation should be made as far in advance as possible and should be announced 5 days prior to the next FTR auction close through posting on www.pjm.com – OASIS System Information and notification through e-mail to the MIC and OC exploder lists. Exceptions to this are limited to estimated short duration planned, emergency or maintenance outages, (e.g., <10 days) to set price, or to allow Demand Response (DR) to set price if a transmission limitation exists as defined in the PJM Tariff and manuals. The posting will include the interface name, effective date, estimated termination date (if applicable), whether included in DA model, whether included in the FTR model, conditions when use is applicable, general description, interface definition/branch names and directions, whether it will set price for DR, generation, or both and any revision history. PJM will post interface definition with network model mapable branch names in CSV or XLS format. In addition PJM will provide notice when PJM is studying if a new closed loop interface may be defined and any information regarding the modeling of such prospective closed loop interface.

1.2 PJM Market Participants 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 Market Buyers and Market Sellers.

1.2.1 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 inside the PJM RTO. A Metered Market Buyer may be further classified as a Generating Market Buyer. A Generating 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.

The scheduling responsibilities of a Metered Market Buyer are to:

- Submit forecasts of customer loads for the next Operating Day
- Submit economic load management agreements to PJM
- Submit Bilateral Transactions for delivery within the PJM RTO, regardless of whether the generation is located inside or outside the PJM RTO

- 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

By definition, all Market Buyers become Market Sellers upon approval of their applications and therefore carry the responsibilities of Market Sellers outlined below.

1.2.2 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 hourly schedules for Self-Scheduled Resource increments
- Submit a forecast of the availability of each Generation Capacity Resource for the next seven days
- Submit Offer Data for Generation Capacity Resources for supply of energy to the PJM Day-ahead Energy Market for the next day whether Self-Scheduled or PJM scheduled
- Submit schedules for bilateral sales to entities outside the PJM RTO from within the PJM RTO
- Submit optional offers for the supply of energy, capacity, and other services from Energy Resources into the Day-ahead Energy Market or the Real-time Energy Market for the next operating day only
-

1.2.3 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.

1.2.4 Curtailment Service Providers

A Curtailment Service Provider is a Member or Special Member, which acting on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market by causing a reduction in demand.

Section 2: Overview of the PJM Energy Markets

Welcome to the Overview of the PJM Energy Markets section of the PJM Manual for Energy & Ancillary Services Market Operations. In this section you will find the following information:

- An overview description of the PJM Energy Markets (see "Overview of PJM Energy Markets").
- A list of the PJM Two-Settlement Market Business Rules (see "PJM Energy Markets Business Rules").

2.1 Overview of PJM Energy Markets

The PJM Energy Markets 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 Locational Marginal Prices (LMPs). The components of Day-ahead hourly LMPs are the Day-ahead System Energy Price, Day-ahead Congestion Price, and the Day-ahead Loss Price. It also allows transmission customers to schedule bilateral transactions at binding Day-ahead congestion charges based on the differences in the Congestion Prices 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 generation capacity resource that has an RPM Resource Commitment 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. Curtailment Service Providers (CSPs) may submit demand reduction bids. All spot purchases and sales in the Day-ahead Market are settled at the Day-ahead prices. Congestion that results from the Day-ahead sales and purchases of energy is settled at the Day-ahead Congestion Price component of

LMP. Transmission losses that result from the Day-ahead sales and purchases of energy are settled at the Day-ahead Loss Price component of LMP. 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 resource 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 Congestion Price component of 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 and Demand 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 the time the office of interconnection posts the results of the Day-ahead Energy Market until 1415 (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 the Real-time LMPs for any demand that exceeds their Day-ahead scheduled quantities (and will receive revenue for demand deviations below their scheduled quantities). In the energy market, generators are paid the 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 the real-time Congestion Price component of LMPs for bilateral transaction quantity deviations from Day-ahead schedules. CSPs may self-schedule demand reductions for Demand Resources not dispatched in real-time by PJM. All spot purchases and sales in the balancing market are settled at the real-time LMPs. Congestion that results from the Real-time sales and purchases of energy is settled at the Real-time Congestion Price component of LMP. Transmission losses that result from the Real-time sales and purchased of energy are settled at the Real-time Loss Price component of LMP.

2.2 Definition of Locational Marginal Price

Locational Marginal Price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received. For accounting purposes, LMP is expressed in dollars per megawatt-hour ($/MWh). LMP is a pricing approach that addresses Transmission System congestion and loss costs, as well as energy costs. Therefore, each spot market energy customer pays an energy price that includes the full marginal cost of delivering an increment of energy to the purchaser's location.

- When there is transmission congestion in PJM, the PJM dispatcher dispatches one or more of the generating units out of economic merit order to keep transmission flows within limits. There may be many resources that are dispatched to relieve the

congestion. The LMP reflects the cost of re-dispatch for out-of-merit resources and cost of delivering energy to that location.

- LMPs are calculated at all injections, withdrawals, EHVs (nominal voltage of 500 KV and above), Interfaces, and various aggregations of these points.

- LMPS are calculated in both the Real-time Energy Market and Day-ahead Energy Market.

- The LMP calculation calculates the full marginal cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of three separate components of LMP. In performing this LMP calculation, the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer is calculated as the sum of the following three components of Locational Marginal Price:

  - System Energy Price - is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource. The System Energy Price may include a portion of the defined reserve penalty factors should a reserve shortage exist.
  - Congestion Price - is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings. The Congestion Prices may include a portion of the defined reserve penalty factors should a reserve shortage exist.
  - Loss Price - is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission losses.

- The energy offer or offers that can serve an additional increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Locational Marginal Price at that bus.

2.3 Energy Market Business Rules

2.3.1 Bidding & Operations Time Line

The day-ahead scheduling/bidding timeline for PJM energy markets consists of the following time frames:

- **1030 —** Day-ahead Market bid period closes. All bids must be submitted to PJM. At 1030 PJM begins to run the day-ahead market clearing software to determine the hourly commitment schedules and the LMPs for the Day-ahead Market. The Day Ahead clearing results in the resource commitment profile that satisfies the fixed demand, cleared price-sensitive demand bids, cleared demand reduction bids, and PJM Day-ahead Scheduling Reserve (Operating Reserve) objectives, while minimizing the total production cost (subject to certain limitations) for energy and reserves. This commitment analysis also includes external bilateral transaction schedules and external resource offers into the PJM Day-ahead Market.

- By 1330 - PJM posts the day-ahead hourly schedules and LMPs in the Markets Gateway System. PJM also makes these results available in downloadable files, via the Markets Gateway System, or a dedicated communication link.

- After Day-ahead Results posting-1415 **—** PJM opens the balancing market offer period. During this time, market participants can submit revised offers for resources not selected in the Day-ahead Market. However if the market participant self-scheduled their unit in the Day-ahead Market, they cannot change the unit status to economic in the rebid period.

- 1415 **–** The balancing market offer period closes. PJM performs a second resource commitment, which includes the updated offers, updated resource 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 start-up and no load costs for any additional resources that are committed.

- **1415 - Operating Day —** PJM may perform additional resource commitment runs, as necessary, based on updated PJM load forecasts and updated resource availability information. PJM sends out individual generation schedules updates to specific generation owners only, as required.

2.3.2 Market Buyers

The following business rules apply to Market Buyers:

- Each Market Participant's profile (which is defined by PJM) shall specify the transmission zones or aggregates for which that participant is eligible to submit demand bids.

- 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).

- Demand bids are assumed to exclude losses (transmission zone losses and share of 500 kV losses).

- 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.

- 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.

- If a Market Buyer submits no day-ahead bid information, then a zero MW quantity is assumed.

- The total MW quantity of demand bids (fixed demand bids and price sensitive demand bids) submitted by a LSE for a given Operating Day must not exceed the LSE's Daily Demand Bid Limit, as described in the Mechanical /Technical Rules section of this manual.

- 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 0800 one week prior to the Operating Day (i.e. if next Operating Day is Monday, the default distribution is from 0800 on Monday of the previous week). The default distribution for a residual metered load aggregate for the Day-ahead Market is the final real-time distribution factors for the residual metered load aggregate at 8 a.m. one week prior to the Operating Day. See Manual 28, Section 3 for additional details on residual metered load aggregates.

- The EDC may update the default distribution factors for a transmission zone only after the state estimator populates the default.

- 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).

- 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.

- The list of transmission zones, aggregates, and single buses at which demand bids are accepted is defined by PJM.

- 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 Web site) 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.

- PJM may require that a market participant shall not submit in excess of 3000 virtual bid/offer segments in the Day-ahead Energy Market, when PJM determines that such limit is required to avoid or mitigate significant system performance problems related to the volume of virtual bids.

- Energy market transactions, except generation resource offers, may be submitted with an energy bid/offer price of no greater than $2,000/MWh plus the sum of the applicable Primary and Synchronized Reserve Penalty Factors not to exceed $3,700/MWh.

2.3.3 Market Sellers

The following business rules apply to Market Sellers:

- Self-scheduled generation shall submit an hourly MW schedule.

- 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.

- Generation Capacity Resources are considered Capacity Performance Resources for purposes of determining the applicable PLS for the resource if they have a daily Capacity Performance obligation for any MW of Capacity Performance product for that delivery day. In other words, if a Generation Capacity Resource has a capacity commitment for a certain number of MW in an RPM Auction for the 2016/2017 or 2017/2018 Delivery Years as an “Annual Resource” (i.e. non-Capacity Performance Resource), but also has a capacity commitment for a certain number of MW through a Transition Incremental Auction for the same Delivery Year as a Capacity Performance Resource, the PLS for that resource shall be the unit-specific PLS applicable to Capacity Performance Resources, not the default PLS that typically applies to “Annual Resources”.

- Generators that are Capacity Resources and are self-scheduling shall submit offer data in the event that they are called upon during emergency procedures. Such offers shall be based on the ICAP equivalent of the cleared UCAP capacity commitment.

- Generation 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.

- The set of offer data last submitted for each Generation Capacity Resource shall remain in effect for each day until specifically superseded by subsequent offers.

- If a Generation 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.

- Generation owners planning to run generation resources scheduled in the Day-ahead Markets are required to call the PJM Control Center at least 20 minutes prior to bringing the unit online. Generation owners of self-scheduled generation resources must also provide at least 20 minutes notice.

- Generation resources that are scheduled in the Day-ahead Market have a financial obligation to sell their output in real-time. Provisions exist in the Tariff that permit make whole payments to be made to those combustion turbines that are scheduled in the Day-ahead Market and then not called on in real-time by PJM that are furthered defined in PJM Manual 28.

- When a generation resource is not scheduled in the Day-Ahead Energy Market or the Reserve Adequacy Commitment (RAC) by PJM, the Market Seller may update the cost-based schedules availability hourly three hours prior to the operating hour. The cost-based schedule made available must follow the Generation Owner's fuel cost policy as defined in PJM Manual 15: Cost Development Guidelines. A generation resource may not change schedule availability once it has been committed by PJM for the hours in which it is committed. In order to update cost-based schedule availability, the Generation Owner must select the 'Use Cost Schedule in Real Time' flag in Markets Gateway (New Schedule Availability Update Tab) between 1415-2100 the day prior to the operating day. Selecting this flag will make the price-based schedule unavailable for the operating day selected.

- Generation Capacity Resources that have notification, startup, and minimum run times that exceed 24 hours must submit binding offer prices for the next seven days.

- Generation Capacity Resources that have notification plus startup times that exceed 24 hours and have been called on by PJM dispatch in advance of the close of the Day-ahead Market bid period for the desired Operating Day must modify their notification and startup time prior to the close of the market bid period for that day in order to create the possibility for the unit to be committed in the Day-ahead Market.

- Generation resources that are committed by PJM in advance of the Day-Ahead Energy Market will be offer capped and committed on the available schedule at the time of the commitment. The cost-based schedule made available must follow the Generation Owner's fuel cost policy as defined in PJM Manual 15: Cost Development Guidelines.

- Each Generation Capacity Resource must make available at least one cost-based schedule and for price based units, if it falls within the types of generators in the PJM

Unit Parameter matrix it must also submit a Price Based Parameter Limited Schedule.

- Generation offers may consist of startup, no-load and incremental energy offer.
- Generation resource cost based incremental energy offers must be developed in accordance with Manual 15 and PJM's governing documents.
- Generation resource market based incremental energy offers may not exceed $1,000/MWh unless cost based incremental energy offer is greater than $1,000/MWh then the market based incremental energy offer is capped at the lesser of the cost based incremental energy offer or $2,000/MWh.
- Market Sellers with a cost based incremental energy offer greater than $2,000/MWh may be eligible to receive credit for Operating Reserves. Market Sellers must submit all relevant documentation demonstrating the calculation of costs greater than $2,000/MWh to PJM and the MMU in accordance with Attachment D.
- Emergency and Pre-Emergency Demand Resource emergency or pre-emergency offer price may not exceed the following:
  - 30 minute lead time: $1,000/MWh, plus the applicable Primary Reserve Penalty Factor, minus $1.00
  - approved 60 minute lead time: $1,000/MWh, plus [the applicable Primary Reserve Penalty Factor divided by 2]; and
  - approved 120 minute lead time: $1,100/MWh.
- An economic demand resource offer may not exceed $1,000/MWh, plus the applicable Primary Reserve Penalty Factor, minus $1.00
- Energy resources may offer into the Day-ahead Market or Real-time Market.
- If an Energy resource does not submit offer data, then the offer is assumed to be a zero MW quantity.
- Intermittent Generation Resources, that are Capacity Resources, and Capacity Storage Resources shall meet the must offer requirement by either self-scheduling (Availability = Must Run) or may allow the Day-ahead Market to schedule by offering the unit as a dispatchable resource (Availability = Economic).
- The hourly Day-ahead self-scheduled values for intermittent resources and Capacity Storage Resources may vary hour to hour from the capacity obligation value,

- For price-based units, a price-based parameter limited schedule must be offered into the Day-ahead and Balancing Market. All price-based units have the option of submitting a second price schedule that is not parameter limited. In addition to the price-based schedules, one cost-based schedule shall be made available for PJM's use in the event that the resource is used to control a transmission constraint. The cost-based schedule shall be parameter-limited.

- A generator offer that is accepted for the Day-ahead Market automatically carries over into the balancing market.

- A generator offer for a generating unit with combined cycle capability shall make available either the schedules for the CTs or the schedule for the combined cycle unit, not both. Only CTs may submit weather curves, which specify MW limits for CTs as a function of temperature.

- Forecast points shall consist of a daytime temperature and a nighttime temperature.

- There are separate weather curves for economic MW and for emergency MW.

- 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.

- The priority of generator offer operating limits are as follows: (1) Unit Hourly MW limits (Markets Gateway>Generator>Unit>Hourly), (2) Daily Unit Schedule Limits (Markets Gateway>Generator> Schedules>Detail), (3) Unit limits (Markets Gateway>Unit>Detail). 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.

- Market Sellers may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interface point (posted on the PJM Web site) 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.

- A price-based unit has the option to choose cost-based start-up and no-load fees. A price-based unit that chooses the cost based option may change the start-up and no-load fees daily. A priced-based unit that chooses the price based option will continue to be able to change the start-up and no-load fees twice a year.

- The choice between using cost-based and price-based startup and no-load fees can be made twice a year during the same open enrollment window (on or before 1030 hours March 31 for the period April 1 through September 30 and on or before 1030

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 the cost-based start-up and no-load fees option, the decision cannot be changed until the next open enrollment period takes place.

- 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.

- 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.

- 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.

- 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.

- 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.

- 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.
- 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.
- 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.
- Hourly integrated, revenue quality meter data must be submitted to Power Meter on the basis of the aggregated unit.
- 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.
- Balancing Operating Reserve deviations for aggregated units will be calculated based on the hourly aggregated unit output as defined in ***PJM Manual 28: Operating Agreement Accounting, Section Operating Reserve Accounting***.
- Balancing Operating Reserve Generator deviations for units deemed to be "not following dispatch" that occur at a single bus will be able to offset one another.
- A "single bus" will be any unit located at the same site and that has the identical electrical impacts on the transmission system. Units are deemed to have identical electrical impacts on the transmission system if they meet the following criteria:
  - Units that have identical dfax to the system
  - Units that are on the same low side of the bus (i.e. connected at same voltage level)
- In the case of units on busses with bus-tie breaker, if bus-tie breaker was open less than 5% of the hours in the previous 3 years, supplier netting of units will be allowed across this bus-tie breaker.
- PJM will maintain a list of units that are deemed to have identical electrical impacts on the transmission system to be used for Balancing Operating Settlement. PJM will review the list on an annual basis. Generators will be reviewed as needed during any new generation activation or reconfiguration process as defined in ***Section 7 of PJM Manual 14d: Generator Operational Requirements.***

- Unit parameters do not have to be identical for the units' deviation MW to offset one another.

- If multiple units are deemed "not following dispatch" at a single bus, the deviation MW and direction of each unit at that bus will be summed to determine the deviation MW at that bus.

- Units at a "single bus" must be owned or marketed by single PJM Market Participant.

- Unit modeling changes in the PJM Markets Gateway 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.

- CT's are permitted to provide an Economic Minimum less than the physical economic minimum value of the unit. Per the ***PJM Manual for Operating Agreement Accounting,*** for settlement purposes, PJM determines the resource's hourly UDS LMP Desired MWh based on its dispatch rate, offer data, and minimum and maximum energy limits for that hour. For steam units, the lesser of the day-ahead scheduled and real-time economic minimum limits, and the greater of the day-ahead scheduled and real-time economic maximum limits, are used. For CT's, operating at PJM direction, the actual real-time output is used as the UDS LMP Desired MWh value.

2.3.4 Minimum Generator Operating Parameters – Parameter Limited Schedules

Below is the list of business rules to require units to submit schedules that meet minimum accepted parameters.

Market Sellers are required to submit, per Section 2.3.3 of this Manual, as follows: (1) at least one cost-based schedule that is parameter limited, (2) one price-based schedule, and (3) one price-based parameter limited schedule. Generation Capacity Resources shall be committed on these schedules under the following circumstances:

- For the 2014/2015 through 2017/2018 Delivery Years, in the event that PJM: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert for all or any part of such Operating Day, generation resources will be committed on the more economic schedule of their price based parameter-limited schedule and price based schedule.

- For Capacity Performance Resources, in the event that PJM: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert, Hot Weather Alert, Cold Weather Alert; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert for all or any part of such Operating Day;

generation resources will be committed on the more economic schedule of their price based parameter limited schedule and price based schedule.

- For Base Capacity Resources, in the event that PJM: (i) declares a Maximum Generation Emergency; (ii) issues a Maximum Generation Emergency Alert, Hot Weather Alert during hot weather operations; or (iii) schedules units based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert during hot weather operations for all or any part of such Operating Day; generation resources will be committed on the more economic schedule of their price based parameter limited schedule and price based schedule.

- If a Market Seller fails the three pivotal supplier test in the Energy Markets, the Seller's resources will be committed on the schedule with the least cost among the cost-based schedule, price-based schedule and price-based parameter limited schedule.

- For the 2014/2015 through 2017/2018 Delivery Years, PJM will define a list of minimum acceptable operating parameters for Generation Capacity Resources other than Capacity Performance Resources, and for the 2018/2019 Delivery Year for generation resources of FRR Entities not committed as Base Capacity Resources or Capacity Performance Resources, based on an analysis of historically submitted offers, for each unit class for the following parameters:
    - Turn Down Ratio
    - Minimum Down Time
    - Minimum Run Time
    - Maximum Daily Starts
    - Maximum Weekly Starts

- For the 2016/2017 and subsequent Delivery Years for Capacity Performance Resources, and for the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, the list of minimum acceptable parameters will consist of the following parameters:
    - Turn Down Ratio
    - Minimum Down Time
    - Minimum Run Time
    - Maximum Daily Starts
    - Maximum Weekly Starts
    - Maximum Run Time
    - Start Up Time

- Notification Time

- For the Delivery Years up to an including of the 2017/2018 Delivery Year, the limits set forth in the Parameter Limited Schedule Matrix shall apply to Generation Capacity Resources, other than Capacity Performance Resources, and for the 2018/2019 Delivery Year for generation resources of FRR Entities not committed as Capacity Performance Resources or Base Capacity Resources, unless the generation resource is operating pursuant to an exception from the default values due to physical operational limitations that prevent the resource from meeting the minimum parameters. The Parameter Limited Schedule Matrix is found in Section 6.6(c) of Attachment K-Appendix of the Tariff and the parallel provision of Schedule 1 of the Operating Agreement found at: http://www.pjm.com/documents/agreements.aspx.

- For the 2018/2019 and 2019/2020 Delivery Years for Base Capacity Resources, and the 2016/2017 Delivery Year and subsequent Delivery Years for Capacity Performance Resources, PJM will determine for each such resource its unit-specific parameter limits based on the operating design characteristics and other constraints of that resource. The resource's unit-specific parameter limits will apply for that resource unless it is operating pursuant to an exception from those limits under section 6.6(h) of Attachment K-Appendix of the Tariff and the parallel provision of Schedule 1 of the Operating Agreement due to operational limitations that prevent it from meeting the minimum resource parameters.

- Market Sellers that do not believe their individual resources can meet the unit-specific parameter limits determined by PJM due to actual operating constraints, can request that PJM establish adjusted unit-specific parameter limits for those resources. The Market Seller may request adjusted unit-specific parameter limits by providing all the necessary data, information and documentation to PJM in order to justify and support the adjusted unit-specific parameter limits at unitspecificpls@pjm.com by no later than the February 28 immediately preceding the first Delivery Year for which the adjusted unit-specific parameter limits are requested to commence, and provide technical information about the operational limits that support the requested adjustment. PJM shall notify the Market Seller if its request was approved or denied by no later than April 15. The effective date of the requested parameter shall be no earlier than June 1 of the first applicable Delivery Year. PJM will consult with the Market Monitoring Unit and consider any input received in its determination of a resource's unit-specific parameter limits.

- Once PJM has made a determination of the unit-specific parameter limited schedule values for a Generation Capacity Resource, those values will remain applicable to the resource until such time as the Office of the Interconnection determines that a change is needed based on changed operational capabilities of the resource.

- The operational limitations that support adjusted unit-specific parameter limits shall be (a) physical operational limitation based on operating design characteristics of the

resource, or (b) other actual physical constraints that are not based on the characteristics of the resource, including contractual limitations. For a contractual limit to be considered a physical constraint which the Market Seller should be permitted to reflect in its unit-specific parameter limits for the resource, and not an economic constraint which should not be taken into consideration in the determination of the unit-specific parameter limits for that resource, the contractual limit must be based on a natural gas pipeline transportation contract that is for the best available service offered by the pipeline and available to the Market Seller rather than a lower cost option that provides less flexible service. For example, if a pipeline offers hourly nominations and/or no notice service, the resource's operational parameters will be based on those more flexible services that are available even if a less flexible service is procured.

- Only actual physical operational limitations, fuel contractual constraints, environmental limitations and other actual constraints on a resource will be considered for adjustment requests. The following list is not an exhaustive list, but provides examples of the types of information and documentation PJM would request to support adjusted unit-specific parameter limits requests:
    - Start Up Time adjustments –OEM (Original Equipment Manufacturer) backup documentation, control room data, startup/loading curves and a detailed start-up sequence listing the required steps along with the time required to perform each step.
    - Maximum Daily/Weekly Starts adjustments –OEM backup documentation and/or detailed start-up and shutdown sequences that show why the default start parameters cannot be physically met.
    - Minimum Run Time adjustments –OEM backup documentation for physical unit constraints that requires the unit to be operated for the requested time period.
    - Minimum Down Time adjustments - OEM backup documentation and a detailed shut down sequence listing the required steps to bring the unit into a ready for startup condition along with the time required to perform each step.
    - Notification Time Adjustment –A detailed sequence of events of the tasks required prior to startup along with the time required to perform each step. In addition gas pipeline contracts may be submitted for review.
    - Turn Down Ratio Adjustments –Requests for adjustments to this parameter based on physical equipment limitations should include OEM backup documentation describing the equipment limitation. Requests for adjustments to this parameter based on emissions permit limitations and related concerns will require inclusion of the applicable Air Permit as well as emissions data for justification.

- There are three different types of exceptions to the Parameter Limited Schedule Matrix default values:

- **Temporary Exception –** is a one-time exception lasting for 30 days or less during the twelve month period from June 1 to May 31.

- **Period Exception –** is an exception lasting for at least 31 days but no more than one year **during** the twelve month period from June 1 to May 31.

- **Persistent Exception –** is an exception lasting for at least one year.

- For the Delivery Years up to and including the 2018/2019 Delivery Year, the MMU shall review the Parameter Limited Schedule Matrix, included in Section 6.6(c) of Attachment K-Appendix of the Tariff and the parallel provision of Schedule 1 of the Operating Agreement, annually, and, in the event it determines that revision is appropriate, shall provide a revised matrix to PJM by no later than December 31 that occurs immediately prior to the commencement of the applicable Delivery Year. Pursuant to section II.B of Attachment M – Appendix of the Tariff, period and persistent exception requests must send to Parameters.Exceptions@pjm.com by no later than February 28 immediately preceding the twelve month period from June 1 to May 31 during which the exception is requested to commence. All market sellers that wish to submit a Parameter-Limited Schedule for units with physical operational limitations that prevent the units from meeting the minimum parameters may submit a request for an exception via Markets Gateway for evaluation. Each market seller seeking an exception must supply the required historical unit operating data in support of the period or persistent exception and if the exception requested is based on new physical operational limits for the resource for which historical operating data is unavailable, the generation resource may also submit technical information about the physical operational limits for period exceptions of the resource to support the requested parameters.

- Physical operational limitations for period or persistent exceptions may include but are not limited to, metallurgical restrictions due to age and long term degradation; physical design modifications; operating permit limitations; operating limits imposed by federal, state or local regulatory requirements or insurance carrier requirements; consent decrees; manufacturer technical bulletins; or environmental permit limitations under non-emergency conditions. Each market seller requesting a period or persistent exception based on new physical operational limitations for a unit may submit the technical information, required due to the unavailability of historical operating data, supporting the requested parameters, which must be based on the definition of physical operational limitations for period or persistent exceptions of the unit. Each temporary, period or persistent exception request will indicate the expected duration of the requested exception including the date on which the requested exception period will end. If physical conditions at the unit change such that the exception is no longer required, the market seller is obligated to inform PJM

and the MMU and the exception will be reviewed to determine if the exception continues to be appropriate.

- If a request for a period or persistent exception is received by February 28, the MMU will review the exception and provide the Market Seller and PJM with a determination in writing whether the request raises market power concerns by April 1, and PJM shall provide its determination whether the request is approved or denied by no later than April 15. Should PJM require additional technical expertise in order to evaluate the exception request, PJM will engage the services of a consultant with the required expertise. A generation resource shall notify the MMU and PJM when the temporary exception commences and terminates and provide to the MMU and PJM within three days following such commencement documentation explaining in detail the reasons for the temporary exception, that includes:
    - Unit Name
    - Parameter Limit Requested
    - Reason for Temporary Exception Request
    - eDart ticket
    - Justification for Temporary Exception Request, including required unit operating data in support of the exception
    - Date on which the exception period will end.
- Market Seller can communicate the resource's current operational capabilities to PJM before and after Day-ahead Energy Market closes through 'Real Time Values' functions on Markets Gateway.
    - Real Time Values should be utilized when a resource cannot operate according to the unit specific parameters (Capacity Performance and Base Capacity resources), default Parameter Limited Schedules (non-Capacity Performance resources), or approved Parameter Limit exceptions.
    - The Real Time Values consist of the following values:
        - Turn Down Ratio
        - Minimum Down Time
        - Minimum Run Time
        - Maximum Run Time
        - Start Up Time
        - Notification Time
    - A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for

such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit -specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection (unitspecificmakewhole@pjm.com) its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

- If PJM does not receive a complete exception request, and the unit did not clear in the Day-ahead Energy Market, the unit schedule will returned to its previous parameter limits.

- Physical operational limitations for temporary exceptions may include, but are not limited to, short term equipment failures, short term fuel quality problems such as excessive moisture in coal fired units, or environmental permit limitations under non-emergency conditions.

- Market Sellers may use exceptions to reflect physical operational limitations (e.g., operational flow orders) on natural gas pipelines and local natural gas distribution companies (LDC). These exceptions will be reviewed by PJM and the MMU and approved by PJM, in accordance with the applicable provisions of the Tariff and Operating Agreement.

- In addition, physical operational limitations for temporary exceptions may include any physical operational limitation for period exceptions that arises during the annual period from June 1 to May 31 to which period exceptions apply.

- For steam units, regardless of fuel type, the average historical values for any of the parameters as offered by the owners for the calendar year 2006 may be used in place of the values in the parameter-limited schedule matrix. For steam units, regardless of fuel type, the historical averages are calculated from the market based

offers for market based units and from cost-based offers for units that made only cost-based offers.

- For combined cycle units:
  - If the 2006 average historical market-based offer parameters are within the limits in the parameter matrix, the unit will be limited to that 2006 historical average. If not then ii) applies;
  - If the unit was offered with market-based offer parameters for 10% or more of the days (36 days minimum) at a level at or more flexible than parameters in matrix, the unit will be limited at that level. If not the iii) applies
  - If the 2006 average historical market based offer parameters exceed the limits in the matrix (less flexible than the parameters in the matrix) then the unit will be limited to the level at which the market-based parameter was bid to the most flexible level for 10% or more of the days (36 days minimum) at that level.
- If physical conditions at the unit change such that the exception is no longer required, the market seller is obligated to inform PJM and the MMU and the exception will be terminated.
- Market sellers may indicate to PJM and the MMU those units with the ability to operate on multiple fuels. Multiple-fuel units may submit a parameter-limited schedule associated with each fuel type. All Parameter-Limited Schedules must be submitted via Markets Gateway seven days prior to the beginning of each period beginning June 1. Any exceptions required for any of the parameter-limited schedules submitted for multiple-fuel units will be required to be submitted and approved via the exception process, by the applicable deadlines.
- Nuclear Units are excluded from eligibility for Operating Reserve payments except in cases where PJM requests that nuclear units reduces output at PJM's direction or where a physical problem at a nuclear unit requires a risk premium and that risk premium is submitted to and accepted by the MMU. Other specific circumstances will be evaluated on a case-by-case basis by PJM and the MMU.
- Market Sellers shall notify in writing the MMU and the PJM of a material change to the facts relied upon by the MMU and/or the PJM to support a temporary, period or persistent exception. MMU will provide written notice of any change to its determination regarding the exception request within 15 days of receipt of such notice to PJM and the Market Seller. PJM will notify the Market Seller and MMU in writing, by no later than 20 days after receipt of the Market Seller's notice, whether it is revoking or confirming its approval of the exception request.
- If PJM determines that its approval of the exception should be revoked or terminated, (1) for Generation Capacity Resources that are not Base Capacity Resources or

Capacity Performance Resources the default values specified in the Parameter Limited Schedule Matrix shall apply, (2) for Base Capacity Resources and Capacity Performance Resources without approved adjusted unit-specific values, the unit-specific values determined by PJM shall apply, and (3) for Base Capacity Resources and Capacity Performance Resources with approved adjusted unit-specific values, the adjusted unit-specific values shall apply. PJM shall notify the market seller 3 business days before such revocation.

2.3.4A External Bilateral and Up-to Congestion Transactions

The following business rules apply to Transmission Customers:

- 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.

- 'Up to' congestion bids shall be no greater than $50/MWh, and no less than -$50/MWh. Any 'up to' congestion transaction that bids higher than $50/MWh or less than -$50/MWh will be rejected.

- PJM will maintain an up-to date list of source/sink combinations that will be available for 'Up to 'congestion bidding on the PJM OASIS.

- Internal bilateral transactions may be designated as day-ahead or balancing market in PJM InSchedule.

- Up-to congestion bids, increment offers, and decrement bids shall be supported in the Day-ahead Market only.

- 'Up to" congestion bids are cleared based on the total LMP price difference between the source and the sink.

- PJM may require that a market participant shall not submit in excess of 3000 'up to' congestion transactions in the Day-ahead Energy Market, when PJM determines that such limit is required to avoid or mitigate significant system performance problems related to the volume of transactions.

2.3.5 Curtailment Service Providers

The business rules that apply to Curtailment Service Providers are set forth in Section 10.

2.3.6 PJM Activities

The following business rules apply to PJM activities:

- PJM shall post on the Markets Gateway System, the PJM load forecast, total bid demand, and Day-ahead Scheduling Reserve (Operating Reserve) objective for each hour of the next Operating Day by 1330 at the completion of the day-ahead scheduling process.

- PJM shall post forecasts of total hourly demand for the next four days and peak demand for the subsequent three days.

- PJM shall post hourly LMP, Congestion Price, and Loss Price values for the next operating day at the completion of the day-ahead scheduling process by 1330.

- PJM shall post the schedule of demand, supply, and bilateral transactions for private viewing by market participants.

- PJM may perform supplemental resource 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.

- During the various resource 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.

- PJM Market Operators will commit in the Day-ahead Market any generation resources that were scheduled by PJM dispatch in advance of the Day-ahead Market and are still required for the operating day and therefore not cancelled. The scheduled hours for the pre-committed generation resource in the Day-ahead Market will at least include the hours where PJM dispatch has scheduled the resource as well as any additional hours where the resource was deemed to be economic as a result of the Day-ahead Energy market solution.

- PJM's market power mitigation procedure continues under the energy market procedure. If transmission limits are identified during the day-ahead scheduling process or during real-time operations, the appropriate generators (those for which the owner fails the Three-Pivotal Supplier Test as detailed in Section 6.4.1 paragraphs (e) and (f) of the PJM Operating Agreement) are offer-capped.

- Units are offer-capped at lesser of their cost-based or price-based schedules, including start-up and no-load components. Specific details regarding determination of cost-based offers may be found in PJM Manual M-15 (Cost Development Guidelines) and Section 6.4.2 of the PJM Operating Agreement.

- For the Day-ahead Market, the offer caps will apply for the length of time the unit is scheduled.

- Non-CT units offer-capped in the Day-ahead Market will be offer-capped in the real-time market.

- Units offer-capped in the real-time market shall remain offer-capped until the unit's minimum run time is exhausted. Once the minimum run time for a particular unit expires in the real-time market, if that unit is no longer needed to control any of the constraints for which it was originally started but the unit is kept on-line, the decision as to whether the unit remains offer-capped will be made as follows:
  - If PJM needs the unit for economics (on its price-based offer) and the unit is not required to relieve a current or anticipated constraint, the unit will be un-capped.
  - If released by PJM, any subsequent offer-capping decision for a unit will be determined by the Three-Pivotal Supplier Test.
  - Units remain eligible to set LMP when offer-capped.

- Units brought on-line for economics prior to constrained conditions will not be offer-capped.

- 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).

- Price-sensitive demand can set LMP in the Day-ahead Market.

- Participants can submit PRD Curves per business rules in Section 12 of this manual.

2.3.7 Mechanical/Technical Rules

A valid generator offer consists of the following elements:

For a Generation Capacity Resource a valid generator offer consists of a parameter limited price-based schedule (if the unit is price-based) and at least one cost-based schedule. The default values for the schedules are:

- Day-ahead Market switch is yes (1).

- Balancing market switch is yes (1).

- Use start-up & no-load switch is yes (1).

- Use offer slope switch is 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.
- For a non-Capacity Resource, a valid generator offer consists of a price-based schedule (if the unit is price-based) and at least one cost based schedule. The default values for the schedules are:
    - Day-ahead Market switch is yes (1).
    - Balancing market switch is yes (1).
    - Use start-up & no-load switch is yes (1).
    - Use offer slope switch is 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.

- External resources can only submit start up and no load costs if the entire output of the unit is available for PJM dispatch

- Valid offers for demand bids, price sensitive and fixed, consist of the following items:
  - MW, with a default value of 0 MW. Demand bids should not include losses.
  - Location (transmission zone, aggregate, or single bus)
  - Price at which demand shall be curtailed (for price-sensitive bids)
  - PJM shall apply Demand Bid Screening to all Demand Bids submitted in the Day-Ahead Energy Market for each LSE, separately by Zone. PJM will automatically reject a LSE's Demand Bids if the total MW volume of such bids exceeds the LSE's Demand Bid limit for any hour in such Operating Day.
  - On a daily basis, PJM will update and post each LSE's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that LSE for each future Operating Day for which it submits bids.
  - The Demand Bid Limit is calculated using the following equation:

    Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

    Where:

    - Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE's Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
    - LSE's Recent Load Share is the LSE's highest share of Network Load in each Zone for any hour over the previous seven Operating Days.
    - Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.
  - PJM may allow a LSE to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a LSE's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members.
  - A LSE whose Demand Bids are rejected as a result of Demand Bid Screening may change the Demand Bids to reduce the total megawatt volume to a level that does not exceed the Demand Bid Limit. Re-submissions must occur prior to Market closing for the operating day.

2.3.8 Modeling

Fixed transactions, including increment offers and decrement bids, are modeled in the Resource Commitment. Up-to congestion transactions are not modeled in the commitment, but are handled in the day–ahead dispatch.

The day-ahead security analysis treats increment offers as injections (generation) and decrement bids as withdrawals (loads)

External bilateral transactions with source = interface bus are modeled as generation at the source bus location. This is the case for both dispatchable and non-dispatchable transactions.

External bilateral transactions with sink = interface bus are modeled as a load at the sink bus location. This is the case for both dispatchable and non-dispatchable transactions.

Only fixed transactions and transactions involving external aggregate resources are modeled in the Resource Commitment (RSC) for the Day-ahead Market.

2.3.9 Day-ahead Locational Marginal Price (LMP) Calculations

The following resources are eligible to set LMP values in the Day-ahead Market:

- All pool-dispatchable steam units
- Pool-scheduled CTs and diesels
- Dispatchable external resource offers
- Increment offers
- Committed Economic Load Response bids
- Price-sensitive demand bids and decrement bids.
- Transactions that bid ‘up to’ congestion charges Settlements Data Requirements can be found in M28: Operating Agreement Accounting.
- Generation resources with cost based incremental energy offers in excess of $2,000/MWh will be dispatched in economic merit order but will be capped at $2,000/MWh for the purposes of calculating LMP.

2.3.10 Operating Parameter Definitions

Cold/Warm/Hot Notification Time - The time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot

temperature state. Start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time - The time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero for a generating unit in its cold/warm/hot temperature state. For a Combined Cycle unit it is the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero. Start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Other more detailed actions that could signal the beginning of the start sequence could include but are not limited to the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Minimum Run Time (hour) - The minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero to the time of generator breaker opening, as measured by PJM's state estimator. For Combined Cycle units this is the time period after the first combustion turbine generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero and the last generator breaker opening as measured by PJM's state estimator.

Turn Down Ratio – The ratio of a unit's economic maximum MW to its economic minimum MW.

Minimum Down Time (hour) - The minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated state estimator MWs greater than zero. For Combined Cycles units this is the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero.

Maximum Daily Starts - The maximum number of times that a unit can be started in an operating day under normal operating conditions.

Maximum Weekly Starts - The maximum number of times that a unit can be started in one week under normal operating conditions (168 hour period starting Monday 0001 hour).

Maximum Run Time (hour) - The maximum number of hours a unit can run over the course of an operating day as measured by PJM's state estimator.

Cold/Warm/Hot Soak Time - The minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero to the time the unit is dispatchable. For Combined Cycle units this is the minimum number of hours from the time just after the first combustion turbine generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero and the time the unit is dispatchable.

Soak Time may include items such as the time necessary to alleviate temperature gradients across boiler or turbine components, the startup and stable operation of environmental equipment, water chemistry evaluations and holds, the maintaining of stable fuel/air ratios, the addition of incremental fuel related or other auxiliary equipment, the starting additional combustion turbines in a combined cycle, and the pressure matching of heat recovery steam generators.

2.4 Real-Time Locational Marginal Price (LMP) Calculations

The PJM Real-time Locational Marginal Price (LMP) calculation process consists of several programming modules that are executed as part of the real-time sequence. The real-time sequence executes every five minutes. In the Market Clearing Engine (MCE), the following systems are used in the calculation of the real-time LMP and ancillary service market clearing prices:

- The Real Time Market Applications (ASO, IT SCED and RT SCED)
- PJM State Estimator
- Locational Pricing Calculator (LPC)

Each of the PJM LMP modules is described in detail below.

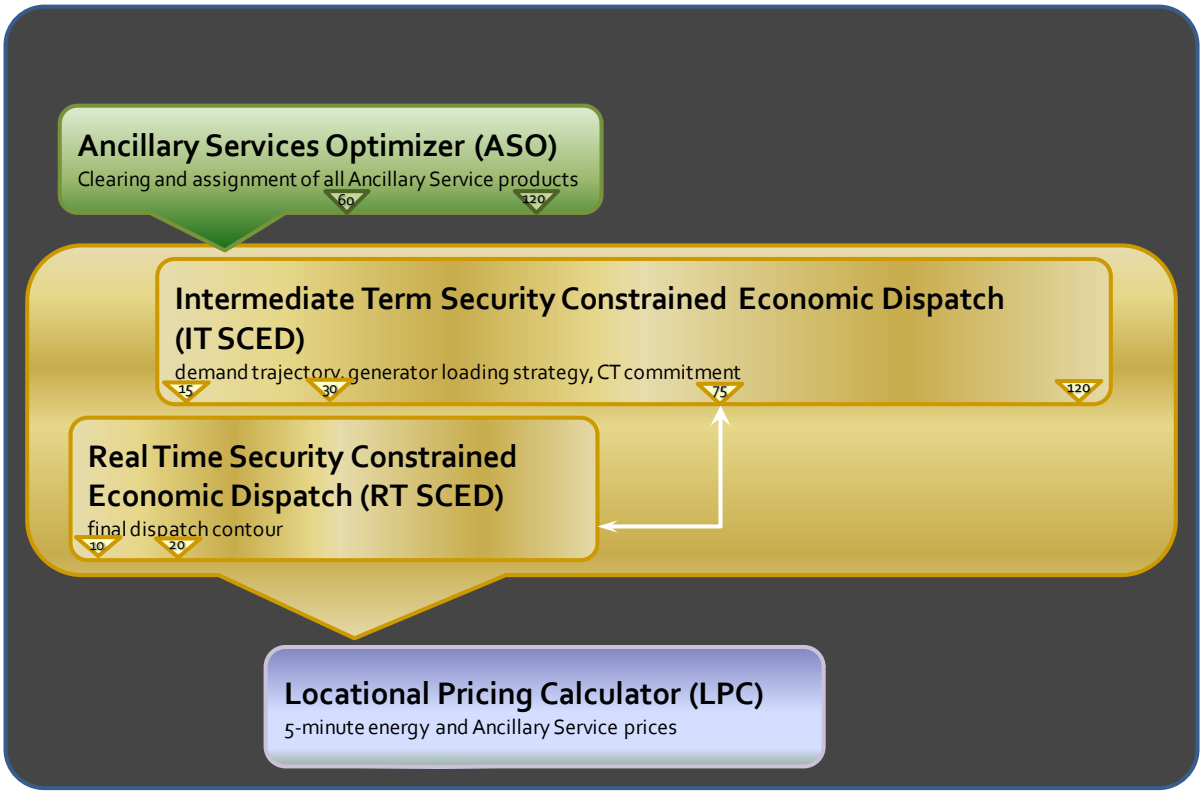
2.5 Real-Time Market Applications

To conduct the real-time markets, a multi-module software platform is used by PJM to dispatch energy, and ensure adequate reserves in real-time and regulation in near time. The applications jointly optimize the products on a 5-minute basis to ensure that all system requirements are met using the least cost resource set. The real-time market applications consistent of the following:

- **Ancillary Service Optimizer (ASO):** The Ancillary Services Optimizer (ASO) performs the joint optimization function of energy, reserves and regulation. The ASO creates an interval-based solution over a one hour look-ahead period, as well as performs the regulation three pivotal supplier test. ASO does not calculate market

clearing prices. The main functions of ASO are the commitment of all regulation resources and inflexible reserve resources for the next operating hour.

- **Intermediate Term Security Constrained Economic Dispatch (IT SCED):** The Intermediate Term Security Constrained Economic Dispatch (IT SCED) application is used by PJM to perform various functions over a 1-2 hour look-ahead period. Historical and current system information is used to anticipate generator performance to various requests, and to provide accurate information regarding generator operating parameters under multiple scenarios. The IT SCED solves a multi-interval, time-coupled solution to perform the following functions:
    - Calculate energy dispatch trajectory for use in real-time dispatch
    - Resource commitment recommendations for energy and reserves
    - Resource commitment decisions for economic demand resources
    - Execution of the Three Pivotal Supplier Test for energy
- **Real-Time Security Constrained Economic Dispatch (RT SCED):** The Real-Time Security Constrained Economic Dispatch (RT SCED) application is responsible for dispatching resources to maintain the system balance of energy and reserves. Historical and current system information is used to anticipate generator performance to various requests, and to provide accurate information regarding generator operating parameters under multiple scenarios. RT SCED will jointly optimize energy, regulation and reserves on online, dispatchable resources to ensure system needs are maintained. The results from the RT SCED are energy basepoints and Tier 2 and Non-Synchronized reserve commitments that are sent to resource owners in real-time. All quantities may change with each solution based on system economics and reserve needs. RT SCED determines reserves shortages.



The real time market applications and various other applications communicate jointly and the most recent information from each application is stored and upon request provides the relevant data to each application. To run the real-time market, data is processed from the markets database and other PJM systems. A dispatch solution is executed automatically every five minutes or when executed by the operator. To calculate the solution, data from multiple sources is used, including but not limited to, data regarding online and available resources, resource offers, forecasted load, scheduled and current interchange, as well as various other input parameters.

Real-time data sources include:

- Load forecast data from EMS
- Constraint data - resource sensitivities from EMS
- State Estimator output from EMS
- Outage data from eDART
- Transaction data from ExSchedule

Multiple cases are then produced, with each solution solving the security constrained economic dispatch problem. Each of these solution cases contains:

- A recommended set of zonal dispatch rates
- A list of exceptions to the dispatch rates for constraint control
- Individual resource dispatch rates
- Individual Resource Desired MW level
- Individual Resource Reserve Commitments

Embedded within the IT SCED and RT SCED are reserve demand curves for each product in each modeled location that are used to articulate the value of maintaining each reserve requirement and ensure product substitution between energy and reserves up to the specified penalty factor. For example, if the penalty factor for synchronized reserves is $100/MWh, resources with merit order prices that exceed the penalty factor will still be committed but the clearing price will be capped at the penalty factor. Such resource will be compensated additionally after the fact to the true cost to provide the service. Additionally, the penalty factor provides a clear indicator of the reserve position of the RTO and modeled Reserve Sub-zones. As the price of either reserve product increases to value near the penalty factor, it indicates to market participants that the system is nearing a reserve shortage. This provides market participants an advanced signal indicating a potential reserve shortage.

- Reserve Demand Curves and Penalty Factors
- Separate demand curves exist for the Synchronized Reserve and Primary Reserve requirements. These demand curves apply to both the RTO and Mid-Atlantic Dominion (MAD) reserve requirements.
- Under normal operating conditions, each reserve demand curve is a single step function at the price of the penalty factor at the value of the requirement for the specific product.
- Under Hot Weather Alert, Cold Weather Alert or escalating emergency procedures as defined in Manual M-13, each reserve demand curve becomes a two-step function if additional resources are brought online by PJM dispatch to account for operational uncertainty after the second resource commitment which occurs after 18:00 the day prior to the Operating Day. The first step is defined as described above. The second step is defined at a lower penalty factor than the first step and at an extended reserve requirement quantity. The calculation of the extended reserve

requirement is defined in Section 4.2.2, Synchronized Reserve Requirement Determination.

- The penalty factors shown below will be used for the dates specified. The penalty factors are the same for each product and location where a reserve requirement exists.

Start Date	End Date	Synchronized Reserve Penalty Factor ($/MWh)		Primary Reserve Penalty Factor ($/MWh)	
		1st Step on Demand Curve	2nd Step on Demand Curve	1st Step on Demand Curve	2nd Step on Demand Curve
June 1, 2012	May 31, 2013	250	N/A	250	N/A
June 1, 2013	May 31, 2014	400	N/A	400	N/A
June 1, 2014	May 31, 2015	550	300	550	300
June 1, 2015		850	300	850	300

- PJM will review the penalty factors used on an annual basis to ensure that they permit PJM Operators to fully utilize all assets on the system and accurately value each product.

2.6 PJM State Estimator

The Real-time LMP calculation depends upon having a complete and consistent power flow solution as input. This input requirement can be achieved by using a state estimator. The state estimator is a standard power system operations tool whose purpose is to provide a base case power flow solution for input into other computer programs.

The state estimator uses actual operating conditions that exist on the power grid (as described by metered inputs) along with the fundamental power system equations to calculate the remaining flows and conditions that are not metered. Since the state estimator solution provides a complete and consistent model of actual operating conditions based upon observable (metered) input and an underlying mathematical model, it can be used to provide the basis for the Locational Marginal Price calculations.

The inputs to the state estimator are the available (metered) real-time measurements, the current status of equipment (lines, generators, transformers, etc.), and the bus load distribution factors.

This standard industry tool depends upon data redundancy and the underlying physical and mathematical relationships of the power system to provide a solution with less error than the original measurements. Therefore the state estimator can correct “bad data” and calculate missing data in the model to provide a consistent representation of existing network conditions.

The PJM state estimator is run on a thirty-second cycle and can provide the following inputs to the PJM LMP Model, on a five-minute basis:

- AC power flow solution
- Actual generator MW output
- Bus loads
- Tie line flows
- MW losses by transmission zone
- Actual MW flow on any constrained transmission facility

2.7 Locational Pricing Calculator (LPC)

The function of the Locational Pricing Calculator (LPC) is to determine the Real-Time LMP values and Ancillary Service clearing prices on a five minute basis. The LPC calculates LMPs for each of the PJM nodes in the state estimator model and for interface busses used as a proxy for transfers to and from PJM and external control areas. The Real-Time LMPs are defined as the cost to serve the next increment of load at each node bus location for the current system, taking into account eligible resource real-time offer prices and the buses’ location with respect to transmission limitations and incremental system losses.

The LPC is an incremental linear optimization program that is formulated to jointly optimize and price energy and reserves. The objective is to minimize the cost function including the cost of energy and reserves subject to the power balance constraint, the Synchronized and Primary Reserve requirements, specific generator and demand resource operating limitations, transaction MW limits, and any transmission constraints that currently exist on the system and a normalized distribution of system losses to a network location.

Every 5 minutes the LPC will calculate:

- Locational Marginal Prices (LMPs)
- Synchronized Reserve Market Clearing Prices (SRMCPs)

- Non-Synchronized Reserve Market Clearing Prices (NSRMCPs)

- Regulation Market Clearing Prices (RMCPs) and Regulation Market Performance Clearing Price (RMPCP), which are then used to derive the Regulation Market Capability Clearing Price (RMCCP)

Each energy and reserve clearing price is calculated as the cost to serve the next MW of demand for each individual product considering its impact on the others. For example, LMPs are calculated such that they reflect the cost to serve the next MW of energy demand in each location while considering the impact of that additional MW of energy on the ability to meet the Primary and Synchronized Reserve requirements. This method of calculation of LMPs is consistent with the joint optimization of energy and reserves performed and will ensure consistency between LMPs and dispatch directives. Regulation clearing prices are calculated as the cost of the last resource committed to meet the Regulation requirement, as further described in section 3.

2.7.1 Determination of LMPS for De-Energized Busses

Due to equipment outages, the main transmission system may contain some de-energized busses for which LMPs cannot be directly calculated. It is necessary for settlement purposes that LMPs for these de-energized busses be established. The methodology for determining LMPs at de-energized busses is to assign to them the LMPs at their neighboring energized busses. The following criteria for a search is designed and implemented in the market clearing software.

Search rules:

1. Search at the same voltage level.

    - Check whether any of the other busses belonging in the same voltage level as the de-energized bus is energized. If an energized bus is found, set the LMP of the de-energized bus equal to the LMP of the energized bus. If a suitable replacement cannot be found, proceed to step 2.

2. Search at the same station.

    - Check whether there are any energized busses located at a voltage level different from the de-energized-bus voltage level but at the same station. If an energized bus is found, set the LMP of the de-energized bus equal to the LMP of the energized bus. If a suitable replacement cannot be found, proceed to step 3.

3. Search in the nearest neighboring stations.

    - Rank all the transmission lines out of the de-energized bus station in the descending order of their admittances.

- Check whether there is any energized bus in the next station available in the rank. If one is found, set the LMP of the de-energized bus equal to the LMP at the energized bus.

If by searching all the neighboring stations no energized bus is found, the PJM Market Operator will be notified that a de-energized bus exists for which no suitable replacement could be found using the above steps and will be required to manually search for a suitable replacement. PJM operators will also review the suitability of the replacements selected by the market clearing software, and in cases where modeling discrepancies cause the selection of a sub-optimal replacement, may elect to use a more suitable replacement.

2.7.2 Determination of LMPs for Generation Resources with offers greater than $2,000/MWh

Generation resources with cost based incremental energy offers in excess of $2,000/MWh will be dispatched in economic merit order but will be capped at $2,000/MWh for the purposes of calculating LMP.

2.8 The Calculation of Locational Marginal Prices (LMPs) During Emergency Procedures

In order to properly calculate LMPs during Emergency Procedures, PJM will perform the following functions to ensure that deployed or purchased emergency capacity is eligible to set LMPs within PJM.

- Pre-Emergency and Emergency Demand Response
  - Pre-Emergency or Emergency Demand Response may be deployed by lead time, by product, and by transmission zone or transmission subzone.
  - PJM will dispatch the resources of all Pre-Emergency or Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the availability, location, dispatch price and/or quantity of load reduction needed, subject to transmission constraints in the PJM Region.
- To give PJM dispatchers the flexibility to address reliability concerns in the most effective and timely manner and invoke the resources that offer the most assurance of effective relief of emergency conditions, the dispatch of Demand Resources may not be solely based on the least-cost resources since such dispatch shall be based not only on price, but also on availability, location and/or quantity of megawatts of load or load reduction needed.
  - Resources in the Full Program Option and Energy Only Option in the Pre-Emergency or Emergency Load Response Program are eligible to set the real

time LMP when PJM has dispatched the resources and such resources are required to reduce demand in the PJM Region.

  - PJM will treat pre-emergency and emergency demand response similar to a dispatchable generator for the purpose of determining whether it is marginal.

- PJM will use operational data submitted by CSPs to determine the availability and actual response of pre-emergency and emergency load response.

- Maximum Emergency Generation
  - Generators who have designated all or portions of the output of their unit as max emergency will be eligible to set price.
  - Max emergency output will only be eligible to set LMP if PJM Operators have loaded maximum emergency generation.

- Emergency Purchases
  - PJM will allow emergency purchase transactions to set LMP to the extent they are required to clear the energy and reserve markets.
  - Emergency purchases will be treated similar to the dispatchable generator for the purpose of determining whether they are marginal or not.
  - If determined to be marginal, an emergency purchase will set price at the lesser of its offer price or the applicable offer cap stated in Section 2.3.2.

In the event that PJM initiates a voltage reduction or manual load dump to maintain system reliability:

- All reserve clearing prices in the region where the voltage reduction and/or manual load dump were initiated will be set consistent with a shortage of the first step on the demand curve.
  - Non-Synchronized Reserve Clearing Price = Primary Reserve Penalty Factor
  - Synchronized Reserve Clearing Price = Primary Reserve Penalty Factor + Synchronized Reserve Penalty Factor

The LMPs and reserve clearing prices in the location that the voltage reduction and/or manual load dump was initiated will be calculated consistent with all reserve products in that region being short until such emergency conditions are terminated as defined in PJM Manual 13: Emergency Operations.

Shortage pricing will be terminated in a Reserve Zone or Reserve Sub-zone when demand and reserve requirements can be fully satisfied with generation and demand resources and

any Voltage Reduction Action and/or Manual Load Dump Action taken for that Reserve Zone or Reserve Sub-zone has been terminated.

2.9 The Calculation of Locational Marginal Prices (LMPs) During Reserve Shortages

When all reserve products can be met at a price less than or equal to the defined penalty factors, LMPs will be set solely using the supply and demand offers from Market Participants. When PJM cannot maintain enough reserves to meet the reserve requirements at a price less than or equal to the associated penalty factors, i.e. a reserve shortage, the penalty factor(s) for the deficient reserve product(s) will be used in the determination of LMPs in the region where the shortage occurred.

- The methodology for calculating LMPs is consistent during periods of adequate reserves and during reserve shortages.
- When reserve requirements can be met at a price less than or equal to the defined penalty factors, the penalty factors will not impact the calculation of LMPs.
- When any reserve requirement cannot be met - at a price less than or equal to the defined penalty factor, the applicable penalty factor(s) will be used in the determination of LMPs.
- The maximum LMP achievable during a reserve shortage is the $2,000/MWh energy offer cap, plus the primary and synchronized reserve penalty factors from the first step on the demand curves, plus or minus congestion and marginal loss impacts.

2.9.1 Determination of a Reserve Shortage

If the Real-Time Security Constrained Economic Dispatch (RT SCED) application forecasts a Primary Reserve shortage and/or a Synchronized Reserve shortage as further described in the Section (s) 2.5 and 2.8 of this Manual, PJM shall deem this to be a Primary Reserve shortage and/or a Synchronized Reserve shortage and shall implement shortage pricing through the inclusion of Primary Reserve and/or Synchronized Reserve Penalty Factors in the Real-Time market applications.

Shortage pricing shall exist until the Real-Time Security Constrained Economic Dispatch (RT SCED) solution is able to meet the specified reserve requirements and no Voltage Reduction Action or Manual Load Dump Action is still in effect.

If a Primary Reserve shortage and/or Synchronized Reserve shortage exists and cannot be accurately forecasted by the Office of the Interconnection due to a technical problem with or malfunction of the Real-Time Security Constrained Economic Dispatch (RT SCED) software program, including but not limited to program failures or data input failures, PJM will utilize

the best available alternate data sources to determine if a Reserve Zone or Reserve Sub-zone is experiencing a Primary Reserve shortage and/or a Synchronized Reserve shortage.

The Office of the Interconnection shall submit to the Federal Energy Regulatory Commission, for informational purposes, a status report within sixty (60) days of the occurrence of a false positive or actual Primary Reserve shortage and/or a Synchronized Reserve shortage.

2.10 PJM Real-time Locational Marginal Price Verification Procedure

During and after each Operating Day, PJM reviews all of the five minute LMP and ancillary service clearing prices prior to finalizing hourly LMPs for posting and use in settlement. If there are any instances where five minute LMPs and ancillary service clearing prices were calculated inaccurately, PJM corrects those five minute intervals in the LMP Verification Procedure. In the event of a data input failure, program failure, data input discrepancy or logging error, corrective actions may be taken to ensure that the resulting Real-time LMPs are as accurate as is reasonably obtainable.

- Data Input Failures (Stale cost data, stale dispatch rates, stale EMS data) or Program Failures (State Estimator failure, LPC Failure, Constraint logger failure) - Data input failures can occur when telecommunication problems exist either on the PJM computer network or on the data lines between PJM and PJM member companies. If failures occur within PJM's network, all possible steps will be taken to recover the original data for use in LMP calculation reruns. In the event of a program failure, an attempt will first be made to correct the reason for the failure and to recalculate LMP values for the affected intervals. If the failure cannot be corrected (due to a data input failure), and the original data cannot be recovered, PJM may utilize data from the best available alternate data sources including, but not limited to, backup systems, dispatcher logs, raw telemetry data, and member company data sources. In the event of a data input or program failure, LMP replacements will be performed as outlined below:
    - If the stale data or program failure exists for less than 6 intervals within the same hour then the affected intervals may be replaced with data from the last successful interval.
    - If the stale data or program failure exists for more than six intervals within the same hour then
    - the LMP values will be recalculated using data from the best available sources.
- *Logging Errors (Transmission constraint logging, CT logging)* – The reference for logging times is the transmission dispatcher manual log. In the event of a logging error, LMP replacements will be performed as outlined below:

  - Transmission constraint or CT logs entered (or removed) with a delay of less than four intervals) – No recalculation of LMP is required.
  - Transmission constraint or CT logs entered (or removed) with a delay of four intervals or more) – The constraint and/or CT data will be corrected and LMP values will be recalculated.
  - Transmission constraint or CT logs entered incorrectly - The constraint and/or CT data will be corrected and LMP values will be recalculated.

- Other Data Input Errors – Data input errors can occur when the applications or processes upstream of the LMP calculation complete successfully but produce erroneous results. These errors may include, but are not limited to, errors with EMS inputs, such as distribution factors and loss sensitivity factors, constraint modeling errors that result in pricing that is inconsistent with the way PJM operators are managing a constraint, and unintentional approval of the RT SCED case upon which the LPC case runs and produces LMPs. In the event of a data input error, LMP replacements may be performed as outlined below:
  - If the EMS data, such as distribution factors or loss sensitivity factors, are found to have errors, the erroneous input data may be replaced with that from a surrounding interval and LMPs will be recalculated, or the LMPs of the impacted pnodes may be replaced with those from electrically equivalent pnodes when the number of pnodes impacted is limited.
  - If a constraint is modeled in the upstream applications in a way that is inconsistent with how PJM operators are managing the constraint, the modeling of the constraint will be corrected in the LPC case inputs and the LMPs will be recalculated.
  - If the RT SCED case upon which the LPC case runs and produces LMPs was approved in error, LMPs will be recalculated using the last intentionally approved RT SCED case as the basis for the LMP calculation.

2.11 Price-Bounding Violations

After each five-minute iteration of the LPC, a set of validation checks are applied to the resulting LMPs and ancillary service clearing prices. These validation checks include but are not limited to criteria such as maximum and minimum LMP level, maximum and minimum ancillary service clearing price level, and the consistency of the pricing results with the dispatch solution. If any of these validation checks fail, the five-minute LMPs and/or ancillary service clearing prices will not be published. This known as a Price-Bounding Violation.

The occurrence of a Price-Bounding Violation does not mean that the originally posted prices are not correct or that they are not used in the settlement of the market. It is an automated process implemented by PJM to limit the publication of market clearing results

that are suspected to have an issue. If a Price-Bounding Violation occurs, PJM Market Operations personnel are notified by the LPC system immediately. Following the notification, the Market Operator will diagnose the cause of the violation. If the solution is found to be accurate, the 5-minute prices will be left as-is and the validation checks will be adjusted to release subsequent pricing information. If the prices are found to be inaccurate, they will be revised in accordance with the PJM Real-time Locational Marginal Price Verification Procedure outlined above.

2.12 Calculation of Ramp Limited Desired MWh

Operating Reserve deviations to generators that are operating at PJM's direction are based on a comparison of their Real-time desired MW with their Real-time MWh. For the purposes of settlement of Operating Reserve charges and credits, a Ramp-Limited Desired MW value will be used to determine whether a unit is following PJM dispatch instructions as well as the actual quantity of deviations that will be calculated when a unit be determined to not be following dispatch instructions.

PJM will calculate a Ramp Limited Desired MW value for units where the economic minimum and economic maximum are at least as far apart in real-time as they are in Day-Ahead.

- Real Time Economic Minimum <= 105% of Day-ahead Economic Minimum or Day-ahead Economic Minimum plus 5MW, whichever is greater.

- Real Time Economic Maximum >= 95% Day-ahead Economic Maximum or Day-ahead Economic Maximum minus 5MW, whichever is lower.

PJM will determine a unit's Ramp-Limited Desired MW according to the following calculation:

$$\mathbf{Ramp_Request}_t = \left(\mathbf{SCEDtarget}_{t-1} - \mathbf{AOutput}_{t-1}\right) \Big/ \left(\mathbf{SCEDLAtime}_{t-1}\right)$$

$$\mathbf{RL_Desired}_t = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp_Request}_t * \mathbf{Case_Eff_time}_{t-1}\right)$$

where the variables are:

- UDStarget = UDS basepoint for the previous UDS case

- AOutput = Unit's output at case solution time

- UDSLAtime = UDS look ahead time

- Case_Eff_time = Time between base point changes

- RL_Desired = Ramp limited desired MW

UDS LMP Desired MWh is calculated by comparing the hourly integrated UDS LMP to the unit's bid curve to determine a corresponding MW value. This value is not ramp-limited.

In the event of technical difficulties where either a) UDS data does not exist or b) there is not a sufficient amount of data to calculate a reasonable Ramp Limited Desired MW value, the UDS LMP Desired MW value will be used.

PJM utilizes the Ramp-Limited Desired MW value to determine whether a unit is following PJM dispatch instructions. PJM will calculate two values, for a generation resource that is operating at PJM's direction:

- the MW off dispatch - is a defined term that is the lesser of the difference between the actual output of a unit in MW and the UDS Basepoint, or the difference between the actual output of a unit in MW and its Ramp-Limited Desired MW.

- % off dispatch.

PJM will use the lesser of the difference between the actual output and the desired dispatch point, or the actual output and Ramp-Limited Desired MW value. The % off dispatch and MW off dispatch will then be calculated as time-weighted averages of the values calculated with each dispatch solution over the course of an hour.

Pool-scheduled and dispatchable self-scheduled resources operating above economic minimum will then be considered to be following dispatch if:

1. actual output is between their Ramp-Limited Desired MW value and desired dispatch point,
2. % off dispatch is less than or equal to 10, or
3. hourly integrated Real-time MWh are within five percent (5%) or 5 MW (whichever is greater) of the hourly integrated Ramp-Limited Desired MW.

Dispatchable pool-scheduled and self-scheduled generation resources that follow dispatch won't be assessed Balancing Operating Reserve deviations, and those that do not follow dispatch will be assessed Balancing Operating Reserve deviations based on |hourly integrated Real-time MWh – hourly integrated Ramp Limited Desired MW|, pursuant to the rules as defined in PJM Manual M28. The rules provide that Ramp-Limited Desired MW value must be used to determine real-time deviations from day-ahead schedules for generation resources. (See "Operating Reserve" section of PJM Manual M28 for a detailed description of the calculation of generator deviation charges).

2.13 Using and Calculating Locational Marginal Prices

LMPs are used in the PJM Energy Market accounting to calculate charges or credits for many of the market services, including:

- *Spot Market Energy* — LMPs are used to calculate the charges for Spot Market Energy purchases and the credits for Spot Market Energy deliveries. (See "Spot Market Energy Accounting" section of PJM Manual M28 for a detailed description of these calculations).

- *Operating Reserve* — LMPs, along with other components, are used to determine whether providers of Operating Reserve are properly compensated for their costs. (See "Operating Reserve Accounting" section of PJM Manual M28 for a detailed description of this calculation).

- *Transmission Congestion* — Congestion price components of LMPs are used in the calculation of Transmission Congestion Charges and to determine the value of FTRs used in the calculation of Transmission Congestion Credits. (See "Transmission Congestion Accounting" section of PJM Manual M28 for a detailed description of this calculation).

- *Transmission Losses* — Loss price components of LMPs are used to determine the charges for transmission losses. (See "Transmission Losses Accounting" section of PJM Manual M28 for a detailed description of this calculation).

- *Emergency Energy* — LMPs are used to calculate the charges and credits for Emergency purchases and sales between PJM and other Control Areas. (See "Emergency Energy Accounting" section of PJM Manual M28 for a detailed description of this calculation).

- *PJM Load Response Programs* – LMPs are used to calculate charges and credits for the PJM Load Response Programs (see "Section 11: PJM Load Response Programs Accounting" of PJM Manual M28 for a detailed description of this calculation).

- *Metering Reconciliation* — Weighted average LMPs are used to calculate monthly meter error correction charges between PJM Members and between Control Areas. (See "Metering Reconciliation Accounting" section of PJM Manual M28 for a detailed description of this calculation).

In general, generators are paid based on the generator bus LMP and loads are charged based on the load bus LMP. Transmission Customers or Energy Market Buyers are charged for congestion on transactions based on the differential in source and sink LMPs. LMPs are calculated on a periodic basis throughout the Operating Day, nominally every five minutes. At the end of each hour, an average of the five-minute LMP values is computed. The

resulting hourly LMPs are then used in the PJM Energy Market accounting, as described in the other sections of this manual.

2.13.1 Day-Ahead Settlement

Day-Ahead settlement is based on Day-ahead hourly LMPs. The components of Day-ahead hourly LMPs are the Day-ahead System Energy Price, Day-ahead Congestion Price, and the Day-ahead Loss Price. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details.

FTR holders receive congestion credits based on hourly day-ahead Congestion Price component of 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 according to the method described in Manual 28: Operating Agreement Accounting.

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. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details.

2.13.2 Balancing Settlement

Balancing settlement is based on Real-time LMP values averaged over the hour. The components of Real-time hourly LMPs are the Real-time System Energy Price, Real-time Congestion Price, and the Real-time Loss Price. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details.

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.

2.14 Balancing Operating Reserve Cost Analysis

Accounting for Operating Reserve is performed on a daily basis. A pool-scheduled resource of a PJM Member is eligible to receive credits for providing Operating Reserve in the day-ahead market and, provided that the resource was available for the entire time specified in its offer data, in the balancing market. The total resource offer amount for generation, including startup and no-load costs as applicable, is compared to its total energy market value for specified operating period segments during the day (including any amounts credited for day-ahead scheduling reserve in excess of the day-ahead scheduling reserve offer, any amounts credited for synchronized reserve in excess of the synchronized reserve offer plus opportunity cost, any amounts credited for non-synchronized reserve in excess of the non-synchronized reserve opportunity cost and any amounts credited for resources

providing reactive services). If the total value is less than the offer amount, the difference is credited to the PJM Member.

Fees are also provided for pool-scheduled energy transactions, for generating units operating as synchronous condensers (not for synchronized reserve nor for reactive services) at the direction of PJM, for cancellation of pool-scheduled resources, for units whose output is suspended or reduced due to a transmission constraint or other reliability reason, for units performing an annual black start test, and for units providing reactive services at the direction of PJM.

The offered price for pool-scheduled resources will be capped for the entire operating day in the event either of the following conditions exists:

- The generation resource is identified in the day-ahead schedule to be dispatched out of economic merit order to control an identified transmission constraint.

- The generation resource is dispatched to provide quick start reserve for reliability.

In the event one of the above conditions exists, the offer prices will be capped at one of the following three levels, as specified in advance by the resource owner:

- The weighted average real-time Locational Marginal Price at the generation bus during all hours over the past six months in which the resource was dispatched in economic merit order above minimum.

- The incremental operating cost of the generation resource as determined in the PJM Cost Development Guideline Manual plus a 10% adder.

- An amount negotiated between PJM and the Market Seller in the event the generation resource cannot recover costs with either of the first two methods above.

The total cost of Day-ahead Operating Reserve for the Operating Day, excluding the total cost for resources scheduled to provide Black Start Service, Reactive Service, or transfer interface control is allocated and charged to PJM Members in proportion to their total cleared day-ahead demand and decrement bids plus their cleared day-ahead exports for that Operating Day. The total cost of Balancing Operating Reserve, excluding the total cost associated with scheduling units for Black Start service or testing of Black Start units, for the Operating Day is allocated and charged to PJM Members in proportion to their locational real-time deviations from day-ahead schedules and generating resource deviations during that Operating Day, or to PJM Members in proportion to their real-time load plus exports during that Operating day for generator credits provided for reliability. In order to determine the reason why the Operating Reserve credit has been earned so that the charges related can be properly allocated, PJM conducts a Balancing Operating Reserve Cost Analysis (BORCA). PJM also calculates a Regional Balancing Operating Reserve rate for the costs of

Operating Reserves that result from actions to control transmission constraints that are solely within pre-defined regions in the RTO. Additional costs of Operating Reserves that result from actions to control transmission constraints that benefit the entire RTO will continue to be allocated equally to deviations across the entire RTO. The total cost of synchronous condenser payments (other than that for synchronized reserve or reactive services) for the Operating Day is allocated and charged to PJM Members in proportion to their total load plus their exports during that Operating Day. The total cost of Reactive Services for the Operating Day is allocated and charged to PJM Members in proportion to their total load in the applicable transmission zone. The total cost of Day-ahead Operating Reserve for the Operating Day for resources scheduled to provide Reactive Services or transfer interface control because the resource is known or expected to be needed to maintain system reliability in a zone(s) are allocated and charged to PJM Members in proportion to their total real-time load in the applicable transmission zone(s). The total cost of Operating Reserves for resources providing Black Start service or testing of Black Start units is allocated to Network and Point-to-Point Transmission Customers based on their monthly transmission use on a megawatt basis. Additional details on this allocation can be found in the Black Start Service Accounting section of Manual 27.

The purpose of the Balancing Operating Reserve Cost Analysis is to separate those Balancing Operating Reserve charges to be allocated to deviations between Day-ahead schedules and Real-time quantities from those that should be allocated to real-time load and exports. The key factor in separating the allocation is the determination of the particular units by which operating reserve credits were earned, and the units for which those credits should be allocated to deviations as opposed to those units for which those credits should be allocated to load and exports. This cost determination will occur in two stages: those units called on during the Reliability Analysis, and those units called on to operate during the Operating Day. In both cases, the proposed changes establish clear, definitive, and objective criteria that will be applied to such units to determine the reason Balancing Operating Reserve credits were earned.

For resources scheduled by PJM during its reliability analysis for an Operating Day, the associated Balancing Operating Reserve charges are allocated based on the reason the resource was scheduled.

- If the resource is committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve Requirement, then in such cases, Balancing Operating Reserve charges will be allocated to real-time deviations from day-ahead schedules.

- If however, a resource is scheduled by PJM during its reliability analysis not to account for anticipated deviations between day-ahead schedules and real time conditions but instead to provide additional reliability margin, Balancing Operating Reserve charges must be allocated to real-time load plus exports.

For resources called on by PJM to operate during the Operating Day, the associated Balancing Operating Reserve charges are allocated based on the reason the resource was scheduled.

- Balancing Operating Reserve credits earned by units called on by PJM to operate during the Operating Day for which the LMP at the unit's bus does not meet or exceed the unit's applicable offer (cost or price) for at least four, five-minute intervals of at least one clock hour during which the unit was running at PJM's direction will be allocated according to ratio share of load plus exports.

- Balancing Operating Reserve credits earned by all other units operating at PJM's direction in real-time will be allocated according to deviations between Day-ahead schedules and Real-time quantities. The logic behind this distinction is that units called on in real-time for which LMP exceeds their offer for a significant number of intervals while they are running are necessary to meet load requirements respecting active transmission constraints.

- Units called on at PJM's direction in real time for which the LMP does not exceed the unit's offer were not needed and were therefore operating in order to ensure reliability is maintained as opposed to account for differences between day-ahead schedules and real-time system conditions.

- PJM further collects Balancing Operating Reserve credits that are accrued to resources operating to manage local transmission constraints. In order to appropriately collect the costs of Balancing Operating Reserve for local constraints within the pre-determined regions where the constraints existed, PJM calculates Regional Balancing Operating Reserve adders.

- PJM calculates Regional Balancing Operating Reserve adders for the following Regions within the PJM RTO.

- Western Region of PJM RTO, comprised of the AEP, APS, ATSI, ComEd, Duquesne, Dayton, DEOK and EKPC Zones.

- Eastern Region of PJM RTO made of the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG and RE Zones.

- Generation resources with market based offers greater than $1,000/MWh in the Day Ahead and Real Time Energy Market that are also greater than the resource's lowest available and applicable cost-based offer are not eligible to receive Operating Reserve Credits.

Balancing Operating Reserve credits that are accrued to resources operating to control transmission constraints that benefit the entire RTO are charged as an RTO Balancing

Operating Reserve rate. (See “Operating Reserve Accounting” section of PJM Manual 28 for a detailed description of the calculation of allocation charges).

2.15 Maximum Emergency Generation in Day-ahead Market

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:

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 of all on-line generation.

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 of all on-line generation.

If generation is still not enough to achieve power balance 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).

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 $2,000/ MWh), whichever is higher.

2.16 Minimum Capacity Emergency in Day-ahead Market

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.

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 lower of zero or to the lowest offer price of all on-line generation.

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 Energy & Ancillary Services Market 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").

3.1 Overview of the PJM Regulation Market

The PJM Regulation Market provides PJM participants with a market-based system for the purchase and sale of the Regulation ancillary service. Resource owners submit specific offers for Regulation Capability and Regulation Performance, and PJM utilizes these offers together with energy offers and resource schedules from the Markets Gateway System, as input data to the Ancillary Service Optimizer (ASO) which is an hour-ahead Market Clearing Engine. ASO then optimizes the RTO dispatch profile and forecasts LMPs to determine hourly commitments of Regulation to meet the requirement. In real-time PJM jointly optimizes the Regulation committed simultaneously with energy and reserve and calculates the Regulation Market Clearing Price (RMCP) and, Regulation Market Performance Clearing Price (RMPCP), which are used to derive the Regulation Market Capability Clearing Price (RMCCP)) every 5 minutes based on the current system conditions. All 5 minute, real-time, Regulation prices will be averaged to calculate the hourly Regulation Market Performance Clearing Price (RMPCP) and the Regulation Market Capability Clearing Price (RMCCP). These clearing prices are then used in market settlements to determine the credits awarded to providers and charges allocated to purchasers of the Regulation service.

PJM uses resource schedules, regulation, and energy offers from the Markets Gateway System as input data to the ASO to provide the lowest cost alternative for the procurement of Regulation for each hour of the operating day. The lowest cost alternative for this service is achieved through a simultaneous co-optimization with Synchronized Reserve, Non-Synchronized Reserve and energy. Within the co-optimization, an RTO dispatch profile is forecasted along with LMPs for the market hour and adjacent hours. Using the dispatch profile and forecasted LMPs, an opportunity cost, adjusted by applicable performance score and benefits factor, is estimated for each resource that is eligible to provide regulation. The estimated opportunity cost for demand resources will be zero. The adjusted lost opportunity cost is added to the adjusted regulation capability cost and the adjusted regulation performance cost to make the adjusted total regulation offer cost. The adjusted total regulation offer cost is then used to create the merit order price. Resource owners may self-schedule Regulation on any qualified resource. The merit order price for any self-scheduled

Regulation resource is zero. All available regulating resources are then ranked in ascending order of their merit order prices, and the lowest cost set of resources necessary to simultaneously meet the PJM Regulation Requirement, PJM Synchronized Reserve Requirement, PJM Primary Reserve Requirement and provide energy in that hour is determined. If there is an excess of self-scheduled and zero-cost offers over and beyond the Regulation requirement, PJM uses resource-specific historic performance scores, selecting those resources with the highest performance scores, as a tie-breaker to determine which set of resources to commit to meet the Regulation requirement. The least cost set of regulation resources identified through this process are then committed. Prices for Regulation will be calculated simultaneously with energy and reserve every 5 minutes for the 12 intervals of the hour by the Locational Pricing Calculator (LPC). The highest merit order price associated with this lowest cost set of resources awarded regulation becomes the RMCP. The RMPCP is calculated as the highest adjusted performance offer from the set of cleared resources. The RMCCP is the difference between RMCP and RMPCP.

In the after-the-fact settlement, any resources self-scheduled to provide Regulation are compensated based on the processes described in Manual 28.

3.2 PJM Regulation Market Business Rules

3.2.1 Regulation Market Eligibility

Regulation offers may be submitted only for those resources electrically within the PJM RTO.

To regulate, a resource must meet the following criteria:

- Generation resources must be able to provide 0.1 MW of Regulation Capability in order to participate in the Regulation Market. Demand Resources must be able to provide 0.1 MW of Regulation Capability in order to participate in the Regulation Market.

- Generation resources must have a governor capable of AGC control.

- Resources must be able to receive an AGC signal. Resources MW output must be telemetered to the PJM control center in a manner determined to be acceptable by PJM.

- New resources must pass an initial performance test (minimum 75% compliance required).

- Resources must demonstrate minimum performance standards, as set forth in the PJM Manual 12: Balancing Operations, Section 4: Providing Ancillary Services.

- Resources should give priority to the regulation signal by not allowing the sum of the regulating ramp rate and energy ramp rate to exceed the economic ramp rate. Only after a regulating resource has accounted for the regulation capability, may a generator use net of the economic base point and the regulation ramp rate to follow the energy signal.

- Demand Resources must complete initial and continuing training on Regulation and Synchronized Reserve Market as documented in Manual 40: Certification and Training Requirements, Section 2.6: Training Requirements for Demand Response Resources Supplying Regulation and Synchronized Reserve.

- When a Demand Resource that is eligible for the Regulation Market is called for a mandatory Emergency or Pre-Emergency Load Management Event, it will be de-assigned from Regulation for any intervals that overlap with the Load Management Event, starting from the notice time of the Load Management Event, unless otherwise approved by PJM. PJM will not assign the resource to Regulation for the remainder of the mandatory portion of the Load Management Event.

The following information must be supplied through the Markets Gateway System:

- Resource Regulating Status (available, unavailable, self-scheduled)

- Regulation Capability (above and below regulation midpoint, MW)

- Regulation Maximum and Minimum values, considering any necessary offsets (MW)

- Demand Resource must submit valid Economic and Regulation Maximum and Minimum MW limits respectively

- Regulation Signal Type – RegA or RegD

- Cost-Based Regulation Offer ($/MWh): This value will be validated using the unit-specific operating parameters submitted with the regulation offer and the applicable $12/MWh regulation margin adder. The portions of the cost based offer are split into:
    - Regulation Capability portion capturing the Fuel Cost Increase and Unit Specific Heat Rate Degradation due to Operating at Lower Loads. The margin adder may only be added to the Regulation Capability portion; and,
    - Regulation Performance portion representing Cost Increase due to Heat Rate Increase during non-steady state operation and Cost Increase in VOM.
        - The $/MW value determined in this step will be converted to $/ΔMW by dividing the value by mileage ΔMW/MW for the applicable signal for that offer.

- Price-Based Regulation Offer ($/MWh, optional): This value is capped at $100/MWh, and its submission is optional on the part of the market participant. The portions of the price-based offer are split into:
  - Regulation Capability portion the capturing the resource owner's price to reserve MWs for regulation in $/MW; and,
  - Regulation Performance portion capturing the resource owner's price to provide regulation movement in $/ΔMW.

The $/MW value determined in this step will be converted to $/ΔMW by dividing the value by mileage ΔMW/MW for the applicable signal for that offer.

In addition to the cost-based regulation offer price, each market participant may also submit additional information to support the cost-based offer price. Using the calculations in Manual M-15: Cost Development Guidelines, PJM will validate the cost-based regulation offer price to ensure that it does not exceed actual regulating cost as determined by this manual, plus the applicable regulation margin adder. Any cost-based offer prices that exceed this value will be rejected by the Markets Gateway System. An example of this calculation is available on the PJM website in the 'Regulation Two Part Cost-Based Offer' document, located at http://www.pjm.com/markets-and-operations/ancillary-services.aspx.

Regulation offers cannot be negative.

If a market participant does not submit a cost-based regulation offer price they will not be permitted to participate in the PJM Regulation Market until such offer has been validated. Any participants that do not submit any of the supporting parameters below will have their cost-based regulation offer price capped at the margin adder of $12/MWh.

The following optional parameters may be submitted in the Markets Gateway System to support the cost-based regulation offer price. If any of these parameters are not submitted they will default to zero.

- **Heat Rate @ EcoMax [BTU/kWh]:** The heat rate at the default economic maximum for a resource. The economic maximum that will correspond to this rate value will be the default economic maximum that is shown on both the Daily Regulation Offers and Unit Details pages.

- **Heat Rate @ RegMin [BTU/kWh]:** The heat rate at the default regulation minimum for a resource. The regulation minimum that will correspond to this rate value will be the default regulation minimum that is shown on both the Daily Regulation Offers and Unit Details pages.

- **VOM Rate [$/MWh of Regulation]:** The increase in VOM resulting from operating the regulating resource at a higher heat rate than is otherwise economic for the purpose of providing regulation.

- **Fuel Cost [$/MBTU]:** The fixed fuel costs of the resource. This value will be used to determine the heat rate adjustments during steady-state and non steady-state operation for the purpose of providing regulation.

Regulation resources that are dual certified as RegA and RegD may submit a set of offers for each signal type. In such case, the market clearing engine evaluates both offers but will clear the resource for either one or neither of the two signal types based on economics and system needs. A dual certified resource offering both signal types in a given hour, if cleared for regulation, will be assigned one signal type for that the entire hour. The signal type assigned may vary from one hour to another during the course of the day if both signal types are made available consistently.

- If a dual certified resource submits self-scheduled regulation offers as both RegA and RegD signal types in the same hour, the market clearing engine will only evaluate the RegA self-schedule offer and then either commit the resource or not based on system needs.

- If a resource submits offers into both the Regulation and Synchronized Reserve Markets in the same hour, the regulation offer receives higher priority in the market clearing process, meaning if economic for both markets, the unit will be committed for Regulation rather than Synchronized Reserve.

3.2.2 Regulation Market Data Timeline

Cost-based and Price-Based Regulation Offer(s) and any applicable cost information must be supplied prior to 1415 day-ahead and is applicable for the entire 24-hour period for which it is submitted. Resource Regulating Status, Regulation Capability, and Regulation Maximum and Regulation Minimum information may be submitted or changed up until sixty (60) minutes prior to the beginning of 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 resource (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.

- Should a resource wish not to participate in the regulation market in any given hour on the operating day, the following update should be made at least 60 minutes prior to the operating hour in the Regulation Updates screens of the Markets Gateway System:
  - Set Offer MW to zero and
  - Set Available status to Not Available.

- Should a resource's regulation operating parameters change after the regulation market closes for an hour, the following changes may be made through direct communication with the PJM Scheduling Coordinator:
  - Resource Regulating Status
    - Available to unavailable
    - Self-scheduled to unavailable
  - High Regulation Limit may be decreased but not increased and Low Regulation Limit may be increased but not decreased.
  - Regulating capability may be decreased but not increased.
  - Regulation Maximum capability may be decreased but not increased and Regulation Minimum capability may be increased but not decreased.

3.2.3 Regulation Bilateral Transactions

Bilateral regulation transactions may be reported to PJM. Such reported bilateral regulation transactions must be for the physical transfer of regulation and must be reported by the buyer and subsequently confirmed by the seller through the Markets Gateway System no later than 1330 the day after the transaction starts. Bilateral transactions that have been reported and confirmed may not be changed; they must be deleted and re-reported. Deletion of a reported 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.

The buyer on the transaction submits the MW amount, the seller, and the start and end time of the transaction via the Markets Gateway System. The seller confirms the transaction via the Markets Gateway System by 1330 the day after the start date of the bilateral transaction.

Payments and related charges associated with the bilateral regulation transactions reported to PJM shall be arranged between the parties to the bilateral contract.

A buyer under a bilateral regulation contract reported to PJM agrees that it guarantees and indemnifies PJM, PJM Settlement, and the market participants for the costs of any purchases by the seller in the Regulation Market, as determined by PJM, to supply the reported bilateral transaction and for which payment is not made to PJM Settlement by the seller.

Upon any default in obligations to PJM or PJM Settlement by a Market Participant, PJM shall not accept any new bilateral reporting by the Market Participant and shall terminate all of the market participant's reporting of Markets Gateway schedules associated with its bilateral regulation transactions previously reported to PJM for all days where delivery had not yet occurred.

3.2.4 Regulation Requirement Determination

The total PJM Regulation Requirement for the PJM RTO is determined in whole MW for the ramp and non-ramp periods. Further detail can be found in Manual 12, Section 4.4.3 Determining Regulation Assignment.

Demand Resources will be limited to providing 25% of the regulation requirement.

3.2.5 Regulation Obligation Fulfillment

LSEs may fulfill their regulation obligations by:

- Self-scheduling the entity's own resources;
- Entering contractual arrangements with other market participants; or
- Purchasing regulation from the regulation market.

3.2.6 Regulation Offer Period

Resource owners wishing to sell regulation service must at least supply a cost-based regulation offer reflecting both Regulation capability offer cost and the Regulation performance cost of the resource by 1415 the day prior to operation, and the remainder of the necessary data prior to Regulation market closing as stated above in the Regulation Market Date Timeline section.

Regulation offers are locked as of 1415 the day prior to operation. The Markets Database is generally unavailable for updates to offers for the next Operating Day between 1030 and the time the office of interconnection posts the results of the Day-ahead Energy Market for that Operating Day while the Day-ahead market is being cleared. All resources listed as available for regulation with no offer price have their offer prices set to zero.

3.2.7 Regulation Market Clearing

PJM clears the regulation market simultaneously with the synchronized reserve market, and posts the results no later than 30 minutes prior to the start of the operating hour.

Dispatch

Economic ramp rate must be adjusted when resources provide regulation to minimize the conflict between energy and regulation products. The segment specific ramp rates should be calculated from the economic ramp rate as follows:

$$Reduced\ Energy\ Ramp\ Rate = \max\left(0, Economic\ Ramp\ Rate - \frac{Cleared\ Regulation\ Capacity\ (AREG)}{5\ Minutes}\right)$$

To increase consistency in the Individual Generator Dispatch (IGD) set point sent by PJM while a unit is regulating, the IGD set point will only move up when the RT-SCED LMP justifies raising the resource and the resource has a non-zero reduced energy ramp rate

entered. The IGD set point will only move down when the RT-SCED LMP justifies lowering the resource and the resource has a non-zero reduced energy ramp rate entered. The reduced energy ramp rate is a member-entered, unit-specific percentage of the bid-in energy ramp rate for each resource. If no value is entered in the Market Gateway system for the resource, a default of zero will be used.

Regulating Capability

For each resource, PJM will calculate an adjusted Capability Cost, as

$$Adjusted\ Regulating\ Capability\ \ Cost\ (\$) = \frac{\begin{pmatrix} Capability \\ Offer\ \left(\frac{\$}{MW}\right) \end{pmatrix}}{\begin{pmatrix} Benefits\ Factor \\ of \\ Offered\ Resource \end{pmatrix}} * \frac{\begin{pmatrix} Capability \\ (MW) \end{pmatrix}}{\begin{pmatrix} Historic \\ Performance \\ Score \end{pmatrix}}$$

The Adjusted Regulating Capability Offer is adjusted by the benefits factor of the specific offered resource and the historic performance score of the resource. The historic performance score is discussed in Manual 12 – Balancing Operations, Section 4.5.5 Disqualification and Requalification of a Resource.

Mileage and the Performance Offer

Mileage is the summation of movement requested by the regulation control signal a resource is following. It is calculated for the duration of the market hour for each regulation control signal (i.e. RegA and RegD).

$$Mileage_{RegA} = \sum_{i=0}^{n} |RegA_i - RegA_{i-1}|$$

$$Mileage_{RegD} = \sum_{i=0}^{n} |RegD_i - RegD_{i-1}|$$

PJM calculates the performance-adjusted Performance Cost, as

$$Adjusted\ Performance\ Cost\ (\$) = \frac{\begin{pmatrix} Performance \\ Offer\ (\$/\Delta MW) \end{pmatrix} * \begin{pmatrix} Mileage \\ of \\ Offered\ Resource \\ Signal\ Type\ (\Delta MW/MW) \end{pmatrix}}{\begin{pmatrix} Benefits\ Factor \\ of \\ Offered\ Resource \end{pmatrix} * \begin{pmatrix} Historic \\ Performance \\ Score \end{pmatrix}} * \begin{pmatrix} Capability \\ (MW) \end{pmatrix}$$

Similar to the Adjusted Regulating Capability Offer, the Adjusted Performance Offer is adjusted by the benefits factor of the specific offered resource and the historic performance score of the resource. Benefits factor is discussed later in this section. The historic

performance score is discussed in Manual 12 – Balancing Operations, Section 4.5.5 Disqualification and Requalification of a Resource. The performance offer is priced on a $ per change in MW, to normalize the performance between signal types, the historical mileage is a rolling 30-day average by the signal type that the resource has qualified to follow.

Lost Opportunity Cost

Estimated resource opportunity cost is calculated as follows:

- The Market Clearing Engine (MCE) optimizes resource energy schedules and forecasts LMPs for the operating hour while respecting appropriate transmission constraints and Ancillary Service requirements.

- MCE utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation.

Regulation opportunity cost is divided into three components.

- The lost opportunity cost incurred in the shoulder hour preceding the initial regulating hour while the unit moves uneconomically into its regulating band to comply with the next hour's regulation assignment.

- The lost opportunity cost incurred in the actual regulating hour from reducing or raising the unit's output uneconomically for the purpose of providing regulation.

- The lost opportunity cost incurred in the shoulder hour following the final hour of the regulation assignment while the unit moves from its uneconomic regulation set point back to its economic set point.

The approximate formula for the lost opportunity incurred during the shoulder hours can be defined as:

$$|LMP_{SH} - ED| * GENOFF * TIME, \text{ where:}$$

1. LMP_{SH} is the forecasted shoulder hour LMP at the generator bus,

2. ED is the price from the lost opportunity cost energy schedule associated with the setpoint the resource must maintain to provide its full amount of regulation, and

3. GENOFF is the MW deviation between economic dispatch and the regulation setpoint.

4. TIME is the percentage of the hour it would take the unit to reduce GENOFF MWs using the applicable offer-in ramp rate.

- The approximate formula for the lost opportunity cost incurred during the regulating hour is:

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

a. LMP is the forecasted hourly LMP at the generator bus,

b. ED is the price from the lost opportunity cost energy schedule associated with the setpoint the resource must maintain to provide its full amount of regulation, and

c. GENOFF is the MW deviation between economic dispatch and the regulation setpoint.

All unit-specific lost opportunity costs will be divided by the benefits factor of the specific offered resource and the resource's historic performance score for the purposes of commitment and setting the regulation market clearing prices. Benefits factor is discussed later in this section. The historic performance score is discussed in Manual 12 – Balancing Operations, Section 4.5.5 Disqualification and Requalification of a Resource.

$$Adjusted\ Lost\ Opportunity\ \ Cost\ (\$) = \frac{\begin{pmatrix} Estimated\ Lost\ Opportunity \\ \left(\frac{\$}{MW}\right) \end{pmatrix}}{\begin{pmatrix} Benefits\ Factor \\ of \\ Offered\ Resource \end{pmatrix}} * \frac{\begin{pmatrix} Capability \\ (MW) \end{pmatrix}}{\begin{pmatrix} Historic \\ Performance \\ Score \end{pmatrix}}$$

Both lost opportunity cost calculations are defined simplistically for the purpose of the manual. The actual calculations are integrations that may be visualized as the area on a graph enclosed by the lost opportunity cost energy schedule, the points on that curve corresponding to the resource's desired economic dispatch and the setpoint necessary to provide the full amount of regulation, and the LMP. A sample calculation can be found on PJM website at http://pjm.com/~/media/markets-ops/ancillary/regulation-uplift-and-lost-opportunity-cost.ashx.

PJM may call on resources not otherwise assigned 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 resource is called on by PJM for the purpose of providing regulation, the resource is eligible for recovery of Regulation lost opportunity costs as well as start-up, no-load, and energy costs. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details.

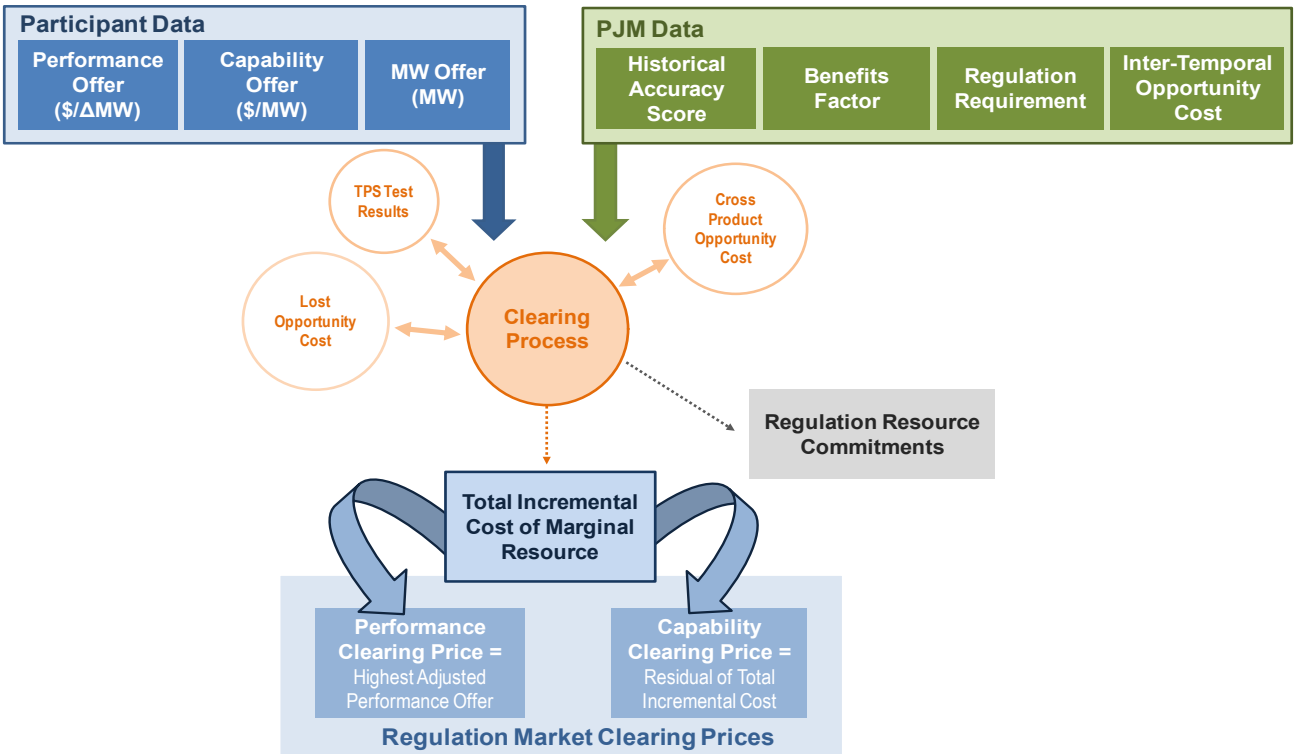
Resources not eligible or with no lost opportunity associated with providing regulation:

- Energy resources that are self-scheduled to provide energy and do not supply an energy offer.
- Demand Resources
- Notwithstanding the above, resources that do not submit an energy offer curve will have a Lost Opportunity Cost of zero.

Total Offer

Each resource must be ranked based on the total expected cost of that resource regulating. PJM calculates the Adjusted Total Offer of the resource as follows

$$Adjusted\ Total\ Offer\ Cost\ (\$) = \begin{pmatrix} Adjusted \\ Regulation \\ Capability \\ Cost \\ (\$) \end{pmatrix} + \begin{pmatrix} Adjusted \\ Lost \\ Opportunity \\ Cost \\ (\$) \end{pmatrix} + \begin{pmatrix} Adjusted \\ Performance \\ Cost \\ (\$) \end{pmatrix}$$



MCE ranks all available regulating resources in ascending merit order price, and simultaneously determines the least expensive set of resources necessary to provide energy, regulation and synchronized reserve for the operating hour taking into account any resources self-scheduled to provide any of these services. The Rank price is determined as follows:

$$Rank\ Price = \frac{Adjusted\ Total\ Offer\ Cost\ (\$)}{Capability\ \ (MW)}$$

Should the MCE application be unable to fulfill both the Regulation and Synchronized Reserve requirements, regulation receives the higher priority.

PJM will clear the market to meet the Regulation Capability Requirement. The Regulation Capability Requirement sets the amount of regulating capability that PJM believes it would need to absorb sustained RTO ACE deviations adjusted by the benefits factor of a specific offered resource and the resource's historic performance score. Benefits factor is discussed later in this section. The historic performance score is discussed in Manual 12 – Balancing Operations, Section 4.5.5 Disqualification and Requalification of a Resource. The market will assign resources until the constraint is met, by

$$\begin{aligned} &Regulation\ Capability\ Requirement \\ &\quad MW \\ &\quad \leq \sum_{i=0}^{n} Capability\ (MW)_{i*} * \ Benefits\ Factor\ of\ Offered\ Resource_i \\ &\quad * Historic\ Performance\ Score_i \end{aligned}$$

With the Regulation Capability constraint satisfied, the Rank Price ($/MW) of the last assigned resource sets the Regulation Market Clearing Price (RMCP). This RMCP is used to derive the clearing price for the Regulation Capability and Regulation Performance components. First the Regulation Market Performance Clearing Price (RMPCP) is calculated by finding the maximum performance offer from the set of all cleared resources' performance offers as follows:

$$\begin{aligned} &Regulation\ Market\ Performance \\ &\quad Clearing\ Price \\ &\quad \$/MW \\ &= \max_{Assigned\ \ Resources} \left(\frac{\begin{pmatrix} Performance \\ Offer \\ (\$/\Delta MW) \end{pmatrix} * \begin{pmatrix} Actual\ Mileage \\ of \\ Offered\ Resource\ Signal\ Type\ \Delta MW/MW \end{pmatrix}}{\begin{pmatrix} Benefits\ Factor \\ of \\ Offered\ Resource \end{pmatrix} * \begin{pmatrix} Historic \\ Performance \\ Score \end{pmatrix}} \right) \end{aligned}$$

Then the RMPCP is subtracted from the RMCP for the Regulation Market Capability Clearing Price (RMCCP), which is the residual between the RMCP and RMPCP.

$$\begin{matrix} Regulation\ Market\ Capability \\ Clearing\ Price \\ \$/MW \end{matrix} = \begin{pmatrix} Regulation\ Market \\ Clearing\ Price \\ \$/MW \end{pmatrix} - \begin{pmatrix} RM\ Performance \\ Clearing\ Price \\ \$/MW \end{pmatrix}$$

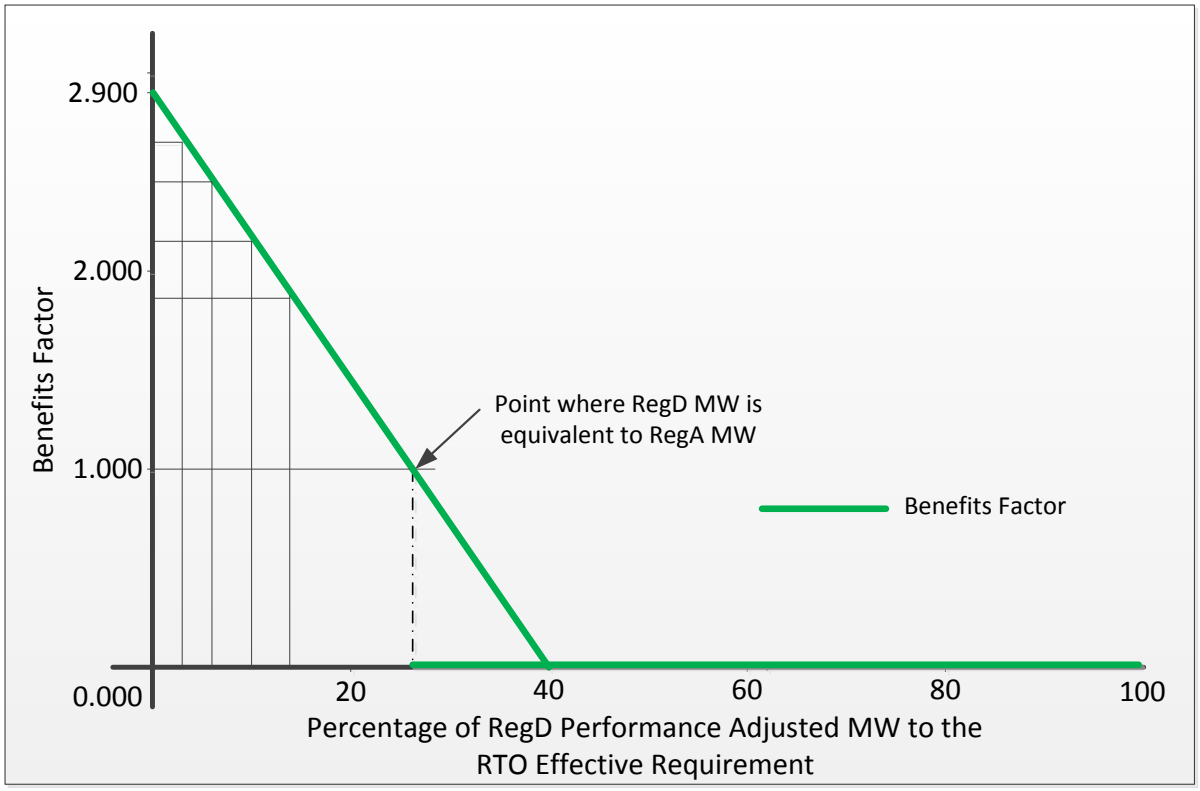
The five minute regulation clearing prices are posted in the Data Viewer user interface public view. RMCP(s) and other billing determinant information is also available on the PJM website at http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/preliminary-billing-reports/pjm-reg-data.aspx.

If no Regulation Market Results are posted to the Markets Gateway MUI for an hour, PJM will continue the current assignments, as needed, into the un-posted hour. There will be no impact to the price calculation. The Regulation Clearing Prices will continue to be calculated every five minutes in real-time and the hourly integrated clearing price will be used for settlement.

Benefits Factor Function

Regulating resources can follow either a RegA (traditional) or RegD (dynamic) signal based on their resources' limitation and business practices. The regulating resources cleared in any hour can be any set of or mix of both traditional and dynamic resources. There is an operational relationship between the regulating resource mix and how the regulation requirement is satisfied. This relationship is included in the market clearing process as the Benefits Factor Function because the relationship is depicted as a curve.

The benefits factor translates a fast moving resource's MWs into traditional MWs or Effective MWs. These Effective MWs reflect the rate of substitution between resources following the different regulation signals. For market clearing, each dynamic resource will be assigned a decreasing and unique benefits factor. The benefits factor of the offered resource or resource specific benefits factor is the marginal point on the benefits factor function that aligns with the last MW, adjusted by historical performance, that specific resource will add to the dynamic resource stack.



The benefits factor ranges from 2.9 to 0 where a benefits factor of 1 is equivalent to a traditional resource. PJM will review the benefits factor as operational conditions warrant to re-evaluate the relationship when needed. These operational conditions could include, among other factors, changes to the regulation signal tuning parameters, changes in the set of resources providing regulation service, and changes to the regulation requirement.

PJM determines the benefits factor based on the expected impact that fast-following resources have on the NERC reliability criteria. Determination of expected response will be based a combination of off-line models, analysis of the regulation signals, and the historical operational data as it accumulates. Historical operational data will be given increasing weight to the benefits factor determination over time. Changes to the benefits factor function will be made periodically after review at the Operating Committee.

The net impact of the use of the benefits factor is to increase the likelihood of dynamic resources being selected in the clearing process, up to the point of diminishing returns. Beyond the point of diminishing returns (1 to 0), the benefits factor will decrease the likelihood of fast-following resources getting clearing.

During identified hours where more sustaining regulation (RegA) and less fast-following regulation (RegD) is warranted, RegD resources with a benefits factor less than 1 will not be considered in the regulation clearing because of its reduced benefits. A cap will be implemented at BF = 1 during these hours. Capped hours will be reviewed on a quarterly basis at the Operating Committee.

The benefits factor is calculated in ASO one hour ahead in real time for each qualified RegD resource participating in the Regulation Market. Also, the benefits factor is re-calculated for each RegD resource that is committed and providing regulation service in real-time for every 5 minute interval of the hour. The recalculation accounts for changes in the resource's adjusted total offer cost due to potential change in LMP at its bus which may affect its lost opportunity cost value. The benefits factor of RegA resources is always 1.

The benefits factor calculation steps include:

- Step 1: Calculation of the Performance Adjusted MW

$$Performance\ Adjusted\ MW = Capability\ (MW) * Historical\ Performance\ Score$$

- Step 2: Calculation of the Initial Adjusted Total Offer Cost

$$Initial\ Adjusted\ Total\ Offer\ Cost\ (\$) = \begin{pmatrix} Adjusted \\ Regulation \\ Capability \\ Cost \\ (\$) \end{pmatrix} + \begin{pmatrix} Adjusted \\ Lost \\ Opportunity \\ Cost \\ (\$) \end{pmatrix} + \begin{pmatrix} Adjusted \\ Performance \\ Cost \\ (\$) \end{pmatrix}$$

$$in\ this\ step, the\ resource\ benefits\ factor\ is\ assumed\ to\ be\ 1$$

RegD resources with initial adjusted total offer cost equal to zero will still be given priority in the ranking, but will instead be ordered using the resource specific historical performance score as a tie-breaker.

- Step 3: Calculation of the rolling performance adjusted MW based on the initial adjusted total cost in ascending rank order

- Step 4: Calculation of the resource specific benefits factor based on the defined benefits factor curve

Three Pivotal Supplier Test

PJM utilizes the Three Pivotal Supplier (TPS) Test in the regulation market to mitigate market power as detailed in section 3.2.2A.1 of the PJM Tariff. Each supplier, from 1 to n, is ranked from the largest to the smallest offered MW of eligible regulation supply adjusted by the resource-specific benefits factor and the resource specific performance score in each hour. Suppliers are then tested in order, starting with the three largest suppliers. In each iteration of the test, the two largest suppliers adjusted by the benefits factors of the offered resources and the resource specific performance scores are combined with a third supplier adjusted by the benefits factor of the offered resource and the resource specific performance score, and the resulting combined supply is subtracted from total effective supply adjusted by the benefits factors of all offered resource and their resource specific performance scores. The resulting net amount of eligible supply is divided by the regulation requirement for the hour adjusted by the resource-specific benefits factors and the resource specific performance scores (D). Where j defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with j=3). Equation 0-1 shows the formula for the residual supply index for three pivotal suppliers (RSI3):

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D}.$$

Where j=3, if RSI3j is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a supplier j result in RSI3j greater than 1.0. When the result of this process is that RSI3j is greater than 1.0, the remaining suppliers pass the test. Any resource owner that fails the TPS Test will be offer-capped.

- Regulating resources are offer-capped at the lesser of their cost-based or market-based regulation offer price.

- An offer-capped resource will only be offer-capped for a single hour at a time as the TPS Test is rerun for each hour of the day.

- Resource merit order price ($/MWh) = Resource regulation offer + estimated resource opportunity cost per MWh of capability adjusted by the resource-specific benefits factor and the resource specific performance score.

3.2.8 Hydro Units

Since hydro units operate on a schedule and do not have an energy bid, opportunity cost for these units is calculated as follows:

- 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 Updates page of the Markets Gateway System.

- If a hydro unit is committed day-ahead with MW greater than zero, the formula is the same as Section 3.2.7.Regulation Market Clearing and Dispatch above, except the ED value is an average of the LMP at the hydro unit bus for the appropriate on-peak (0700 - 2259) or off-peak (0000 – 0659, 2300 - 2359) 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 lost opportunity costs for settlement.

- If a hydro unit is brought on out of schedule to provide regulation or not committed in day-ahead market with MWs greater than 0, the opportunity cost is equal to the average LMP (calculated as stated above) minus the actual LMP at the generator bus. If the actual LMP is higher than the average, the opportunity cost is zero.

- 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.

- An example of Regulation Hydro Lost Opportunity Cost Calculations can be found on the PJM website at http://pjm.com/~/media/markets-ops/ancillary/regulation-uplift-and-lost-opportunity-cost.ashx

3.2.9 Regulation Market Operations

The PJM Operator periodically evaluates the set of resources 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 resources beginning with the highest cost resource currently providing regulation and moving downward.

In the event of a regulation deficiency, the PJM dispatcher uses the Intermediate-Term Security Constrained Economic Dispatch (IT SCED) application to select resources to provide regulation beginning with the lowest cost resource currently not providing regulation and moving upward.

The RMCP and therefore RMPCP and RMCCP may change based upon regulating resource adjustments made in real time. Any opportunity costs that exceed the RMCP are credited after the fact on a resource-specific basis.

The PJM Energy Management System (EMS) will send a RTO based signal(s) to each Local Control Center (LCC), as well as signals to individual resources or plants as requested by the owner.

The PJM Operator communicates any change in resource 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.

Resource 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.

For a dual qualified regulation resource, should the assignment change within the operating hour, the resource will continue to be committed or re-committed on the regulation signal type that the resource was initially committed on.

3.2.10 Settlements

Please refer to Manual 28: Operating Agreement Accounting, Section 4: Regulation Accounting for settlement details.

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.

A resource's regulation performance score for the hour or the portion of the hour it is regulating will determine the resource's eligibility for regulation credit and lost opportunity cost for that hour. A resource whose performance score for the hour or the portion of the hour is below 25% will forfeit regulation credit and Lost Opportunity for that hour.

Opportunity cost is calculated as shown above in Section 3.2.7 Market Clearing and Dispatch using actual integrated LMPs as opposed to that which was forecasted. PJM then adjusts the opportunity cost calculated for each resource based on the actual hourly integrated value of the real-time PJM regulation signal to account for the fact that the resource may have been held above or below its regulation set point for greater than half the hour and also adjusted by the resource-specific benefits factor and the resource specific performance score. Energy resources that are self-scheduled to provide energy and do not supply an energy offer are not eligible to collect opportunity cost credits. These resources will receive credit equal to the RMPCP and RMCCP times the amount of regulation self-scheduled on or assigned to them adjusted by the mileage ratio between the requested

mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal and the resource's actual performance score for an hour.

For market settlement, regulating resources are compensated with consideration toward the resource's Regulation performance, and where applicable, the mileage ratio between the requested mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal.

Section 4: Overview of the PJM Synchronized Reserve Market

Welcome to the Overview of the PJM Synchronized Reserve Market section of the PJM Manual for Energy & Ancillary Services Market Operations. In this section, you will find the following information:

- An overview description of the PJM Synchronized Reserve Market (see "*Overview of PJM Synchronized Reserve Market*").
- A list of the PJM Synchronized Reserve Market Business Rules (see "*PJM Synchronized Reserve Market Business Rules*").

4.1 Overview of the PJM Synchronized Reserve Market

The PJM Synchronized Reserve Market provides PJM participants with a market-based system for the purchase and sale of the Synchronized Reserve ancillary service. Resource owners submit resource-specific offers to provide Synchronized Reserve, and PJM utilizes these offers together with energy offers and resource schedules from the Markets Gateway System, as input data to the Ancillary Service Optimizer (ASO). ASO then optimizes the RTO dispatch profile and forecasts LMPs to determine hourly commitments of the inflexible Synchronized Reserves. Although the ASO considers all available resources during its commitment process, the hourly commitments for Synchronized Reserve from the ASO are limited to inflexible resources only and may only represent a portion of PJM's Synchronized Reserve needs for the hour. In real-time PJM will jointly optimize the remaining RTO reserve needs simultaneously with energy and regulation and calculate a clearing price for Synchronized Reserve every 5 minutes based on the current system conditions. All 5 minute, real-time, Synchronized Reserve prices will be averaged to calculate the hourly Synchronized Reserve Market Clearing Price (SRMCP) that will be used for market settlement.

Inflexible resources are defined as those resources that physically require an hourly commitment due to minimum run time constraints or staffing constraints. Inflexible resources include but are not limited to synchronous condensers that are operating in condensing mode solely for the purpose of providing Synchronized Reserves and Demand Resources that are prepared to curtail in response to a PJM reserve event.

PJM initially uses forecasted LMPs and resource schedules to estimate the amount of incidental Synchronized Reserve present on the PJM system due to economic dispatch and this capability is designated as Tier 1. Tier 1 is provided by any resource that is on line, following economic dispatch, and capable of increasing its output within ten (10) minutes following a call for a Synchronized Reserve Event. If the forecasted amount of Tier 1 estimated for a given duration is insufficient to meet the PJM Synchronized Reserve Requirement, PJM must commit resources 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. ASO will commit any inflexible resources that are forecasted to be economic to provide Synchronized Reserves during the operating hour. If the solution does not foresee the need to commit Tier 2 reserves or does not commit enough inflexible resources to meet the Synchronized Reserve requirement due to economics, PJM will jointly optimize the balance of the Tier 2 required in real-time with energy.

During each execution of RT SCED, any additional Synchronized Reserves will be committed that are required to meet the Synchronized Reserve requirement based on current system conditions while the IT SCED has the ability to project conditions further out into the future and make a recommendation to commit additional inflexible resources for reserves where they are economic. RT SCED has the ability to re-dispatch online generating resources to meet the Synchronized Reserve requirement in addition to committing additional flexible resources to provide Synchronized Reserves should they be economic. Prices for Synchronized Reserves will be calculated simultaneously with energy, regulation and non-synchronized reserve every 5 minutes by LPC. For each product, the 5 minute prices will be averaged over the operating hour to determine the hourly Synchronized Reserve Market Clearing Price (SRMCP) that will be used for market settlement. In the after-the-fact settlement, any resources cleared as self-scheduled to provide Synchronized Reserve are compensated at the hourly SRMCP. Any pool-scheduled resources selected to provide Synchronized Reserve are compensated at the higher of the hourly SRMCP or their real-time opportunity cost plus their Synchronized Reserve offer price. LSEs required to purchase Synchronized Reserve are charged the hourly SRMCP plus their percentage share of opportunity cost credits and Tier 1 credits.

4.2 PJM Synchronized Reserve Market Business Rules

4.2.1 Synchronized Reserve Market Eligibility

Synchronized Reserve offers must be submitted for those resources located electrically within the Synchronized Reserve Zone.

Resources not located electrically within the Synchronized Reserve Zone may not submit Synchronized Reserve offers.

Resources participating in the Synchronized Reserve market are divided into two Tiers:

- Tier 1 is comprised of all those resources on line following economic dispatch and able to ramp up from their current output in response to a Synchronized Reserve Event, or Demand Resources capable of reducing load, within 10 minutes.

- Tier 2 consists of:

  - additional capacity that is synchronized to the grid and operating at a point that deviates from economic dispatch (including condensing mode) to provide additional Synchronized Reserve not available from Tier 1 resources; and
  - dispatchable load resources that have controls in place to automatically drop load in response to a signal from PJM.

- Tier 1 estimates for Demand Resources will equal zero.

- Tier 1 estimates for other resource types that cannot reliably provide Synchronized Reserve service shall be set to zero MW during the market clearing process. Such resource types include, but are not limited to: Nuclear, Wind, Solar, Energy Storage Resources, and Hydro units. Owners of any specific resource(s) or these resource types may request an exception from the default zero MW estimated value of their resource(s) if they notify PJM that the resource(s) are able to reliably provide Tier 1 Synchronized Reserve. PJM will only grant such requested exceptions on a prospective basis. A resource will only be credited for Tier 1 Synchronized Reserve if the resource was considered during the market clearing process, unless such resource actually provides Tier1 Synchronized Reserve during a Synchronized Reserve Event. For further information on the exception process, please visit "Communication Process for Consideration of Some Resources for Tier 1" at this link: http://www.pjm.com/markets-and-operations/ancillary-services.aspx.

- All resources operating on the PJM system with the exception of those assigned as Tier 2 resources are by definition Tier 1 resources. Any resource capable of operating in condensing mode or physically able to operate with an output less than that dictated by economic dispatch must offer Tier 2. There is no qualification process for Tier 2 resources. However, compensation refunds exist as described in section 4.2.12 below for response by Tier 2 resources that is less than that which is committed.

- All on-line non-emergency generation resources providing energy are deemed to be available to provide Tier 1 Synchronized Reserve and Tier 2 Synchronized Reserve, as applicable to the capacity resource's capability to provide these services. During periods for which PJM has issued a Primary Reserve Warning, Voltage Reduction Warning or Manual Load Dump Warning, all other non-emergency generation capacity resources available to provide energy shall have submitted offers for Tier 2 Synchronized Reserves. PJM will monitor compliance with the Tier 2 must offer requirement.
  - To monitor the Tier 2 must offer requirement, PJM will check to ensure that every generator subject to the must offer requirement has submitted a Tier 2 offer greater than or equal to 90% of its energy ramp rate for the ramp rate segment including its economic max, multiplied by 10 minutes. If the Tier 2 offer is less than that quantity, PJM will contact the generation owner regarding the Tier 2 offer.

- Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in Markets Gateway prior to the offer submission deadline (1415 the day prior to the operating day). Offer MW and other non-cost offer details can be changed during the operating day via the hourly update page (Synchronized Reserve Updates).

- Tier 2 offer quantities submitted for a capacity resource on the Synchronized Reserve Offer page in Markets Gateway are automatically carried over from one day to the next unless updated. Changes made on the Synchronized Reserve Updates page of Markets Gateway are not carried over into the next day. Any changes made to the Synchronized Updates page supersedes the values on the Offer page.

- The following information must be supplied through the Markets Gateway System:
  - Synchronized Reserve ramp rate for Tier 1 resources (MW/minute). A separate ramp rate may be submitted for multiple segments of a resource's MW range, and these ramp rates must be greater than or equal to the real-time economic ramp rate(s) submitted for the resource. Synchronized Reserve ramp rates that exceed economic ramp rates must be justified via submission of actual data from past Synchronized Reserve Events to the PJM Performance Compliance Department.
    - Resource's energy ramp rate is used for Tier 2 MW calculation.
  - Synchronized Reserve maximum for Tier 1 resources: This value represents the maximum MW output a resource can achieve in response to a Synchronized Reserve Event. Synchronized Reserve maximum for Tier 1 resources must be greater than or equal to the economic maximum for the resource except for qualified resources that have been granted exception due to their physical limitation. Additional information on the communication process for consideration of resource physical limitation can be found on the PJM website under "Modification to Synchronized Reserve Market to Better Reflect the Operating Characteristics of Participating Generating Units" at this location: http://www.pjm.com/markets-and-operations/ancillary-services.aspx.
  - Generation resources must be able to provide 0.1 MW of Tier 2 Synchronized Reserve Capability in order to participate in the Tier 2 Synchronized Reserve Market. Demand Resources must be able to provide 0.1 MW of Tier 2 Synchronized Reserve Capability in order to participate in the Tier 2 Synchronized Reserve Market.
  - Synchronized Reserve availability for Tier 2 resources: Resources may be made unavailable to provide Tier 2 Synchronized Reserve only if they are physically unavailable. Otherwise, they must be made available or self-scheduled to provide Tier 2 Synchronized Reserve per the must offer requirement.
  - Synchronized Reserve offer quantity for Tier 2 resources (MW): This quantity is defined as the increase in output achievable by the resource in ten (10) minutes, or the load reduction achievable in ten (10) minutes.

- A non-emergency generation capacity resource that cannot reliably provide Synchronized Reserve service may submit an offer quantity of zero MW. The participant responsible for a given resource must be able to justify a zero MW offer quantity. Certain unit types including, but not limited to, Nuclear, Wind, Solar, and Energy Storage Resources, are expected to have zero MW Tier 2 Synchronized Reserve offer quantities.

- Synchronized Offer Price for Tier 2 resources ($/MWh): Synchronized Reserve offer prices will be capped at a maximum value of the resource's O&M cost (as determined by the Cost Development Task Force) plus $7.50/MWh margin.
  - Offer Price cannot be a negative value
  - Energy use for condensing Tier 2 resources (MW): This is the amount of instantaneous energy a condensing resource consumes while operating in the condensing mode. The value submitted as part of the Synchronized Reserve offer must be less than or equal to the actual energy consumed as observed in real time.
  - Should a resource be unable to participate in the Synchronized Reserve market in any given hour on the operating day, the following update should be made 60 minutes prior to the operating hour in the Synchronized Reserve Update screens of Markets Gateway (both updates must be made):
    - Set Offer MW to zero
    - Set Available status to Not Available
  - 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.
  - Shutdown Costs: These are the costs a Demand Resource incurs when reducing load in response to a Synchronized Reserve Event.
  - Condense Startup Cost: This is the actual cost associated with getting a resource from a completely off-line state into the condensing mode including fuel, O&M, etc.
  - Condense Hourly Cost: This is the hourly cost to condense and is equal to the actual, variable O&M costs associated with operating a resource in the condensing mode, including any fuel costs. It does not include any estimate for energy consumed
  - Condense Notification Time: The amount of advance notice, in hours, required to notify the operating company to prepare the resource to operate in synchronous condensing mode. The default value is 0 hours.
  - Spin as Condenser: This is used to identify if a combustion turbine or a hydro resource can be committed for Synchronized Reserve as a condenser.

- Condense Available Status: Indicates a resource's availability to provide voltage/reactive support. This value is not directly related to Synchronized Reserve Market.

4.2.2 Synchronized Reserve Requirement Determination

PJM will select resources in the Synchronized Reserve Zone and Reserve Sub-zone hourly and intra-hourly to provide synchronized reserve based on a joint optimization between energy, regulation, non-synchronized reserve and synchronized reserve. Assignments will be communicated to the resource owners/operators by Markets Gateway and/or the appropriate application.

- In the PJM RTO there will be a single Synchronized Reserve Zone and potential Reserve Sub-zone. Total PJM Synchronized Reserve Requirement for each Synchronized Reserve Zone and Reserve Sub-Zone is determined in whole MW for each hour of the operating day.

- The PJM Primary Reserve and Synchronized Reserve Zone and Reserve Sub-zone Reliability Requirements are documented in PJM Manual 13: Emergency Operations, Section 2.2.

- Due to transmission security considerations on the PJM system, it is sometimes necessary to carry a minimum amount of synchronized reserve in specific sub-zones in PJM such that loading 100% synchronized reserve will not result in an overload of any of the PJM transfer interfaces. The Mid-Atlantic Dominion Sub-Zone is defined in the Synchronized Reserve Market to ensure that reserves are available in or deliverable to the eastern part of the system under constrained conditions. The Mid-Atlantic Dominion Sub-Zone is defined by the most limiting monitored transfer interfaces. The interface modeled may be revised by PJM to match operation and meet the system reliability needs.

- As system conditions dictate, PJM may need to redefine or include additional sub-zones into the RTO Synchronized Reserve Markets. PJM will notify the stakeholders in the event any additional sub-zones need to be created due to unforeseen system conditions that impact reliability.

  - PJM shall obtain and maintain for each Reserve Zone and Reserve Sub-zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone and Reserve Sub-zone.

  - PJM shall create additional Reserve Zones or Reserve Sub-zones to maintain the required amount of reserves in a specific geographic area of the PJM Region as needed for system reliability. Such needs may arise due to planned and unplanned system events that limit PJM's ability to deliver reserves to a specific geographic area of the PJM Region where reserves are required.

- PJM must ensure that adequate synchronized and primary reserves MW are procured and maintained to recover from the loss of the single largest generator contingency, which is normally the largest online generator's output. However, there is, at times, an outage condition at a station whereby a single fault would trip multiple generators resulting in a loss of generation greater than the largest single generator. In such instances, PJM will carry an increased reserve requirement in equivalent summation of output of those multiple generators in accordance with reserve requirements described in PJM Manual 13: Emergency Operations, Section 2.2.

- At times, anticipated heavy load conditions may result in PJM operators carrying additional reserves to cover increased levels of operational uncertainty. PJM may extend the Primary Reserve and Synchronized Reserve Requirements in the Market Clearing Engines during the on-peak period in order to incorporate these actions in energy and reserve pricing when a Hot Weather Alert, Cold Weather Alert or an escalating emergency procedure (as defined in Manual 13: Emergency Operations) has been issued for the Operating Day. The extended Synchronized Reserve Requirement and Primary Reserve Requirement will be equal to the existing reserve requirement plus the sum of any additional MW brought online for that hour by PJM dispatch to account for operational uncertainty after the second resource commitment which occurs after 1415 the day prior to the Operating Day. If reserve deliverability issues are anticipated, then the requirements for the Sub-Zone(s) in which the additional resources are located will be extended. For example, if additional resources are specifically scheduled in the Mid-Atlantic Dominion Sub-Zone in anticipation of transmission constraints inhibiting the delivery of reserves into that region, both the Mid-Atlantic Dominion Sub-Zone and RTO Reserve Zone requirements would be extended. If additional resources are scheduled in the non-Mid-Atlantic Dominion portion of the RTO Reserve Zone, then only the RTO Reserve Zone requirement would be extended.

- The requirements will return to their original values upon exit from emergency procedures or when the additional resources have been released by PJM dispatch.

- PJM will notify market participants of changes to the reserve requirements in relation to emergency procedures via the Emergency Procedure Posting Application once the decision to change the reserve requirements is made.

- Regardless of the reserve requirements modeled in the Market Clearing Engines, PJM operators will continue to initiate emergency procedures based on the reserve requirements defined in Manual 13: Emergency Operations.

4.2.3 Synchronized Reserve Obligation Fulfillment

Each Load Serving Entity (LSE) on the PJM system incurs a synchronized reserve obligation in kWh based on their real-time load ratio share and the Synchronized Reserve Zone total assigned MW. During hours when the Synchronized Reserve Market Clearing Price (SRMCP) is the same throughout the Synchronized Reserve Zone, an LSE's

synchronized reserve obligation is equal to its load ratio share times the amount of synchronized reserve assigned for the Synchronized Reserve Zone. During hours when congestion causes Synchronized Reserve Market Clearing Prices (SRMCP) to separate, each LSE's obligation is equal to its load ratio share within its sub-zone times the amount of synchronized reserve assigned in that sub-zone. Any PJM market participant may incur or fulfill a synchronized reserve obligation through the execution of a bilateral synchronized reserve transaction as described below.

- Participants may fulfill their synchronized reserve obligations by:
  - Owning Tier 1 resources from which the Synchronized Reserve Zone obtains synchronized reserve;
  - Self-scheduling owned Tier 2 resources;
  - Entering bilateral arrangements with other market participants; or
  - Purchasing synchronized reserves from the market.

Note that LSEs whose reserve obligations are satisfied through an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 will not have a synchronized reserve obligation.

4.2.4 Synchronized Reserve Offer Period

Synchronized Reserve offer prices for Tier 2 resources and Synchronized Reserve ramp rates are locked as of 1415 hours on the day preceding the operating day. All resources listed as available for Tier 2 Synchronized Reserve with no offer price will have their offer prices set to zero.

To accurately reflect each resource's reserve capability and availability during the Operating Day, 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 Synchronized Reserve Market closes.

- Synchronized Reserve Availability for Tier 2 resources
- Synchronized Reserve Offer Quantity (MW)
- Synchronized Reserve Maximum (This parameter is called Spin Max on the Markets Gateway Synchronized Reserve Hourly Updates screen)

4.2.5 Bilateral Synchronized Reserve Transactions

Bilateral synchronized reserve transactions may be reported to PJM. Such reported bilateral synchronized reserve transactions must be for the physical transfer of synchronized reserve and must be reported by the buyer and subsequently confirmed by the seller through the Markets Gateway System no later than 1330 the day after the transaction starts. Bilateral

transactions that have been reported and confirmed may not be changed; they must be deleted and re-reported. Deletion of a reported bilateral transaction after its start time has passed will result in a change in the end time of the transaction to the current hour.

Bilateral synchronized reserve transactions reported to PJM 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.

Payments and related charges associated with the bilateral synchronized reserve transactions reported to PJM shall be arranged between the parties to the bilateral contract.

A buyer under a bilateral synchronized reserve transaction reported to PJM agrees that it guarantees and indemnifies PJM, PJM Settlement, and the market participants for the costs of any purchases by the seller in the Synchronized Reserve Market, as determined by PJM, to supply the reported bilateral transaction and for which payment is not made to PJM Settlement by the seller.

Upon any default in obligations to PJM or PJM Settlement by a Market Participant, PJM shall not accept any new bilateral reporting by the Market Participant and shall terminate all of the market participant's reporting of Markets Gateway schedules associated with its bilateral synchronized reserve transactions previously reported to PJM for all days where delivery had not yet occurred.

PJM calculates and posts Synchronized Reserve Zone preliminary billing data on which market participants can use as a resource for pricing bilateral synchronized reserve transactions. The information can be found on the PJM website at http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/preliminary-billing-reports/sync-reserve.aspx.

4.2.6 Synchronized Reserve Commitment

60-minutes prior to the operating hour PJM will execute the Ancillary Services Optimizer (ASO). The ASO will jointly optimize energy, synchronized reserves, non-synchronized reserves and regulation based on forecast system conditions to determine an economic set of inflexible reserve resources to commit for the operating hour.

Any self-scheduled offers for synchronized reserves that are available at the time of the ASO execution will be assumed valid and committed for the hour.

Any reserve commitments on inflexible resources that are made will be locked for the operating hour and communicated via Markets Gateway.

The following reserve information will be posted to Markets Gateway 30-minutes prior to the operating hour:

- Reserve requirements for the RTO and each sub-zone
- Estimated Tier 1 for the RTO and each sub-zone

- Total synchronized and non-synchronized reserves available for the RTO and each sub-zone
- Total pool-committed inflexible reserves for the RTO and each sub-zone
- Total self-scheduled synchronized reserves for the RTO and each sub-zone
- Forecasted reserve shortage quantities for the RTO and any sub-zone
- Any additional Tier 2 synchronized reserves required in real-time in excess of the current Tier 1 on the system and the inflexible Tier 2 commitments will be committed via the joint optimization of energy, reserves and regulation.
- Additional Tier 2 synchronized reserve commitments made in real-time may be made on flexible reserves resources by the RT SCED application and inflexible reserves resources recommendations by the IT SCED application. Commitments on flexible reserves resources may change with each execution of the RT SCED application while commitments on inflexible reserve resources will respect the minimum run time of those resources.
- Flexible reserve resource Tier 2 commitments will not be posted to Markets Gateway but will be telemetered via ICCP or other communication protocol to resource owners.
- Additional inflexible resource commitments will be communicated to the resource owners via phone call and ICCP or other communication protocol.
- Any resource that is committed for Tier 2 when a synchronized reserve event occurs is obligated to respond for their commitment at the start of the event within 10 minutes.
- For the purpose of determining the most economic set of resources with which to meet the Synchronized Reserve requirement, PJM will calculate a resource-specific merit order price for each resource using the following methodology:
    - Resource merit order price ($/MWh) = Resource synchronized reserve offer + estimated resource opportunity cost per MWh of capability + energy use per MWh of capability + condense startup cost

Note: Condense startup cost is not included in the determination of the clearing price.

The resource synchronized reserve offer is that which is submitted by the owner via the Markets Gateway System by 1415 hours on the day preceding the operating day.

Estimated resource opportunity cost for condensing CTs is calculated as follows:

O.C.= [positive (forecast LMP – energy offer price)] x MW capability / synchronized reserve capability

Estimated resource opportunity cost for non-condensing resources is calculated as follows:

O.C. = |LMP – ED| x GENOFF, where:

LMP is the forecasted hourly LMP at the generator bus,

ED is the price associated with the set point the resource must maintain to provide its assigned amount of synchronized reserve, and

GENOFF is the MW amount of synchronized provided.

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

Energy use for each condensing resource is entered in MW by the owner via the Markets Gateway system as part of the synchronized reserve offer. Estimated energy use is calculated as part of the merit order price as follows:

E.U. = forecast LMP x energy use MW / synchronized reserve capability

For each of these calculations, forecast LMP is the result of the 1-hour look-ahead calculated in the ASO. Energy resources for which an energy offer is not submitted will be ineligible for opportunity cost credit.

When calculating the SRMCP in real-time, the actual LMP is used instead of the forecast LMP in the previous equations and calculated in the LPC engine. The 5-minute SRMCP is integrated to calculate an hourly value for settlements.

The opportunity cost for a Demand Resource is zero.

- PJM may call on resources not otherwise scheduled to run in order to provide synchronized reserve, in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. If a resource is called on by PJM for the purpose of providing synchronized reserve, the resource is guaranteed recovery of synchronized reserve lost opportunity costs as well as start-up, no-load and energy costs. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details.

- Due to transmission considerations on the PJM system, it is sometimes necessary to carry a minimum amount of synchronized reserve in specific areas in PJM such that loading 100% synchronized reserve will not result in an overload of any of the PJM transfer interfaces. The goal is to minimize the cost of synchronized reserve such that given current system conditions, the flow on binding transmission constraints is

not increased after a synchronized reserve event is initiated and the associated response is achieved. Therefore, PJM clears the Tier 2 market based on this locational synchronized reserve requirement and calculates sub-zonal Tier 2 clearing prices. Whenever the locational synchronized reserve constraint is not binding, the clearing prices are equal. However, when more synchronized reserve is required in a given area than would have been assigned without this requirement, the clearing prices will separate. Resources will be identified and receive the applicable clearing price based on their location with respect to the binding constraint(s). That is, resources for which synchronized reserve event response would help the constraint will receive the higher clearing price, whereas resources for which synchronized reserve event response would aggravate the constraint will receive the lower clearing price. Analysis to determine the location of generation and load buses with respect to the binding constraint is performed at least once with each quarterly network model update. The Mid-Atlantic Dominion sub-zone list resulting from this analysis can be found on the PJM Web site under "Mid-Atlantic-Dominion Subzone Bus and Resource List" at this location: http://www.pjm.com/markets-and-operations/ancillary-services.aspx. Resource owners should be aware if their resources are listed in the file and are therefore located in the MAD reserve subzone. Resources that do not appear in the list may respond only to PJM's request for Synchronized Reserve event in the RTO Reserve Zone. Resources that appear in the list may respond to PJM's request for Synchronized Reserve event in the MAD Reserve Sub-zone and the RTO Reserve Zone.

- Preliminary 5-minute market clearing prices will be made available in real-time through Data Viewer.

4.2.7 Hydro Units

Hydro units condensing to provide synchronized 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 synchronized reserve offer.

- If a hydro unit is held to synchronized reserve condense or reduced to provide synchronized reserve during a time when it is 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 'Synchronized Reserve Commitment', O.C. = |LMP – ED| x GENOFF, except the ED value is the average value of the LMP at the hydro unit bus for the appropriate on-peak (0700 – 2259) or off-peak (0000 – 0659, 2300 - 2359) period, excluding those hours during which all available units at the hydro plant were operating. Day-ahead values are used for the purposes of committing 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 spilling mode, 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 on the Regulation Hourly Updates page in the Markets Gateway System.

- 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 synchronized reserve offer for those units and made the units available for spin.

- An example of Tier 2 synchronized reserve lost opportunity cost calculation is very similar to that of regulation hydro lost opportunity cost calculation detailed on the PJM website at http://pjm.com/~/media/markets-ops/ancillary/regulation-uplift-and-lost-opportunity-cost.ashx

4.2.8 Demand Resources

Demand resources providing Synchronized Reserve are required to provide metering information at no less than a one minute scan surrounding a synchronized reserve event. Residential customers without one-minute metering may participate using the statistical sampling method detailed in Manual 19: Load Forecasting and Analysis, Attachment D and subject to PJM approval.

Metering information for demand resources is not required to be sent to PJM in real time. Load data for all Synchronized Reserve events must be submitted two business days following the event day.

Members that offer into the Synchronized Reserve market and do not provide complete, accurate and timely load data for all Synchronized Reserve events may be suspended from participating in the Synchronized Reserve Market until corrective measures are implemented and may be referred to the PJM Market Monitor and/or the FERC Office of Enforcement for further investigation as necessary.

Demand resources are limited to providing 33% of the Synchronized Reserve requirement.

Demand resources that are considered to be “batch load” resources are limited to providing 20% of the Synchronized Reserve requirement. If PJM determines that satisfying 20 percent of the Synchronized Reserve requirement from Batch Load demand resources is causing or may cause a reliability degradation, PJM may reduce the percentage of the requirement that may be satisfied by Batch Load demand resources in any hour to as low as 10 percent.

Demand resources must complete initial and continuing training on Regulation and Synchronized Reserve Markets as documented in Manual 40: Certification and Training Requirements, Section 2.6: Training Requirements for demand response Resources Supplying Regulation and Synchronized Reserve.

When a Demand Resource that is eligible for the Synchronized Reserve Market is called for a mandatory Emergency or Pre-Emergency Load Management Event, it will be de-assigned from Synchronized Reserves for any intervals that overlap with the Load Management Event, starting from the notice time of the Load Management Event, unless otherwise approved by PJM. PJM will not assign the resource to Synchronized Reserves for the remainder of the mandatory portion of the Load Management Event.

4.2.9 Synchronized Reserve Market Clearing Price (SRMCP) Calculation

PJM will calculate real-time prices for Synchronized Reserve simultaneously with LMPs every 5-minutes in real-time.

The real-time prices for Synchronized Reserve will be calculated as the marginal cost to serve an additional MW of synchronized reserve demand in the RTO Reserve Zone or applicable Reserve Sub-zone while simultaneously satisfying energy requirements, regulation requirements, primary reserve requirements and transmission limitations.

Preliminary real-time 5-minute SRMCPs will be published to Data Viewer for public view.

During periods when there is no synchronized reserve shortage, real-time prices for Synchronized Reserve will be determined by the cost of the marginal synchronized reserve resource.

- The cost of the marginal synchronized reserve resource is defined as its synchronized reserve offer plus any opportunity cost for this resource relative to forgone energy or other ancillary service payments.

- Non-shortage prices for synchronized reserves will not exceed the sum of the primary reserve and synchronized reserve penalty factors.

When there is a simultaneous shortage of primary and synchronized reserves the real-time prices for Synchronized Reserve will be the sum of the primary reserve and synchronized reserve penalty factors.

The real-time prices for Synchronized Reserve will always be greater than or equal to the NSRMCP in the same location because synchronized reserve is a higher quality product than non-synchronized reserves and may be substituted for it.

The real-time prices for Synchronized Reserve in each hour will be used to calculate the hourly SRMCP that will be used for settlement purposes. The hourly SRMCP for a reserve zone will be the average of the 5-minute SRMCPs in the applicable Reserve Zone or Reserve Sub-zone.

4.2.10 Settlements

Please refer to Manual 28: Operating Agreement Accounting, Section 6: Synchronized Reserve Accounting for settlement details.

Synchronized Reserve settlement is a zero-sum calculation based on the synchronized reserve provided to the market by generation owners and purchased from the market by participants.

Tier 1 credits will be awarded to each eligible resource for response up to 110% of the resource's capability based on the synchronized reserve ramp rate(s) submitted by the resource's owner day-ahead. Credits to individual resources 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 resources.

Resources providing regulation at the initiation of a synchronized reserve event will be compensated for Tier 1 response. Tier 1 response is calculated according to the following formula:

$$\left\{\begin{array}{l}\left[\max\left(0, \text{integrated}\left(\text{Output} - \min\left(\text{EcoMax, RegHighLimit}\right)\right)\right)\right] + \\ \left[\max\left(0, \left(\text{integrated}\left\{\begin{array}{l}\min\left(\text{EcoMax, RegHighLimit, Output}\right) - \\ \text{Initial Output} - \left(2 \times \text{RegMW}\right)\end{array}\right\}\right)\right)\right]\end{array}\right\}, \quad \text{where:}$$

Final Output is the resource's greatest telemetered output between 9 and 11 minutes after synchronized reserve event is initiated

Initial Output is the resource's lowest telemetered output between 1 minute before and 1 minute after synchronized reserve event is initiated

RegMW is the resource's assigned amount of regulation

As a result of this formula, resources that are assigned regulation when a synchronized reserve 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 resource's regulation maximum commitment will be defined as the resource's full regulating range (i.e. – twice the amount of assigned regulation.)

- Tier 1 synchronized reserve resources are compensated when the Non-Synchronized Reserve Market Clearing Price is non-zero. When the Non-Synchronized Reserve Market Clearing Price is non-zero Tier 1 synchronized reserve credits are equal to the lesser of the integrated increase in MWh output or decrease in MWh of consumption from each resource over the length of a synchronized reserve event or the Tier 1 estimate attributed to the resource multiplied by the Synchronized Reserve Market Clearing Price. During hours where no synchronized reserve event occurs, the Tier 1 resource will be compensated for the Tier 1 estimated amount for only those resource that can reliably provide

Synchronized Reserve service per the rules in this manual, section 4.2.1 Synchronized Reserve Eligibility.

- Tier 2 synchronized reserve credits are awarded to generation owners that have either self-scheduled synchronized reserve or sold synchronized reserve into the market. Synchronized reserve credits for resources self-scheduled to provide synchronized reserve are equal to Tier 2 clearing price times the resource's self-scheduled synchronized reserve capability. Synchronized reserve credits for resources that are pool-scheduled to provide synchronized reserve are the higher of:
  - Tier 2 clearing price times the resource's assigned synchronized reserve capability, or
  - The resource's synchronized reserve offer times its assigned synchronized reserve capability plus opportunity cost and/or energy use incurred.
- Opportunity cost and energy use are calculated as shown above in Market Clearing using actual integrated LMP as opposed to that which was forecasted.
- Resources that are pool-assigned Tier 2 synchronized reserve (and actual MWh are less than day-ahead scheduled MWh) and Tier 1 resources that respond to a synchronized reserve event are therefore exempt from deviations for the purpose of accumulating operating reserves charges for the hours during which the Tier 2 assignment or Tier 1 response is effective.

4.2.11 Verification

The magnitude of each resource's response to a synchronized reserve event (both Tier 1 and Tier 2) is the difference between the resource'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, resource 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 resource'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 resources (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 resource will be reduced by the amount the MW output of that resource 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.

For demand resources that are considered "batch load" resources, a second method of verification will be used for instances where a synchronized reserve event is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (a) the resource's

consumption at the end of the event and (b) the maximum consumption within a ten (10) minute period following the event provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

4.2.12 Non-Performance

There is no consequence for a Tier 1 resource that does not respond with the amount of Synchronized Reserve that was expected of it in response to a Synchronized Reserve Event. Tier 1 resources are simply credited for the amount of response they provide.

Since Tier 2 resources are credited with a capacity payment any time they are expected to be ready to respond to a Synchronized Reserve 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 Synchronized Reserve:

- The resource is credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all hours the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the day the event occurred, and;

- The owner of the resource incurs a retroactive obligation to refund at SRMCP the amount of the shortfall measured in MW for all of the hours the resource was assigned or self-scheduled over the immediate past interval, the duration of which is equal to the lesser of the average number of days between events as determined by the annual review of the last 2 years, or the number of days since the resource failed to respond with its assigned or self-scheduled Synchronized Reserve amount in response to a Synchronized Reserve Event.

    - The annual review described above will be completed during the month of November and cover a 2 year window from November 1st (year – 2) through October 31st (current year). The calculation will be the average interval between Synchronized Reserve Events over the last two years of Synchronized Reserve Event data, rounded down to a whole day value. The results will be communicated to the Operating Committee in December and implemented annually on January 1st.

Market Participants that own multiple resources assigned or self-scheduled to provide Tier 2 Synchronized Reserve are permitted to demonstrate aggregate response, such that any resource that has responded greater than their assignment or self-schedule can be used to offset any resource that has responded less than their assignment or self-schedule of Tier 2 Synchronized Reserve during a Synchronized Reserve Event. The Market Participant's aggregate response shall not affect how an individual resource is credited for Tier 2 Synchronized Reserve it provides as described above, but shall be used to determine what the Market Participant owes in refund charges for each resource that was assigned or self-scheduled to provide Tier 2 Synchronized Reserve and responded less than their

assignment or self-schedule of Tier 2 Synchronized Reserve. Additional details can be found in Manual 28, Section 6.3: Charges for Synchronized Reserve.

In cases where a Synchronized Reserve Event lasts less than 10 minutes, Tier 2 resources are credited with the amount of Synchronized Reserve capacity they are assigned. The owner of the resource will not incur a retroactive obligation to refund any shortfall between the amount of Tier 2 assigned or self-scheduled and the amount of response provided during the event. 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 resource 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.

Resources that choose to respond to a Synchronized Reserve Event for their reserve zone in an hour when they are cleared or assigned regulation are expected to return to their regulating band within 10 minutes of the end of the Synchronized Reserve Event. From the start of the event, through the event, and for the 10 minutes after the end of the event, the performance scores for all regulating resources in the reserve zone where the Synchronized Reserve Event takes place will be null.

Section 4b: Overview of the Non-Synchronized Reserve Market

Welcome to the Overview of the Non-Synchronized Reserve Market section of the PJM Manual for Energy & Ancillary Services Market Operations. In this section you will find the following information:

- An overview description of the PJM Non-Synchronized Reserve Market (see "Overview of PJM Non-Synchronized Reserve Market").
- A list of the PJM Non-Synchronized Reserve Market Business Rules (see "PJM Non-Synchronized Reserve Market Business Rules").

4b.1 Overview of the Non-Synchronized Reserve Market

PJM has an obligation to maintain a certain quantity of total 10 minute reserves on the system. Total 10 minute reserve, or Primary Reserve, includes both Synchronized and Non-Synchronized Reserves. As defined in Section 4 of this manual, a subset of the Primary Reserve capability must be maintained in resources that are synchronized to the system. That quantity is defined by the Synchronized Reserve requirement. The balance between the Primary and Synchronized Reserve requirements can be met by the most economic combination of additional Synchronized Reserve or Non-Synchronized reserve or some combination of the two products. This means that there is no defined, hourly requirement for Non-Synchronized reserves but it will be procured when economic to meet the Primary Reserve requirements.

The PJM Non-Synchronized Reserve Market provides PJM participants with a market-based system for the purchase and sale of the Non-Synchronized Reserve ancillary service. PJM determines the MW capability of each resource based on its operational characteristics and uses this information together with energy offers and resource schedules as input data to real-time market applications. The real-time market applications optimize the RTO dispatch profile while simultaneously determining the most economic set of resources to provide Synchronized and Non-Synchronized Reserves. Non-Synchronized Reserve commitments are telemetered to each resource. As a result of the real-time joint optimization of energy and reserves, PJM will calculate a clearing price for Non-Synchronized Reserve every 5 minutes based on the current system conditions. All 5 minute, real-time, Non-Synchronized Reserve prices will be averaged to calculate the hourly Non-Synchronized Reserve Market Clearing Price (NSRMCP) that will be used for market settlement.

4b.2 Non-Synchronized Reserve Market Business Rules

4b.2.1 Non-Synchronized Reserve Resource Eligibility

Non-synchronized reserves may be provided only by generation resources electrically within the PJM RTO.

Non-synchronized reserve resources are defined as generation resources that meet the following eligibility requirements to provide non-synchronized reserve.

The Non-Synchronized Reserve capability of a generation resource shall be the increase in energy output or achievable by the generation resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response

Examples of Non-Synchronized Reserve resources generally include:

- Shutdown run-of-river, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle and diesels.
- Demand Resources will not be eligible to provide Non-Synchronized Reserve
- Generation resources that have designated their entire output as emergency will not be considered eligible to provide non-synchronized reserves.
- Generation resources that are not available to provide energy will not be considered eligible to provide non-synchronized reserves.

4b.2.2 Non-Synchronized Reserve Zones and Levels

There will be a single RTO Non-Synchronized Reserve Market with a static, nested Mid-Atlantic Dominion Reserve Sub-zone.

- The Mid Atlantic Dominion Reserve Sub-zone is defined to ensure that non-synchronized reserves are available in or deliverable to the eastern part of the system under constrained conditions. The Mid-Atlantic Dominion Reserve Sub-zone is defined by the most limiting monitored transfer interface. The interface modeled may be revised by PJM to match operation and meet the system reliability need.
- Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. Non-synchronized reserve is eligible to be used to meet the difference between the primary and synchronized reserve requirements if it is economic.
- During a Synchronized Reserve Event, PJM may request generation resources, which are assigned to provide Non-Synchronized Reserve within ten minutes, to increase their energy output by the amount of assigned Non-Synchronized capability.

- Each Primary Reserve requirement will have an associated reserve demand curve as specified in section 2.5 Real-Time Market Applications.

4b.2.3 Non-Synchronized Reserve Offer Information

No offer data for non-synchronized reserves will be submitted through Markets Gateway.

Non-emergency generation resources that are available to provide energy and can start in 10 minutes or less will be considered available for Non-Synchronized Reserves.

PJM will calculate the non-synchronized reserve MW quantity available from each generation resource based on the offered in startup and notification time, the economic minimum, the economic maximum, and the energy ramp rate.

$$NSRMW = \max\{0, \min[EcoMax, EcoMin + (10 - Startup - NotificationTime) * EnergyRampRate]\}$$

All offers to provide non-synchronized reserves will be $0.00/MWh.

4b.2.4 Non-Synchronized Reserve Commitments

PJM will commit Synchronized and Non-Synchronized Reserve simultaneously in real-time via the joint optimization of energy and reserve.

Non-Synchronized Reserve commitments will be telemetered to each committed generation resource via ICCP or other communication protocol.

Because the requirement for Synchronized Reserves is included within the Primary Reserve requirement, Non-Synchronized Reserves can only be used to meet the difference between the synchronized and primary reserve requirements if it is economic.

Both Synchronized Reserves and Non-Synchronized Reserves can be used to meet the difference between the Synchronized and Primary Reserve requirements. PJM will commit the most economic combination of both resources to simultaneously meet all energy and reserve requirements.

When calculating the 5-minute NSRMCP, the unit-specific opportunity cost for a generation resource that is not providing energy, because it is providing Non-Synchronized Reserves, is calculated as:

a. The product of:
   - The deviation of the value of the generation resource's output necessary to follow PJM dispatch instruction from the value of the generation resource's expected output level if it had been dispatched in economic merit order
   - The estimated real-time Locational Marginal Price (LMP) at the generation bus of the unit

b. Minus:

- The applicable offer for energy from the generation resource

If the real-time LMP at the generator bus is less than the generator's cost at its Economic Minimum then the generator has no opportunity cost.

4b.2.5 Non-Synchronized Reserve Market Clearing Price (NSRMCP) Calculation

PJM will calculate NSRMCPs simultaneously with LMPs every 5-minutes in real-time.

The NSRMCP will be calculated as the cost to serve an additional MW of primary reserve demand in the RTO Reserve Zone or applicable Reserve Sub-zone.

Real-time 5-minute NSRMCPs will be published to Data Viewer for public view.

During periods when there is no Primary Reserve shortage, the NSRMCP is the cost of the marginal primary reserve resource. If the marginal resource is a Non-Synchronized Reserve resource, the cost of the marginal Primary Reserve resource is defined as any opportunity cost for this resource relative to forgone energy or other ancillary service payments. If the marginal resource is a Synchronized Reserve resource, the cost of the marginal Primary Reserve resource is defined as its synchronized reserve offer plus any opportunity cost for this resource relative to forgone energy or other ancillary service payments. Non-shortage prices for Non-Synchronized Reserves will not exceed the Primary Reserve penalty factor.

During periods when there is a shortage of Primary Reserves, the NSRMCP will be equal to the penalty factor of the location where the shortage occurred.

The NSRMCP will always be less than or equal to the SRMCP in the same location because Synchronized Reserve is a higher quality product than Non-Synchronized Reserve and may be substituted for it.

The 5-minute NSRMCPs for each hour will be averaged to an hourly NSRMCP that will be used for market settlement purposes.

Resources that are assigned Non-Synchronized Reserve will be paid the NSRMCP corresponding to the location in which they provided the service.

Settlement for the Non-Synchronized Reserve market will function as follows:

- On an hourly basis PJM will determine the cost for each pool scheduled resource to provide Non-Synchronized Reserve and compensate it at the higher of the NSRMCP or the cost to provide the service (including any lost opportunity cost).

4b.2.6 Non-Synchronized Reserve Obligation Fulfillment

Each Load Serving Entity (LSE) on the PJM system incurs a Non-Synchronized Reserve obligation in kWh based on their real-time load ratio share of the Non-Synchronized Reserve assigned. During hours when the Non-Synchronized Reserve Market Clearing Price (NSRMCP) is the same throughout the RTO, an LSE's Non-Synchronized Reserve obligation is equal to its load ratio share times the amount of Non-Synchronized Reserve

assigned for the entire RTO. During hours when congestion causes NSRMCPs to separate each LSE's obligation is equal to its load ratio share within its Reserve Sub-zone times the amount of Non-Synchronized Reserve assigned in that Reserve Sub-zone. Any PJM market participant may incur or fulfill a Non-Synchronized Reserve obligation through the execution of a Non-Synchronized Reserve bilateral transaction as described below. Each PJM Member LSE that is not part of an agreement to share reserves with external entities subject to the requirements in NERC Reliability Standard BAL-002 incurs a non-synchronized reserve obligation based on their hourly real-time load ratio share and applicable reserve zone's Non-Synchronized Reserve assigned during that hour.

Participants may fulfill their Non-Synchronized Reserve obligations by:

- Self-supply from its own generation resources capable of providing Non-Synchronized Reserve
- Entering bilateral arrangements with other market participants; or
- Purchasing Non-Synchronized Reserve from the Non-Synchronized Reserve market.

4b.2.7 Non-Synchronized Reserve Bilateral Transactions

PJM Settlement shall be the Counterparty to the purchases and sales of Non-Synchronized Reserve.

Non-Synchronized Reserve bilateral transactions must be entered by the buyer and subsequently confirmed by the seller through Markets Gateway no later than 1415 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.

Non-Synchronized Reserve bilateral transactions may be entered in MW. Participants will also be required to indicate the Reserve Zone or Reserve Sub-zone for which the transaction is applicable. The minimum MW value is .1 MW

PJM calculates and posts Non-Synchronized Reserve Zone preliminary billing data on which market participants can use as a resource for pricing bilateral Non-Synchronized Reserve transactions. The information can be found on the PJM website at http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/preliminary-billing-reports/non-sync-reserve.aspx.

4b.2.8 Non-Synchronized Reserve Settlement

Non-Synchronized Reserve settlement is a zero-sum calculation based on the Non-Synchronized Reserve provided to the market by generation purchased from the market by participants. Details on Non-Synchronized Reserve settlement can be found in PJM Manual M28.

4b.2.9 Verification

The magnitude of each generation resource's response to a Non-Synchronized Reserve event is its output ten minutes after the start of the event. A generation resource'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 generation resources that have been committed to provide Non-Synchronized Reserve 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 resource will be reduced by the amount the MW output of that resource 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.

In cases where a non-synchronized event lasts less than 10 minutes, non-synchronized resources are credited with the amount of Non-Synchronized Reserve event capacity they are assigned.

4b.2.10 Non-Performance

In the event a resource that has been assigned to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will only be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

Section 5: Market Clearing Processes and Tools

Welcome to the Market Clearing Processes and Tools section of the PJM Manual for Energy & Ancillary Services Market 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").

5.1 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 resources as needed to satisfy the PJM Load Forecast and the additional Day-ahead Scheduling Reserve (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 resource compared with every other available generating resource. The philosophy for scheduling the PJM RTO requires:

- Scheduling sufficient generation in the Day-ahead Energy Market to cover aggregate Demand bids and Day-ahead Scheduling Reserve (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 Day-ahead Scheduling Reserve (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 Synchronized 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 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.

5.2 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 resources for short-term and hourly activities. The scheduling tools include:

- PJM ExSchedule
- PJM InSchedule
- Load Forecasting Algorithms
- Markets Gateway and Market Database System
- Hydro Calculator
- Energy Market Technical Software (RSC, SPD and SFT)
- PJM Ancillary Service Optimizer (ASO)
- Real-Time Market Applications
- Transmission Outage Data System

Together these tools recognize the following conditions:

- Reactive limits
- Resource constraints
- Unscheduled power flows
- Inter-area transfer limits
- Resource distribution factors
- Self-Scheduled Resources

- Limited fuel resources
- Bilateral Transactions
- Hydrological constraints
- Generation requirements
- Reserve requirements

5.2.1 ExSchedule

ExSchedule is an application that facilitates the scheduling of interchange transactions between PJM and other Balancing Authorities. Market participants can view and reserve a portion of PJM's Net Ramp capability, review Tags linked to their account, and submit Day-Ahead Bids that align with their Real-Time interchange transactions. ExSchedule is also used to automatically assess and validate bilateral interchange transactions per PJM's interchange scheduling business rules.

Bilateral interchange transactions that are reported to PJM must be for the physical transfer of electric energy. Payments and related charges associated with such bilateral interchange transactions reported to PJM shall be arranged between the parties to the bilateral transaction. A buyer under a bilateral interchange transaction reported to PJM agrees that it guarantees and indemnifies PJM, PJM Settlement, and the market participants for the costs of any Spot Market Backup, as determined by PJM, to supply the reported bilateral interchange transaction and for which payment is not made to PJM Settlement by the seller. Upon any default in obligations to PJM or PJM Settlement by a Market Participant, PJM shall not accept any new bilateral interchange transaction reporting by the Market Participant and shall terminate all of the market participant's reporting of associated with its bilateral interchange transactions previously reported to PJM for all days where delivery had not yet occurred.

5.2.2 PJM InSchedule

PJM InSchedule is an Internet application that is used, among other functions, to report internal Bilateral Transactions.

5.2.3 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.

- 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.

- 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
- 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 2 presents the typical approach PJM uses to forecast load.

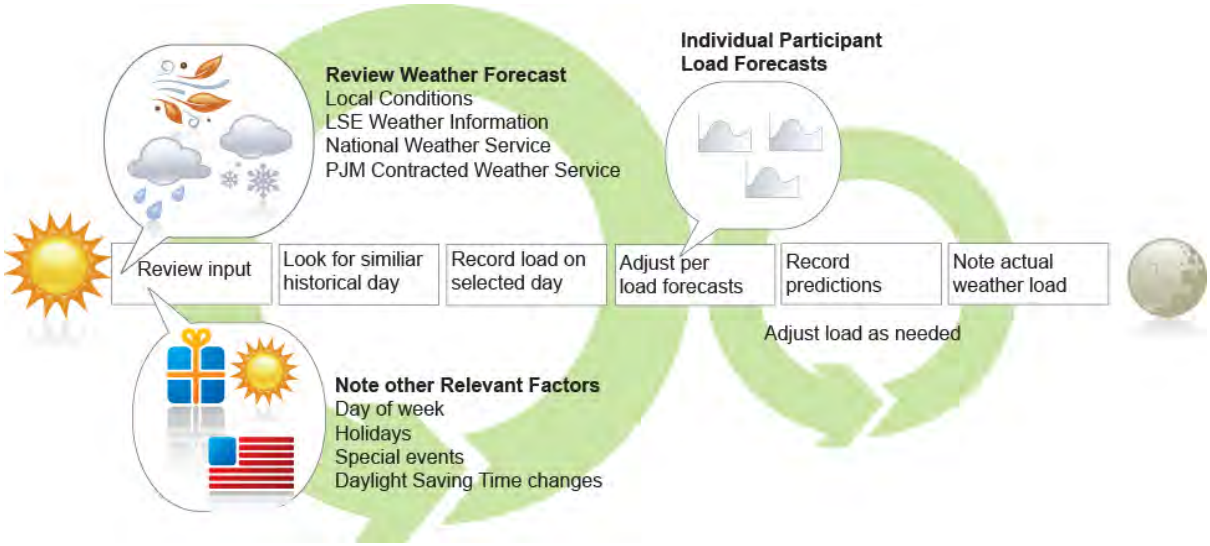


Exhibit 2: Load Forecasting Process

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.

5.2.4 Markets Database System

The Markets Database System is a two-part system:

- The Markets Database stores the basic resource data supplied by the PJM Members, including operating limits and resource availability.

- The Markets Gateway Web site 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, Synchronized Reserve Offers, into the Markets Database.

The Markets Database is a very large database that contains information on each generating resource that operates as part of the PJM Energy Market, Demand Information, Increment Offers, Decrement Bids, Regulation Offers, Synchronized Reserve Offers, Day-ahead Energy Market results, Day-ahead Scheduling Reserve Market Clearing Prices, Regulation Market Clearing Prices and Synchronized Reserve Market Clearing Prices. A description of the Markets Database can be found in the Markets Database Dictionary (http://www.pjm.com/markets-and-operations/etools/~/media/etools/emkt/market-database-data-dictionary.ashx).

Market participants may access the Markets Database by using the PJM Markets Gateway Web site via the Internet using manual entry or bulk upload/download via XML format.

Please refer to Exhibit 3: Energy Market Daily

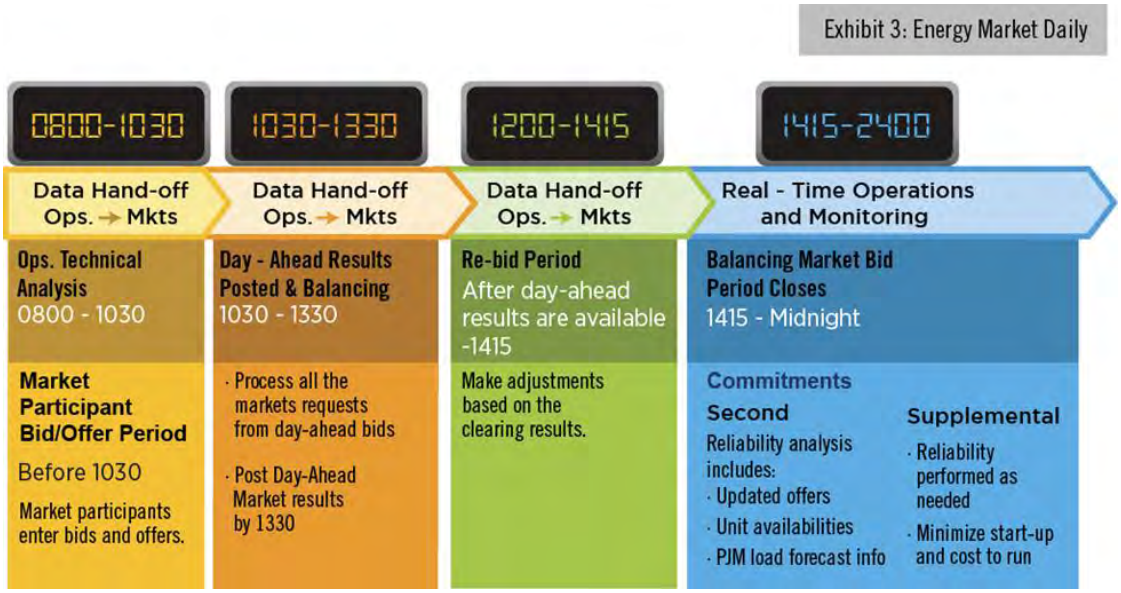


Exhibit 3: Synchronized Reserve and Regulation Market Daily Timeline

Please refer to Exhibit 3: Synchronized Reserve and Regulation Market Hourly Timeline.

- PJM clears the synchronized reserve and regulation markets on an hourly basis. The following is the timeline by which this hourly clearing is accomplished:

- 60-minutes prior to the operating hour PJM will execute the Ancillary Services Optimizer (ASO). The ASO will jointly optimize energy, synchronized reserves, non-synchronized reserves and regulation based on forecast system conditions to

determine an economic set of inflexible reserve resources to commit for the operating hour

The data that needs to be submitted by PJM Members to participate in the Day-ahead Energy, Synchronized Reserve, and Regulation Markets is described in detail in the Markets Database Dictionary.

5.2.5 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.

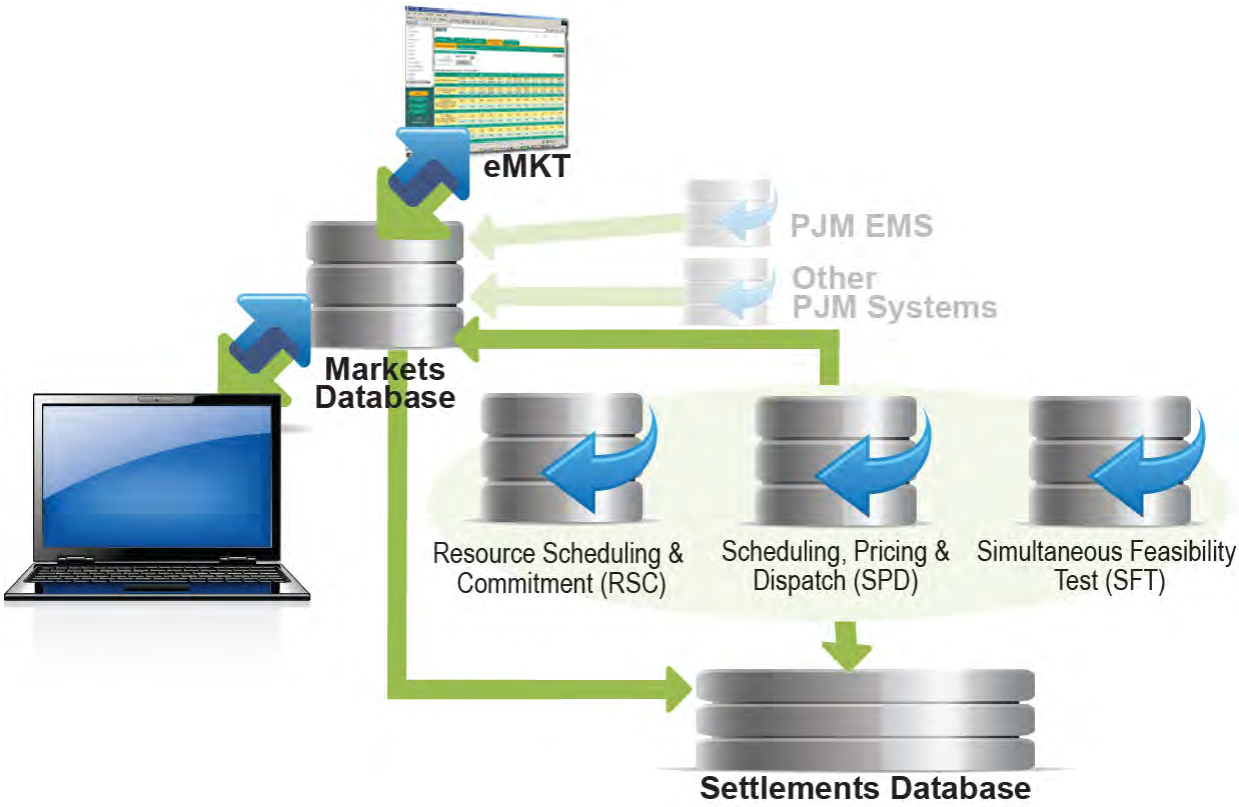
5.2.6 PJM Energy Market Technical Software

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

- **Resource Scheduling & Commitment (RSC) –** Performs security-constrained resource commitment based on generation offers, demand bids, Day-ahead Scheduling Reserve Offers, Increment Offers, Decrement bids and transaction schedules submitted by participants and based on PJM RTO reliability requirements. RSC will enforce physical resource 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 resource commitment schedule for the next seven days and it utilizes a Mixed Integer linear programming solver to create an initial resource 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 resource generation MW levels, LMPs and Day-ahead Scheduling Reserve Clearing Prices 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.

- **Simultaneous Feasibility Test (SFT) –** SFT performs AC contingency analysis using contingency list from PJM EMS and creates generic constraints equations based on any violations that are detected. These generic constraints equations are then passed them back to SPD for resolution. SFT ensures that the Day-ahead Market results are physically feasible considering PJM RTO security constraints and reliability requirements.



UDS/DMT

Exhibit 4: Settlement Subsystems

The Energy Market technical software develops the Day-ahead Market results based on minimizing production cost of energy and reserve 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 1415, the RSC is the primary tool used to determine any change in steam resource commitment status based on minimizing the additional startup costs and costs to operate steam resources at economic minimum in order to provide sufficient operating reserves to satisfy the PJM Load Forecast (if greater that cleared total demand in the Day-ahead Market) and adjusted Day-ahead Scheduling Reserve (Operating Reserves) requirements. The purpose of this second phase of resource 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 resources are included in the scheduling process and are scheduled in the Day-ahead

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

Download Data from Markets Database

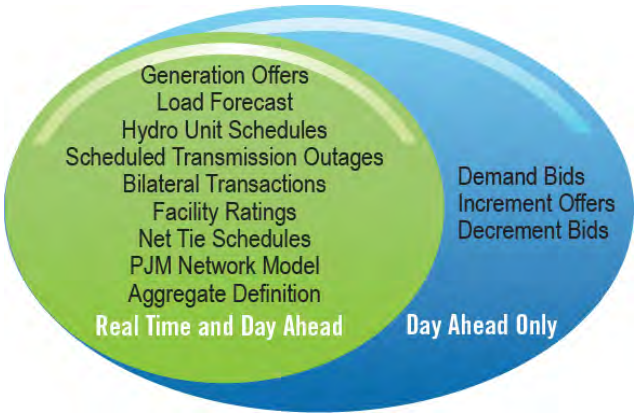


Exhibit 5: Download Data from Markets Database

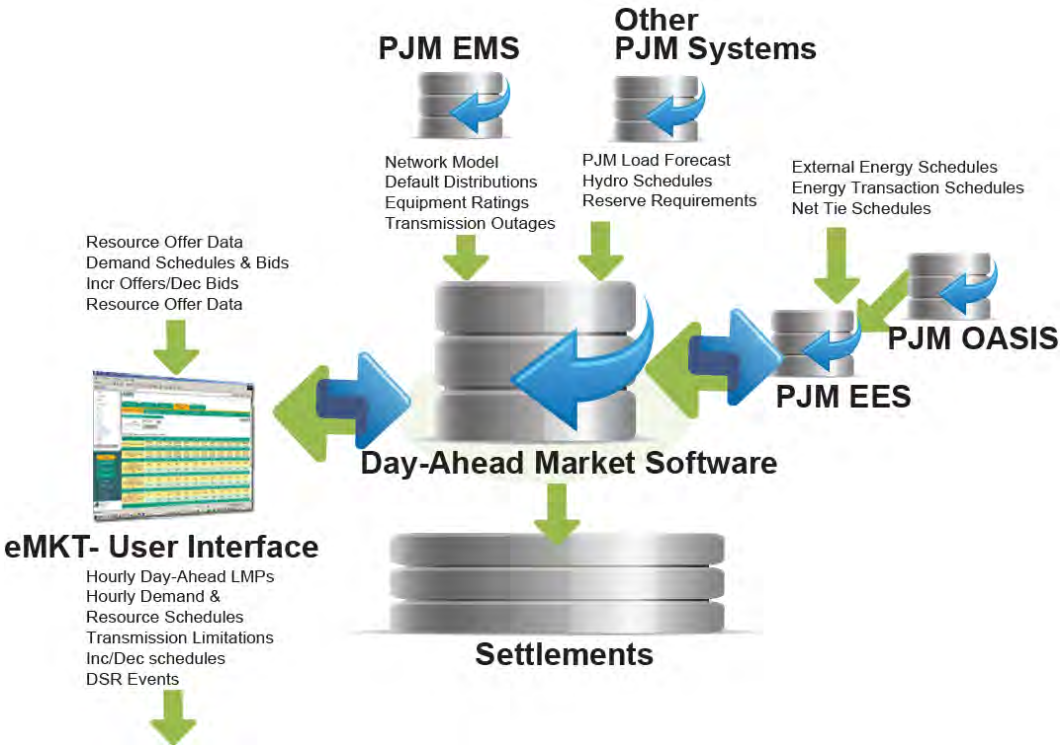


Exhibit 6: Energy Market Data Flow

Section 6: Reserve Requirements in PJM Energy Markets

Welcome to the Reserve Requirements in PJM Energy Markets section of the PJM Manual for Energy & Ancillary Services Market 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 synchronized reserve requirements are determined (see "PJM Synchronized 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 operations (dispatching) of monitored facilities. Details on the dispatching procedures for all facilities can be found in PJM Manual 12 Dispatch Operations. 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.

6.1 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 7 illustrates the Real-time Market relationships in the form of a bar chart.

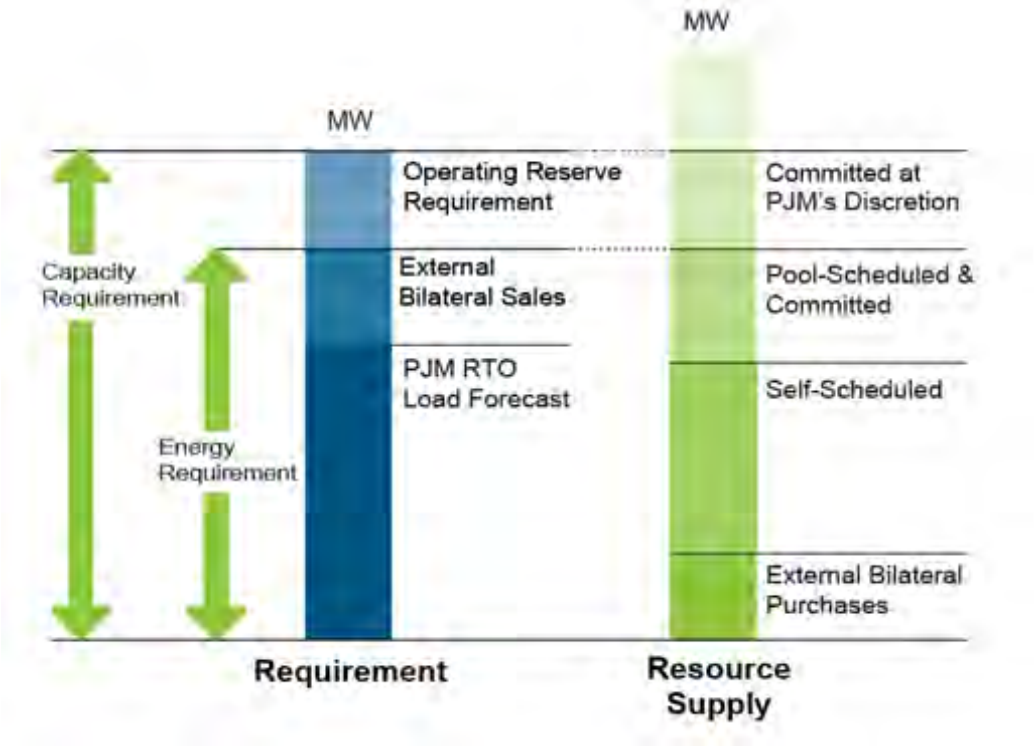


Exhibit 7: Requirement Versus Resource Supply

Exhibit 7 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:
  - Energy requirement, consisting of the PJM load forecast plus External Transaction sales to External Control Areas
  - Day-ahead Scheduling Reserve (Operating Reserve) requirement
- The PJM resource supply is represented by the bar on the right which consists of four supply components:
  - External Transaction purchases from External Control Areas
  - Resources that are self-scheduled by the PJM Members
  - Resources 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
  - Additional capacity to satisfy the Day-ahead Scheduling Reserve (Operating Reserve) requirement is committed at the discretion of the PJM

The identity of the 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/~/media/etools/emkt/market-database-data-dictionary.ashx)

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.

6.1.1 PJM Regulation Requirement

The total PJM Regulation Requirement for the PJM RTO is determined in whole MW for the ramp and non-ramp periods each day. Further detail is described in Manual 12 – Balanceing Operations, Section 4.4.3 Determining Regulation Assignment.

PJM Actions:

- PJM clears the Regulation Market by establishing the list of resources to provide regulation for the next operating hour and by calculating the Regulation Market Clearing Prices (RMCCP and RMPCP) every 5 minutes, then averaging for the hour as defined in Section 3 of this Manual.

- 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:

- PJM Members submit Individual Synchronized Reserve and Regulation offer data for each Resource that is available to provide synchronized reserve and/or regulation (for generation or demand resources meeting the Regulation quality standard and Synchronized 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 Markets Gateway Web site and is passed to the PJM Ancillary Service Optimizer (ASO). Exhibit 8 summarizes this information.

- PJM Members update regulating resource operating limits and availability in the PJM Markets Gateway Web site

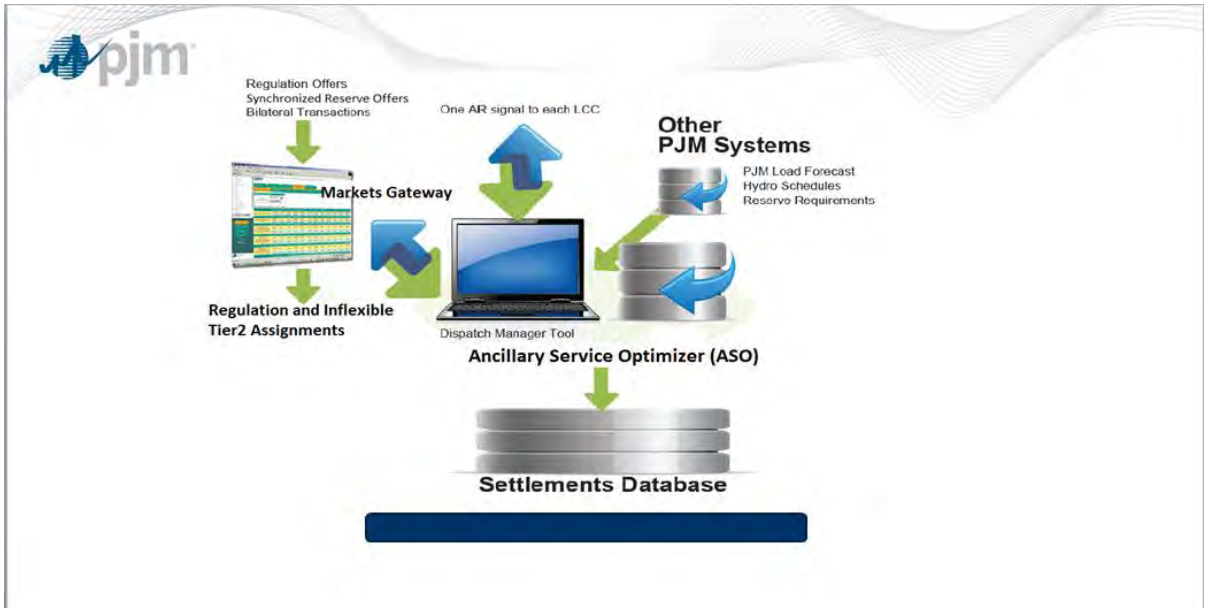


Exhibit 8: Synchronized Reserve and Regulation Data Flow

6.1.2 Regulation Service

PJM operates a bidding market for Regulation services in the PJM RTO. PJM Members that have generation or demand resources 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 Markets Gateway Web site and is passed to the Ancillary Service Optimizer (ASO). Generation owners and Demand Resources wishing to sell regulation service must supply a regulation offer price by 1415 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 9 defines the Regulation parameters of a qualified generating resource.

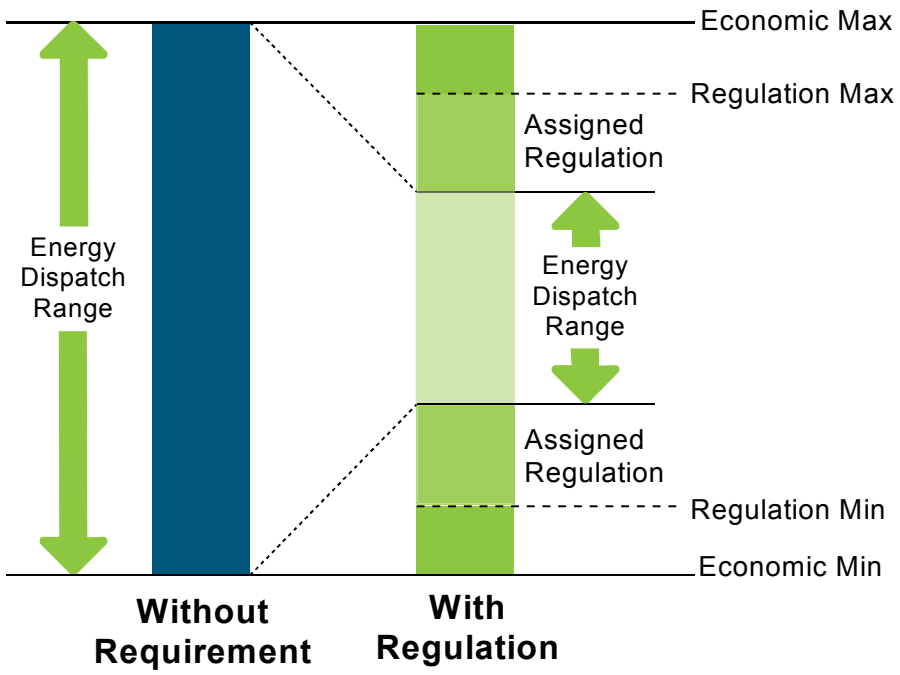


Exhibit 9: Generator Regulation Service

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 Balancing Operations (M-12) for a description of the Regulation allocation process during the course of system operation.

6.2 PJM Synchronized Reserve Requirements

The PJM RTO Reserve Zone is defined as that amount of 10-minute reserve that must be synchronized to the grid. The PJM Primary Reserve and Synchronized Reserve Zone and Reserve Sub-zone Reliability Requirements are documented in PJM Manual 13: Emergency Operations, Section 2.2.

PJM Actions:

- PJM clears the Synchronized Reserve and Non-Synchronized Markets by establishing the list of resources to provide Synchronized Reserve and Non-Synchronized Reserve for the next operating hour and by calculating the Synchronized Reserve Market Clearing Prices (SRMCP) and Non-Synchronized Reserve Market Clearing Prices (NSRCP) every 5 minutes, then averaging for the hour as defined in Sections 4 and 4b of this Manual.

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

PJM Member Actions:

- PJM Members submit Individual Synchronized Reserve and Regulation offer data for each Resource that is available to provide Synchronized Reserve and/or regulation (for generation or demand resources meeting the Regulation quality standard and Synchronized 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 Markets Gateway website and is passed to the PJM real-time market applications.

- PJM Members update Synchronized Reserve resource operating limits and availability in the PJM Markets Gateway Web site.

6.2.1 Synchronized Reserve Service

PJM operates a bidding market for Synchronized Reserve services in the PJM RTO. PJM Members that have resources meeting the Synchronized Reserve quality standard may submit Synchronized Reserve offer data for each individual resource that is available to provide synchronized reserve. The offer information is maintained within the PJM Markets Gateway Web site and is passed to the Ancillary Service Optimizer (ASO), Intermediate Term Security Constrained Economic Dispatch engine (IT SCED) and Real Time Security Constrained Economic Dispatch Engine (RT SCED). Resource owners wishing to sell synchronized reserve or regulation service must supply an offer price by 1415 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, Synchronized Reserve and Non-Synchronized Reserve markets close.

6.3 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, Demand Reduction 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 resource commitment and dispatch.

6.3.1 PJM Member Load Forecasts

Each PJM Electric Distribution Company (EDC) within the PJM RTO provides PJM with a forecast of its requirements by 1030 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.

6.3.2 Reserve Service

The Day-ahead Scheduling Reserve (Operating Reserve) objective is a Control Zone requirement (not allocated to PJM Members individually). PJM schedules sufficient generating resources to meet the PJM Day-ahead Scheduling Reserve (Operating Reserve) objective as part of the Day-ahead Scheduling Reserve Market Clearing process. See the PJM Manual for Emergency Operations (M 13) and section 11.2.1 (Day-ahead Scheduling Reserve Market Reserve Requirement) of this manual for the detailed methodology for determining Reserve Requirements.

6.3.3 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 choices are dependent on their scheduling philosophy.

6.3.4 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 resource 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 resource is needed for reliability purposes, he/she will inform the generation owner. The generation owner may still elect to not run the resource, but a forced outage for the duration of the scheduled operation of the resource 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 resource'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 resource. This allows PJM adequate time for determining if the resource is needed for reliability.

6.3.5 Fees 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 fee is defined as the actual costs incurred that are typically included in Start-up Costs, when PJM cancels a pool-scheduled generation resource's start and the resource has not yet reached the point after generator breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero. Cancellation Fees shall be, capped at the appropriate Start-up Cost for the resource as specified in its offer data. Requests for such credits must be submitted, in writing, to the PJM Manager of Market Settlement Operations Department, within forty-five days of invoice being received by participant for the month in question.

6.3.6 Resource Specific Data Requirements

Internal PJM Members Offer Data for resource specific offers is submitted directly into the Markets Database via the Markets Gateway Web site. Exhibit 10 summarizes the data requirements for capacity and energy resources

Capacity and Energy Only Data Requirements		
Resource Type	**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 Resource characteristics
	Next day	Must run output Whether or not to request bid acceptance notification by 4:00 p.m.
Energy only	Next day	Availability status Must run output

Exhibit 10: Capacity and Energy Resource Data Requirements

If offer data for a capacity resource is not submitted by 1030 of the day before the operating day, PJM uses the offer data and resource 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/markets-and-operations/etools/~/media/etools/emkt/market-database-data-dictionary.ashx).

6.3.7 External Market Sellers

An External Resource is a generation resource that is located outside the metered boundaries of PJM. If an external resource is qualified as a capacity resource in PJM, then in accordance with the PJM Tariff, all external resources being offered in as capacity resources must bid into the PJM Day-ahead Market as generation resources.

For an external resource to be offered as a unit resource, a valid generator offer, which consists of a price-based schedule, is submitted in the Markets Gateway system and a valid energy schedule is submitted in the ExSchedule system.

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 resource 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
- Resource 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

The Network Customer may request Network External Designated transmission service for the delivery of a designated network resource. Requests for service are subject to Available Transmission Capability (ATC) and other PJM Regional Practices (http://pjm.com/~/media/etools/oasis/20130612-Regional_Practices-clean-pdf.ashx).Energy Scheduling (ExSchedule and eTag) Requirements:

A valid NERC eTag is required for all hours that the external resource will be bid into PJM. The firm OASIS reservation assigned to the external resource shall be linked to the tag. The tag will also have a special exception attached in the form of the Token/Value pair: “EXCEPTION”/”CAPBACK”, and the tag will be subject to PJM interchange ramp limits.

6.3.7.1 Day-ahead Market between 1030 and 1330

As specified in the Energy Market Business Rules, Bidding and Operations Timeline section, all bids must be received by 1030(EPT). From 1030 to 1330(EPT), the bids will be evaluated. Results will be posted in the Markets Gateway system by 1330(EPT). External Capacity Participants will be required to check the Markets Gateway system to see if the bid has been accepted.

For bids accepted in the Day-ahead Market, External Capacity Participants may submit adjustments to the hourly profile of their tag in order to avoid balancing market MW deviations.

6.3.7.2 Rebidding Period between 1330 and 1415

If the unit is accepted in the Reliability Run, External Capacity Participants will be required to submit a NERC eTag that matches the hourly energy profile.

If the bid is not accepted in the Day-ahead Market the participant may choose to either modify an already existing tag to zero (0) MW, or take no action.

If the participant wishes to schedule the resource as a self-scheduled/must run unit they may choose to do so and must submit an eTag. The participant must also notify the PJM Generation Dispatcher that the unit is being self-scheduled into PJM as a contract.

6.3.7.3 Real Time Market

If the bid is not accepted in the Day-ahead Market or Reliability Market, but is requested during the operating day the Generation Dispatcher will notify the participant who will then submit an eTag to match the request. This tag will be subject to all scheduling timing requirements and PJM interchange ramp limits

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Section 7: External Transaction Scheduling

Welcome to the External Transaction Scheduling section of the PJM Manual Energy & Ancillary Services Market Operations. In this section you will find the following information:

- How PJM may utilize a net interchange cap to manage interchange during emergency conditions

Other information regarding External Transaction Scheduling is contained in the PJM Regional Transmission and Energy Scheduling Practices document.

7.1 Net Interchange Cap

During emergency conditions, PJM may elect to implement a cap on net interchange transactions to mitigate the impact of interchange volatility on system and price stability. The net interchange cap will represent the maximum level of RTO-wide net interchange beyond which the scheduling of additional non-dispatchable transactions using Spot Market Import or non-firm hourly point to point transmission service will be disallowed.

The net interchange cap may be implemented for the peak hour(s) of the day and the several surrounding hours when the following conditions are met. The application of the cap will be evaluated individually for each eligible hour.

- A Hot or Cold Weather Alert or escalating emergency procedures as defined in Manual 13: Emergency Operations for the RTO, Mid-Atlantic Dominion or Mid-Atlantic regions is in effect for the hour

- PJM dispatch has called on firm resources whose minimum operating criteria must be honored for the hour (e.g., dispatched demand response resources or combustion turbines)

- The level of interchange anticipated by PJM dispatch at the time the firm resource commitments are made, coupled with the firm resource commitments, are sufficient to meet the projected load pickup for the hour

When implemented, the interchange cap will apply for the entire hour. PJM dispatch may subsequently elect to adjust the interchange cap intra-hour in response to reliability concerns. The interchange cap value will be set equal to the interchange MW anticipated by PJM dispatch at the time the cap is implemented plus a 700 MW margin to allow additional interchange to be scheduled following the implementation of the cap in accordance with interchange scheduling rules.

Market participants will be notified of the potential for the implementation of the interchange cap day-ahead when a hot weather alert or cold weather alert has been issued for the operating day. Notification of the actual implementation of the cap will occur as soon as the cap is implemented. The interchange cap will typically be implemented one to two hours in advance of the hour to which it is applied, coincident with the scheduling of additional firm resources. The implementation notification will include the hour(s) to which the cap applies and the MW value at which the net interchange cap has been set. Notifications will occur via the Emergency Procedure Posting Application.

Section 8: Posting OASIS Information

Section Removed: Information regarding Posting OASIS Information is contained in the online OASIS User Guide, which is available at: http://www.pjm.com/markets-and-operations/etools/oasis/oasis-user-guide.aspx.

Section 9: Hourly Scheduling

Welcome to the Hourly Scheduling section of the PJM Manual for Energy & Ancillary Services Market Operations. In this section, you will find the following information:

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

9.1 Hourly Scheduling Adjustments

During the course of Bulk Electric 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.

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).

Section 10: Overview of the Demand Resource Participation

Welcome to the Overview of the Demand Resource Participation section of the PJM Manual Energy & Ancillary Services Market Operations. In this section you will find the following information:

- An overview description of the Demand Resource Participation in the PJM Energy Market (see "Demand Resource Participation").
- A list of the Demand Resource Registration Requirements (see "Demand Resource Registration Requirements").
- A list of the Demand Resource Energy Market Participation (see "Demand Resource Energy Market Participation").
- A list of the Demand Resource Metering and Settlement Data Requirements ("Demand Resource Metering and Settlement Data Requirements").

10.1 Overview of Demand Resource Participation

The integration of Demand Response into the PJM Markets recognizes the importance of load response to a fully functioning market as well as the effect of load response on the reliability of the grid. The purpose of these rules is to enable Demand Resources under the direction and control of Curtailment Service Providers to participate in the various PJM markets. Curtailment Service Providers (CSPs) are Members or Special Members of PJM that participate in the PJM Markets by causing Demand Resources to reduce demand.

PJM Emergency or Pre-Emergency Load Response enables Demand Resources that reduce load during emergency or pre-emergency conditions to receive payment for those reductions.

- Demand Resources in the Energy Only Option of Emergency Load Response are defined as Demand Resources that receive only an energy payment for reductions.
- Demand Resources in Full Emergency or Pre-Emergency Load Response are defined as Demand Resources that receive both an energy payment for reductions and a capacity payment.
- Demand Resources in Capacity Only Option of Emergency or Pre-Emergency Load Response are defined as Demand Resources that receive only a capacity payment for reduction.

PJM Economic Load Response enables Demand Resources to respond to PJM energy, synchronized reserve, and/or day-ahead scheduling reserve prices by reducing consumption

and receiving a payment for the reduction or following PJM signal to reduce or increase load if providing regulation services.

- The Day-ahead Option will provide a mechanism by which any qualified market participant may offer Demand Resources the opportunity to reduce the load they draw from the PJM system in advance of real-time operations and receive payments based on day-ahead LMP for the reductions

- The Real-time Option will provide a mechanism by which any qualified market participant may offer Demand Resources the opportunity to commit to a reduction and receive payments based on real-time LMP for the reductions.

Energy Settlements shall be limited to demand reductions that are executed in response to the real-time and/or day-ahead LMP or as dispatched by PJM and that are not implemented as part of normal operations. Reductions that do not meet these requirements will not be eligible for settlement. Examples of ineligible settlements include, but are not limited to the following:

- Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to the real-time and/or day-ahead LMP

- Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand.

- Settlements based on On-Site Generator data if the On-Site Generation is not supporting demand reductions executed in response to the real-time and/or day-ahead LMP

- Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint except that settlements based on such demand reduction shall be allowed if the demand reduction alleviates congestion.

- Settlements based on load reductions from normal operations that would have occurred without PJM dispatch, or that would have occurred absent PJM energy market compensation as approved under Order 745.

PJM shall disallow settlements for demand reductions that do not meet the requirements set forth above. If the CSP continues to submit settlements for demand reductions that do not meet the requirements set forth above then PJM shall suspend the CSP's Energy Market activity and refer the matter to the FERC Office of Enforcement.

10.1.1 Economic Load Response Participant Review Process

PJM shall review the participation of a CSP, EDC and/or LSE in the Energy Market under the following circumstances:

- The CSPs registrations are disputed more than 10% of the time by the relevant EDC or LSE.
- The CSP's settlements are disputed more than 10% of the time by the relevant EDC or LSE.
- The CSP's settlements are denied by PJM more than 10% of the time.

PJM shall have 30 days to conduct the required review. PJM may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant CSP and/or EDC or LSE is engaging in activity that is inconsistent with the Economic Load Response rules.

10.2 Demand Resource Registration Requirements

Curtailment Service Providers shall register Demand Resources that choose to participate in the PJM Energy, Capacity, Synchronized Reserve, Day-Ahead Scheduling Reserve or Regulation Market according to the rules and requirements set forth below. A CSP is required to have effective agreement with a customer to register a location.

10.2.1 Registration combinations

One or more CSPs may register the same location (EDC account number) to one or more registrations based on the following conditions:

Scenario	Economic (Energy, SR, DASR, Reg)	Economic (Energy Only)	Economic Regulation Only	Emergency or Pre-Emergency Capacity Only	Emergency or Pre-Emergency Full (Capacity and Energy)	Emergency Energy Only
CSP1	Yes	No	No	No	Yes	No
CSP1	Yes	No	No	Yes	No	Yes
CSP1 CSP2	Yes No	No No	No No	No Yes	No No	Yes No
CSP1	No	No	Yes	No	No	No

Scenario	Economic (Energy, SR, DASR, Reg)	Economic (Energy Only)	Economic Regulation Only	Emergency or Pre-Emergency Capacity Only	Emergency or Pre-Emergency Full (Capacity and Energy)	Emergency Energy Only
CSP2	No	Yes	No	No	Yes	No
CSP1 CSP2	No No	Yes No	Yes No	No Yes	No No	Yes No
CSP1 CSP2 CSP3	No No No	No Yes No	Yes No No	No No Yes	No No No	No Yes No

Economic (Energy, SR, DASR, Reg) – registration will allow participation in the energy market and ancillary service market(s) if certified and approved by PJM.

Economic (Energy Only) – an economic registration that only allows participation in the Energy market. This is normally used when 1 economic CSP has an Economic Regulation Only registration and the second economic CSP has the Economic (Energy Only) registration.

Economic Regulation Only – registration that only allows participation in the regulation market.

Emergency Capacity Only – registration that only allows participation in capacity market as an RPM or FRR capacity resource. If the registration is dispatched for emergency conditions the resource will not receive an energy payment. Only resources that rely on on-site generation to fulfill its load reduction obligations and have environmental restrictions as defined and required by applicable local, state or federal law, ordinances and regulations, on when it can operate such that it is only permitted to operate if PJM is in emergency conditions may register as Emergency Capacity Only resource.

Pre-Emergency Capacity Only – registration that only allows participation in capacity market as an RPM or FRR capacity resource. If the registration is dispatched for Pre-Emergency conditions the resource will not receive an energy payment.

Emergency Full (Capacity and Energy) – same as Capacity Only registration but receives emergency energy compensation when dispatched for emergency conditions. . Only resources that rely on on-site generation to fulfill its load reduction obligations and have environmental restrictions on when it can operate such that it is only permitted to operate if PJM is in emergency conditions may register as Emergency Full resource.

Pre-Emergency Full (Capacity and Energy) – same as Capacity Only registration but receives emergency energy compensation when dispatched for Pre-Emergency or emergency conditions.

Location that registers with one CSP for Emergency Full or Pre-Emergency Full can register with second CSP only for Economic Regulation-Only

Location that registers with one CSP for Emergency Capacity Only or Pre-Emergency Capacity Only can register with second CSP for:

- Economic (Energy, SR, DASR, Reg) or;
- Economic (Energy Only) and/or;
- Economic Regulation Only

Location that registers with one CSP for Emergency Capacity Only or Pre-Emergency Capacity Only, and with second CSP for Economic Regulation Only, can also register with third CSP for Economic (Energy Only).

A single location may only register as either Pre-Emergency or Emergency resource for the Delivery Year.

10.2.2 Curtailment Service Providers

The following business rules apply to Curtailment Service Providers:

- Prior to participating in the PJM Markets, Curtailment Service Providers must complete a registration in the appropriate PJM eSuite application which identifies the specific location(s) based on the unique EDC account number that will participate and their associated load reduction capability. Curtailment Service Providers shall maintain the accuracy of the registration information provided to PJM for each demand resource and each time the CSP registers the location or extends the registration, the CSP will review all information to ensure it is reasonably accurate and update as necessary. On a periodic basis, PJM may request supporting information from the CSP to verify that the information provided by the CSP is reasonably accurate.

- In order to register demand resources all specific information as defined in the eLRS User Guide shall be provided including the following:
    - Business Segment - CSPs shall classify locations according to the location's primary purpose or business use. CSP should first determine if the location's business use falls under one of the following primary categories: Hospitals, Industrial / Manufacturing, Office Building, Residential, Retail Service, Correctional Facilities or Schools. In cases where the location does not fit into one of the primary categories the CSP shall select from one of the following

categories: “Agriculture, Forestry and Fishing”, “Mining”, “Transportation, Communications, Electric, Gas and Sanitary Services” or “Services”. A description of each category will be included in the appropriate PJM system user guide.

- Load Reduction Method and associated Capability - The CSPs shall provide for each location the load reduction method and the associated load reduction kilowatts capability. Load reduction methods indicate the type of electrical equipment that will be controlled to provide the demand response activity and include: Heating, Ventilation and Air Conditioning (HVAC), Lighting, Refrigeration, Manufacturing, Water Heaters, Batteries, Plug Load and Generation. In cases, where multiple on-site generators are behind the meter, CSPs should report aggregate load reduction capabilities for all generation units.

A Plug Load represents an electronic device that’s plugged into a socket, which is not already represented by the methods described above. Examples of Plug Load include IT Peripherals, such as large computers, monitors, printers, routers, copiers and scanners or appliances such as washers, dryers or dishwashers.

The CSP shall provide the load reduction kilowatt capability for each method which represents a reasonable estimate of the location’s expected hourly energy load reduction (at the retail meter) that will be performed during a system emergency when wholesale energy prices are high and the resource participates in the wholesale market. The load reduction kilowatts capability may be significantly different than the capacity commitment or the economic energy offered into wholesale market on a daily basis. The load reduction capability should not reflect the entire load for the location unless the location expects to reduce all loads during a PJM emergency when participating in the wholesale capacity and/or energy market. If Generation will be used to reduce all of the load at the location and the location will reduce load with other load reduction methods then the Generation load reduction capability should reflect the expected load after the other load reduction methods have been deployed (this will allow the sum of each load reduction method capability to reflect the total load reduction capability for the location).

The CSP shall report the following generation attributes for each generation unit at the location. Only locations with on-site generation that will be used to provide the load reduction and have environmental restrictions as defined and required by applicable local, state or federal law, ordinances and regulations, that require emergency conditions to operate may qualify as an Emergency Demand Resource.

On-Site Generator Type - CSPs shall provide PJM with the type of on-site generation used for load reduction. On-Site Generator types are: Internal Combustion Engine, Combustion Turbines, Steam Engines and Cogeneration units (this also include Central Heat and Power units).

Generator Fuel Type - Locations that use generators, in whole or in part as a load reduction method shall provide PJM with the primary fuel type used for each generator which includes: Coal, Diesel, Natural Gas, Oil, Gasoline, Kerosene, Propane, Wood, Landfill Gases and

Waste products. In cases where the on-site generator has a mixed fuel type, CSPs should report on the primary fuel source as the on-site generator fuel type.

Generator Vintage - The year the generator was built (included on nameplate). If you do not know the exact year the CSP should use reasonable estimate.

Generator Retrofit Year - If the generator was retrofit for pollution control equipment please include the year of the retrofit or a reasonable estimate of year if specific year is not available

Nameplate Capacity - MW rated capacity for the generator

Permit Status - The current status of environmental permits for the generator where:

- "Available" - indicates that the CSP represents to PJM that the end-use customer generator has all the Local, State and Federal permits required to operate in the PJM Market as a demand response resource. Unless notified otherwise, the Office of the Interconnection shall deem such representation applies to each time the On-Site Generator is used to reduce demand to participate in the PJM markets and that the On-Site Generator is being operated consistent with all applicable permits.

- "Not Available" - indicates that the CSP represents to PJM that the end-use customer generator does not have the required Local, State and Federal permits required to operate in the PJM Market as a demand response resource. The CSP shall enter a load reduction value of zero, until all required permits become available.

- "Permit Application in Progress" - indicates that the CSP represents to PJM that one or more of the required Local, State and/or Federal permits for the end-use customer generator are pending and are expected to be received prior to the effective date of registration. CSP will terminate the registration, if the on-site generator is the only source for the demand response activity, and update the status if necessary permits are not received prior to such end-use customer generator's registration effective date.

- "Not Applicable" – indicates that the CSP represents to PJM that one or more of the Local, State and/or Federal permits for the end-use customer generator are not required for generator to participate as a demand resource and all other necessary permission from appropriate Local, State and Federal environmental agencies has been received.

- Permit Type – The permit type indicates whether on-site generators can run during emergency or non-emergency conditions:

  - "Emergency Only" – An "Emergency Only" permit type indicates that the on-site Generator has the Local, State and Federal permits required to operate in the PJM Market as a demand response resource during grid emergency conditions. This also indicates that such location may qualify as Emergency resource instead of being a Pre-Emergency resource.

- "Non-Emergency" – A "Non-Emergency" permit type indicates that the on-site Generator has the Local, State and Federal permits required to operate in the PJM Market as a demand response resource during emergency and non-emergency grid conditions.

- Economic registration must have the same EDC, LSE, Transmission zone and Pricing point where each location is defined as a unique EDC account number and may be included on the registration subject to aggregation rules in this manual. Emergency registrations, Economic Regulation Only registrations, and Economic registrations for Residential customers that do not participate in the Day-Ahead Market must have the same EDC and Transmission zone.

- If CSP has Economic Regulation Only registration then Economic registration will only allow same location(s) to participate in energy market ("Economic (Energy Only)" in chart above) and they will not be permitted to participate in the SR or DASR market.

- If CSP has Economic registration with any certified ancillary service (SR, DASR or Reg) then Economic Regulation Only registration may not be submitted.

- Econ Regulation Only CSP must be able to manage regulation for location whether or not the location has been called to provide capacity during an emergency or pre-emergency situation or is providing a load reduction as an economic resource in the energy market.

- Economic demand resource registration may be associated with a dispatch group. The dispatch group will allow the Curtailment Service Provider to have one real time or Day-Ahead energy market bid for the entire dispatch group.

- The dispatch group must have the registrations with the same Transmission Zone and energy market pricing point.

- Registrations that participate in ancillary service markets will not be permitted to use a dispatch group unless approved by PJM.

- Registration cannot be in a dispatch group and as a standalone registration. This will ensure that each registration is only available to bid once in the market and avoid duplications.

- Registrations must be confirmed before they may be added to a dispatch group.

- Registration that clears in Day-Ahead market is not allowed to be assigned to dispatch group on same day it cleared in Day-Ahead market. If CSP does try to assign to dispatch group on such day then PJM will remove (because this may

create conflict between single registration that cleared in Day-Ahead market and dispatch group that may be dispatched in real time market for same Operating Day).

- The CSP is responsible for ensuring that at least 1 registration is in a dispatch group when bid in the Day-Ahead or Real Time energy market through the appropriate PJM system.

- Demand resources may be registered simultaneously as Economic Load Response Resources and Emergency or Pre-Emergency Load Response Resources.

- Demand resources may switch CSPs. The CSP registering the switching Demand resource shall provide PJM with the registration information of the resource. Registrations may only be submitted when there is an effective contract with the customer for the term and product on the registration. CSP will check their records to ensure they have an effective contract to support the registration and contact customer as appropriate before they submit the registration. PJM will treat the switching as a new registration. If the current registration is a full emergency or full Pre-Emergency registration and the Delivery Year has begun, the new registration will be denied. Both new and current CSPs will be notified by PJM of the switch and will be given 5 business days to affirm they have a valid contract with the end-use customer for the term and product as included on their registration and notify PJM through the appropriate system that the customer has affirmed the contract. After 5 business days, if only one CSP has affirmed their registration in the appropriate PJM system, that CSP's registration will continue and the other registration will be terminated as soon as possible. If both CSPs have affirmed their registration, both registrations will be terminated as soon as possible. In order to accommodate day-ahead load response the switch or termination will become effective at 0001of the third business day after the previous registration is terminated or deemed terminated by PJM. The previous registration will remain active for the sole purpose of settlement of load reductions that occurred before the switch became effective.

- Demand Resource intending to run an On-Site Generator in support of local load represents to PJM that it holds all applicable environmental and use permits for running those generators by submitting a registration. Continuing participation will be deemed as a continuing representation by the owner that each time its On-Site Generator is run it complies with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

- To assist CSPs in obtaining the electric usage information of the end-use customer the following Customer Usage Information Authorization form has been developed.

- A Curtailment Service Provider shall not submit a request to be an Emergency resource (instead of Pre-Emergency) unless it has done its due diligence to confirm that the Demand Resource meets the requirements and has obtained from the end-use customer documentation supporting the exception request. The Curtailment Service Provider shall provide the Office of the Interconnection with a copy of such

supporting documentation within three (3) business days of a request therefor. Failure to provide such supporting documentation by the deadline shall result in the Demand Resource being classified as a Pre-Emergency resource.

Customer Usage Information Authorization

for PJM Load Response Programs ("Authorization")

_____ , the end-use customer, ("Customer") hereby authorizes _____, and _____, its electric distribution company(ies) ("EDCs"), to release its electric usage information, including hourly or sub-hourly usage history (kWh/kW), EDC loss factors, and peak load contribution assignments for the current delivery year and the upcoming delivery year, if known, to _____, the curtail service provider ("CSP"), which has been or may be retained by Customer to act on its behalf in the PJM Load Response Programs. Customer's EDCs and end-use sites are identified on Attachment A-1 and A-2 hereto, which are incorporated herein by reference.

1. Customer's contact information for purposes of its participation in the PJM Load Response Programs is as follows:

Customer Name: _____

Contact Person: _____

Mailing Address: _____

_____

City State Zip Code

Telephone Number: _____

Fax Number: _____

Contact Person's Email Address: _____

2. Customer hereby advises CSP that it deems the information obtained pursuant to this Authorization to be confidential and therefore requests that such information not be divulged to any third party, except as required to participate in the PJM Load Response Programs.

3. This Authorization shall terminate as follows (mark ONE of the options below):

____ This Authorization shall be perpetual and shall not terminate unless written notice is provided to CSP at least ____ days in advance.

____ This Authorization shall automatically terminate on _____, with no further notice to CSP being required.

4. I understand that termination of this Authorization will not affect any action that CSP took in reliance on this Authorization before it automatically terminated or before CSP received Customer's written notice of termination.

5. The undersigned affirms that he/she has authority to execute this Authorization on behalf of Customer.

IN WITNESS WHEREOF, Customer executes this Authorization to be effective as of the date written below.

Customer: _____

By: _____

Print Name

_____

Title

_____

Signature

_____

Date

ATTACHMENT A–1

LIST OF SITES FOR WHICH EDC, _____, HAS AUTHORIZATION TO PROVIDE ELECTRIC USAGE INFORMATION TO CSP

Account Number(s):

Service Address:

Account Number(s):

Service Address:

Account Number(s):

Service Address:

Account Number(s):

Service Address:

10.2.3 PJM Activities

The following business rules apply to PJM activities:

- PJM will, as necessary, propose or determine an alternative CBL calculation together with supporting analysis. The process for determining an alternative CBL is set forth below.

- PJM will confirm with the appropriate Load Serving Entity (LSE) and Electric Distribution Company (EDC) whether the load reduction is under other contractual obligations. (The EDC and LSE have ten (10) business days to respond or PJM assumes acceptance.)

- Other contractual obligations may not preclude participation, but may require special consideration by PJM such that appropriate settlements are made within the confines of the existing contract.

- PJM will inform the CSP, EDC and LSE of the demand resource's acceptance into the program as appropriate.

- PJM will create LSE negative DEC bids for DR that clears in DA market for dispatch group based on registration DR load reduction capability. PJM will create LSE negative DEC bids for DR that clears in DA market for registrations based on amount that cleared in DA market.

10.2.4 Electric Distribution Company ("EDC") and Load Serving Entity ("LSE") activities

EDC will have 10 business days to review the all registrations and verify the EDC account number, Zone, Pricing point, Line losses, existence of EDC interval meter if applicable, accuracy of peak load contribution (PLC), and whether or not the customer may or may not participate based on the Relevant Electric Retail Regulatory Authority orders, ordinances or resolutions. If the information provided by the CSP is incorrect the EDC may deny the registration. Once the registration is denied the CSP may correct the inaccurate information and resubmit the registration only to the EDC, as appropriate.

LSE will have 10 business days to review registrations except the Emergency registration and Economic Regulation Only registration and verify whether or not the customer may or may not participate based on the Relevant Electric Retail Regulatory Authority orders, ordinances or resolutions. LSE will also review registration to determine if the load reductions for the location(s) are subject to an LSE contractual obligation. If the information provided by the CSP is incorrect the LSE may deny the registration. Once the registration is denied the CSP may correct the inaccurate information and resubmit the registration only to the LSE, as appropriate.

10.2.5 CBL Certification Process

All Economic registrations, except Economic Regulation Only registrations, should go through the CBL certification process to ensure that the CBL used to predict the customer load and therefore determine the quantity of each hourly load reduction is reasonably accurate and non-biased. All registrations should use a CBL with a relative root mean square error ("RRMSE") no greater than 20% unless otherwise approved by PJM. Registrations with a RRMSE greater than 20% based on hourly load data provided in the registration process are considered variable load customers.

CBL certification is performed by the CSP prior to registration submission. CSP should always calculate an RRMSE for the standard CBL defined in the tariff. An alternative CBL may be requested if the alternative CBL is more accurate than the standard CBL and has an RRMSE less than or equal to 20%.

The RRMSE will be based on 60 most recent days of contiguous hourly load data where the most current load data should be 60 days or less than the date the RRMSE is calculated unless otherwise approved by PJM.

PJM and CSP shall have 30 days from the day the alternative CBL proposal is received by the other party to agree on a proposed alternative CBL calculation. If the parties agree on an alternative CBL calculation, then the agreed upon CBL calculation shall be effective from the date of the registration.

If PJM and CSP do not agree on an alternative CBL calculation within 30 days, then PJM shall determine the CBL calculation within 20 days of the expiration of the prior 30 day period. The CBL established by PJM shall be binding on the parties unless agreement on an alternative CBL is reached before the end of the 20 day period.

The process for determining the appropriate CBL shall not delay the registration, provided that the alternative CBL established shall be used for all applicable energy settlements.

PJM shall periodically publish herein alternative CBL calculations established through this process.

Relative Root Mean Squared ERROR (RRMSE) calculation is performed as follows unless otherwise approved by PJM:

- To perform the RRMSE calculation, daily CBL calculations are first performed for the CBL method using hours ending 14 through hours ending 19 unless otherwise approved by PJM as the simulated event hours for each of the 60 non-event days according to the CBL method rules.

- Actual Hourly errors are calculated by subtracting the CBL hourly load from the actual hourly load for each of the simulated event hours of the non-event day.

- The Mean Squared Error (MSE) is calculated by summing the squared actual hourly errors and dividing by the number of simulated event hours.

- The Average Actual Hourly Load is the average of the actual hourly load for each of the simulated event hours.

- The Relative Root Mean Squared Error (RRMSE) is calculated by taking the square root of the MSE then divide that quantity by the average of the actual load.

10.3 Economic Energy Market Participation

Qualified Curtailment Service Providers may offer the load reductions of demand resources into the Day-ahead and/or Real-time Energy Market pursuant to the PJM Manuals, Markets Gateway User Guide, and the following rules and requirements.

Curtailment Service Provider that would like to participate in the Energy market shall submit a bid for each demand resource (registration or dispatch group) which includes:

- Transmission zone and pricing point based on where the demand resource is located and the associate pricing point used to settle the load in the retail market and as defined by PJM.

- Demand resource market type which determines how the bid will be utilized by the Energy Market:
    - Day-Ahead Market – If hour clears in Day-Ahead market then demand resource should respond with associated MWs. PJM will not dispatch in Real Time for hours that clear in Day-Ahead market.
    - Real Time Market (Balancing) – demand resource should follow the Real Time dispatch signal for the MW that have been dispatched
    - Both:

If specific hour clears in Day-Ahead market then demand resource should respond with associated MWs. PJM will not dispatch in Real Time market for hours that clear in Day-Ahead market.

If hour does not clear in Day-Ahead market then hour is eligible to be dispatched in Real Time market.

- Incremental Offer curve (minimum increments of 0.1MW) that represents up to 10 combinations of MW load reduction and offer price. This determines the price offered into the Day-Ahead market for respective MW amount in each hour and the price offered for dispatch in the Real Time market.

- Hourly availability which determines the specific hours when the demand resource may be cleared in the Day-Ahead Market and the associated MW volume that is available to clear for each hour. This also determines the specific hours when the demand resource may be dispatched in the Real Time market and the associated MW volume that may be dispatched for each hour.

- Economic Min and Max MW used to determine the dispatch of demand resources in the Real Time Energy Market can be changed up to 3 hours before the operating hour by the CSP. For example, hourly updates for HE 15 which starts at 1400 can be changed up to 1059 during the same day.

- Shut down costs, for each period. The default will be zero if not submitted. Shutdown cost will be expressed in dollars, and represents the fixed cost associated with committing a load response resource. Shutdown costs will be changeable only every six months, corresponding to the six-month periods during which price-based start-up costs may be changed for generators. The six month periods for shutdown costs are defined as follows: Period 1 is defined as April 1 – September 30 and Period 2 is defined as October 1 - March 30.

- Minimum down times for which the load reduction must be committed. The default will be zero if not submitted. Minimum down time will be expressed as a number of hours, and represents the minimum number of contiguous hours for which a load response bid must be committed in the Day-ahead Market or dispatched in Real Time Market.

- Load Response bids in the Day-Ahead market or hourly MW availability in the RealTime market should exclude losses (transmission zone losses and share of 500 kV losses). This means bids should be based on expected retail metered load reductions grossed up for line losses.

- Day-Ahead Energy Market bids and associated information must be submitted based on overall Energy Market rules and associated time line as described in this manual.

- Shutdown cost will be expressed in dollars, and represents the fixed cost associated with committing a load response resource.

- Demand resources will be eligible to set Day-Ahead and Real Time Energy market prices if selected as the marginal resource.

10.3.1 Net Benefits Test to determine Net Benefits Threshold

The Net Benefits Threshold is the point on the aggregate supply curve at which the participation of Demand Response Resources results in a greater overall savings to the load on the system compared to the Demand Response Resources remaining on the system as load. PJM shall compute the Net Benefits Threshold monthly as described below. PJM shall post the Net Benefits Threshold and associated supporting information for each month by the 15th of the prior month on pjm.com. CSP will only receive compensation for demand resources cleared in Day-Ahead market or dispatch by PJM in the Real Time market if the applicable LMP is greater than or equal to the monthly NBT.

The Net Benefits Test is executed using the following steps:

Step 1: Retrieve generation offers from the same calendar month of the prior calendar year for which the calculation is being performed. These generation offers will use market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available.

Note: To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region, PJM shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. To accomplish this adjustment, spot fuel prices for the reference month will be compared to forward prices for the study month. First, the spot prices for representative PJM fuels will be averaged together for the reference month.

For natural gas, the Henry Hub price is used, since natural gas prices tend to move in concert with Henry Hub. For oil, the New York Harbor price for No. 2 fuel oil is used. For coal adjustments, PJM has determined a mix of 20% Powder River Basin, 50% Northern Appalachia, and 30% Central Appalachia coal to be representative of the fuel used by PJM resources. Representative coal prices will be combined in a weighted average to form a representative RTO coal price for the reference month.

Forward prices will be used to determine a similar representative price for the study month. These two values will be used as a ratio. If the representative price from June 2010 was $4.10, and the forward price for June 2011 was $4.51, then the ratio would be 1.1 (prices were up 10%, or June 2011's price is 110% of June 2010's price.)

The offers of generation units will then be adjusted by this scaling factor. The price of fuel typically represents 80 to 90 percent of a generator's offer with the remainder being variable operations and maintenance costs and other uncertainties. As such, 85 percent of each generator's offer will be scaled by the fuel scalar.

Where generators offer multiple points on a curve, each point on the curve is adjusted in this manner.

Step 3: Combine the offers to create daily supply curves for each day in the period.

Step 4: Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5: Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve. PJM shall publish the

details of the equation and parameters each month along with the Net Benefit Threshold results.

Step 6: Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

10.4 Demand Resource Metering and Settlement Data Requirements

The settlements submitted to PJM by Curtailment Service Providers must conform to the following requirements for data, including metered data, and Customer Baseline Load (CBL) calculations. All settlement related calculations for economic and emergency demand resources are provided in Manual 28.

10.4.1 Metered Data

Demand Resources must be equipped with interval meters recording electrical usage at the EDC account level. The interval of data collection must be sufficient to provide PJM with hourly, one minute or real time load data as applicable for wholesale market. Residential Direct Load Control aggregates may have interval meters installed on a statistical sample of EDC accounts per Manual 19: Load Forecasting and Analysis, Attachment D and subject to PJM approval.

For load reduction that is not metered directly by PJM, Curtailment Service Providers are responsible for forwarding the appropriate meter data (as defined in this Manual) to PJM within 60 days of the reduction. Participants submitting a settlement for an energy payment when load reduction complies with a synchronized reserve event or regulation assignment must use data provided by the load meter. This data shall be forwarded through the appropriate PJM system.

If the meter data files are not received within 60 days, no payment for participation is provided.

Load data must be provided for all hours of the day and for all days necessary for PJM to calculate the CBL for settlements or to measure compliance as necessary.

When on-site generation is used solely to enable the Participant to provide demand reductions then the CSP may provide qualified meter generation output data, upon approval by PJM, from the on-site generation for each hour of the event day instead of actual load metered data. Provision of hourly meter data from the on-site generation will be deemed a certification by the CSP that the on-site generation was not used for any purpose other than to support the load reduction during the event day. If the On-Site Generator is used on a regular basis for normal operations then the CSP may provide qualified meter data from the On-Site Generator for each hour of the event provided the amount of generation run to provide Economic Load Response can be quantified in a manner that is acceptable to PJM. For example, if a 5 MW On-Site Generator that normally provides 3 MW boosts its output to

5 MW in response to LMPs the CSP will be eligible to receive a demand response energy settlement for the additional 2 MW of output.

Meter data will be forwarded to the EDC upon receipt, and these parties will then have ten (10) business days to review accuracy and provide feedback to PJM.

Objection by the EDC to the Meter Data shall be clearly set forth in the Comments related to the Settlement Data. The CSP shall correct and re-submit the Settlement Data within 2 business days. The objecting EDC shall have 5 business days to review the re-submitted Settlement Data or PJM will assume acceptance.

All load reduction data are subject to PJM Market Monitoring Unit audit.

10.4.2 Customer Base Line (CBL)

The following tables list all available CBLs and represent the different parameters used for each calculation. The 3 Day Type with SAA (symmetric additive adjustment) represents the standard, tariff defined CBL which is utilized for most Non-Variable economic demand resources and is set forth in section 3.3A.2 of the PJM tariff. The alternative CBLs on the list have been created over time to provide options, especially for Variable Load customers that have an RRMSE above 20%.

PJM will make available the Customer Baseline (CBL) calculations to the appropriate EDC and LSE for optional review.

The CSP shall inform PJM, of any significant change to the demand resource's operations that increases or decreases the demand resource's CBL. A significant incremental change is defined as any operational or physical change to the demand resource's facilities that will adjust more than half the hours in the demand resource's CBL by at least 20% for more than twenty consecutive days. PJM may require and approve such adjustments to the CBL as are necessary to reflect the significant incremental change.

Parameter/CBLs	3 DayTypes		3 Day Types with SAA (Tariff Default)		3 Day Types with WSA	
DayType	Weekdays,	Sat ,Sun/Hol	Weekdays	Sat,Sun/Hol	Weekdays	Sat, Sun/Hol
Calculation[1]	Average	Average	Average	Average	Average	Average
CBL Basis Window[2]	5	3	5	3	5	3
CBL Basis Window Limit[3]	45	45	45	45	45	45
Start Selection From Days Prior to Event[4]	1	1	1	1	1	1
Exclude Previous Curtailment Days[5]	Y	Y	Y	Y	Y	Y
Exclude Long/Short DST Days[6]	N/A	Y	N/A	Y	N/A	Y
Exclude Avg. Event Period Usage Less than Threshold[7]	25%	25%	25%	25%	25%	25%
Exclude # of Low Usage Days[8]	1	1	1	1	1	1
Use Previous Curtailment if CBL Basis Window incomplete[9]	Yes	Yes	Yes	Yes	Yes	Yes
Use Highest or Recent Previous Curtailment Day[10]	Highest	Highest	Highest	Highest	Highest	Highest
Adjustments[11]	None	None	Symmetric Additive	Symmetric Additive	Weather Sensitive	Weather Sensitive
Allow Negative Adjustments[12]	N/A	N/A	Yes	Yes	Yes	Yes
Adjustments Start (HE0-x)[13]	N/A	N/A	4	4	0	0
Adjustment Basis Hours[14]	N/A	N/A	3	3	Event Hours	Event Hours

Parameter/CBLs	7 DayTypes	7 Day Types with SAA	MBL(Max Base Load)[A]		Metered Generation[B]
DayType	Mon,Tue,Wed,Thu,Fri,Sat,Sun/Hol	Mon,Tue,Wed,Thu,Fri,Sat,Sun/Hol	Weekdays	Sat,Sun/Hol	N/A
Calculation[1]	Average	Average	Average	Average	N/A
CBL Basis Window[2]	3	3	5	3	N/A
CBL Basis Window Limit[3]	60	60	45	45	N/A
Start Selection From Days Prior to Event[4]	1	1	1	1	N/A
Exclude Previous Curtailment Days[5]	Y	Y	Y	Y	N/A
Exclude Long/Short DST Days[6]	Y	Y	N/A	Y	N/A
Exclude Avg. Event Period Usage Less than Threshold[7]	25%	25%	25%	25%	N/A
Exclude # of Low Usage Days[8]	0	0	0	0	N/A
Use Previous Curtailment if CBL Basis Window incomplete[9]	Yes	Yes	Yes	Yes	N/A
Use Highest or Recent Previous Curtailment Day[10]	Highest	Highest	Recent	Recent	N/A
Adjustments[11]	None	Symmetric Additive	None	None	N/A
Allow Negative Adjustments[12]	N/A	Yes	N/A	N/A	N/A
Adjustments Start (HE0-x)[13]	N/A	4	N/A	N/A	N/A
Adjustment Basis Hours[14]	N/A	3	N/A	N/A	N/A

Parameter/CBLs	Same Day (3+2)[D]	Match Day (3 Day Average)[E]
DayType	N/A	N/A
Calculation[1]	Average	Average
CBL Basis Days[2]	N/A	3
CBL Basis Day Limit[3]	N/A	45
Start Selection From Days Prior to Event[4]	N/A	1
Exclude Previous Curtailment Days[5]	N/A	Y
Exclude Long/Short DST Days[6]	N/A	Y
Exclude Avg. Event Period Usage Less than Threshold[7]	N/A	N
Exclude # of Low Usage Days[8]	N/A	0
Use Previous Curtailment if CBL Basis Window incomplete[9]	N/A	Y
Use Highest or Recent Previous Curtailment Day[10]	N/A	Recent
Adjustments[11]	None	None
Allow Negative Adjustments[12]	N/A	N/A
Adjustments Start (HE0-x)[13]	N/A	N/A
Adjustment Basis Hours[14]	N/A	N/A

Notes:

A) MBL(Max Base Load). The MBL CBL for weekdays shall be the average of the daily minimum hourly loads during the event hours over the 5 most recent weekdays preceding the load reduction event within the 45 calendar day period preceding the load reduction event. The daily minimum load calculation must be based on a minimum of three hours. If the number of event hours is less than three, then the daily minimum load calculation will use the following hours of the same calendar day: hour prior to event, event hour(s), hour after event, in that order until three hours are attained. Exceptions: use only event hours in same calendar day if start of event is sometime between 2100 and midnight OR if end of event is sometime before 0300.

B) Metered Generation. The use of this methodology must be approved by PJM. Historical data will be required showing that the unit does not normally run or is not normally active. If

the data indicates that the unit runs normally, is active, or if the unit is a cogen operation then another CBL methodology may be required to ensure economic dispatch activity is isolated from normal operations.

C) Same Day (3+2). Average of 3 hours prior to event (after skipping first hour before the event) and 2 hours after the event (after skipping first hour after the event) to determine CBL that will be used for all event hours. If there are multiple non-contiguous events during same day PJM will use earliest 3 hours and last 2 hours from same day. PJM will use hours available on the operating day to calculate the CBL, where at least 3 hours will be used. Resource may not participate in HE 1, 2, 3, 23, 24 to ensure there are enough hours to calculate the CBL. CSP will ensure there is no significant pre-event or post-event change in operations during the operating day that will increase the load in the hours selected for the CBL beyond what would have normally occurred. If the load will be shifted to one of the 3 + 2 hours and therefore significantly increase the CBL, the CSP may not use this CBL for such resource.

D) Match Day (3 Day Average). Determine event day non-event hours or "comparison hours". Comparison hours are all hours in operating day except for the hour before the earliest event hour through the hour after the last event hour. For example, if economic DR resource is dispatch HE12 – HE14 and then re-dispatched in HE17-HE20 the comparison hours are HE1- HE10 and HE22-HE24 (13 comparison hours in total). For each non-event day within the CBL Basis Day limit:

(1) Take the difference between each comparison hour from the event day and the same hour in each day in the CBL Basis Day Limit to determine the hourly difference for each comparison hour for each day.

(2) Square all the hourly differences for each day and then sum the squared differences to determine the daily differences.

(3) Select the 3 days from the CBL Basis Day Limit with the smallest daily differences to determine the CBL Days. Average each of the event hours across the three CBL Days to determine the CBL.

Additional Notes:

1) Calculation. Whether to use median or average to calculate the CBL after the CBL Basis Window has been defined and high and low usage days have been excluded.

2) CBL Basis Days. This is the set of days that will serve as representative of end-use customer's typical usage. If the number of days specified is 5, then after all exclusions (e.g.: before excluding event days and Low Usage Days), the set will contain 5 days.

3) CBL Basis Day Limit. Limit on number of historical calendar days used to select the CBL Basis Days (e.g.: If 45 this means CBL days must be selected from prior 45 calendar days). This ensures recent information is used to predict future consumption.

4) Start Selection from Days before Event Day. Determines most recent historic CBL day to select (e.g. if 1 then select most recent day with same daytype, if 2 then skip most recent day with same daytype and select next day with same daytype).

5) Exclude Previous Curtailment Days. If this is set to “Y”, exclude all previous curtailment days. Previous Curtailment Days are previous economic settlements days that include at least 1 hour in pending or confirmed status.

6) Exclude Long/Short DST Days. If this is set to "Y", then any long/short DST day is excluded from the CBL Basis Window.

7) Exclude Avg. Daily Event Period Usage Less than Threshold. If the Average Daily Event Period Usage for the CBL day selected is less than the threshold indicated, then that day will be excluded from the CBL Basis Window.

8) Exclude # of Low Usage Days. If the CBL Basis Days is set to 5 and this switch is set to 1, then the 1 day with the lowest Average Daily Event Period Usage will be excluded from the CBL calculation.

9) Use Previous Curtailment Day if CBL Incomplete. If this is set to “Y”, and if the CBL is unable to attain the minimum number of days required to calculate the CBL, then Previous Curtailment Days will be used as CBL Basis Days until such minimum is attained. If this is set to “Y”, then Exclude Previous Curtailment Days must also be set to “Y”.

10) Use Highest or Recent Previous Curtailment Day. Required if the Use Previous Curtailment Day if CBL Incomplete is set to “Y”. "Highest" means that the model will rank Previous Curtailment Days based on event period usage within the CBL Basis Day Limit and add them to the CBL Basis Days in descending order until the CBL Basis Days contains the minimum number of days required to calculate CBL. "Recent" means that the model will start adding days to the CBL Basis Days starting with the Most Recent Curtailment Day that was excluded until the CBL Basis Days contains the minimum number of days required to calculate CBL.

11) Adjustments. Symmetric Additive Adjustment is CBL average usage for Event Day divided by Adjustment Basis Hours for same hours. Weather Sensitivity Adjustment compares difference is average weather over CBL days to weather on event day and then calculates adjustment based on weather sensitivity as described in this manual.

12) Allow Negative Adjustments. If this is set to “Y”, then the Adjustments may be positive or negative. Otherwise, Adjustments will always be greater than zero.

13) Adjustment Start (HE0-x). The starting point for the hour(s) to be used in calculating the Adjustments. If the event starts with HE13 and Adjustment Start is 4, then HE9 will be the first hour used to calculate Adjustments.

14) Adjustment Basis Hours. Determines total number of hours to use in the adjustment from the Adjustment Start. If the event is on HE13, Adjustment Start is 4, and Adjustment Basis Hours is 3, then the adjustment will be based on the load from HE9-HE11.

Weather Sensitive Adjustment

The WSA Factor Method adjusts the hourly CBL (up or down) to compensate for the average hourly temperature differences between the CBL basis days and the temperature of the event hour.

The WSA Factor represents the kW change in load for each degree of temperature change within a specified temperature range. The WSA factor is the slope of the line that describes the load and temperature relationship at the customer site between two temperature set points. The WSA Factor or slope of the line is obtained by performing a linear or piecewise linear regression analysis on the load and temperature data from the customer site. There should be at least two years of data used in the linear regression analysis to indicate the normal operation of the facility. Exceptions may be granted by PJM to use less data in cases where the normal operations have changed significantly between years. The analysis data should only include the day types and hours where load reductions are expected. For example, if the customer is only expected to respond during the hours of 0800 to 1800 from Monday through Friday during non-holidays, then such historic hours should be used in the regression model.

The hourly CBL Adjustment is obtained by multiplying the WSA Factor by the temperature of the event hour minus the hourly average temperature of the CBL. The hourly average temperature of the CBL is the hourly average of the basis days used for the CBL.

Example 1:

- Hourly average temperature of the CBL for hour ending 12 = 86°
- Event temperature for Hour Ending 12 = 81°
- WSA Factor = 688 kW/°F
- CBL Adjustment for Hour Ending 12 = Temperature Delta * WSA Factor = (81° - 86°) * 688 kW/°F = -3440 kW

The CBL is adjusted down because the temperature of the event day is lower than the average hourly temperature of the CBL basis days

A simple linear regression analysis fits a straight line through the set of points (load and temperature data) in such a way that makes the sum of squared residuals as small as possible. The first and last points of the estimated line are known as the Temperature Set Points. The Slope of the line between the two Temperature Set points is the WSA factor.

A piecewise linear regression analysis fits multiple contiguous straight lines through the set of data points (load and temperature data) in such a way that makes each of the sum of squared residuals as small as possible. The piecewise linear regression analysis results in multiple lines with multiple slopes that estimate the load and temperature relationship of the customer site data. The end points of each of the estimated lines are known as the

Temperature Set Points. Determining the number Temperature Set Points can be accomplished by using a Piecewise Linear Regression Break Point algorithm or by data observation at points where the slope of the data appears to change significantly. Either methodology should result in minimizing the sum of squared residuals for each of the estimated lines.

The following table represents the weather station used for each Transmission Zone

Zone	Weather Station Short Name	Weather Station
AECO	ACY	Atlantic City International
AEP	CMH	Port Columbus International
APS	PIT	Pittsburgh International
ATSI	CAK	Akron Canton International
BGE	BWI	Baltimore Washington International
COMED	ORD	Chicago O'Hare International
DAY	DAY	Cox-Dayton International
DEOK	CVG	Cincinnati/Northern Kentucky International
DOM	RIC	Richmond International
DPL	PHL	Philadelphia International
DUQ	PIT	Pittsburgh International
EKPC	SDF	Louisville International-Standiford
JCPL	EWR	Newark International
METED	PHL	Philadelphia International
PECO	PHL	Philadelphia International
PENELEC	JST	Johnstown Airport
PEPCO	DCA	Washington Reagan National
PPL	ABE	Allentown Lehigh Valley International
PSEG	EWR	Newark International
RECO	EWR	Newark International

10.4.3 Economic Energy Settlements

The CSP is responsible for providing all necessary information for each EDC account number unless otherwise approved by PJM for settlement and compliance calculations. CSPs are eligible to be paid full LMP for the Registration's or dispatch group's reductions, provided that the LMP at the pricing point is at or above the Net Benefits Price and in accordance with Manual 28.

All Registrations or dispatch groups must either clear in the Day-Ahead Market or be dispatch by PJM in order to be eligible for settlement revenue.

All Registrations or dispatch groups are eligible for Make Whole payments subject to performance. Make Whole is hourly and based on lesser of bid volume and actual volume delivered:

- Make whole is only eligible for hour if load reductions is within +/- 20% of dispatch amount
- Make whole compensation is based on bid if bid => NBT
- Shutdown cost will not be paid if any hour in segment is outside 20% volume deviation
- Shutdown cost is paid once for all contiguous hours
- Segment make whole is sum of hourly make whole (i.e.: negative make whole will offset positive make whole)

All Registrations or dispatch groups are subject to Balancing Operating Reserve (BOR) charges for deviations greater than 20% from the PJM Day-Ahead or Real-Time Dispatch instructions.

DR resources may submit bids that are less than the Net Benefits price but will only be paid if appropriate LMP is greater than or equal to NBT.

All settlements that are not submitted within 60 days of the economic event will settled by PJM with 0 kW hourly reductions. BOR will be assessed based on the deviations of the stand alone settlement or Dispatch Group settlement.

All settlements that are still pending, denied or withdrawn after 75 days from the economic event will be settled by PJM with 0 kW hourly reductions. BOR will be assessed based on the deviations of the registration settlement or Dispatch Group settlement, as appropriate.

Dispatch Group Settlements

To calculate the reductions achieved by the Dispatch Group after an economic event, individual settlements need to be created in eLRS.

- The CBL needs to be calculated in order to calculate the reductions for the individual registrations.

- The Dispatch Group economic event will be de-aggregated to the registration level settlements based on the registrations in the Dispatch Group early in morning the day after the operating day. The individual settlements are submitted by the CSP based on the normal registration level settlement process.

- The total reduction for the Dispatch Group is calculated once a day as the sum of all the reductions of the settlements. Once all of the settlements in the Dispatch Group reach their final state, the Dispatch Group load reduction is settled.

- The final state for a Dispatch Group economic settlement is achieved when all of the individual settlements within the Dispatch Group achieve the following status:
    - All settlements in Dispatch Group are confirmed.
    - Prior to the 60th day after the event, the CSP may mark the Dispatch Group ready for settlement. No further updates to any settlements may be done in the Dispatch Group.
    - On the 61st day after the event and all settlements are either confirmed, withdrawn or expired.
    - The 75th day after the event has been reached, the Dispatch Group settlement will be sent to settlements regardless of the individual status of any settlements in the group

- Dispatch Groups that are cleared or dispatched will be evaluated at the Dispatch Group level when evaluating BOR. Deviations and BOR will be assessed based on the reduction of the Dispatch Group.

- Market Settlements will provide settlement report based on Dispatch Group(s) and not by registrations.

10.4.4 Economic Energy Settlements Cost Allocation

The cost of Economic Demand Response settlements will be allocated to all of the Market participants with real-time exports from PJM and LSE's within a zone where zonal LMP is greater or equal to the appropriate Net Benefits Price and as described in Manual 28.

10.4.5 Emergency and Pre-Emergency Energy Settlements

The CSP is responsible for providing all necessary information for each EDC account number unless otherwise approved by PJM for energy settlement. Locations with approved economic registration prior to a Load Management Event that have an economic CBL different than the maximum base load as defined in PJM Manual will use the associated economic CBL to determine the energy load reduction subject to the following:

- A registration that is already responding to a PJM economic event where the economic CBL is based on SAA will use a SAA period prior to economic and emergency or pre-emergency event.

- Locations that do not have an approved economic registration prior to a Load Management Event and have an economic CBL different than the maximum base load will use the CBL as defined in section 3.3A.2 and associated Symmetric Additive Adjustment as defined in section 3.3A.2, unless an alternative CBL is approved pursuant to section 3.3A.2.01to determine the energy load reduction.

- Locations on economic registrations dispatched in the real time energy market or cleared in Day-Ahead energy market that are also included on an Emergency or Pre-Emergency full registration and have been dispatched as part of an emergency event for the same hour ("overlapping dispatch hour") will be compensated for energy based on emergency energy settlement and cost allocation rules as outlined in this section, and PJM manuals. Overlapping dispatch hours will use shutdown cost-based on what was considered for the economic event and no balancing operating reserve charges will be assessed for deviations from real time dispatch amount or from cleared Day-Ahead amount. Overlapping dispatch hours for aggregate registrations (multiple locations on same registration) or Dispatch Groups where locations on Emergency or Pre-Emergency registration are not the same as locations on the economic registration will have hourly economic energy load reduction with associated cleared Day-Ahead or real time dispatch amount and/or hourly emergency energy load reduction prorated based on load reduction capability provided by the Curtailment Service Provider for the location to avoid duplicative energy payment and appropriate balancing operating reserve charges, as applicable.

- Emergency and Pre-Emergency registration dispatched by PJM for less than 1 hour will be eligible for compensation for 1 hour (i.e.: minimum run time is 1 hour)

- The Curtailment Service Provider will only submit energy settlements for Load Management Events that occur outside of the product specific availability period as defined for each product specified in the Reliability Assurance Agreement for each Demand Resource type if the Curtailment Service Provider has confirmed that the customers on the registration did take action to reduce load or the registration reflects the entire group of mass market customers for which an energy settlement will either be submitted for all or none of the mass market customers, as approved by PJM. Curtailment Service Provider confirmation may include email, voicemail, letter or other form of confirmation that indicates the registration took actions to reduce load in response to PJM dispatch. The Curtailment Service Provider will only submit energy settlements for each registration for Load Management Events that occur during the product specific availability period as defined for each product in the Reliability Assurance Agreement if the Curtailment Service Provider also provides associated load data for each registration in order to calculate that registration's capacity compliance.

10.4.6 Emergency and Pre-Emergency Energy Settlements Cost Allocation

See Manual 28, section 10.2 for cost allocation rules.

10.5 Aggregation for Economic and Emergency Demand Resources

The purpose for aggregation is to allow the participation of end-use customers in the energy market that can provide less than 100 kW of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 100 kw of demand response in the day-ahead scheduling reserve (DASR), synchronized reserve (SR) or regulation (REG) markets when they currently have no alternative opportunity to participate on an individual basis. An aggregation shall meet the following requirements:

- If the aggregation will only provide energy to the market then only 1 end use customer within the aggregation shall have the ability to reduce more than 99kw of load unless the CSP, LSE and PJM approve. If the aggregation will provide a DASR or SR to the market then only 1 end use customer within the aggregation shall have the ability to reduce more than 99kw of load unless the CSP, LSE and PJM approve. If the aggregation will provide Regulation Only through and Economic Regulation Only registration to the market then only 1 end use customer within the aggregation shall have the ability to reduce more than 99kw of load unless the CSP and PJM approve.

- All end-use customers in an economic registration shall be served by the same electric distribution company and Load Serving Entity (LSE) and have the same energy pricing point. All end use customers in an Emergency and Pre-Emergency registration, Economic registration of residential customers not participating in the Day-Ahead market, and Economic Regulation Only registration shall be served by the same electric distribution company and located in the same transmission zone. If the aggregation will provide synchronized reserves, all customers in the aggregation must also be part of the same synchronized reserve sub-zone.

- All end-use customers in an aggregation that settle at Transmission Zone, existing load Aggregate, or node prices shall be located in the same Transmission Zone, existing load Aggregate, or at the same node except for an Economic Regulation Only registration.

- Each end-use customer site must meet the requirements for market participation by a demand resource except for the 100 kW minimum load reduction requirement for energy and ancillary services.

- An end use customer's participation in the energy and ancillary service markets shall be administered either under one economic registration or if only providing Regulation service then with and Economic Regulation Only registration and an Economic (Energy Only registration) as outlined in this manual.

10.5.1 Calculations for the weighted average line loss factor

When all end-use customers in a Registration are not subject to the same line loss factor, the factor for the Registration shall be the registration load reduction weighted average of the factors for end-use customers in an aggregation.

PJM shall calculate the Ratio Share for each end-use customer as the percentage share of the summation of the individual anticipated load reduction capabilities (Total kW).

PJM shall calculate the Weighted Average line loss factor (WA LF) by multiplying the Ratio Share times the loss factor (LF) for each end-use customer and totalizing the results. The WA LF shall represent the loss factor of the Registration.

PJM shall provide the calculation of all load weighted values and their supporting data to the LSE and CSP at the time of registration.

Customer	1	2	3	Total
kW	32.02	22.46	50.91	105.38
Ratio Share	30.38%	21.31%	48.31%	100.00%
G&T	$ 0.0500	$ 0.0660	$ 0.0890	
LF	1.0680	1.0790	1.0900	
WA G&T	$ 0.0152	$ 0.0141	$ 0.0430	$ 0.0722
WA LF	0.32448	0.22995	0.52654	1.08097

10.5.2 Settlement for Aggregation

All end-use customers in the Registration are considered to have individually participated in each curtailment event if cleared in Day-Ahead market or dispatched by PJM in Real Time market for the Registration. All supporting details as outlined below will be available to the LSE after the settlement is submitted by the CSP, except where the end-use customers in the registration are not required to have the same LSE.

- Registration Customer Baseline (CBL) based on the sum of the each end use customer's meter data where each end use customer is defined as a unique EDC account number.

- Meter data for each end use customer in the aggregation, except for non-interval metered residential Direct Load Control registrations, where a statistical sample of end use customers may be used for meter data, in accordance with PJM Manual 19: Load Forecasting and Analysis, Attachment D.

- Metered Load - Each individual end-use customer in the aggregation will have its own metered load and the summation of the individual metered loads will represent the Registration metered load. Non-interval metered residential Direct Load Control registrations may use a statistical sample of end-use customers' meter data to

represent the Registration metered load in accordance with PJM Manual 19: Load Forecasting and Analysis, Attachment D.

- Weighted Average Loss Factor - The load reduction weighted average loss factor shall be the value calculated for registration.

10.6 Interval Meter Equipment and Load Data Requirements

A CSP, LSE, EDC or agent designated by the CSP may fulfill the interval metering equipment and load data responsibilities that are required by PJM of the CSP for economic and emergency demand response resources including ancillary services. Interval metering equipment and load data used for retail electricity service shall be deemed to meet PJM requirements for energy settlement and capacity compliance.

The following documentation shall be provided by the CSP to PJM when non-retail electric service metering equipment and load data will be utilized for settlements or compliance. The CSP shall verify that all documentation is accurate and maintain compliance to PJM metering equipment and load data requirements.

- The date the metering equipment was installed, tested and ready to record, store and communicate interval load data for DSR activity
- The person that installed the metering equipment
- The make and model of the meter
- Metering equipment accuracy (meter, CT and PT)
- CT & PT type designation
- CT ratio
- All metering equipment shall, at a minimum, meet appropriate ANSI c12.1 and c57.13 standards to ensure the metering equipment is within the Tariff defined accuracy standards
- Metering equipment used for ancillary services shall meet additional requirements as defined in the PJM Tariff and/or Manuals.
- If equipment does not meet these standards, then on an exception basis, a field test may be conducted to validate the accuracy as long as the electricity service is less than 600 volts. PJM will review the field test results and associated metering equipment configuration to determine whether or not the use of metering equipment will be permitted.

- Metering equipment may include a pulse data recorder used in conjunction with a meter.

The CSP or designated agent shall maintain the relationship between the load data, metering equipment, EDC account number and other Customer Identifiers as defined. Further, the CSP or designated agent shall submit to PJM the quality assurance protocol used to ensure metering equipment accuracy over time. All interval load data, except where also used for retail electric service, shall at a minimum comply with the NAESB VEE (validate, edit & estimate) standards, where applicable, for retail electric service to ensure the quality of the information. If a pulse data recorder is utilized then time shall be managed on a daily basis or per communication whichever is least frequent. Time may be checked and reconciled through the network time protocol. Load data, including both pre and post VEE data shall be maintained for 36 months by CSP or designated agent. The CSP and/or designated agent will comply with request for metering equipment and load data audit as necessary that may include but not be limited to the following:

- Being available for on-site verification of metering equipment
- Providing load data history for Pre and Post VEE load data
- Providing work order, cut sheet or other documentation to validate the installation of the metering equipment
- Load data reconciliation where there are two metering systems present

A CSP or their designated agent that violate these standards will not be allowed to manage the installation/maintenance of metering equipment and associated load data for PJM settlements or compliance.

Non-retail electric service load data used for settlements or compliance will not be reconciled by PJM to the retail electric service load data unless, to troubleshoot an issue or as part of an audit.

If the CSP elects to utilize non-retail electric service load data for settlements then CSP will provide 90 consecutive days of load data on an annual basis near the effective date of the registration to PJM and PJM will make this load data available to the appropriate LSE. In addition, CSP or PJM shall provide load data to the EDC, as appropriate, for the peak load contribution add back process.

All metering equipment and load data shall comply with these standards by October 1, 2009.

10.7 Use of Sub-meter load data to support demand response regulation compliance

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

- Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.

- The CSP will submit single line diagrams to PJM unless otherwise approved by PJM with sub metered device(s) clearly specified at the location. PJM will verify that all similar devices at the location are sub metered and if the similar devices are not sub metered, PJM will deny use of sub meter load data unless the CSP can demonstrate that the electricity usage of such similar devices not sub-metered will not offset change in electricity usages of the electrical device that will provide the regulation service.

- If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission **process upon request by PJM.**

- All telemetry load data to PJM will be based on device electricity consumption for each registration. The registration load data must include load data from all locations and from all devices approved at each location on the registration. For example, if the registration has 3 locations and each location has 1 pump that will regulate then the telemetry load data will include the aggregate load data for all 3 pumps.

- If the registration is an aggregation of locations, the CSP will provide PJM with load data for each location's sub-meter through an after the fact load data submission process as determined by PJM. This will allow PJM to confirm that the aggregate load data sent through telemetry consist of all locations on such registration.

The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.

Auditing will include a method of sampling location level load data without CSP's prior knowledge of sites sampled. CSP will provide location level load data (which represents load data for the EDC account number) to PJM upon request through after the fact meter data submission process as determined by PJM.

All CSP meter equipment will conform to meter data standards set forth in the PJM Tariff and the PJM Operating Agreement and as defined in Manual 11, section 10 and all CSP telemetry will comply with the standards set forth in the PJM Tariff, PJM Operating Agreement and PJM Manual 12, section 4.

The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the matter to the Independent Market Monitor and/or the Federal Energy Regulatory Commission Office of Enforcement.

Section 11: Overview of the Day-Ahead Scheduling Reserve Market

Welcome to the Overview of the Day-Ahead Scheduling Reserve Market section of the PJM Manual for Energy & Ancillary Services Market Operations. In this section you will find the following information:

- An overview description of the PJM Day-ahead Scheduling Reserve Market (see "Overview of PJM Day-Ahead Scheduling Reserve Market").
- A list of the PJM Day-Ahead Scheduling Reserve Market Business Rules (see "PJM Day-Ahead Scheduling Reserve Market Business Rules").

11.1 Overview of Day-Ahead Scheduling Reserve Market

The Day-Ahead Scheduling Reserve Market is a construct for a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System. The Day-Ahead Scheduling [30-Minute] Reserve Market is an offer-based market that will clear existing reserve requirements on a day-ahead, forward basis.

The Day-Ahead Scheduling Reserve Market is designed to create an explicit value for an additional ancillary service in the PJM Markets, on a short-term basis. A Day-Ahead Scheduling [30-Minute] Reserve market can provide a pricing method and price signals that can encourage generation and demand resources to provide Day-Ahead Scheduling reserves and to encourage new resources to be deployed with the capability to provide such services.

The Day-Ahead Scheduling Reserve Market is designed to interact with the current PJM Operating Reserve construct. While a clearing market for Day-Ahead Scheduling [30-Minute] Reserves may reduce out-of-market payments to generators in the form of Operating Reserve credits, it will not eliminate them, and the remaining Operating Reserve costs will continue to be allocated.

11.2 PJM Day-Ahead Reserve Market Business Rules

11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement

Current reserve requirements are detailed in ***PJM Manual M-13, Section 2***, and vary according to the specific PJM region. The requirements for each region are combined to determine the overall requirement for the RTO, and the overall RTO requirement would form the basis for clearing the forward market.

The Day-Ahead Scheduling Reserve Requirement will adhere to the requirements for Day-Ahead Scheduling [30-Minute] Reserve defined by Reliability First Corporation and all applicable reliability councils for areas within the PJM RTO.

The PJM RTO Day-Ahead Scheduling Reserve Requirement will be defined as the sum of the Day-Ahead Scheduling Reserve requirements defined for all zones and areas within the PJM RTO, including any additional Day-Ahead Scheduling reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

Following the issuance of a Hot or Cold Weather Alert or escalating emergency procedures as defined in Manual 13: Emergency Operations for the RTO, Mid-Atlantic Dominion or Mid-Atlantic region, PJM will increase the Day-ahead Scheduling Reserve requirement to reflect the additional reserves typically carried under such conditions and to ensure that adequate resources are procured to meet real-time load and reserve requirements. The increased reserve requirement will be applied to the days for which the alert(s) were issued, provided that the alerts are issued prior to the close of the Day-ahead Market bidding period. Under such conditions, the hourly Day-ahead Scheduling Reserve requirement will be increased by no more than the following amounts:

- The amount of any additional generation committed for that hour by PJM dispatch in advance of the Day-ahead Market in order to account for operational uncertainty

- Applied hourly for each hour of the day, the greater of:
  - difference between submitted fixed demand bids and forecasted RT load minus for each hour Adjusted Fixed Demand for the hour

    and
  - Zero

- Adjusted Fixed Demand = Total Fixed Demand * (1 + Seasonal Conditional Demand Factor)
  - The Seasonal Conditional Demand Factor scales up the sum of Fixed Demand Bids by the average percentage of additional net demand that has historically cleared from the net of price sensitive demand bids, decrement bids and increment offers during peak hours (conditional demand)
  - The Seasonal Conditional Demand Factor will be calculated separately for the winter and summer seasons. The Winter Seasonal Conditional Demand Factor will be based on the top ten peak load days from November through March of the prior year. The Summer Seasonal Conditional Demand factor will be based on the top ten peak load days from April through October of the prior year. In the event the same season in the prior year was not representative of typical seasonal conditions, PJM may use a different, more typical year as the reference season in this calculation.
    - For each of the ten peak days within the reference season, PJM will calculate the hourly conditional demand factor for each of the peak hours, which for these purposes are defined as hours beginning 7 through 10 and 17 through 20 in the winter and hours 14 through 19 in the summer.

- The Hourly Conditional Demand Factor is calculated as:
- Sum(price sensitive demand + decrement bids – increment offers) / Sum(fixed demand)
- The Hourly Conditional Demand factors for each day are then averaged to calculate a daily conditional demand factor
- The ten daily conditional demand factors are then averaged to arrive at the Seasonal Conditional Demand Factor

- PJM will calculate the Seasonal Conditional Demand Factors and post them to PJM.com by no later than November 15 of each year.

- Future reserve requirements may be defined locationally based on operation criteria as documented in the PJM Manuals.

11.2.2 Day-Ahead Scheduling Reserve Market Eligibility

Day-Ahead Scheduling Reserve Resources are defined as resources that meet the following eligibility requirements to provide Day-Ahead Scheduling Reserve:

Day-Ahead Scheduling Reserve Resources comprise of all those resources that can provide reserve capability that can be fully converted into energy within 30 minutes from the request of the PJM dispatcher at the time of the request and is provided by equipment which may not necessarily at the time of the request be electrically synchronized to the system.

A Day-Ahead Scheduling Reserve Resource may be:

- Equipment not electrically synchronized to the system. The equipment that generally qualifies in this category pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle and diesels; or

- Additional generating capacity that is synchronized to the grid and scheduled and can increase output in 30 minutes (including condensing mode and pumped hydro that is in pumping mode) to provide additional Day-Ahead Scheduling Reserve;

  or

- Load response resources must be registered in the Economic Load Response program, indicate that they can be dispatchable by PJM in real-time and be able to be reduced within 30 minutes.

- Load response resources that are considered “batch load” resources as defined in the section 1.3.1A.001 of the Operating Agreement, may participate in the Day-Ahead Scheduling Reserve market under the same conditions as exist for Synchronized Reserve with respect to having already reduced prior to receiving a PJM dispatch instruction to do so. Such resources must remain off line for the

duration of the PJM dispatch request in order to receive the Day-Ahead Scheduling Reserve market payment.

- Day-Ahead Scheduling Reserve Market offers may be submitted only for those resources located electrically within the PJM RTO. Resources that cannot reliably provide Day-Ahead Scheduling Reserve obligations in real time shall be excluded from the Day-Ahead Scheduling Reserve process. Such resources types includes, but are not limited to: Nuclear units, run-of-river and self-scheduled pumped hydro units, Wind units, Solar units, and non-energy resources such as batteries which do not have capability to provide the obligations of Day-Ahead Scheduling Reserve for entire hour. Owners of any specific resource(s) or these resource types may request an exception from the default non-eligibility to provide Day-Ahead Scheduling Reserve if they notify PJM that the resource(s) are able to reliably provide Day-Ahead Scheduling Reserve Obligation in real time.

- Resources may participate and be compensated in both the Day-Ahead Scheduling Reserve and Synchronized Reserve Markets. In addition, resources may participate and be compensated in both the Day-Ahead Scheduling and Regulation Markets However, since resources cannot participate in both the Synchronized Reserve and Regulation markets; no resources can participate in the Day-Ahead Scheduling Reserve, Synchronized Reserve AND Regulation markets and be compensated for all three.

- The following additional Demand Resources requirements must also be met in order to participate in the Day-Ahead Scheduling Reserve Market:
    - Demand resources' response controls must be approved by PJM prior to participation in the Day-Ahead Scheduling Reserve Market including ability to be dispatched by PJM's Security Constrained Economic Dispatch system.
    - Demand resources providing Day-Ahead Scheduling Reserve are required to provide telemetry that is capable of providing metering information at no less than a one minute scan rate.

- Metering information of demand resources is not required to be sent to PJM in real time. Daily uploads at the close of the next business day after the operating day if an event has occurred are sufficient, as the response evaluation is performed after the fact.

- Demand resources may be aggregated and offered into the PJM Day-Ahead Scheduling Reserve Market as one combined resource if the appropriate telemetry is provided for the aggregated resource.

- Demand resource participation will be limited to 25% of the RTO Day-Ahead Scheduling Reserve Requirement.

- Demand Resources will be allowed to participate in the Day-Ahead Scheduling Reserve Markets if approved by the appropriate Regional Reliability Council.

- Dynamic Transfer resources are eligible to provide Day-Ahead Scheduling Reserve as per Attachment F of Manual 12.

11.2.3 Day-Ahead Scheduling Reserve Market Rules

The following offer and operational information must be supplied through the Markets Gateway System:

- Day-Ahead Scheduling Reserve Availability.

- Day-Ahead Scheduling Reserve Offer Price - Offers to provide Day-Ahead Scheduling [30-Minute] Reserve are in dollars/MW of reserve to be provided, and $0/MW is a valid offer.

- A valid generator or demand response energy offer must be available in the Day-Ahead Energy Market to participate.

- Energy resources will need to have an energy offer available in the Day-Ahead Market to participate in the Day-Ahead Scheduling Reserve Market.

- All generator units that have submitted day-ahead energy offers and meet the Day-ahead Scheduling Reserve Market Eligibility requirements will be considered available to provide Day-Ahead Scheduling reserve (Must offer requirement).

- All demand resources that have submitted day-ahead energy offers and meet the Day-Ahead Scheduling Reserve Market Eligibility requirements may provide Day-Ahead Scheduling reserve (Markets Gateway System default = unavailable). Demand resources may voluntarily make themselves available to provide Day-Ahead Scheduling Reserve.

Day-Ahead Scheduling Reserve Offer Quantity (MW) for Online Units is derived as the lesser of:

- difference of the Economic Max – DA Dispatch Pt scheduled

- Default Ramp Rate * (30 minutes)

Day-Ahead Scheduling Reserve Offer Quantity (MW) for Offline Units is derived as the lesser of:

- Economic Max

- Economic Min + (Default Ramp Rate * (30 minutes – Startup Time plus Notification Time in minutes))

11.2.4 Day-Ahead Scheduling Reserve Market Offer Period

Market participants wishing to offer into the Day-Ahead Scheduling Reserve Market must supply offer and operational data on a day-ahead basis, with offers due to PJM by 1030 EPT on the day before the operating day (same timeline as Day-Ahead Energy Market).

Day-Ahead Scheduling Reserve offers are locked as of 1030 EPT the day prior to operation. All generating units listed as available for Day-Ahead Scheduling Reserve with no offer price will have their offer prices set to zero.

11.2.5 Day-Ahead Scheduling Reserve Market Clearing

PJM would clear the forward market for Day-Ahead Scheduling Reserves via a simultaneous optimization with the energy market as part of the Day-Ahead Market mechanism.

The Operating Reserve objective utilized in the Day-Ahead Market and on which the Day-Ahead Scheduling [30-Minute] Reserve market that would clear will be calculated based on the PJM load forecast for the upcoming operating day.

The market clearing would result in an hourly price for Day-Ahead Scheduling [30-Minute] Reserve for the next day, and would be posted along with the resource-specific Day-Ahead Scheduling [30-Minute] Reserve awards by 1330 EPT via the PJM Markets Gateway System.

The hourly Day-Ahead Scheduling Reserve clearing price is fixed once calculated and posted by 1330 EPT the day before the Operating Day.

The hourly clearing price for Day-Ahead Scheduling Reserve would be based upon the offer prices submitted by the selected resources, together with any opportunity cost a resource incurs in the day-ahead market as a result of being backed down in the day-ahead joint-optimization process in order to meet the RTO Day-Ahead [30-minute] reserve requirement.

The Day-Ahead Scheduling Reserve Market clearing price is set equal to the merit order price of the highest cost Day-Ahead Scheduling Reserve resource necessary to meet the remaining requirement.

Resource merit order price ($/MWh) = resource Day-Ahead Scheduling Reserve offer + resource Day-ahead Scheduling Reserve opportunity costs.

Both generator startup costs and demand resource shutdown costs are divided over the expected commitment period for the resource, as part of the market clearing process. Neither of these costs are including in the clearing price.

Day-Ahead Scheduling Reserve start-up costs are defined as applicable generator startup costs required to provide Day-Ahead Scheduling Reserve or demand resource shutdown costs required to provide Day-Ahead Scheduling Reserve.

Day-Ahead Scheduling Reserve opportunity costs are defined as applicable generator opportunity costs required to provide Day-Ahead Scheduling Reserve or applicable demand resource opportunity costs required to provide Day-Ahead Scheduling Reserve. Opportunity cost for Demand Resources is zero.

The resource Day-Ahead Scheduling Reserve offer is that which is submitted by the owner via the Markets Gateway System by 1030 on the day preceding the operating day.

The Day-Ahead Energy Market LMP is used in the Day-Ahead Scheduling Reserve opportunity cost calculations.

11.2.6 Day-Ahead Scheduling Reserve Market Operations

Those resources receiving a day-ahead award for Day-Ahead Scheduling [30-Minute] Reserve would receive the hourly clearing price for the awarded MW amount as long as they were capable of providing the reserve in real time as outlined in the Day-Ahead Scheduling Reserve Performance section below.

11.2.7 Day-Ahead Scheduling Reserve Performance

Resources that receive a Day-Ahead Scheduling [30-minute] Reserve award are not required to maintain the awarded amount of reserve capability in real-time operations.

Measurement of the performance of assigned resources will be as follows:

- For resources with a start time plus notification time of greater than 30 minutes, the resource is required to be on line and operating at PJM's direction during the hour of the award with a real-time dispatchable range (Real-time Economic Maximum – Real Time Economic Minimum) at least as great as day-ahead dispatchable range (Day-Ahead Economic Maximum – Day-Ahead Economic Minimum).

- For resources with a start time plus notification time of less than or equal to 30 minutes, the resource would be required to be available to the PJM operator for dispatch during the hours of the award and start within 30 minutes if dispatched by PJM.

If a unit with a Day-Ahead Scheduling Reserve award for any hour in the day is requested to start in an hour that it did not receive a Day-Ahead Scheduling Reserve award, the unit must start within 30 minutes in order to receive the award for the day.

Hydro resources are required to be available to the PJM operator for dispatch during the hours of the award.

- For Demand Resources, measurement is the difference between the demand resource's MW consumption at the time a resource is requested by PJM dispatch to reduce and its MW consumption after 30 minutes of the request. In order to allow for small fluctuations and possible telemetry delays, demand resources consumption at the start of the event is defined as the greatest telemetered consumption between one (1) minute prior to and one (1) minute following the issuance of the dispatch instruction. Similarly, a demand resource's consumption thirty minutes after the dispatcher request is defined as the lowest consumption measured between twenty nine (29) and thirty (31) minutes after the start of the request.

11.2.8 Day-Ahead Scheduling Reserve Market Obligation Fulfillment

Each Load Serving Entity (LSE) on the PJM system incurs a Base Day-Ahead Scheduling Reserve obligation in kWh based on their real-time load ratio share of the Base Day-Ahead Scheduling Reserve eligible MW as defined in Manual 28: Operating Agreement Accounting. Each LSE's obligation is equal to its load ratio share within the RTO times the amount of Base Day-Ahead Scheduling Reserve eligible MW in the RTO. Any PJM market participant may incur or fulfill a Base Day-Ahead Scheduling Reserve obligation through the execution of a bilateral Day-Ahead Scheduling Reserve transaction as described below.

Participants may fulfill their Day-Ahead Scheduling Reserve obligations by:

- Owning Day-ahead Scheduling Reserve resources from which the RTO obtains Day-Ahead Scheduling Reserve;
- Entering bilateral arrangements with other market participants; or
- Purchasing Day-Ahead Scheduling Reserve from the Day-Ahead Scheduling Reserve market.

If PJM issues a Hot or Cold Weather Alert or escalating emergency procedures resulting in an increase in the Day-ahead Scheduling Reserve Requirement, charges for the additional requirement resulting from the difference between fixed demand and forecasted load will be allocated to differences in Day-ahead demand and Real-time load when Day-ahead demand is less than Real-time load. See Manual 28, Section 19.3 for additional details.

11.2.9 Day-Ahead Scheduling Reserve Bilateral Transactions

Bilateral Day-ahead Scheduling Reserve bilateral transactions may be reported to PJM. Such reported bilateral Day-Ahead Scheduling Reserve transactions must be for the physical transfer of Day-Ahead Scheduling Reserve and must be reported by the buyer and subsequently confirmed by the seller through the Markets Gateway System no later than 1330 the day after the transaction starts. Bilateral transactions that have been reported and confirmed may not be changed; they must be deleted and re-reported. Deletion of a

reported 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.

Bilateral Day-Ahead Scheduling Reserve transactions reported to PJM may be entered in MW of the purchaser's obligation. The minimum MW value is .1 MW

Payments and related charges associated with the bilateral Day-Ahead Schedule Reserve transactions reported to PJM posts shall be arranged between the parties to the bilateral contract.

A buyer under a bilateral Day-Ahead Scheduling Reserve preliminary billing data transaction reported to PJM agrees that it guarantees and indemnifies PJM, PJM Settlement, and other market participants for the costs of any purchases by the seller in the Day-Ahead Scheduling Reserve Market, as determined by PJM, to supply the reported bilateral transaction and for which payment is not made to PJM Settlement by the seller.

Upon any default in obligations to PJM or PJM Settlement by a market participant, PJM shall not accept any new bilateral reporting by the Market Participant and shall terminate all of the Market Participant's reporting of Markets Gateway schedules associated with its bilateral Day-ahead Scheduling Reserve transactions previously reported to PJM for all days where delivery had not yet occurred.

PJM posts Day-Ahead Scheduling Reserve preliminary billing data on which market participants can use as a resource for pricing bilateral Day-Ahead Scheduling Reserve transactions. The information can be found on the PJM Website at http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/preliminary-billing-reports/dsr-pjm.aspx.

11.2.10 Day-Ahead Scheduling Reserve Market Settlement

Please refer to PJM Manual 28: Operating Agreement Accounting, Section 19: Day-Ahead Scheduling Reserve Accounting for settlement details.

Day-Ahead Scheduling Reserve settlement is a zero-sum calculation based on the Day-Ahead Scheduling Reserve provided to the market by generation and demand resource owners and purchased from the market by participants.

Section 12: Overview of the Price Responsive Demand

Welcome to the Overview of the Price Responsive Demand section of the PJM Manual for Energy & Ancillary Services Market Operations. In this section you will find the following information:

- An overview description of the Price Responsive Demand (see "Overview of PJM Price Responsive Demand").
- A list of the Price Responsive Demand Business Rules (see "PJM Price Responsive Demand Business Rules").

12.1 Overview of Price Responsive Demand

The development and implementation of dynamic and time-differentiated retail rates, together with utility investment in Advanced Metering Infrastructure (AMI) has lead an increasing quantity of load in PJM to be responsive to changing wholesale prices. Through enabling technology and behavioral changes, consumers modify their demand as prices change without being centrally dispatched by PJM or bidding demand reductions into the PJM markets. Given the linkage between dynamic retail rate structures and wholesale prices, this price responsiveness is predictable and needs to be accounted for in the wholesale market design and operations. This predictable reduction in consumption in response to changing wholesale prices is known as Price Responsive Demand (PRD). The continued development of Price Responsive Demand requires coordination between the wholesale market and the retail rate design to maximize its benefit to consumers. The deployment of AMI for small commercial and residential customers enables dynamic and time–differentiated retail rate structures linked to wholesale prices. AMI supports dynamic retail rate structures and these types of retail rates provide the exposure to market prices necessary to provide the incentive for retail customers to reduce or shift consumption in response to price.

Although Price Responsive Demand is not directly dispatchable by PJM, automated retail customer response to real time energy prices signals can produce a predictable demand curve as a function of price. Prices typically increase during capacity emergencies and as a consequence demand drops. Price Responsive Demand will therefore be able to reduce the installed capacity required to meet Loss of Load Expectation (LOLE) based reliability standards.

PRD is provided by a PJM Member that represents retail customers that have the capability to reduce load in response to price. PJM Member acting on behalf of such retail customers for the purpose of providing PRD is referred to as the PRD Provider. A PRD Provider for a given retail customer may be the customer's retail Load Serving Entity (LSE). However,

PRD may also be provided in the PJM markets by an entity such as an Electric Distribution Company (EDC), or Curtailment Service Provider (CSP) that does not have direct

responsibility for serving the retail load but meets all of the eligibility requirements for providing PRD.

12.2 Price Responsive Demand Business Rules

12.2.1 Price-Demand Curves in the Energy Market

Price Responsive Demand that is committed in RPM for a Delivery Year will bid in the PJM Energy Market per the business rules below. For details about PRD participation in the PJM Capacity Market, refer to PJM Manual M18: PJM Capacity Market.

Price Responsive Demand that is not committed in RPM for a Delivery Year has the option to bid in the Energy Market as an “Energy Only” bid. If PRD is bid into the market as “Energy Only”, the Maximum Emergency segments that are not committed MW of capacity may submit a bid price up to the energy market offer cap for the respective delivery year.

End-use customer loads identified as Price Responsive Demand may not, (i) be registered as Economic Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Resource Sell Offer in any RPM Auction; or (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider

12.2.2 Characteristics of Price-Demand Curves in PJM Energy Market

The Price-Demand Curves (PRD Curves) for Price Responsive Demand committed in RPM for a Delivery Year will have the following characteristics and can be submitted in the PJM Energy Market on a daily basis:

- PRD Curves accepted at the time of PRD registration, will be used as default Price Responsive Demand bids in the Day-Ahead Market clearing process. Updates to the default curves may be submitted into the Day-Ahead Market on a daily basis by 1030 at the closing of the Day-ahead bid period

- PRD Curves in the Energy Market will be modeled in the real-time dispatch algorithms and can set Real-Time LMP. Price Responsive Demand will set Real-Time LMP based on offer price on the PRD curve, as described in next section. If a PRD Curve is marked as “unavailable”, the PRD curve is ineligible to set Real-Time LMP. PRD Curves in the Energy Market must be submitted locationally; identified at the substation location within a transmission zone as electrically close as practical to the applicable load (i.e., PNODE). PJM will provide assistance to EDCs to post mapping files that map PNODES to geographic locations such as zip codes.

- PRD curves will include the following parameters:

a) Availability flag

b) Response rate

c) Minimum quantity of PRD

d) Maximum quantity of PRD

- PRD Curves in the Energy Market must be non-increasing and can have up to 10 price-quantity segments for each hour.

- PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to Real Time LMPs for the PRD Curves that are submitted.

- The maximum bid price of the PRD Curve is the applicable energy market offer cap

12.2.3 Business Rule Changes to Price Sensitive Demand Bids

Participants may indicate in Price Sensitive Demand Bids if the bids are available to be used in the Real Time Market.

12.2.4 Price-Demand Curves in Real-time Energy Market Operations

During normal Economic conditions:

- PRD Curves will be included in Security Constrained Energy Dispatch (SCED)

- Price Responsive Demand can set Real-time LMP up to the energy market offer cap

During Emergency conditions:

- Price Responsive Demand must be curtailed once PJM has;

a) Declared and loaded Max Emergency Generation; or

b) Loaded emergency purchases; or

c) Initiated a voltage reduction; and

d) The real-time LMP at the applicable location meets or exceeds the price on the submitted PRD curve at which the load has committed to curtail.

- PJM will issue an emergency procedures notification to clearly indicate when PRD must be reduced to its committed value based on the MESL, as follows: "At this time, PRD Providers are required to take all actions, including use of supervisory control if necessary, to reduce Price Response Demand (PRD) down to the Maximum Emergency Service Level (MESL)"

- During Emergency conditions, PJM will use real-time data submitted by PRD Providers to determine the availability and actual response of PRD, per the rules for Load Management Operational Reporting.

12.2.5 Balancing Operating Reserves Deviations

While PJM will not send dispatch signals to PRD load, PRD load that reduces consumption in real time in response to price will be viewed as having "followed dispatch instructions" and therefore not accrue Balancing Operating Reserve (BOR) deviations for the reduced demand.

- PJM will sum an LSE's total fixed and price sensitive demand cleared in the Day-Ahead market in each zone.

- PJM will sum the LSE's total real time load in each zone.

- If the LSE has PRD load in a given zone, the Real- Time LMP at the PNODEs where such PRD was modeled for a given hour is higher than the Day-ahead LMP at those PNODEs for that hour and the LSEs real time load minus its Day-Ahead fixed demand was less than the LSE's Day-Ahead cleared price sensitive demand in that zone, then the LSE will not accrue BOR deviations for the amount by which the Day-Ahead cleared price sensitive demand exceeded the real time load minus the Day-Ahead fixed demand.

12.2.6 PRD Curves Submitted by Curtailment Service Providers (CSPs)

PRD Curves may be submitted by PRD Providers without direct load responsibility in the PJM energy market by 1030 at the closing of the Day-ahead bid period.

PRD Curves submitted by PRD Providers without direct load responsibility will be identified as CSP-PRD bids in the Day-ahead Market software and user interface.

CSP-PRD bids will be modeled in the Real-time Energy market only, and will be modeled in the real-time dispatch algorithms. CSP-PRD bids will not be modeled in the Day-ahead Market Clearing process.

CSP-PRD bids will not result in any energy market charges or credits to the CSP

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 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.

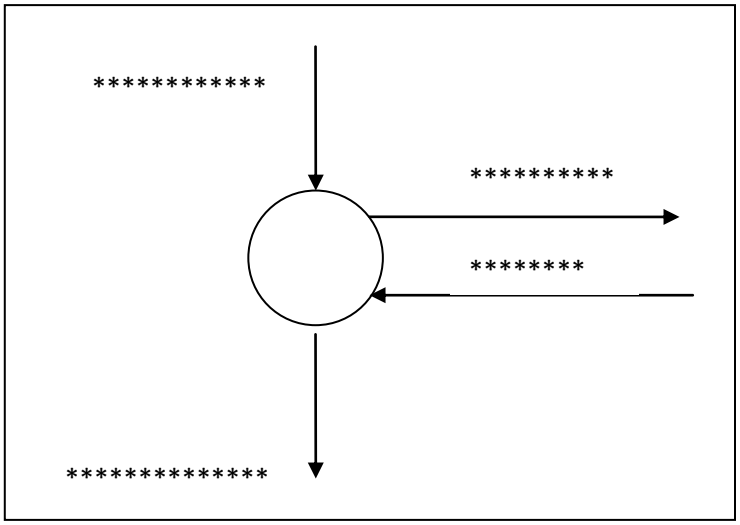
Example: Unit A has a summer rated capacity of 80 MW, where 60 MW is designated as installed capacity and 20 MW is not. If there is a 40 MW partial outage of the unit, 3/4 (or 60/80) of the remaining capacity is considered installed. 1/4, or 20/80, of the remaining capacity is available as non-installed 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.

Attachment B: Pumped Storage Modeling

This Attachment describes the pumped storage model developed by PJM that can be used by participants to schedule their pumped storage plants optimally.

Description of Model

The model treats the pumped storage plant as a MWh reservoir. When the plant generates MW are removed from the reservoir, when the plant pumps MW are added.. A pumping efficiency factor is used to translate the pump load to energy transferred into the reservoir. The following figure illustrates the model for a single time period.



This model enforces the classical “Conservation of Flow” constraint for each hour.

Hourly PlantStorage may also be constrained by MaxStorage and MinStorage values.

The Beginning and Ending storage for the day can then be constrained by setting MaxStorage and MinStorage values.

Since the objective of the unit commitment software is to minimize total cost over the study period, the resulting generation and pumping schedule will be maximized so as to produce the lowest possible system cost (maximum benefit). The conservation of flow constraint assures us that pumping will only occur if the cost of pumping can be offset by an associated benefit of generating.

The inputs to the model include:

Plant Data

- Initial Storage Level
- Final Storage Level
- Maximum Storage Level
- Minimum Storage Level
- Pumping efficiency factor.

Unit Data

- Minimum and Maximum generating and pumping limits

Note that pumping increases the storage by – Pumping Efficiency * Pumping Mwh and generation decreases the storage by Mwh the plant is generating

Attachment C: PJM Procedure for Cost Adjustment

This section addresses the procedures by which Market Sellers may report differences between cost-based offers and actually incurred costs for resettlement. These differences may result in a settlement credit adjustment if a generation resource's costs were underestimated or overestimated at the time the offer was selected and cleared. This section also addresses the procedures by which Market Sellers may request reimbursement for manning units above normal station manning levels at the direction of PJM. The aim of the procedure is to:

- Enable generation resources that are requested to operate by PJM System Operations outside of a day-ahead commitment and cannot accurately estimate intraday costs as described in the Generation Owner's fuel cost policy.

- Explain the process for the recovery of costs to staff the station above normal station manning levels at the direction of PJM ("manning costs") that cannot be submitted in the cost-based startup, because they are unknown at the time of the offer submittal. These manning costs are considered to be "start cost" as defined in PJM Manual 15: Cost Development Guidelines. This procedure is not intended to guarantee cost recovery nor is it intended to address compensation of units for normal manning costs.

Eligibility

Generation resources must meet the following criteria in order to be compensated for differences between cost-based offers and actually incurred costs for resettlement using this procedure:

- The generation resource must have a fuel cost policy that has been submitted to the MMU as described in PJM Manual 15: Cost Development Guidelines.

- The generation resource has documented in the generation resource's fuel cost policy the conditions under which the resource cannot accurately estimate intraday costs and therefore will be allowed to be compensated using this procedure. For example, if there is no publicly traded commodity or index that could be used to reflect the generation resource's fuel cost and the fuel cost is only known at the time of purchase.

Offers

Market Sellers who elect to make their market-based schedules unavailable should make their most applicable cost-based schedule available. In every case, the submitted costs must follow the current PJM Manual 15: Cost Development Guidelines. Participants will be required to provide fuel cost documentation as documented in Section 1.8: Cost Methodology and Approval Process in PJM Manual 15: Cost Development Guidelines for the basis for the estimated fuel cost(s) and associated operating cost(s).

Operations

If a generation resource has been asked by PJM System Operations to operate and has no prior commitment, the Market Seller may elect to make its market-based schedule unavailable and update their cost-based schedule availability in real time. If the Market Seller elects to do this, the Market Seller must update the availability of their submitted schedules in Markets Gateway. to ensure their actual cost is reflected. All schedules submitted must be based on a verifiable methodology documented in the generation resource's fuel cost policy. The PJM operator will evaluate whether the specified cost-based schedule is economic and if so, will log and dispatch the unit on the applicable schedule.

If a station is directed by PJM to be manned beyond normal and required operating hours, the unit may submit the additional costs – manning costs – as defined below. Participants choosing to self schedule a unit after PJM has directed the station to be manned above normal station manning levels are not eligible for recovery of manning costs.

Settlements

Generation owners of resources committed by PJM that meet the eligibility criteria to be compensated using this procedure have until 1030 on the business day following the operating day to submit an e-mail to mrkt_settlement_ops@pjm.com with the following information:

- Unit Name
- Date of operation
- Applicable time of operation
- Contact information (name of sender, phone, e-mail)
- Date and time of PJM Dispatch contact to generator
- Invoice with actual fuel cost. The invoice must include:
  - Fuel cost in dollars per unit of volume (e.g. $/bbl, $/ccf) and heat content in MMBTU per unit of volume (e.g. MMBTU/bbl, MMBTU/ccf) or fuel cost in dollars per MMBTU.
  - Actual fuel consumed for power generation.
- Revised cost-based schedule using actual fuel costs and actual fuel consumption. The revised cost-based schedule should include startup cost, no load cost and incremental offer curve. Because Market Sellers will be compensated based on actual costs, Market Sellers shall not be allowed to include the 10 percent adder defined in Section 6.4 of PJM Tariff Attachment K - Appendix in their revised cost-based schedule.

The information shall be reviewed by PJM and the MMU. PJM Market Operations personnel will confirm with PJM System Operations the operation of the unit. The MMU shall inform PJM if it considers the information to be accurate or not after discussion with the participant. If PJM approves the submitted information, the revised cost-based schedule will be forwarded to the PJM Market Settlements department for the settlement credit adjustment. In the event that PJM and the Market Seller cannot come to agreement regarding the revised cost-based schedule, the generation resource will be paid based on the cost-based schedule determined by PJM. The Market Seller shall have the option to request a determination by FERC at its discretion. The MMU shall have the option to request a determination by FERC at its discretion.

If a unit uses a cost-based start-up and is manned above normal station manning levels at the direction of PJM and all units at the station do not run during the operating day, written confirmation of actual costs incurred due to such manning requirements can be submitted to PJM as cancellation fees per Section 1.10.2 of Schedule 1 of the PJM Operating Agreement and the parallel provisions of Attachment K Appendix of the PJM Tariff. Submittal should follow the “Credits for Canceled Pool-Scheduled Resources” timelines in Manual 28 (to be received within 45 days of date invoice was received by participant for the month in question). Request should include the normal station manning hours, the hours outside of normal station manning levels in which the unit was requested to be manned by PJM and the actual costs incurred for manning above normal station manning levels. The Balancing Operating Reserve credit for manning costs equals the actual costs incurred less any CT Lost Opportunity Credit in excess of day-ahead scheduled MW times the difference in real-time and day-ahead LMPs.

If a unit uses a price based start-up and is manned above normal station manning levels at the direction of PJM and all units at the station do not run during the operating day, written confirmation of actual costs incurred due to such manning requirements can be submitted to PJM as cancellation fees per Section 1.10.2 of Schedule 1 of the PJM Operating Agreement and the parallel provisions of Attachment K Appendix of the PJM Tariff. Submittal should follow the “Credits for Canceled Pool-Scheduled Resources” timelines in Manual 28 (to be received within 45 days of date invoice was received by participant for the month in question). Requests should include the normal station manning hours, the hours outside of normal station manning levels in which the unit was requested to be manned by PJM and the actual costs incurred for manning above normal station manning levels. The Balancing Operating Reserve credit for manning costs equals the actual costs incurred less any CT Lost Opportunity Credit in excess of day-ahead scheduled MW times the difference in real-time and day-ahead LMPs, capped at the appropriate price based start cost as specified in the generating resource’s offer data.

If a unit uses a cost-based start-up and is manned above normal station manning levels at the direction of PJM and any unit at the station does run during the operating day, the manning costs that are not included in their cost-based start recovered through normal operations may be submitted to the PJM Market Settlements Department (mrkt_settlement_ops@pjm.com). Requests should include the normal station manning hours, the hours outside of normal staffing hours in which the resource was requested to be manned by PJM and the additional actual costs incurred for manning that is not included in the cost-based start. These manning costs will be added to startup costs and will be evaluated with Balancing Operating Reserve credits for the unit.

Attachment D: Verification of Cost Offers greater than $2,000/MWh

This section addresses the procedures by which Market Sellers that incur incremental operating costs for a generation resource greater than $2,000/MWh can receive credit for Operating Reserves. The aim of the procedure is to:

- Enable generation resources that are requested to operate by PJM System Operations with cost based offers greater than $2,000/MWh to be made whole under certain conditions.
- Explain the process by which units with cost offers greater than $2,000/MWh can submit relevant documentation to PJM and the IMM to verify the cost offer. This procedure does not guarantee cost recovery. PJM must review and approve the Market Sellers cost calculation before any Operating Reserve credits will be paid to a Market Seller under this attachment.

Eligibility

A generation resource with a cost offers greater than $2,000/MWh in accordance with Manual 15 Cost Development Guidelines (M15) and the generator's applicable fuel cost policy is eligible when:

- PJM and the IMM have received the Market Seller's submitted documentation that supports make-whole compensation and PJM has approved the credits.

Settlements

Generation owners of resources committed by PJM that meet the eligibility criteria to be compensated using this procedure have until 1030 on the business day following the operating day to submit an e-mail to mrkt_settlement_ops@pjm.com with the following information:

- Unit Name
- Date of operation
- Applicable time of operation
- Contact information (name of sender, phone, e-mail)
- Date and time of PJM Dispatch contact to generator

- Documentation of the Market Seller's calculation of the cost based offer in accordance with M15 and applicable fuel cost policy.

Revision History

Revision 87 (3/23/2017):

- Section 4.2.2; 4b.1 and 6.2 – Providing one location on where to find the Primary Reserve and Synchronized Requirements (Manual 13, Section 2.2)
- Section 4.2.2 – provided updated explanation of what resources and the associated MWs are used for "double spin"; removed on peak / off peak requirement differentiation during "double spin"
- Section 4b.2.3 – added clarity that the NSRMW should not go negative

Revision 86 (02/01/2017):

- Revision to sections 3.2.4 and 6.1.1: updated the regulation requirement period and the regulation requirement effective MW to defer to Manual 12 Section 4.4.3 – Determining Regulation Assignment.
- Removed references to Manual 35 as this manual was retired on November 17, 2016.

Revision 85 (11/01/2016):

- Revisions to 10.4.5 Emergency and Pre-Emergency Settlements to use Economic CBL for energy settlements instead of "hour before" CBL method. Corresponding tariff provisions approved by FERC under ER16-2460.

Revision 84 (08/25/2016):

- Cover to Cover Periodic Review

Revision 83 (07/28/2016):

- Revisions to section 11.2.2 regarding the default non-elegibility in Day-Ahead Scheduling Reserve process for certain unit types.

Revision 82 (07/01/2016)

- Revisions to section 11.2.2 regarding Day-Ahead Scheduling Reserve eligibility for Dynamic Transfer resources.

Revision 81 (06/01/2016):

- Revisions to section 2.3.4 for 'Real Time Values'.

Revision 80 (03/31/2016):

- Revisions to various sections regarding effective operating day of 04/01/2016 for Day-Ahead Market timeline changes related to dockets No. ER14-24-000 & ER15-2260-001
- Changed all timings to 24 hour format
- References to eMKT application were updated to Markets Gateway
- Revisions to sections 2.3.3 and 2.3.4 for Parameter Limited Schedule changes related to the implementation of Capacity Performance effective from 06/01/2016 (dockets No.ER15-623 and EL15-29).
- New section 2.3.10 for operating parameter definitions
- Revisions to section 6.3.5 for cancellation fee of pool-scheduled resources
-

Revision 79 (12/17/2015):

- Revisions to section 2.3.2 Market Buyers, 2.3.3 Market Sellers, 2.3.9 Day-ahead Locational Marginal Price (LMP) Calculations, 2.7.2 Determination of LMPs for Generation Resources with offers greater than $2,000/MWh, 2.9 The calculation of Locational Marginal Prices (LMPs) During Reserve Shortages, 2.14 Balancing Operating Reserve Cost Analysis, 2.15 Maximum Emergency Energy in the Day-Ahead Market, and Attachment D: Verification of Cost Offers greater than $2,000/MWh effective 12/14/2015 offer cap language conforming change related to Docket No. ER16-76-000.

Revision 78 (12/14/2015):

- 3.1 – Revisions for clarity and to clean up formatting
- 3.2.4 – Minor revision for clarity
- 3.2.7 – Revised the Benefits Factor Curve to a more steeper slope intersecting x-axis at 40 (from 62)
- 3.2.7 – Updated business rules to recognize hours of the day with need for more sustaining regulation (RegA) and where RegD with benefits factor less than 1 will not be considered in the regulation clearing because of its reduced benefits
- 3.2.7 – Added frequency of benefits factor calculation

- 3.2.7 – Added benefits factor calculation steps

- 3.2.9 – Removed a bullet about operating bandwidth around the RTO regulation requirement. A new requirement had been defined during the Performance Based Regulation implementation in section 4.4.3 of Manual 12 – Balancing Operations

Revision 77 (08/27/2015):

- Added language in Section 1.1 to clarify the stakeholder notification process related to the creation of new closed loop pricing interfaces and the timing of their use to set Local Marginal Prices.

- Administrative Change: Updated references from edata to Data Viewer.

Revision 76 (08/03/2015):

- Conforming revisions for FERC Order ER15-1849, accepted on 7/23/15 and effective 8/3/15, to improve measurement and verification procedures for CSPs with Residential Demand Response Customers. Residential customers without interval metering may participate in the DA, RT, and SR market using the statistical sampling method detailed in Manual 19 Attachment D and subject to PJM approval (sections 4.2.8, 10.4.1, 10.5.2). Residential customers that do not participate in the Day Ahead market do not need to have the same LSE on economic registrations (sections 10.2.2, 10.5)

- Cleanup from a previous change in section 10.4.1: LSEs do not review meter data for DR.

Revision 75 (04/09/2015):

- Added second step on the reserve demand curves in section 2.5.5

- Added language in sections 4.2.2 to address the extension of the synchronized reserve requirement under certain emergency conditions

- Added language in sections 11.2.1 and 11.2.8 detailing the increase in the day-ahead scheduling reserve requirement under certain emergency conditions to account for the difference between fixed demand and forecasted load in the day-ahead market

Revision 74 (04/09/2015):

- Added language in section 2.3.2 and 2.3.7 for Demand Bid Screening Process that was implemented in Day-Ahead market.

Revision 73 (04/01/2015):

- Removal of revisions to section 2.3.2 Market Buyers, 2.3.3 Market Sellers, 2.9 The Calculation of Locational Marginal Prices (LMP) during Reserve Shortages and 2.15 Maximum Emergency Energy in the Day-Ahead Market effective 01/16/2015 – 03/31/2015 offer cap language conforming change related to Docket No. EL15-31-000.

- Administrative changes to Exhibit numbering.

Revision 72 (01/16/2015):

- Revisions to section 2.32 Market Buyers, 2.3.3 Market Sellers, 2.9 The Calculation of Locational Marginal Prices (LMP) during Reserve Shortages and 2.15 Maximum Emergency Energy in the Day-Ahead Market effective 01/16/2015 – 03/31/2015 offer cap language conforming change related to Docket No. EL15-31-000.

Revision 71 (01/01/2015):

- Section 2.3.3 and Attachment C– Added business rule regarding Intraday Cost Schedule updating. The effective date of the business rule is February, 2015

- Intermediate business rules for Manual Intraday Cost Schedule updating can be referenced at http://www.pjm.com/markets-and-operations/etools/emkt.aspx

Revision 70 (01/01/2015):

- Section 2.3.6 – Added business rule regarding the commitment of long lead resources in the day-ahead market

- Section 4.2.2 – Added business rules surrounding the increase to the Primary Reserve Requirements under emergency procedures

- Section 11.2.3 – Updated the calculation of the DASR Offer quantity

- Other minor revisions to clean up formatting and references to retired applications

Revision 69 (10/30/2014):

- Sections 3.2.1 and 3.2.7 – Corrected typographical errors of mileage ratio to mileage, and multiply by to divide by

- Section 3.2.1 – Added business rules regarding Demand Resources that have overlapping commitments in Regulation and Load Management

- Section 4.2.1 – Added business rules around resources Tier 1 MW estimation in the clearing process, and Tier 1 MW credit when Non-Sync Reserve MCP is above zero

- Section 4.2.8 – Added business rules regarding Demand Resources that have overlapping commitments in Synchronized Reserves and Load Management

Revision 68 (08/21/2014):

- Updated section 2.8 to include new Pre-Emergency Load Management resource types that was accidently not included in revision 67. Changes were approved at 8/21/14 MRC.

Revision 67 (06/01/2014):

- Section 2.3.2 added language detailing that PJM may require a specific bid limit volume on virtual bid/offer segments in the Day-ahead market.

- Section 2.3.4 added language detailing that PJM may require a specific bid limit volume on 'up to' congestion transactions in the Day-ahead market.

- Section 2.3.3 added requirement for units with notification and startup exceeding 24 hours to modify notification and startup time to allow unit to be committed in the Day-ahead Market if the unit was scheduled by PJM dispatch in advance of the close of the Day-ahead Market bidding period

- Section 4.2.2 added language detailing the increase of Synchronized Reserve and Primary Reserve requirements following Hot or Cold Weather Alerts or Maximum Generation Emergency Alerts to reflect additional reserves being carried to cover operational uncertainty.

- Section 11.2.1 added language detailing the increase of the Day-ahead Scheduling Reserve requirement following Hot or Cold Weather Alerts or Maximum Generation Emergency Alerts.

- Effective date 6/1/14 unless otherwise approved by FERC based on PJM compliance filing regarding the conforming manual changes for tariff changes approved in ER14-822- proceeding (improve DR resource operational flexibility). The DR operational changes for this manual include: (i) Section 10, requiring all Demand Resources participating in PJM's capacity market to serve as Pre-Emergency Load Response, unless the resource utilizes behind-the-meter generation that is subject to an environmental restriction; (ii) Section 10.4.5, limiting the duration of the required minimum load response reduction period from two hours to one; (iv) Section 2.3.3, establishing revised Demand Resource offer price caps which vary based on the registrations lead time

Revision 66 (03/07/2014):

- Section 10.1 - included conforming language to tariff provisions approved under order 745 that customer baseline should represent what the load would have otherwise been

and therefore settlements are not permitted for load reductions that would have otherwise occurred as part of normal operations.

Revision 65 (01/21/2014):

- Conforming changes to Docket No Docket No. ER14-373-000 approved on December 11, 2013 and approved by the PJM Markets and Reliability Committee on August 1, 2013. The changes are in section 2.3.4 and change the periods and requirements for parameter limited schedule exceptions.

Revision 64 (01/06/2014):

- Conforming changes to Docket No14-277 tariff changes approved on 12/17/13 by FERC and approved at 9/26/2013 by PJM Markets and Reliability Committee. The changes are in Section 10 and remove the requirement to include the LSE on PJM Emergency DR registrations.

Revision 63 (01/01/2014):

- Section 2.7 – Removing Regulation Marginal Benefits Factor from 5 minute LPC posting as directed by the FERC in ER12-1204.

- Section 3.2.7- Removing Regulation Marginal Benefits Factor from market settlements as directed by the FERC in ER12-1204.

- Section 3.2.10- Removing Regulation Marginal Benefits Factor and inserting Regulation Mileage Ratio into market settlements as directed by the FERC in ER12-1204 and consistent with Manual 28, Section 4.2.

- Section 4.2.1 – clarifying updates for the Tier 2 Synchronized Reserve must offer requirement.

- Section 4.2.4 – Rewording of Synchronized Reserve offer period.

- Section 4.2.12 – Augment language for Tier 2 Synchronized Reserve non-performance to a Synchronized Reserve Event.

- Section 7 – Updated link to retired Manual 41.

Revision 62 (8/30/2013):

- Section 10.4.2 updated to include 2 additional alternative CBLs: Same Day (3+2) and Match Day (3 day average)

Revision 61 (06/27/2013):

- Clarifying updates throughout sections 1, 2, 4 and 6 for shortage pricing.

- Section 3.2.9 documents that intra hour commitment or re-commitment for dual qualified regulation resources will continue to use the signal type (RegA or RegD) the resource cleared for the hour

- Corrections to section 4
  - Rewording of section 4.2.7 for hydro synchronized reserve events.
  - Conforming change to section 4.2.12 from to Manual 12, Section 4.5.8 regulating resources responding to a synchronized reserve event should return to their regulating band within 10 minutes of the end of the event.

- Clarification added to Attachment C to address the number of cost schedules, add clarity to units that change fuels after their DA commitment or minimum runtime has been met and unforeseeable manning cost recovery.

Revision 60 (06/01/2013):

- Conforming changes to incorporate rules for Residual Zone Pricing as approved by FERC in Docket (s) ER13-347. Residual metered load pricing is effective 6/1/2015. Conforming revisions made to section 2.

- Updates for EKPC Market Integration:
  - Section 2.13: Added EKPC to Western Region BOR.
  - Section 10.4.2: Added EKPC and DEOK to the weather station used for each Transmission Zone

Revision 59 (04/01/2013):

The following changes were approved at the 3/28/13 MRC

- Changes to Section 2 outlining the allocation of Day-ahead Operating Reserve Credits for resources scheduled to provide Reactive Services or transfer interface control per Docket #ER13-418

- Updated section 3.2.7 to provide refinement to the reduced energy ramp rate logic with the reduced ramp rate floor percent.

Revision 58 (3/1/2013):

- The following changes were approved at the 2/28/13 MRC.
  - Update section 10.2 to provide additional clarification on load reduction capability, business segment and generation attributes provided by CSPs.

- Update section 10.2 to clarify and change the CSP duplicate registration resolution process.
- Update section 10.4 to clarify how load reductions for emergency energy settlements are calculated and to determine rules for energy settlements when hourly emergency and economic event overlap. Update to section 10.4.5 are subject to FERC approval of corresponding tariff changes (expect to file in April and receive FERC decision by June 1, 2013).

Revision 57 (12/01/2012):

- Changes to Section 2.13 outlining the allocation of Operating Reserve Credits for the scheduling of units for Black Start service and testing of Black Start units
- References to the eSchedules application were updated to InSchedule to reflect the recent upgrade and renaming of this PJM application

Revision 56 (11/29/2012):

Section 4.2.9 updated for the following:

- Change language to require load data to be provided by CSP for all SR events and for all DR resources with an SR commitment.
- Change CSP load data submission deadline from 1 business day to 2 business days after the SR event,
- Include clarification that CSPs that fail to provide complete, accurate and timely load data may be suspended from participating in the Synchronized Reserve Market until corrective measures are implemented and may be referred to the PJM Market Monitor and/or the FERC Office of Enforcement for further investigation as necessary,
- Increase limit on DR resources from 25% of hourly SR requirement to 33% of the hourly SR requirement.

Revision 55 (10/25/2012):

- Conforming changes to incorporate rules for Shortage Pricing as approved by FERC in Docket (s) ER09-1063 and ER12-2262, effective 10/01/2012.
- Conforming revisions made to sections 2, 4, 5, & 6.
- An additional section created, Section 4b – Non-Synchronized Reserve Market, to incorporate new rules.

- Revisions endorsed by Markets & Reliability Committee on 10/25/2012.

Revision 54 (10/01/2012):

- Conforming changes to section 10 (demand response participation) based on order 745 (ER11-4106-000). Changes include DR compensation, cost allocation, CBL and associated approval process, elimination of self scheduling, implementation of dispatch group. Conforming changes to section 10 based on elimination of compensation based on LMP-G&T under NBT (ER12-1705-000). Conforming changes to section 10 based regulation market changes (ER12-1430) for demand response (Economic Regulation Only registration and ability to use additional CSP, modified aggregation rules for Economic Regulation Only registration and use of submeter load data to determine regulation performance. This change also included miscellaneous clean up and reformatting for section 10.

Revision 53 (10/01/2012):

- Added Section 12: Overview of the Price Responsive Demand. Conforming revisions for FERC Order ER11-4628 accepted on 12/14/2011 and effective 05/15/2012 to integrate Price Responsive Demand (PRD) in PJM Capacity Market.

Revision 52 (10/01/2012):

Based on FERC Order 755 for Frequency Regulation Compensation in the Organized Wholesale Power Markets encompassed in FERC Docket Nos. ER12-1204 and ER12-2391, the following changes were made to these sections in this Manual:

- Section 1.1 – PJM Responsibilities added detail about two-part regulation offer.

- Section 2.5 – Unit Dispatch System added detail about Regulation A and Regulation D.

- Section 3.1 – Overview of the PJM Regulation Market added detail about two-part regulation offer for capability and performance.

- Section 3.2.1 – Regulation Market Eligibility added detail about cost and price offers under the new two-part offer for capability and performance.

- Section 3.2.1 – Regulation Market Data Timeline added detail about two part regulation offer.

- Section 3.2.4 – Regulation Requirement Determination edited section to refer back to Manual 12, Section 4.4.3 Determining Regulation Assignment.

- Section 3.2.6 – Regulation Offer Period added detail about cost and price offers under the new two-part offer for capability and performance.

- Section 3.2.7 – Regulation Market Clearing and Dispatch added detail about two-part regulation offer for capability and performance and their impact on offer adjustment, three pivotal supplier test, lost opportunity cost, benefits factor and market clearing.

- Section 3.2.8 – Hydro Units reorganized to mirror corresponding language in Manual 28, Section 4.2 Regulation Credit.

- Section 3.2.9 – Regulation Market Operations added detail about two-part regulation offer for capability and performance.

- Section 3.2.10 – Settlements added detail about two-part regulation settlement for capability and performance including the use of the marginal benefit factor, as well as, hourly performance threshold of 25%.

- Section 5.2.7 – ASO edited section to reflect the new Ancillary Service Optimizer engine, which replaces SPREGO.

- Section 6.1.1 – PJM Regulation Requirement edited section to refer back to Manual 12, Section 4.4.3 Determining Regulation Assignment.

Revision 51 (08/08/2012):

- Add bullet to 3.2.1 to clarify priority of the regulation signal and economic dispatch.

- Add subsection Dispatch to 3.2.7 for the reduced energy ramp rate check to prevent units from over ramping when following both regulation and economic dispatch. Also added a check on the set points based on the MW output of the resource.

Revisions 50 (04/03/2012):

- Add bullet to Section 2.3.3 pointing to Manual M-28 regarding make whole provisions for generators committed in the Day-ahead Market and not run in real-time.

- Republished 04/12/2012 to remove an erroneous bullet point that had stated: “A Generator that has been notified of a restriction due to a projected reliability condition, should not submit an economic maximum or maximum emergency bid into the Day-Ahead market higher than the communicated restriction. A forced outage ticket should be entered into eDART (Outside Management Control) for the duration of the restriction.”

Revisions 49 (01/01/2012):

- Revisions made to reflect integration of the DEOK zone into the PJM footprint.

Revisions 48 (10/20/2011):

- Revision made to change the Synchronized Reserve Market interface from APSOUTH to the most limiting monitored transfer interface

- Revision made to the Synchronized Reserve maximum such that it can be less than or equal to the economic maximum for qualified resources that are granted exception due to a physical limitation

- Revision made to include Tier2 Synchronized Reserve floor offer of 0.1 MW in section 4.2.1

Revisions 47 (10/20/2011):

- Updated Section 3.2.1 to state that both Generation and Demand Resources must be able to provide 0.1 MW of Regulation Capability in order to participate in the Regulation Market.

Revisions 46 (06/01/2011):

- Revisions made to reflect integration of the ATSI zone into the PJM footprint.

Revisions 45 (06/23/2010):

- Revisions approved by stakeholders at MRC on June 23, 2010 to incorporate changes due to PJM markets manuals review.

- Revisions made to clarify that PJM will be the counterparty to all transactions, unless market participants expressly and mutually contract between themselves (or self schedule to themselves). Revisions have been approved at the Markets and Reliability Committee on April 21, 2010 and by FERC (Order ER10-1003 issued on May 5, 2010) (Reference: FERC Order ER10-1003)

Revisions 44 (01/01/2010):

- Revisions approved by stakeholders at MRC on November 11, 2009 to incorporate the following revision:

- One CSP rule (Section 10)

Revisions43 (9/24/2009):

- Revised Section 2: Overview of Two-Settlement System section to reflect revisions to rules for submitting PLS, as approved by, as approved by the Markets & Reliability Committee on September 23, 2009

Revisions 42 (07/31/2009)

- Revised Section 2: Overview of Settlement System section to reflect Balancing Operating Reserve construct change as approved by FERC (ER08-1569).

- Revised Section 2: Overview of Settlement System to incorporate revisions to allow generators with negative offers to set price in the Day-ahead Market during a Minimum Generation event, as approved by the Markets & Reliability Committee on July 30, 2009

- Revised Section 10: Overview of Demand Response Participation to incorporate enhancement to DSR economic aggregation rules for resources providing Ancillary Services, as approved by the Markets & Reliability Committee on July 30, 2009

Revisions 41 (06/18/2009)

- Revisions to Section 3 to incorporate rules as approved by FERC on March 29, 2009 (Docket No. ER09-789) to allow for the recovery of lost opportunity costs incurred by generating market buyers and market sellers during the hour preceding the initial regulating hour and the hour following the final regulation hour.

- Cleanup revision on page 121.

Revision 40 (03/18/2009):

- Revision to Section 10 to change the current rule requiring a participating end-use customer site have only one Curtailment Service Provider. Revision approved by Markets Reliability Committee on April 23, 2009.

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Revision 39 (03/18/2009):

- Revisions to Section 10 for Interval Meter Equipment and Load Data Requirements for DSR resources, Revisions approved by the Markets and Reliability Committee on March 18, 2009. Interval Meter Equipment and Load Data Requirements become effective on **October 1, 2009**.

Revision 38 (01/15/2009):

- Revised Section 3 to incorporate rules to implement the Three Pivotal Supplier Test in the Regulation Market as approved by FERC (ER09-013) on November 26, 2008.

- Revisions to Section 10 to incorporate Customer Usage Information Form

Revision 37 (11/24/2008)

- Revised Synchronized Reserve Market rules to allow recalculation of Tier 1 Synchronized Reserve estimates 60 minutes prior to the market hour [as approved by MRC on June, 2008]

Revision 36 (08/06/2008)

- Revised offer capping rules to eliminate exemptions per FERC Order EL08-34 (Effective May 16, 2008). Revisions made to Section 2.

- Revised terminology for revised RFC Definition for Bulk Electric System (BES. Revisions made to Sections 1, 11 & 9.

- Created new Section 11: Overview of Day-ahead Scheduling Reserve Market to incorporate markets rules approved per FERC Order ER08-780 (Effective May 30, 2008). Additional revisions made to Sections 1, 2, 5 & 6 for consistency.

- Revised the Regulation Market Requirement to calculate on and off peak values. Revisions made to Sections 3 & 6.

Revision 35 (06/13/2008)

- Section 10: Demand Resources Participation

- Revised Demand Response Participation Rules effective June 13, 2008 for calculation of Customer Baseline (CBL) and associated rules per FERC Order ER08-824.

Revision 34 (2/29/2008)

- Corrected typographical error made in Revision 33 on page 23.

Revision 33 (02/21/2008)

- Section 2 – Revisions to reflect changes to the business rules for ‘up-to-congestion’ transactions.

Revision 32 (09/28/2007)

- Section 2 – Revisions to reflect changes to the Day-ahead modeling of external bilateral transactions to put the generator or load (for import or export respectively) at the interface point.

Revision 31 (06/01/2007)

- Revisions for the implementation of Marginal Losses

- Revisions for the implementation of the Reliability Pricing Model

Revision 30 (03/20/02007)

- Section 2: Clarifying changes for consistency

- Section 3: Clarifying changes to reflect the implementation of Mixed-Integer Programming (MIP) in SPREGO optimization. Clarifying changes to reflect posting of Regulation Market Results.

- Section 4: Clarifying changes to reflect the implementation of Mixed-Integer Programming (MIP) in SPREGO optimization. Clarifying changes to reflect posting of Synchronized Reserve Market Results.

- Section 4: Revised rules to reflect the requirements of Demand Resources that are considered "batch load"

- Section 4: Revised rules to reflect Synchronized Reserve Market Consolidation for Reliability First Corporation.

- Section 5: Clarifying changes for terminology

- Section 6: Clarifying changes for consistency and terminology

- Section 6: Clarifying changes to reflect the scheduling process for External Market Sellers (XIC Units)

- Revision History permanently moved to the end of the manual.

Revision 29 (08/11/2006)

- Exhibit 1: Updated to include the new Manual 30: Alternative Collateral Program.

- Section 2: Revised rules to clarify the determination of a resource's hourly Desired MWh value and no-load compensation values.

- Section 7: Timing requirement updates made regarding ramp reservations that are not scheduled against and ramp reservations that are placed In-Queue.

- Added new section (Section 10) for Demand Response Participation

Revision 28 (06/13/06)

- Revised Ancillary Services Rules for DSR.
- Revised Ancillary Services Rules for RFC.
- Revised for Three Pivotal Supplier rules.

Revision 27 (05/12/06)

- Section 7: Overview of External Transaction Scheduling
- Removed exception for spot import service.
- Revisions were made to the following pages: 101 and 106.

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.
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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 Settlement System
- Changed PJM Settlement Business Rules for to allow Unit Modeling Changes quarterly.

Revision 22 (10/01/04)

- Section 2: Overview of PJM Settlement System
- Changed PJM Settlement Business Rules for Virtual Bidding at External Interfaces
- Added PJM 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 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 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 Settlement Market User Interface: Condense Startup Cost, Condense Hourly Cost, Condense Notification Time, and 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 can be found on the PJM Web site 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 settlement, regulation markets and spinning reserve markets. The user guide describes the 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 Web site 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 Web site at http://www.pjm.com/documents/downloads/user-guides/ts-userguide.pdf
- Participants can also download the PJM Network Model information from the PJM Web site 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 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 Web site at http://www.pjm.com/services/training/downloads/ 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 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 p.m. of the day before operations and Non-Firm schedules requested after 2:00 p.m. 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 beforehand. 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 as 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 0700 or 2300.

- (A1) Two possible solutions are 1) the energy may be scheduled from 0000 to 0800 or 2) the energy may be scheduled from 0000 to 0715 and from 2315 to 2400.

- (Q2) A Market Participant has reserved on-peak weekly transmission. Ramp room is available from 0700 to 2300 Tuesday through Friday, but ramp room is not available at 0700 or 2300 on Monday.

- (A2) The energy may be scheduled 0700 to 2300 Tuesday through Friday. One solution to the Monday ramp limit would be to schedule the energy from 0645 to 2245.”

- 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***.