



Working to Perfect the Flow of Energy

PJM Manual 28:

Operating Agreement Accounting

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Prepared by:

Market Settlements Development
Department

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PJM Manual 28: Operating Agreement Accounting

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Market Settlements Development

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- ~~Updated Section 3.5 to provide a description of a fully metered EDC.~~

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Introduction

Welcome to the ***PJM Manual for Operating Agreement Accounting***. In this Introduction, you will find information about PJM Manuals in general, an overview of this PJM Manual in particular, and information on how to use this manual.

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by the PJM for the operation, planning, and accounting requirements of PJM 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](http://www.pjm.com), ~~www.pjm.com and select “Manuals” under the “Documents” pull-down menu.~~

About This Manual

The ***PJM Manual for Operating Agreement Accounting*** is one of a series of manuals within the Accounting and Billing set of manuals. This manual focuses on the accounting for energy with the PJM Energy Market. It establishes the basis for the charges and credits for the purchase and sale of energy and related services.

The ***PJM Manual for Operating Agreement Accounting*** consists of 21 sections. The sections are listed in the table of contents beginning on page ii.

Intended Audience

The intended audiences for this PJM Manual for Operating Agreement Accounting are:

- PJM Members and Transmission Customers
- Other Control Areas



- External auditors, lawyers, and regulators
- PJM settlements staff and audit staff
- PJM customer relations and training staff

References

The references to other documents that provide background or additional detail directly related to the *PJM Manual for Operating Agreement Accounting* are:

- PJM Manual for [Open Access Transmission Tariff Accounting \(M-27\)](#)
- PJM Manual for [Balancing Operations \(M-12\)](#)
- PJM Manual for [Billing \(M-29\)](#)
- PJM Manual for [Energy & Ancillary Services Market Operations \(M-11\)](#)
- PJM Manual for [Administrative Services for the PJM Interconnection Agreement \(M-33\)](#)
- Operating Agreement of PJM Interconnection, L.L.C.
- PJM Open Access Transmission Tariff

Using This Manual

We believe that explaining concepts is just as important as presenting the 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.

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 PJM Member actions



- A section at the end detailing all previous revisions of this PJM manual



Section 1: Market Overview

Welcome to the *Market Overview* section of the *PJM Manual for Operating Agreement Accounting*. In this section, you will find the following information:

- A description of the PJM Energy Market accounting services (see “Market Accounting Overview”).
- A description of PJM Market Settlements Accounting Input Data (see “Accounting Input Data”).

1.1 Market Accounting Overview

There are several services within the PJM Energy Market for which PJM calculates charges and credits that are allocated among the PJM Members. PJM provides accounting for the following services that are described in detail in the other sections of this manual.

- Spot Market Energy — Energy bought or sold by PJM Members through the PJM Energy Market.
- Transmission Congestion — The increased cost of energy delivered when the Transmission System is operating under constrained conditions.
- Transmission Losses — Energy requirements in excess of load requirements due to the energy consumed by the electrical impedance characteristics of the Transmission System.
- Regulation — The capability of a specific resource with appropriate telecommunications, control, and response capability to increase or decrease its output in response to a regulating control signal (see the PJM Manual for Balancing Operations).
- Synchronized Reserve – The capability of a specific resource with appropriate telecommunications, control, and response capability to increase output (or reduce consumption) in response to a synchronized reserve event and/or operate at a point that deviates from economic dispatch (including condensing mode) to provide 10-minute reserve (see the PJM Manual for Balancing Operations).
- Non-Synchronized Reserve – The capability of a specific non-emergency generation resource with appropriate telecommunications, control, and response capability to increase output from an offline state in response to a non-synchronized reserve event to provide 10-minute reserve (see the PJM Manual for Balancing Operations).



- Operating Reserve — The amounts of generating Capacity scheduled to be available for specified periods of an Operating Day to ensure the reliable operation of PJM.
- Reactive Services — The amounts of generation altered by PJM to maintain reactive reliability.
- Synchronous Condensing — The instructions to generators to operate in synchronous condensing mode for reasons other than reactive support or synchronized reserve to ensure the reliable operation of PJM.
- Emergency Energy — Energy bought from other Control Areas or sold to other Control Areas by PJM due to Emergencies either within PJM or within the other Control Areas.
- PJM Emergency Load Response — The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for voluntarily reducing load during an emergency event.
- PJM Economic Load Response — The Economic Load Response Program is designed to provide incentive to end-use customers or Curtailment Service Providers (“CSP”) to enhance the ability and opportunity for reduction of consumption when PJM Locational Marginal Prices (“LMP”) are high.
- Metering Reconciliation — Metering errors and corrections that are reconciled at the end of each month by a meter error correction charge adjustment.
- Inadvertent Interchange — Differences between hourly net actual energy flows and net scheduled energy flow into or out of the PJM control area.
- Unscheduled Transmission Service — Service that PJM Members can provide to or receive from the New York ISO and are credited or charged according to the Operating Agreement.
- Ramapo PAR Facilities — Carrying charges collected from PJM Mid-Atlantic Control Zone transmission owners paid to the New York ISO for the Phase Angle Regulators (PARs) at Ramapo and charged according to the Operating Agreement.
- Financial Transmission Rights Auction — market participants may purchase/sell FTRs by participating in the Annual and Monthly auctions.
- Auction Revenue Rights — ARRs are the mechanism by which the proceeds from the FTR auctions are allocated.



These services are applicable to the different types of market participation, as shown in Exhibit 1. Each service is further broken down in the billing statement (see the *PJM Manual for Billing*).

	MARKET BUYERS	MARKET SELLERS	TRANSMISSION CUSTOMERS
Spot Market Energy	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Regulation	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Operating Reserves	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Transmission Congestion	<input checked="" type="checkbox"/>		<input checked="" type="checkbox"/>
Transmission Losses	<input checked="" type="checkbox"/>		<input checked="" type="checkbox"/>
Emergency Energy	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Meter Reconciliation	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Unscheduled Transmission Service	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Capacity Credit Market	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
Financial Transmission Rights	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>
Auction Revenue Rights	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>

Exhibit 1: Types of PJM Services

The PJM Energy Market accounting is designed to operate on a balanced basis. That is, the total amount of the charges equals the total amount of the credits; there are no residual funds. With certain exceptions, each of the services also operates on a balanced basis. That is, the charges and credits for a particular service, such as regulation, offset each other exactly. In certain cases, charges in excess of credits, or vice versa, in one service are used to offset the costs of providing another service.

1.2 Accounting Input Data

At the end of each operating hour, PJM collects information regarding actual operations during the hour. This information is recorded either by the PJM dispatchers or by automated systems. The market accounting processes use this information as input data. Other accounting input data is provided from various systems and databases. This information includes data describing PJM Members' installed generating resources, scheduling information for PJM Members' transactions, and Transmission System parameters, such as loss factors determined annually by PJM system planning staff. The market accounting processes use this information as described in the following sections of this manual



Section 2: Interface Pricing

Welcome to the *Interface Pricing* section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- An overview of the interface pricing settlements business rules (see “Business Rules for Interface Pricing”).

2.1 Business Rules for Interface Pricing

Market Participants have the ability to transact energy in-to, out-of or through the PJM RTO (see OASIS – Regional Transmission and Energy Scheduling Practices for details on the PJM processes for facilitating the transaction and scheduling process). The source and sink pricing assignments for these external transactions are determined using mappings that use a combination of the ExSchedule system source and sink selection, the NERC Tag, and the OASIS reservation.

- For Day-ahead export (out-of PJM RTO) transactions where the source and sink on the OASIS are the same, the source and sink price is assigned based on the Export Pricing Point selected by the customer in the ExSchedule system. Where the source and sink are not the same, the source price is assigned based on the source of the OASIS reservation being used, while the sink price is the Export Pricing Point selected by the customer in the ExSchedule system.
- For Real-time export (out-of PJM RTO) transactions where the source and sink on the OASIS are the same, the source and sink price is assigned based on the sink of the NERC Tag and the applicable interface pricing mapping*. Where the source and sink on the OASIS are not the same, the source price is assigned based on the source of the OASIS reservation being used, while the sink price is based on the sink of the NERC Tag and the applicable interface pricing mapping*.
- For Day-ahead import (in-to PJM RTO) transactions using a Spot-In OASIS reservation, both the source and sink prices are based on the Import Pricing Point selected by the customer in the ExSchedule system.
- For Day-ahead import (in-to PJM RTO) transactions using an OASIS reservation (other than a Spot-In OASIS reservation) where the source and sink on the OASIS are the same, the source and sink price is assigned based on the Import Pricing Point selected by the customer in the ExSchedule system. Where the source and sink are not the same, the source price is based on the Import Pricing Point selected by the customer in the ExSchedule system, while the sink price is based on the sink of the OASIS reservation being used.



- For Real-time import (in-to PJM RTO) transactions using a Spot-In OASIS reservation, both the source and sink prices are based on the source of the NERC Tag and the applicable interface pricing mapping*.
- For Real-time import (in-to PJM RTO) transactions using an OASIS reservation (other than a Spot-In OASIS reservation) where the source and sink on the OASIS are the same, the source and sink price is assigned based on the source of the NERC tag and the applicable interface pricing mapping*. Where the source and sink are not the same, the source price is based on the source of NERC tag and the applicable interface pricing mapping*, while the sink price is based on the sink of the OASIS reservation being used.
- For Day-ahead wheel (through PJM RTO) transactions, the source price is based on the Import Pricing Point selected by the customer in the ExSchedule system, while the sink price is based on the Export Pricing Point selected by the customer in the ExSchedule system.
- For Real-time wheel (through PJM RTO) transactions, the source price is based on the source of the NERC tag and the applicable interface pricing mapping*, while the sink price is based on the sink of the NERC tag and the applicable interface pricing mapping*.

* The Pricing Point Guide which contains the complete listing of the Mapping of External Balancing Authorities to Interface Pricing Points can be found on the PJM website at <http://www.pjm.com/markets-and-operations/etools/exschedule.aspx>.

During any hour in which any entity makes any purchases from other external areas outside of such area or sub-area (other than delivery of external designated Network Resources or such other exceptions specifically documented for such area or sub-area) at the same time that energy sales into PJM are being made, pricing will revert to the applicable Import or Export Pricing Point that would otherwise be assigned to such external area or sub-area. There are currently no exceptions to this process.

During any hour in which any entity purchases energy from PJM for delivery into such area or sub-area while sales from such area to other external areas are simultaneously implemented (subject to any exceptions specifically documented for such area or sub-area in the PJM Manuals), pricing will revert to the applicable Import or Export Pricing Point that would otherwise be assigned to such external area or sub-area. There are currently no exceptions to this process.

Beginning May 3, 2009 the following interface pricing rules for NERC Tags which source or sink in the CPLE, DUKE, or NCMPA1 were effective.

- Real-time transactions between PJM and the CPLE, DUKE, and NCMPA1 control areas are reviewed hourly to determine if the transactions qualify for the DUK/CPLE/NCMPA1 import or export price.



- Each hour, Real-time telemetry from the CPLE, DUKE, and NCMPA1 control areas is used to validate whether the NERC Tag between the CPLE/DUK/NCMPA1 control areas and PJM control area should qualify for the given CPLE/DUK/NCMPA1 import or export price.
- If transactions do not qualify for the CPLE/DUK/NCMPA1 import or export price, the SOUTHIMP or SOUTHEXP prices are used.
- The interface price definitions for CPLE, DUKE, and NCMPA1 can be found on the PJM website at <http://www.pjm.com/markets-and-operations/energy/real-time.aspx>.



Section 3: Spot Market Energy Accounting

Welcome to the *Spot Market Energy Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- An overview of the spot market accounting (see “*Spot Market Accounting Overview*”).
- How PJM determines spot market net interchange for each PJM Member (see “*Calculating Spot Market Interchange*”).
- How charges for spot market energy are calculated for market buyers and sellers (see “*Interchange Market Buyers’ Charges*”).
- How spot market energy charge reconciliations are calculated (see “*Reconciliation for Spot Market Charges*”).

3.1 Spot Market Accounting Overview

The PJM Energy Market is the regional competitive market that is administered by PJM for the purchase and sale of Spot Market energy. PJM Members buy and sell energy from the spot market based on metered and scheduled use. PJM schedules and dispatches generation on the basis of least-cost, security constrained dispatch and the bids and operating characteristics offered by the sellers into PJM. PJM dispatches generation to meet the PJM Member buyers’ requirements, as well as the requirements for Ancillary Services.

PJM is responsible for administering the Day-ahead and Balancing PJM Energy Markets, including, performing the following accounting-related functions:

- accounting for transactions
- rendering bills to buyers and sellers
- receiving payments from and dispersing payments to buyers and sellers

The Spot Market facilitates the trading of energy by PJM Members. The Spot Market clears hourly at the appropriate day-ahead and real-time System Energy Price component of LMP. PJM calculates a day-ahead and a real-time System Energy Price each hour for the entire PJM RTO, as specified in **Section 2** of this PJM Manual. Energy delivered to the Spot Market is compensated at the System Energy Price for that hour. Energy purchased from the Spot Market is charged at the System Energy Price for that hour.



3.2 Business Rules for InSchedule and Power Meter Data Submissions

Unilateral Corrections to InSchedule Load Responsibility Data

- For load responsibility InSchedule data submitted by the LSE (as opposed to the typical EDC submittal), EDCs need more certainty of accurate and final data prior to the PJM InSchedule data submission deadline in order for them to accurately calculate load responsibilities for all other LSEs in their territory by the InSchedule deadline.
- These LSEs must submit their data two hours prior to the established PJM InSchedule data submission deadlines.
- If this does not occur, EDCs shall be allowed to e-mail PJM with the LSE's load responsibility data (with a copy provided to the applicable LSE) so that PJM can enter that EDC-calculated data prior to the InSchedule data submission deadline as the official data to be used for settlements.
- Any discrepancies remaining after the InSchedule deadline may be resolved via the EDC load reconciliation data submissions.

Unilateral Corrections to Power Meter Generation Data

- For generation MWh data submitted by the generation owner (as opposed to the EDC submittal), EDCs need more certainty of accurate and final Power Meter data prior to the PJM InSchedule data submission deadline in order for them to accurately calculate load responsibilities for all other LSEs in their territory by the InSchedule deadline.
- If gross data errors in the submitted data are identified by the EDC (and PJM concurs with the findings), EDCs shall be allowed to e-mail PJM with the correct generator data (with a copy provided to the applicable generation owner) so that PJM can enter that data prior to the Power Meter data submission deadline as the official data to be used for settlements.
- Any discrepancies remaining after the Power Meter deadline may be resolved via monthly Meter Error Correction data submissions.

3.3 Calculating Spot Market Interchange

Net interchange for PJM Members is the difference between a participant's total energy resources (including both generation and purchased energy) and its energy demand (including both load and energy sale obligations).



For each hour, PJM calculates each market participant's hourly day-ahead and real-time net spot market energy interchange.

Day-ahead net interchange equals the sum of a market participant's demand and decrement bids cleared in the day-ahead market, less any accepted generation and increment offers cleared in the day-ahead market, and is adjusted for all day-ahead energy transactions in which the customer account is involved.

Real-time net interchange consists of a market participant's hourly metered tie line flows (if applicable), less any ownership of metered generation, and is adjusted for all real-time energy transactions (including any load obligations [de-rated for transmission losses] or generation modeled by InSchedule transactions, and including any InSchedule transactions that were priced day-ahead) in which the customer account is involved.

3.4 Transmission Loss De-rating Factors

Because PJM employs a Marginal Loss methodology, energy market-related settlements need to use load responsibilities de-rated for transmission losses. This is due to the fact that the LMPs include a loss price component. In order to remove all transmission losses, as represented in PJM's network system model, hourly EDC loss de-rating factors are applied to the total EDC load and to individual LSE load responsibilities. In general, these loss de-rating factors represent total transmission losses divided by total load including losses. (Note that these are different from traditional loss factors which reflect total losses divided by load excluding losses.)

Each hour, PJM calculates a loss de-rating factor for each EDC that has their tie lines fully metered directly to PJM. For non-PJM Mid-Atlantic EDCs (that do not receive an allocation of the jointly-owned PJM 500 kV transmission system losses), the calculation is as follows:

$$\text{EDC total state-estimated Loss MWh} / \text{EDC total revenue-metered load MWh including all losses}$$

For PJM Mid-Atlantic EDCs (that do receive an allocation of the jointly-owned PJM 500 kV transmission system losses), the calculation is as follows:

$$(\text{EDC total state-estimated non-500kV Loss MWh} + \text{EDC revenue-metered 500kV Loss Allocation MWh}) / (\text{EDC total revenue-metered load MWh including all non-500kV losses} + \text{EDC revenue-metered 500kV Loss Allocation MWh})$$

These EDC hourly loss de-rating factors are applied to the LSE load responsibility InSchedule MWh quantities (which are inclusive of all losses) that are carved-out of the applicable EDC's total load, as well as applied to any residual load responsibility remaining with the EDCs, as follows:

$$\text{Loss De-rated Load MWh} = (1 - \text{EDC Loss De-rating Factor}) \times \text{InScheduled, or Revenue-Metered, Load Responsibility MWh}$$

3.5 State-estimated vs. Revenue-metered Energy Quantities

Real-time generation MWh are initially determined by the PJM State Estimator, however, they are replaced by revenue meter data, if the equivalent revenue meter values are available via PJM Power Meter.

The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distribution Company (EDC) that reports hourly net energy flows from all



metered tie lines to PJM via Power Meter and revenue meter data for the hourly net energy delivered by all generators within that EDC's territory via Power Meter, for the purposes of energy market accounting the EDC is classified as a fully metered EDC. The total fully metered EDC revenue-metered load is calculated as the sum of the net import energy flows reported by their tie revenue meters plus the net generation reported by the generator revenue meters. The amount of load at each of such fully metered EDC's load buses calculated by the PJM State Estimator is then adjusted, in proportion to its share of the total load of that fully metered EDC, in order that the total amount of load across all of the fully metered EDC's load buses matches its total revenue meter calculated load.

PJM will assess and trend quarterly the degree of net energy injections at load buses modeled in the PJM network system model (i.e., reverse power flows) in order to detect and correct and modeling issues and to identify any generation in excess of load that appears at a load bus. PJM will determine and use a relevant net energy injection threshold at a load bus that may impact LMP and/or load accuracy. For load buses with persistent negative MWh, PJM will work with the applicable EDC to determine if the cause is suboptimal modeling or actual reverse power flows from distribution-level system(s) to the PJM transmission system, or simply normal results due to state estimation. Properly modeled load buses with consistent excess energy injections due to distribution-level reverse power flows should be modeled as generation buses in the PJM network system model at the load bus location in order to minimize the amount of negative MWh observed at those load buses.

3.6 Residual Metered Load

For settlements purposes, load within a fully metered EDC's territory is assigned to non-metered entities by submitting hourly load obligation data in the InSchedule system. Data submitted in the InSchedule system includes the names of the LSE responsible for serving the load and the EDC in whose territory the load is located, the number of megawatts of load assigned to the LSE for each hour, the aggregate at which load is to be priced, and the start and end dates for the load contract. During the settlements process, load assigned to an LSE at a specified aggregate is further assigned to individual load buses based on the aggregate definition, which specifies the percentage of the overall aggregate that each bus represents, to identify the LSE's hourly megawatts of load at each bus. Nodal priced load is defined as any hourly load submitted under an InSchedule contract that is priced at an aggregate comprised of a single identifiable bus or set of identifiable buses at which the load is located. A detailed description of the nodal pricing settlements business rules can be found in Manual 27 Section 5.6. The hourly nodal load amounts submitted in InSchedule are multiplied by the nodal aggregates definitions to calculate the nodal priced load at each bus. Residual metered load at each bus is defined as the bus load (adjusted revenue meter calculated load as calculated in Section 3.5) less the nodal priced load at each bus.

3.7 Residual Metered Load Aggregate Definitions

Residual Metered Load aggregates more accurately reflect the composition of non-nodal priced load in fully metered EDC territories. Effective June 1 2015, Residual Metered Load aggregates are the default for which real-time load is settled if it has not elected to settle at a nodal load aggregate. Upon implementation of residual metered load pricing on June 1 2015, physical zone pricing for real-time load will no longer be available.



Residual Metered Load aggregate distribution factors are determined by dividing the residual metered load for each bus in the fully metered EDC territory by the total residual metered load for the fully metered EDC territory. Residual Metered Load aggregate prices are defined by weighting each load bus LMP by that bus' residual metered load aggregate distribution factor. For the majority of PJM transmission zones, the EDC territory is the same as the physical transmission zone. In cases where the fully metered EDC's territory differs from the physical transmission zone, residual metered load aggregates exist for each fully metered EDC territory within the transmission zone. Residual Metered Load aggregate congestion prices, loss prices, and total LMPs are calculated using the Residual Metered Load aggregate distribution factors. Factors for each Residual Metered Load aggregate sum to exactly 100%.

Residual Metered Load aggregate definitions used for the calculation of Day-ahead LMPs, preliminary and final Real-time LMPs, and FTRs/ARRs are defined as follows:

- Day-ahead Residual Metered Load aggregate distribution factors default to the final real-time distribution factors for the Residual Metered Load aggregate at 8:00 a.m. one week prior to the Operating Day (i.e., if next Operating Day is Monday, the default distribution is from 8:00 a.m. on Monday of the previous week). Consistent with physical transmission zones, the definition applies to all hours in the day.
- Preliminary 5 minute real-time Residual Metered Load aggregate LMPs are calculated using the same Residual Metered Load aggregate distribution factors as used in the Day-ahead market for the Operating Day.
- Final hourly real-time Residual Metered Load aggregate distribution factors are calculated using InSchedule-submitted nodal load MWh.
- Residual Metered Load aggregate distribution factors for ARR/FTR purposes are fixed for the planning period (June 1st – May 31st). Consistent with physical transmission zones, the residual metered load aggregate distributions for FTRs/ARRs are initially determined using the hourly individual residual load bus contribution to the total residual load at the time of the previous year's PJM annual peak. In cases where there are new nodal load requests pursuant to the nodal pricing rules in Manual 27, the initial residual metered load aggregate definition for FTRs/ARRs are adjusted by the LSE's nodal load peak distribution. LSEs moving to nodal load settlement for the upcoming PJM planning year will be required to submit a peak load at the time of the PJM annual peak from the previous year per the nodal pricing rules in Manual 27. This value in conjunction with the distribution percentages currently required according to the nodal pricing rules in Manual 27 will be used to determine the final residual metered load aggregate distribution.

3.8 Spot Market Energy Charges

Market participant customer accounts incur +/- charges for Day-ahead Spot Market Energy based on their day-ahead net interchange. If a market participant's day-ahead net interchange is a net purchase of day-ahead spot market energy in an hour (a positive



value), they are charged for purchasing their net interchange for that hour at the hour's day-ahead System Energy Price. If a market participant's day-ahead net interchange is a net sale of day-ahead spot market energy in an hour (a negative value), they are provided with a negative charge for selling their net interchange for that hour at the hour's day-ahead System Energy Price.

Market participant customer accounts incur +/- charges for Balancing Spot Market Energy based on the deviation between their real-time net interchange and their day-ahead net interchange. Hourly balancing spot market deviations are calculated by subtracting the hour's day-ahead net interchange from the hour's real-time net interchange. If a market participant's balancing spot market deviation is a net purchase of real-time spot market energy in an hour (a positive value), they are charged for purchasing their balancing deviation for that hour at the hour's real-time System Energy Price. If a market participant's balancing spot market deviation is a net sale of real-time spot market energy in an hour (a negative value), they are provided with a negative charge for selling their balancing deviation for that hour at the hour's real-time System Energy Price.

PJM Actions:

- PJM accounting process retrieves the following information:
- Each market participant's hourly day-ahead and real-time net interchange (MWh)
- The hourly RTO system-wide System Energy Price (\$/MWh)
- PJM calculates the Day-ahead Spot Market Energy charge (positive or negative) for each hour for each Market Participant as:

$$\text{Day-ahead Spot Market Energy Charge} = (\text{Day-ahead Net Interchange}) * (\text{Day-ahead System Energy Price})$$

- PJM calculates the Balancing Spot Market Energy charge (positive or negative) for each hour for each Market Participant as:

$$\text{Balancing Spot Market Energy Charge} = (\text{Real-time Net Interchange} - \text{Day-ahead Net Interchange}) * (\text{Real-time System Energy Price})$$

3.9 Reconciliation for Spot Market Energy Charges

PJM will calculate reconciled Spot Market Energy charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.



PJM calculates the Spot Market Energy charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the real-time PJM System Energy Price for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Spot Market charges for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.



Section 4: Regulation Accounting

Welcome to the *Regulation Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of how Regulation is provided and accounted for in the PJM Regulation Markets (see “*Regulation Accounting Overview*”).
- How credits are calculated for providers of Regulation (see “*Regulation Credits*”).
- How charges are calculated for users of Regulation (see “*Regulation Charges*”).
- How regulation charge reconciliations are calculated (see “*Reconciliation for Regulation Charges*”).

4.1 Regulation Accounting Overview

Regulation is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at 60 cycles per second (60 Hz). PJM commits on-line resources whose output is raised or lowered as necessary to follow moment-to-moment changes in load. Regulation is predominantly achieved using automatic generation control equipment. Regulating resources include both generators and demand side response resources.

PJM operates the Regulation Market where the Regulation Market Clearing Prices are determined based on Regulation offers and opportunity costs. PJM assigns the most economically efficient set of regulating resources available in real-time to separately meet the applicable NERC regions’ regulation zone requirements. For more detailed information about how regulating requirements are developed and how Regulation is assigned, see the **PJM Manual for Balancing Operations (M-12)**. For an overview of the Regulation Market, see the **PJM Manual for Energy & Ancillary Services Market Operations (M-11)**.

Each PJM load serving entity has an hourly Regulation obligation equal to their regulation zone real-time load ratio share of the applicable Regulation requirement for the hour, prorated to reflect the total amount of Regulation actually supplied.

A market participant’s Regulation obligation can be satisfied from their own resources capable of providing Regulation, by contractual arrangements with other Market Participants capable of providing Regulation, and/or by purchases of Regulation from the PJM Regulation Market.

Resource owners supplying self-scheduled Regulation are credited based on the hourly Regulation Market Capability Clearing Price (RMCCP) and Regulation Market Performance Clearing Price (RMPCP) for each MW of Regulation supplied, with consideration of the resource’s Regulation performance, and where applicable, the ratio between the requested mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal (mileage ratio). Resource owners supplying pool-scheduled Regulation are credited for each Regulation MW at the higher of the hourly Regulation



Market Performance and Capability Clearing Prices, with consideration of the resource's Regulation performance, and where applicable the mileage ratio, or their Regulation offer price (plus real-time opportunity cost including shoulder hours' lost opportunity costs, for generating resources). Regulation buyers are charged the hourly Regulation Market Capability Clearing Price (RMCCP) and Regulation Market Performance Clearing Price (RMPCP) plus their percentage share of any Regulation provider's unrecovered costs over and above their total Regulation Clearing Price credits.

4.2 Regulation Credits

Each resource supplying pool-scheduled Regulation is credited at the higher of the hourly RMCCP and RMPCP with consideration of the resource's Regulation performance, and where applicable, the mileage ratio or its Regulation offer price (plus real-time opportunity cost including shoulder hours' lost opportunity costs, for generating resources). A resource supplying self-scheduled Regulation is credited based on the hourly RMCCP and RMPCP with consideration of the resource's Regulation performance, and where applicable, the mileage ratio. Regulation credits for joint-owned generators supplying Regulation are allocated to the owners based on their ownership shares.

Any resource with an hourly performance score below the applicable threshold for minimum hourly performance in Manual 11 Section 3.2.10 will receive zero regulation credits for that market hour.

PJM Actions:

- From the Regulation log, PJM identifies each resource that supplied Regulation (both pool-scheduled and self-scheduled) with an hourly performance score greater than or equal to the applicable threshold for minimum hourly performance in Manual 11 Section 3.2.10 during an hour.
- PJM calculates the hourly Regulation RMCCP Credit for each applicable regulating resource by multiplying each increment of such Regulation in megawatts during the hour by the Regulation Market Capability Clearing Price (RMCCP) and the resource's actual performance score for that hour.

$$\text{Regulation RMCCP Credit} = \text{Hourly-integrated Regulation MW} \times \text{Actual Performance Score} \times \text{RMCCP}$$

- PJM calculates the hourly Regulation RMPCP Credit for each applicable regulating resource by multiplying each increment of such Regulation in megawatts during the hour by the Regulation Market Performance Clearing Price (RMPCP) for that hour, the applicable mileage ratio, and the resource's actual performance score for that hour.

$$\text{Regulation RMPCP Credit} = \text{Hourly-integrated Regulation MW} \times \text{Actual Performance Score} \times \text{Mileage Ratio} \times \text{RMPCP}$$



- PJM calculates the total Regulation Clearing Price Credit as the Regulation RMCCP Credit plus the Regulation RMPCP Credit for that hour.

$$\text{Regulation Clearing Price Credit} = \text{Regulation RMCCP Credit} + \text{Regulation RMPCP Credit}$$

- The lost opportunity costs calculated as part of the real-time pricing algorithm as adjusted by the applicable performance score and unit-specific benefits factor will be used in the settlement calculation for intra-hour lost opportunity costs.
- PJM calculates shoulder hours' lost opportunity costs incurred by each generator providing pool-scheduled Regulation for the preceding and following hour. Note that the energy offer referred to below is the generator's incremental energy offer curve that is associated with the price-based or cost-based schedule used in the real-time dispatch of the unit.
- CT¹ and hydro generators are not eligible for shoulder hour lost opportunity costs.
- A generator is eligible for preceding shoulder hour lost opportunity costs when: it is online the hour prior to regulating; the Regulation assignment starts at the top of the hour; it is not regulating during the preceding hour; and the LMP Desired from the prior hour is not already within the regulation hour regulation limits.
- A generator is eligible for following shoulder hour lost opportunity costs when: it is online the hour following regulating; the Regulation assignment ends at the top of the following hour; it is not regulating during the following hour; and the LMP Desired from the following hour is not already within the regulation hour regulation limits.
- In the preceding hour of regulation, if a generator must reduce its output to provide regulation and foregoes revenues, its shoulder hour lost opportunity cost equals the amount of its energy offer at the preceding hour economically desired level in excess of its energy offer at its Regulation setpoint at the start of the regulation hour adjusted by the percentage of the shoulder hour during which the reduction in output occurred.
- In the preceding hour of regulation, if a generator must increase its output to provide regulation and incurs additional costs, its shoulder hour lost opportunity cost equals the amount of its energy offer at its Regulation setpoint at the start of the regulating hour in excess of its energy offer at the preceding hour economically desired level adjusted by the percentage of the shoulder hour during which the increase in output occurred.

¹ Note: Unless otherwise specified, diesel unit types are treated as CTs in settlements based on their similar operating characteristics.



- In the following hour of regulation, if a generator increased its output to provide regulation and incurs additional costs, its shoulder hour lost opportunity cost equals the amount of its energy offer at its Regulation setpoint at the end of the regulating hour in excess of its energy offer at the following hour economically desired level adjusted by the percentage of the shoulder hour during which the decrease in output occurred.
- In the following hour of regulation, if a generator reduced its output to provide regulation and foregoes revenues, its shoulder hour lost opportunity cost equals the amount of its energy offer at the following hour economically desired level in excess of its energy offer at its Regulation setpoint at the end of the regulating hour adjusted by the percentage of the shoulder hour during which the increase in output occurred
- The percentage of the shoulder hour in which the resource would have to operate uneconomically is determined by dividing the reduction or increase in output by the resource's submitted ramp rate.
- If the economically desired level, LMP desired MW, is less than or equal to the regulation low limit in the hour the unit regulated, the regulation set point equals the regulation low limit plus the regulation assigned MW in the hour the unit regulated. If the LMP desired MW is greater than or equal to the regulation high limit in the hour the unit regulated, the regulation set point equals the regulation high limit minus the regulation assigned MW in the hour the unit regulated. The regulation MW at the beginning of the hour is used when calculating shoulder hour lost opportunity costs in the preceding shoulder hour while the regulation MW at the end of the hour is used when calculating shoulder hour lost opportunity costs in the following shoulder hour.
- Since hydro units operate on a schedule and do not have an energy bid, lost opportunity costs for these units are calculated using the average of the real-time 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.
- During those hours when a hydro unit is in spill, the average of the real-time LMP value is set to zero such that the lost opportunity cost is equal to (i) the regulation setpoint (biased to reflect the actual regulation signal and adjusted by the applicable performance score and benefits factor) multiplied by (ii) the full value of the real-time LMP at the generator bus.
- If a hydro unit is committed day-ahead with MW greater than zero, the lost opportunity cost is equal to (i) the regulation setpoint (biased to reflect the actual regulation signal and adjusted by the applicable performance score and benefits factor) multiplied by (ii) the difference between the real-time LMP at the generator bus and the average real-time LMP (calculated as stated above). If this average



real-time LMP value is higher than the real-time LMP at the generator bus, the lost opportunity cost is zero.

- If a hydro unit is not committed day-ahead with MW greater than zero, the lost opportunity cost is equal to (i) the regulation setpoint (biased to reflect the actual regulation signal and adjusted by the applicable performance score and benefits factor) multiplied by (ii) the difference between the average real-time LMP (calculated as stated above) minus the real-time LMP at the generator bus. If the actual real-time LMP is higher than the average real-time LMP, the lost opportunity cost is zero.
- Additional details on hydro units in the Regulation Market can be found in Manual 11: Energy and Ancillary Services Market Operations.
- For each resource providing Regulation at the direction of PJM, the sum of its Regulation offer price (and lost opportunity costs, including shoulder hours' lost opportunity costs, for generators) is compared to its hourly Regulation Clearing Price credits.
- If the resource's pool-scheduled Regulation offer price (plus lost opportunity costs, including shoulder hours' lost opportunity costs, for generators) is greater than its Regulation Clearing Price credit for that hour, then the resource receives an additional credit equal to the amount that its Regulation offer price (plus lost opportunity costs, including shoulder hours' lost opportunity costs, for generators) is in excess of its Regulation Clearing Price credit.

Lost Opportunity Cost Credit = (Regulation Offer + Lost Opportunity Cost, including Shoulder Hours' Lost Opportunity Cost, if applicable) – Regulation Clearing Price Credit, only if quantity is positive

- PJM sums the Regulation credits (both Regulation Clearing Price credits and Lost Opportunity Cost credits) to determine the total hourly credit for each Regulation market participant, taking into account joint-ownership of regulating generators.

4.3 Regulation Charges

Each PJM load serving entity, or other Regulation buyer, is charged at the hourly Regulation Market Capability Clearing Price (RMCCP) and the Regulation Market Performance Clearing Price (RMPCP) for the amount of Regulation purchased to meet their hourly obligation. Hourly Regulation obligations equal their real-time load ratio share of the total amount of Regulation supplied excluding the mileage ratio component by PJM that hour, adjusted for any bilateral Regulation transactions. Participants are also charged at the hourly RMPCP for the mileage ratio component of the regulation supplied based on their hourly adjusted obligation share. In addition, net purchasers of Regulation in an hour are also charged a proportionate share of any lost opportunity credits paid to regulating generators for unrecovered costs over and above their Regulation Clearing Price credits.



PJM Actions:

- From the Regulation log, PJM sums the total amount of Regulation supplied (both pool-scheduled and self-scheduled) during an hour.
- Total Regulation Supplied (excluding mileage) = Sum of Hourly-integrated Regulation MW * Actual Performance Score for all eligible resources
- Total Regulation Supplied Mileage Adder = (Sum of Hourly-integrated Regulation MW * Actual Performance Score * Mileage Ratio for all eligible dynamic resources) – (Sum of Hourly-integrated Regulation MW * Actual Performance Score for all eligible dynamic resources)
- PJM determines each load serving entity’s (LSE’s) applicable regulation zone load ratio share based on their real-time load (excluding transmission losses).

$$\text{Load Ratio Share} = \frac{\left(\begin{array}{c} \text{Real Time Load} + \text{Retail or Wholesale Load Responsibility} \\ \text{InSchedule MW, if buyer} \\ \text{Retail or Wholesale Load Responsibility} \\ \text{InSchedule MW, if seller} \end{array} \right)}{\text{Total PJM Real Time Load}}$$

- PJM calculates each LSE’s hourly Regulation obligation by multiplying their applicable regulation zone load ratio share for that hour by the total amount of Regulation supplied in that hour for the applicable regulation zone’s market.

$$\text{Regulation Obligation} = \text{Load Ratio Share} * \text{Total Regulation Supplied excluding mileage}$$

- PJM adjusts obligations to reflect bilateral Regulation transactions among Regulation market participants.

$$\text{Adjusted Obligation} = \text{Regulation Obligation} - \text{Regulation MW Purchased} + \text{Regulation MW Sold}$$

- PJM calculates the hourly capability clearing price charge for each Regulation buyer by multiplying their adjusted regulation zone obligation in megawatts during the hour by the Regulation Market Capability Clearing Price (RMCCP) for that hour.

$$\text{Regulation Capability Clearing Price Charge} = \text{Adjusted Obligation} * [\text{RMCCP}]$$

- PJM determines each load serving entity’s (LSE’s) hourly adjusted obligation ratio share

$$\text{Adjusted Obligation Ratio Share} = \text{Participant's Adjusted Obligation} / \text{Total PJM Adjusted Obligation}$$



- PJM determines each LSE's Regulation mileage obligation by multiplying their adjusted obligation ratio share by the Total Regulation Supplied Mileage Adder

$$\text{Mileage Obligation Adder} = \text{Participant's Adjusted Obligation Ratio Share} * \text{Total Regulation Supplied Mileage Adder}$$

- PJM calculates the hourly performance clearing price charge for each Regulation buyer by multiplying their adjusted obligation and mileage obligation adder for the hour by the Regulation Market Performance Clearing Price (RMPCP) for that hour.

$$\text{Regulation Performance Clearing Price Charge} = (\text{Adjusted Obligation} + \text{Mileage Obligation Adder}) * \text{RMPCP}$$

- PJM calculates amount of Regulation each market buyer purchased from the applicable market by subtracting the amount of self-scheduled regulation MW provided by that market buyer from their adjusted obligation for the hour.

$$\text{Net Regulation Purchase} = \text{Adjusted Obligation} - \text{Self Scheduled Regulation MW}$$

- If any lost opportunity or other unrecovered costs due to regulating were credited to Regulation providers, each Regulation market buyer is allocated a share of the hourly costs based on the amount of Regulation they purchased from the market that hour.

$$\text{Lost Opportunity Charge} = \frac{\text{Total Lost Opportunity Costs} * \text{Net Regulation Purchase}}{\text{Total PJM Regulation Purchases}}$$

- PJM sums the Regulation charges (both Regulation Clearing Price charges and Lost Opportunity charges) to determine the total hourly charge for each Regulation market participant.

4.4 Reconciliation for Regulation Charges

PJM will calculate reconciled Regulation charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Regulation charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Regulation billing determinant for that hour. The hourly Regulation charge billing determinant (in \$/MWh) is calculated by dividing the total hourly Regulation charges by the total real-time PJM load (de-rated for transmission losses) for in that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Regulation charges for a month may



be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.



Section 5: Operating Reserve Accounting

Welcome to the *Operating Reserve Accounting* section of the *PJM Manual for Operating Agreement Accounting*. In this section, you will find the following information:

- A description of how Operating Reserve is provided and accounted for in the Day-ahead and Balancing PJM Energy Markets (see “*Operating Reserve Accounting Overview*”).
- How day-ahead and balancing credits are calculated for providers of pool-scheduled Operating Reserve (see “*Credits for Operating Reserve*”).
- How the total pool cost of day-ahead and balancing Operating Reserve, Synchronous Condensing, and Reactive Services are allocated (see “*Charges for Operating Reserve*”).

5.1 Operating Reserve Accounting Overview

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 plus opportunity cost, 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 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.

Credits are also provided for pool-scheduled energy transactions, for dispatchable economic load reduction resources, 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 Services 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 for the Operating Day, excluding the total cost associated with scheduling units for Black Start service or testing of Black Start units, 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. A detailed description of the Regional Balancing Operating Reserve Cost Analysis (BORCA) analysis can be found in Manual 11. 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) is 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.



5.2 Credit for Operating Reserve

Credits for Operating Reserve are calculated for each of the following situations:

- pool-scheduled generating resources (day-ahead and balancing markets)
- pool-scheduled transactions (day-ahead and balancing markets)
- canceled pool-scheduled resources (balancing market)
- resources providing quick start reserve (balancing market)
- resources reduced or suspended due to a transmission constraint or for other reliability purposes (balancing market)
- resources performing annual scheduled black start tests (balancing market)
- resources scheduled to provide Black Start service (day-ahead and balancing market)
- synchronous condensing for purposes other than providing synchronized reserve
- resources providing reactive services
- dispatchable economic load reduction resources that follow dispatch (day-ahead and balancing markets). See Section 11 for details on Load Response Operating Reserves Credits and Charges.

5.2.1 Credits for Pool-Scheduled Generating Resources

At the end of each Operating Day, PJM calculates the credits due each PJM Member for pool-scheduled generating resources.

PJM Actions:

- PJM retrieves the following information:
 - dispatcher generation scheduling and operations logs
 - resource offer data
 - scheduled MWh for generation offers cleared in day-ahead market



- state estimator generation MWh, trued-up to match revenue meter generation MWh from PJM Power Meter (if available)
- scheduled MWh for InSchedule “Generation” contracts, if applicable
- generator dispatch rates, UDS basepoint MWh, and ramp-limited desired MWh
- generator day-ahead and real-time LMPs
- PJM calculates the resource’s hourly day-ahead offer amount based on its day-ahead offer data and its cleared day-ahead Scheduled MWh for that hour.
- PJM accounting process applies the startup and hourly no-load bids if the start-up and no-load switch is set in the resource offer data and if the start-up bid is applicable for the MWh and status of the resource.
- Day-ahead credits for startup reflect the appropriate hot, intermediate, or cold state of the resource as it was scheduled in the day-ahead market.
- PJM calculates the resource’s hourly day-ahead energy market value as:

$$\text{Scheduled MWh} * \text{Day ahead LMP}$$

- PJM calculates the daily Day-ahead Operating Reserve credits for each resource as follows:
 - Sum hourly day-ahead offer amounts, including applicable no-load and startup costs, for the day
 - Sum hourly day-ahead energy market values for the day
 - Day-ahead Operating Reserve credit equals any portion of the resource’s total day-ahead offer amount in excess of its total day-ahead market value
- PJM sums the Day-ahead Operating Reserve generating resource credits for each PJM Member, taking into account joint-ownership of generating units.
- PJM determines eligibility for Balancing Operating Reserve credits for each generating resource from dispatcher logs. The following operating guidelines are used in the determination of Operating Reserve credits:
 - Resource must operate according to the on and off times requested by PJM, and units tripping during pool-scheduled periods of operation will retain their eligibility up through the hour in which the unit trips (unless the unit trips before half-past the hour, in which case the hour of the trip will not be eligible).



- Resources that trip or fail to start are required to notify PJM per the Synchronization and Disconnection procedures in Manual 14D.
- Resources that trip, are requested to restart by PJM, and return to operate as requested, are eligible to receive credits for the latter period of operation. Resources that trip or failed to start, are requested to restart by PJM for reliability, and operate as requested, are eligible for additional startup costs.
- Resources that operate on a different schedule from the schedule that was accepted in the day-ahead market are ineligible for credits.
- PJM determines the resource's hourly Real-time MWh based on its state estimated generator bus MWh or its scheduled MWh via a unit-specific InSchedule "Generation" contract or its revenue meter value from PJM Power Meter, as applicable, for that hour.
- Generation resources that are scheduled in the Day-ahead Market are financially responsible for selling their output in real-time. Section 3.2.3(f-1)(ii) of the PJM OATT details provisions for lost opportunity credits for those combustion turbines (CTs) that were scheduled in the Day-ahead Market but are not called on by PJM to run in real-time (See Section 5.2.6 – Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons). CTs eligible to be called on in real-time must have a startup plus notification time of 2 hours or less for PJM to accurately economically assess the value of the unit and are therefore the only units eligible for these provisions. Any resource scheduled in the Day-ahead Market with a startup plus notification time of greater than 2 hours should assume that they are committed by PJM in real-time for the duration of the Day-ahead commitment and are therefore only eligible for the aforementioned make whole provisions if PJM denies the commitment of that unit in real-time for either economics or reliability.
- If a generation owner calls PJM to bring on a CT per its Day-ahead schedule and PJM does not permit the unit to operate in real-time either for reliability or economics, it may receive lost opportunity costs as described in section 3.2.3(f-1)(ii) of the OATT as it was not permitted to run by PJM in real-time (See Section 5.2.6 – Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons).
- If a CT is committed in the Day-ahead Market with a startup plus notification time of 2 hours or less at the time of the Day-ahead commitment and then extends its startup plus notification time to more than 2 hours, it will not be eligible to receive the aforementioned lost opportunity cost provisions in section 3.2.3(f-1)(ii) of the PJM Tariff.
- PJM determines the resource's hourly Operating Reserve Desired MWh based on its ramp-limited desired MWh or UDS basepoint MWh, when available. If available, UDS basepoint MWh is used when 1.) the UDS basepoint MWh are less than or equal to the ramp-limited desired MWh or 2.) the UDS basepoint MWh is greater than the



ramp-limited desired MWh and the resource's Real-time MWh is greater than the ramp-limited desired MWh.

- PJM determines the resource's percent off dispatch as the lesser of the difference between the resource's Real-time MWh and the UDS basepoint MWh or the Real-time MWh and the ramp-limited desired MWh, if available. UDS LMP desired MWh is used to calculate a resource's percent off dispatch when 1.) data is unavailable due to technical difficulties or 2.) a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its day-ahead economic maximum 5% or 5MW, whichever is lower.
- If the resource's UDS basepoint MWh and ramp-limited desired MWh are not available or the percent off dispatch is greater than 20%, PJM determines the resource's hourly UDS LMP Desired MWh based on its dispatch rate, applicable schedule's 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 CTs, operating at PJM direction, the actual real-time output is used as the Operating Reserve Desired MWh value.
- PJM calculates the resource's hourly real-time energy offer amount based on its applicable schedule's offer data and its Real-time MWh for that hour. However, for any hour where the resource's Real-time MWh is greater than 110% of its Operating Reserve Desired MWh, Operating Reserve Desired MWh is used to determine the hourly real-time energy offer amount.
- PJM applies the startup and hourly no-load bids if the startup and no-load switch is set in the resource offer data and if the startup bid is applicable for the MWh and status of the resource.
- If applicable, when a resource is started during the day at the direction of PJM, the resource's real-time offer amount for that day includes its startup costs based on the appropriate hot, intermediate, or cold state of the resource. For resources that start generating for PJM from a condensing state, the applicable startup cost for that resource equals the amount submitted in writing to the PJM Market Settlement Operations Department to be in effect that Operating Day.
- If applicable, the resource's real-time offer amount includes its hourly no-load costs prorated for any hour during which it starts generating or stops generating as follows, using a 10% tolerance:

*If: Real time MWh < 0.9 * Scheduled Minimum MWh,*

Then: Hourly No Load is prorated by (Real time MWh / Scheduled Minimum MWh)



- PJM calculates the resource's hourly balancing energy market value as:

*(Real time MWh or Operating Reserve Desired MWh** – Day-ahead Scheduled MWh) * RT LMP*

***If a resource is committed in the Day-ahead market and a reduction in Real-time MWh from the DA Scheduled MWh is not the result of a PJM dispatch direction, the maximum of the Real-time MWh and the Operating Reserve Desired MWh (capped at the Day-ahead Scheduled MWh) will be used in the hourly balancing energy market value calculation, otherwise Real time MWh are used.*

- Balancing Operating Reserve credits are calculated by operating segment within an Operating Day. A resource will be made whole for the duration of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources) and made whole separately for the block of hours it is operated at PJM's direction in excess of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources). Startup costs (shut down costs for demand resources), as applicable, will be included in the segment represented by the longer of the day-ahead schedule or minimum run time (minimum down time for demand resources).
- PJM calculates the daily Balancing Operating Reserve credits for each generating resource's operating segment as follows:
 - Sum hourly real-time offer amounts and include applicable no-load and startup costs for the segment
 - Sum hourly balancing energy market values for the segment
- For each operating segment, Balancing Operating Reserve credit equals any portion of the resource's total real-time offer amount in excess of: 1) its total day-ahead market value, plus 2) its total balancing market value, plus 3) any Day-ahead Operating Reserve credits, plus 4) any Day-Ahead Scheduling Reserve Market revenues in excess of its offer plus opportunity cost, plus 5) any Synchronized Reserve Market revenue in excess of its offer plus opportunity cost plus energy use plus startup costs, plus 6) any Non-Synchronized Reserve Market revenue in excess of its opportunity costs, plus 7) any Reactive Services revenue.
- For any operating day in which PJM declares a Maximum Generation Emergency or a Maximum Generation Emergency Alert, or schedules units based on the anticipation of a Max Generation Emergency or Maximum Generation Emergency Alert, if a generator's priced-based offer results in revenues for "economic" hours to produce an effective offer price greater than or equal to \$1000/MWh and is greater than a Market Seller's lowest available and applicable cost-based offer, that generator shall not receive any operating reserve credits in accordance with the PJM Operating Agreement sections 3.2.3 (l), (m), and (n).
 - For the Real-time market, PJM calculates an effective offer price by summing the Operating Reserve credits which would have been applicable absent this exemption, plus the Real-time LMP market value provided to the generator during "economic" hours, all divided by the sum of the generation MWh during



those “economic” hours. “Economic” hours are defined as: 1) those hours in which the Real-time LMP is at or above the generator’s offer price; 2) those hours that PJM dispatched the generator in excess of its min run time and the generator’s offer price is above the Real-time LMP; and, 3) those hours that a generator with a min run time of less than or equal to 1 hour and more than one available starts per day is operated at the request of PJM.

- PJM sums the Balancing Operating Reserve generating resource credits for each PJM Member, taking into account joint-ownership of generating units.

5.2.2 Credits for Pool-Scheduled Transactions

At the end of each Operating Day, PJM calculates the credits due each PJM Member for pool-scheduled energy sales to the spot market.

PJM Actions:

- PJM retrieves the following information:
 - dispatcher transaction logs
 - day-ahead and real-time external energy sales to spot market
 - hourly transaction bid rate and MW (\$/MWh, MW)
 - day-ahead and real-time LMPs
- PJM calculates the hourly day-ahead offer amount for each spot market import transaction by multiplying the cleared day-ahead transaction MWh by the transaction offer price.
- PJM calculates the hourly day-ahead energy market value for each spot market import transaction by multiplying the cleared day-ahead transaction MWh by the day-ahead LMP at the sink of the transaction.
- PJM calculates the daily Day-ahead Operating Reserve credits for each transaction as follows:
 - Sum hourly day-ahead offer amounts for the day
 - Sum hourly day-ahead energy market values for the day
 - Day-ahead Operating Reserve credit equals any portion of the transaction’s total day-ahead offer amount in excess of its total day-ahead market value



- PJM sums the Day-ahead Operating Reserve transaction credits for each PJM Member.
- PJM calculates the hourly real-time offer amount for each spot market import transaction by multiplying the real-time transaction MWh by the transaction offer price.
- PJM calculates the hourly balancing energy market value for each spot market import transaction by multiplying the real-time hourly deviation from the cleared day-ahead transaction MWh amount by the real-time LMP at the sink of the transaction.
- PJM calculates the daily Balancing Operating Reserve credits for each transaction as follows:
 - Sum hourly real-time offer amounts for the day
 - Sum hourly balancing energy market values for the day
- Balancing Operating Reserve credit equals any portion of the transaction's total real-time offer amount in excess of: 1) its total day-ahead market value, plus 2) its total balancing market value, plus 3) any Day-ahead Operating Reserve credits.
- PJM sums the Balancing Operating Reserve transaction credits for each PJM Member.

5.2.3 Credits for Synchronous Condensing

At the end of each Operating Day, PJM calculates the credits due each PJM Member for synchronous condensing for purposes other than providing synchronized reserve or reactive services.

PJM Actions:

- PJM retrieves the following information:
 - dispatcher generation scheduling and operations logs
 - resource offer data
 - resource generation data
 - real-time LMPs
- PJM calculates the duration of each pool-scheduled period of synchronous condensing operations based on logged start and stop times.



- PJM calculates each eligible resource's condensing cost for each period by multiplying the duration (in hours) by the hourly cost to condense plus energy use cost as specified in the offer data.
- When a resource is requested to start condensing from an off state, a condensing credit is provided equal to the resource's condensing startup cost as specified in the offer data.
- PJM calculates the daily synchronous condensing cost for each resource by summing all hourly condensing and energy use costs, including applicable startup costs, for the day.
- PJM calculates the unit-specific lost opportunity cost credits for providing synchronous condensing for purposes other than providing synchronized reserve or reactive services.
- Lost Opportunity Cost Credit = $[(RT \text{ LMP} - \text{Offer at LMP Desired MW}) * (\text{LMP Desired Mw} - \text{Max (Unit Mw, 0)})]$ only if quantity is positive.
- PJM sums the synchronous condensing credits for all resources for each PJM Member.

5.2.4 Credits for Canceled Pool-Scheduled Resources

At the end of each month, PJM calculates the credits due to each PJM Member for pool-scheduled resources that were canceled before coming on-line.

PJM Actions:

- PJM retrieves the following information:
 - list of canceled resources (dispatcher log)
 - resource startup cost data
 - resource generation data
 - written confirmation of actual costs incurred by participants due to cancellations (to be received within 45 days of date invoice was received by participant for the month in question)
- PJM credits each PJM Member for cancellations based on the actual costs incurred and submitted in writing to the PJM Market Settlement Operations Department. Eligibility is confirmed using resource generation data and dispatcher logs. 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.

- PJM sums the Balancing Operating Reserve cancellation fees for all pool-scheduled resources for each PJM Member.
- PJM Market Settlement Operations Department enters the appropriate adjustment into the current month's billing.

5.2.5 Credits for Resources providing Quick Start Reserve

At the end of each month, PJM calculates the credits due to each PJM Member for resources providing quick start reserve (under emergency conditions).

PJM Actions:

- PJM retrieves the following information:
 - list of units called on to provide quick start reserve for reliability (dispatcher log)
 - resource offer data
 - resource generation data
 - written confirmation of actual costs incurred by participants (to be received within 45 days of date invoice was received by participant for the month in question)
- PJM credits each PJM Member for resources providing quick start reserve based on the actual costs incurred and submitted in writing to the PJM Market Settlement Operations Department. Eligibility is confirmed using resource generation data and dispatcher logs.
- PJM sums the Balancing Operating Reserve quick start resource credits for all pool-scheduled resources for each PJM Member.
- PJM Market Settlement Operations Department enters the appropriate adjustment into the current month's billing.



5.2.6 Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons

At the end of each Operating Day, PJM calculates the credits due to each PJM Member for resources incurring lost opportunity costs associated with following PJM's request to reduce or suspend the output of a generating resource due to a transmission constraint or for other reliability reasons.

Pool-scheduled generators whose output is reduced or suspended and the hourly integrated real-time LMP at the unit's bus is higher than its offer corresponding to the level of output requested by PJM are credited hourly in an amount equal to: $(\text{Desired MWh} - \text{Actual MWh}) * \text{Real-time LMP} - \text{applicable offer for energy}$. The Desired MWh used in this calculation is based on the hourly integrated real-time LMP at the generator's bus and adjusted for any effective regulation or synchronized reserve assignments and is limited to the lesser of the unit's economic maximum or the unit's maximum facility output as specified in the Interconnection Service Agreement. If a unit does not have an Interconnection Service Agreement with PJM, the Desired MWh is limited to the unit's economic maximum. The applicable offer for energy is the unincurred production cost associated with the MW reduction which is the area under the offer curve of the generating unit between the Desired MWh and the Actual MWh. If the unit is pool-scheduled/running for PJM, the offer calculation will use the price or cost-based schedule the unit is committed on. If the unit is self-scheduled, the offer calculation uses the offer the unit was committed on unless the unit was committed on its price based schedule and the highest available cost based schedule is higher than the price based schedule. In this case, the highest available cost based offer curve is used in the LOC offer calculation.

Pool-scheduled combustion turbine units scheduled to produce energy in the day-ahead market, but are not called on by PJM and do not operate in real-time, are credited hourly in an amount equal to the higher of the:

$(\text{Real-time LMP} - \text{Day-ahead LMP}) * \text{Day-ahead scheduled MWh}$; or

$(\text{Day-ahead scheduled MWh} * \text{Real-time LMP}) - (\text{the applicable offer for energy including no-load costs} + (\text{the start-up cost} / \text{number of contiguous hours scheduled in the Day-ahead Energy Market}))$

The applicable offer for energy is the unincurred production cost associated with the MW reduction which is the area under the offer curve of the generating unit between the Desired MWh and the Actual MWh

In the case where a combustion turbine unit operates in real-time following PJM dispatch and at least one hour of real-time operation coincides with the any of the hours of the day-ahead commitment, the start-up costs will be excluded from the calculation.

Pool-scheduled or self-scheduled wind generators whose output is reduced or suspended at the request of the Office of the Interconnection and the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by PJM are credited hourly in an amount equal to: $(\text{Desired MWh} - \text{Actual MWh}) * \text{Real-time LMP} - \text{applicable offer for energy}$. The Desired MWh used in this calculation is the lesser of the point on the unit's offer curve corresponding to the hourly integrated real-time LMP at the generator's bus adjusted for effective regulation or synchronized reserve assignments or



the PJM forecasted output for the unit. The Desired MWh is also limited to the lesser of the unit's economic maximum or the unit's maximum facility output as specified in the Interconnection Service Agreement. If a unit does not have an Interconnection Service Agreement with PJM, the Desired MWh is limited to the unit's economic maximum. The applicable offer for energy is the unincurred production cost associated with the MW reduction which is the area under the offer curve of the generating unit between the Desired MWh and the Actual MWh. If the unit is pool-scheduled/running for PJM, the offer calculation uses the price or cost-based schedule the unit is committed on. If the unit is self-scheduled, the offer calculation uses the offer the unit was committed on unless the unit was committed on its price based schedule and the highest available cost based schedule is higher than the price based schedule. In this case, the highest available cost based offer curve is used in the LOC offer calculation.

Pool-scheduled or self-scheduled wind generators are only eligible for the above-referenced credit if they:

- Operated the resource according to PJM Manual and Tariff requirements for wind resources (PJM Manual 14D: Generator Operational Requirements)
- Have SCADA capability to transmit and receive instructions from PJM

If PJM experiences a technical issue (e.g. computer system failure or disruption or failure of communications equipment) resulting in an erroneous forecast, PJM and the market participant will determine a mutually agreeable settlement value. Recommendations for reconciliation include but are not limited to:

Using the average forecast values as determined by PJM wind forecasting tool from before and after the technical issue to determine forecast value during the issue

- Using the forecast value as determined by PJM wind forecasting tool from before the technical issue for the first half of the duration of the technical issue and forecast value from after the technical issue for the latter half of the duration of the technical issue
- Using Market Seller's forecast value during the technical issue

PJM Actions:

- PJM retrieves the following information:
 - list of units and timeframes reduced or suspended for a transmission constraint or other reliability reason (dispatcher logs and Market Operations eligibility data)
 - resource offer data
 - scheduled MWh for generation offers cleared in day-ahead market



- state estimator generation MWh, trued-up to match revenue meter generation MWh from PJM Power Meter (if available)
- scheduled MWh for InSchedule “Generation” contracts, if applicable
- generator day-ahead and real-time LMPs
- assigned regulation MWh, performance scores and marginal benefit factors
- assigned synchronized reserve MWh
- hourly integrated wind forecast from PJM’s wind forecasting tool
- maximum facility output MW from Interconnection Service Agreements
- PJM sums the Balancing Operating Reserve lost opportunity cost credits for all reduced or suspended generating resources for each PJM Member.

5.2.7 Credits for Resources Performing Annual Scheduled Black Start Tests

At the end of each month, PJM calculates the credits due to each PJM Member for resources performing annual black start tests. Compensation for energy delivered to the transmission system shall be provided for the unit’s minimum run time at the higher of the unit’s cost-capped offer or real-time LMP plus start-up and no-load for up to two start attempts, if necessary. Compensation for tests where no energy was delivered to the transmission system shall be provided for the unit’s start-up costs for up to two start attempts, if necessary.

PJM Actions:

- PJM retrieves the following information:
 - list of units performing annual scheduled black start tests (PJM Performance Compliance Department log)
 - resource cost-capped offer data
 - resource generation data
 - applicable real-time LMP
 - applicable start-up and no-load costs
- PJM sums the Balancing Operating Reserve annual black start test credits for all resources for each PJM Member.
- PJM Market Settlement Operations Department enters the appropriate adjustment into the current month’s billing.



5.2.8 Credits for Resources Providing Reactive Services

At the end of each month, PJM calculates the credits due each PJM Member for reactive services. Generators whose active energy output is altered at the request of PJM for the purpose of maintaining reactive reliability within the PJM Region are credited hourly for lost opportunity costs if their output is reduced or suspended and credited in accordance with balancing operating reserve credit calculations if their output is increased.

Generators operating as synchronous condensers for the purpose of maintaining reactive reliability at the request of PJM, are credited for each hour (or partial hour) of condensing an amount equal to the higher of: 1) the Synchronized Reserve Market Clearing Price for the hour multiplied by the amount of synchronized reserve provided (i.e., economic maximum limit of the unit); or 2) the sum of the unit's offered cost to condense, energy use cost, start-up cost, and the unit-specific lost opportunity cost of the resource supplying the increment of Synchronized Reserve.

Lost Opportunity Cost is equal to $(\text{Desired MWh} - \text{Actual MWh}) * \text{Real-time LMP} - \text{applicable offer for energy}$. The Desired MWh used in this calculation is based on the hourly integrated real-time LMP at the generator's bus and adjusted for any effective regulation or synchronized reserve assignments and is limited to the lesser of the unit's economic maximum or the unit's maximum facility output as specified in the Interconnection Service Agreement. If a unit does not have an Interconnection Service Agreement with PJM, the Desired MWh is limited to the unit's economic maximum. The applicable offer for energy is the unincurred production cost associated with the MW reduction which is the area under the offer curve of the generating unit between the Desired MWh and the Actual MWh. If the unit is pool-scheduled/running for PJM, the offer calculation uses the price or cost-based schedule the unit is committed on. If the unit is self-scheduled, the offer calculation uses the offer the unit was committed on unless the unit was committed on its price based schedule and the highest available cost based schedule is higher than the price based schedule. In this case, the highest available cost based offer curve is used in the LOC offer calculation.

PJM Actions:

- PJM retrieves the following information:
 - dispatcher generation scheduling and operations logs
 - resource offer data
 - scheduled MWh for generation offers cleared in day-ahead market
 - state estimator generation MWh
 - state estimator generation MWh, trued-up to match revenue meter generation MWh from PJM Power Meter (if available)
 - scheduled MWh for InSchedule "Generation" contracts, if applicable
 - generator day-ahead and real-time LMPs



- assigned regulation MWh, performance scores and marginal benefit factors
- assigned synchronized reserve MWh
- maximum facility output MW from Interconnection Service Agreements
- PJM sums the reactive services credits for all generating resources for each PJM Member.

5.3 Charges for Operating Reserve

The total cost of providing Operating Reserve for the Operating Day is the sum of the credits provided to PJM Members for supplying the Day-ahead and Balancing Market Operating Reserve except those Operating Reserve credits associated with the scheduling of units for Black Start service or testing of Black Start Units. The daily total cost of Day-ahead Operating Reserve excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control, is allocated and charged to PJM Members in proportion to their cleared day-ahead demand and decrement bids plus their cleared day-ahead exports. The daily total cost of Balancing Operating Reserve excluding the total cost for resources scheduled to provide Black Start Service is determined for each region (RTO, East and West) and allocated and charged to PJM Members in proportion to their real-time deviations from day-ahead schedules and generator deviations, or to PJM Members in proportion to their real-time load plus exports for generator credits provided for reliability. The total daily cost of synchronous condenser payments (other than that for synchronized reserve or reactive services) is allocated and charged to PJM Members in proportion to their real-time load (excluding losses) plus exports during that Operating Day. The total daily cost of reactive services is allocated and charged to PJM members serving load in the transmission zone in which the generator is providing reactive services in proportion to their real-time load (excluding losses) during that Operating Day. The total daily cost of day-ahead Operating Reserve 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) is allocated and charged to PJM Members in proportion to their total real-time load in the applicable transmission zone(s). The total monthly 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.

PJM Actions:

- PJM calculates for each Operating Day the Total Cost of Day-ahead Operating Reserve by summing the following credits for all PJM Members:
 - Total Day-ahead Operating Reserve generating resource credits excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control (\$)
 - Total Day-ahead Operating Reserve transaction credits (\$)



- Note: Day-ahead Operating Reserve generating resource credits associated with the scheduling of units for Black Start service are allocated in accordance with the Black Start charge allocations and are not included in the Day-ahead Operating Reserve charge allocation.
- Note: Day-ahead Operating Reserve generating resource credits for resources scheduled to provide Reactive Service or transfer interface control are allocated in accordance with the Reactive charge allocations and are not included in the Day-ahead Operating Reserve charge allocation.
- PJM calculates for each Operating Day the Day-ahead Operating Reserve charges by allocating the total cost of Day-ahead Operating Reserve excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control to each PJM Member based on their daily share of cleared day-ahead demand and decrement bids plus cleared day-ahead exports.
- PJM calculates for each Operating Day the Total Regional Cost of Balancing Operating Reserve to be charged for reliability by summing the total Balancing Operating Reserve resource credits for reliability (\$) for each region and for all PJM Members excluding those credits associated with the scheduling of units for Black Start service or testing of Black Start units.
- PJM calculates for each Operating Day the Balancing Operating Reserve charges for reliability by allocating the total cost of Balancing Operating Reserve for reliability on a regional basis to each PJM Member based on their daily share of the sum of their load plus exports in each region (RTO, East, and West). West region is defined as transmission zones AEP, AP, ATSI, ComEd, DEOK, DUQ, and Dayton, and EKPC, and East region is defined as transmission zones AE, BGE, DOM, Penelec, PEPCO, Meted, PPL, JCPL, PECO, Delmarva, PSEG, and Rockland. RTO region includes the East and West region and exports that are at interfaces or hubs not completely contained in either the East or West region.
- PJM calculates for each Operating Day the Total Cost of Balancing Operating Reserve to be charged to deviations by summing the following credits for all PJM Members:
 - Total Regional Balancing Operating Reserve generating resource credits for deviations (\$)
 - Total Balancing Operating Reserve demand resource credits (\$)
 - Total Balancing Operating Reserve transaction credits (\$)
 - Total Balancing Operating Reserve cancellation fees (\$)
 - Total Balancing Operating Reserve quick start resource credits (\$)



- o Total Balancing Operating Reserve reduction/suspension credits (\$)

Note: Balancing Operating Reserve generating resource credits associated with the scheduling of units for Black Start service or testing of Black Start units are allocated in accordance with the Black Start Service charge allocations and are not included in the Balancing Operating Reserves charge allocation.

- PJM calculates for each Operating Day the total generating resource deviations as the sum of hourly deviations for generating resources that are not following dispatch as follows:
 - o Each pool-scheduled or dispatchable self-scheduled generator not following PJM dispatch due to its actual output not being between its ramp-limited Desired MWh and UDS Basepoint MWh, and its % off dispatch is > 10%, will be assessed deviations as Real-time MWh – ramp-limited desired MWh. If the % off dispatch is > 20%, deviations will be assessed as Real-time MWh – UDS LMP Desired MWh (as determined in the Credits for Pool-Scheduled Generating Resources section of this manual).
 - o For each self-scheduled generating resource with an economic maximum limit less than or equal to 110% of the economic minimum limit or not dispatched by PJM above its economic minimum, unless the resource is lowering its output in accordance with PJM direction in response to a minimum generation emergency event (or declaration) will be assessed deviations as Real-time MWh – Day-ahead Schedule MWh.
 - o Each unit that has tripped or is scheduled Day-ahead and does not run in Real-time will be assessed deviations as Real-time MWh – Day-ahead scheduled MWh
 - o Each unit that is dispatchable Day-Ahead but is Fixed Gen in real-time will be assessed deviations as Real-time MWh – UDS LMP Desired MWh
 - o Each unit that is not dispatchable in both the Day-ahead and Real-time market will be assessed deviations as Real-time MWh – Day-ahead scheduled MWh. Units that choose to participate in the Day-ahead pumped storage optimization program are considered not dispatchable in the Day-ahead market.
 - o Each unit where the real-time economic minimum is greater than its Day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its day-ahead economic maximum by 5% or 5MW, whichever is lower, and UDS LMP Desired MWh for the hours is either below the real-time economic minimum or above the real-time economic maximum, will be assessed deviations as Real-time MWh – UDS LMP Desired MWh
 - o Deviations are not calculated if 1.) the absolute value of the hourly deviation MWh is less than 5 MWh or 2.) the absolute value of the deviation MWh ratio to



applicable day-ahead scheduled MWh or desired MWh is less than or equal to 5%

- Hours during which a generator is assigned by PJM for: Regulation; assigned by PJM for Synchronized Reserve (and actual MWh are less than day-ahead scheduled MWh), or assigned by PJM for Non-Synchronized Reserve (and actual MWh are less than the day-ahead scheduled MWh) are omitted from this calculation.
- Resource deviations for units located 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. Unit parameters do not have to be identical for the units’ deviation MWh to offset one another. Units at a “single bus” must be contained in the same customer account.
- PJM calculates for each Operating Day the withdrawal deviations as the sum of the following hourly real-time deviations from day-ahead values for each customer account:
 - Absolute Value of (cleared day-ahead demand bid MWh + cleared day-ahead decrement bid MWh + day-ahead sale transaction MWh – real-time load de-rated for transmission losses including the impact of load reconciliation MWh – real-time sale transaction MWh)
 - Withdrawal deviations will be calculated separately for each zone, hub, and interface whereby allowing netting to occur within each of those locations. Further netting will also occur for any hubs and aggregates fully contained within a given zone.
 - Dynamically scheduled export transactions are omitted from this calculation.
 - Positive demand deviations (real-time withdrawal MWs less than day-ahead withdrawal MWs) will not be included in the total withdrawal deviation by location during hours in which an Primary Reserve or Synchronized Reserve shortage in real-time occurs or when PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
- PJM calculates for each Operating Day the injection deviations as the sum of the following hourly real-time deviations from day-ahead values for each customer account:
 - Absolute Value of (cleared day-ahead increment offer MWh + day-ahead purchase transaction MWh – real-time purchase transaction MWh)
 - Injection deviations will be calculated separately for each zone, hub, and interface whereby allowing netting to occur within each of those locations.



Further zonal netting will also occur for any hubs and aggregates fully contained within a given zone.

- Resource, withdrawal, and injection deviations that occur within a single zone (including applicable hubs and aggregates) will be associated with a particular PJM region (East or West). Deviations at an interface shall be associated with the East or West region with which the majority of the buses that define the interface are most closely electrically associated. Deviations at hubs (not fully contained in a zone) shall be associated with the East or West region if all buses that define the hub are located in the region.
- PJM calculates for each Operating Day the Balancing Operating Reserve charges to deviations by allocating the total cost of Balancing Operating Reserve for deviations on a regional basis to each customer account based on their daily share of the sum of the total hourly deviations in each region (RTO, East, and West).
- A PJM Member's deviations in the RTO region include deviations at hubs, aggregates, and interfaces that are not associated with either the East or West region as well as deviations in either the East or West region.
- PJM calculates for each Operating Day the Balancing Operating Reserve charges for reliability by allocating the total cost of Balancing Operating Reserve for reliability on a regional basis to each PJM Member based on their daily share of the sum of their load plus exports in each region (RTO, East, and West).
- A PJM Member's load plus exports in the RTO region include exports at hubs and interfaces that are not completely contained in either the East or West region as well as load plus exports in either the East or West region.
- Any Operating Reserve charges attributable to generators operated on behalf of transmission owners for local constraints, or on behalf of generation owners for special unit constraints, are directly assessed to the applicable requesting party.
- PJM calculates for each Operating Day the synchronous condensing charges by allocating a pro-rata share of the total cost of synchronous condensing payments to PJM exports (excluding dynamically scheduled exports) with the remaining costs separately allocated based on PJM Region real-time load (excluding losses) ratio shares.
- PJM calculates for each Operating Day the total cost of reactive services for the purpose of maintaining reactive reliability. The cost of reactive services are allocated and charged to each market participant based on real-time load (excluding losses) ratio shares in the transmission zone(s) in which the reactive services were provided.



- PJM calculates for each Operating Day the total cost of Day-ahead Operating Reserves for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a zone(s). The Day-ahead Operating Reserve costs for these resources are charged to each market participant based on real-time load (excluding losses) ratio shares in the applicable transmission zone(s).

5.4 Reconciliation for Operating Reserve Charges

PJM will calculate reconciled Operating Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the “actual” usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Operating Reserve charge for Reliability reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the region (RTO, East, and West) by the Operating Reserve charge for Reliability billing determinants for that region and day. The daily Operating Reserve charge for Reliability billing determinant (in \$/MWh) for each region is calculated by dividing the total Balancing Operating Reserve charges for Reliability in that region by the total real-time load (de-rated for transmission losses) and real-time exports in that region for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for Reliability for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

PJM calculates the Reactive Services charge reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the transmission zone by the Reactive Services billing determinants for that zone and day. The daily Reactive Services billing determinant (in \$/MWh) for each transmission zone is calculated by dividing the total Reactive Services charge in that transmission zone by the total real-time load (de-rated for transmission losses) in that transmission zone for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for reactive services for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

PJM calculates the Synchronous Condensing charge reconciliations by multiplying the daily kWh data (de-rated for transmission losses) for the PJM Region by the Synchronous Condensing billing determinants for that day. The daily Synchronous Condensing billing determinant (in \$/MWh) for the PJM Region is calculated by dividing the total Synchronous Condensing charges in the PJM Region by the total real-time load (de-rated for transmission losses) and real-time exports in the PJM Region for that day. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Operating Reserve charges for synchronous condensing for a month may



be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.



Section 6: Synchronized Reserve Accounting

Welcome to the *Synchronized Reserve Accounting* section of the *PJM Manual for Operating Agreement Accounting*. In this section, you will find the following information:

- A description of how Synchronized Reserve are provided and accounted for in the PJM Energy Markets (see “*Synchronized Reserve Accounting Overview*”).
- How credits are calculated for providers of Synchronized Reserve (see “*Credits for Synchronized Reserve*”).
- How the total cost of Synchronized Reserve is allocated (see “*Charges for Synchronized Reserve*”).
- How Synchronized Reserve charge reconciliations are calculated (see “*Reconciliation for Synchronized Reserve Charges*”).

6.1 Synchronized Reserve Accounting Overview

Accounting for Synchronized Reserve is performed on an hourly basis. Synchronized Reserve shall be supplied from resources located within the metered boundaries of PJM. Resources participating in the 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. Tier 2 consists of the additional resources that are 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. Synchronized Reserve resources include generators and demand side response resources.

The total PJM Synchronized Reserve Requirement is defined as the amount of 10-minute reserve that must be synchronized to the grid in accordance with the applicable NERC Council standards.

Tier 1 synchronized reserve credits are awarded to all resource owners whose resources increased output or decreased consumption in response to a synchronized reserve event (with the exception of those resources that were assigned Tier 2 synchronized reserve). Tier 1 synchronized reserve resources are also compensated when the Non-Synchronized Reserve Market Clear Price is non-zero. Tier 2 synchronized reserve credits are awarded to all resource owners that have assigned self-scheduled or pool-scheduled synchronized reserve.

When the Non-Synchronized Reserve Clearing Price is zero Tier 1 synchronized reserve credits are equal to the integrated increase in MWh output or decrease in MWh of consumption from each resource over the length of a synchronized reserve event times the synchronized energy premium less the hourly integrated LMP. The synchronized energy premium is defined as the average of the 5-minute LMPs calculated during the synchronized reserve event plus \$50/MWh.



When the Non-Synchronized Reserve 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 resources that can reliably provide Synchronized Reserve service per the rules in [Manual 11](#), Section 4.2.1 Synchronized Reserve Eligibility.

The synchronized reserve offer price for Tier 2 resources will be capped at a maximum value of the unit's Operating and Maintenance cost (as determined by the Cost Development Task Force) plus \$7.50/MWh.

Generator resources on-line and providing Tier 2 are made eligible for make-whole payments to recover applicable start-up, no-load and minimum energy costs in the Balancing Operating Reserve billing line item. Demand response resources which respond to a synchronized reserve event, and are eligible for make-whole payments to recover shutdown cost will be made-whole in the Operating Reserve for Load Response billing line item.

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). Additional details can be found in PJM Manual 11, Section 4.2.11.

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 synchronized reserve obligation based on their hourly real-time load ratio share and applicable reserve zone's requirements during that hour. During hours when the Synchronized Reserve Clearing Price is the same throughout the reserve zone, an LSE's synchronized reserve obligation is equal to its real-time load ratio share times the amount of synchronized reserve assigned for the entire reserve zone. During hours when congestion causes the Synchronized Reserve Clearing Price to separate, each LSE's synchronized reserve obligation is equal to its real-time load ratio share within its reserve zone or sub-zone and the amount of synchronized reserve assigned in that reserve zone or sub-zone.

Participants may fulfill their synchronized reserve obligations by: owning Tier 1 resources from which PJM obtains synchronized reserve, entering bilateral arrangements with other PJM market participants or purchasing synchronized reserve from the PJM synchronized reserve market.

6.2 Credits for Synchronized Reserve

At the end of each hour, PJM calculates the credits due each PJM Member for Synchronized Reserve.



PJM Actions:

- PJM retrieves the following information:
 - Synchronized Reserve Ramp rate for Tier 1 resources
 - Synchronized Reserve maximum for Tier 1 resources
 - Synchronized Reserve availability for Tier 2 resources
 - Synchronized Reserve assigned quantity for Tier 2 resources (MW)
 - Synchronized Reserve offer price for Tier 2 resources (\$/MWh)
 - Energy use for condensing Tier 2 resources
 - Condense-to-generate startup cost
 - Synchronized Reserve bilateral transactions
 - 5-minute interval LMP data
 - Total PJM synchronized reserve requirement as determined in whole MWh for each hour of the operating day
 - Synchronized Reserve Clearing Price (\$/MWh)
 - Non-Synchronized Reserve Clearing Price (\$/MWh)
- PJM calculates the hourly Synchronized Reserve credits for each Tier 1 resource as follows:
 - During hours where the Non-Synchronized Reserve Market Clearing Price is zero for the same reserve zone or sub-zone that a Tier 1 resource is located, Tier 1 synchronized reserve credits are equal to the integrated increase in MW generator output (or decrease in MW consumption for demand side response resources) from each resource over the length of a synchronized reserve event multiplied by the difference between the synchronized energy premium and the hourly integrated LMP. The synchronized energy premium is defined as the average of the 5-minute LMPs calculated during the synchronized reserve event plus \$50/MWh. If the hourly integrated LMP is greater than the synchronized energy premium, the Tier 1 credit is zero.
 - When the Non-Synchronized Reserve Clearing Price is non-zero for the applicable reserve zone or subzone, Tier 1 synchronized reserve credits are equal to the applicable reserve zone or sub-zone Synchronized Reserve Market Clearing Price multiplied by 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 and the estimated Tier 1 the resource could have provided. During hours when no synchronized reserve event occurs in the applicable reserve zone or sub-zone, the Tier 1 resource will be compensated using the estimated Tier 1 amount for only those resources that can reliably provide Synchronized Reserve service per the rules in Manual 11, Section 4.2.1 Synchronized Reserve Eligibility.

- In cases where a synchronized reserve event spans two or more hours, the response from each resource will be integrated according to the length of the response in each hour for the purpose of calculating the Tier 1 credit. Details on the amount of increase in output (or decrease in MW consumption for demand side response resources) can be found in Manual 11: Energy & Ancillary Services Market Operations, Section 4.
- PJM calculates the hourly Synchronized Reserve credits for each Tier 2 resource as follows:
 - These credits are awarded to resource owners that have either assigned self-scheduled or pool-scheduled synchronized reserve.
 - Synchronized reserve credits for resources assigned self-scheduled synchronized reserve equal the Tier 2 clearing price times the resource's self-scheduled synchronized reserve capability less any shortfall due to failure to provide assigned capability during a synchronized reserve event.
 - Synchronized reserve credits for resources that are assigned pool-scheduled synchronized reserve are the higher of: the Tier 2 clearing price times the resource's assigned synchronized reserve capability less any shortfall due to failure to provide assigned capability during a synchronized reserve event or the resource's synchronized reserve offer times its assigned synchronized reserve capability less any shortfall due to failure to provide assigned capability during a synchronized reserve event (plus opportunity cost, energy use costs, and startup costs incurred, for generators), as applicable.

6.3 Charges for Synchronized Reserve

The total cost of providing Synchronized Reserve for each hour is the sum of the credits provided to PJM Members for supplying Synchronized Reserve in that hour. The hourly cost of Tier 1 and Tier 2 Synchronized Reserve is allocated separately and charged to PJM Members.

PJM Actions:

- PJM calculates for each hour the Total Cost of Synchronized Reserve by summing the following credits for all PJM Members:
 - Total Tier 1 credits for Synchronized Reserve (\$)



- Total Tier 2 credits for Synchronized Reserve (\$)
- PJM calculates for each hour each participants synchronized reserve obligation as determined by applying the real-time load ratio share (adjusted for load responsibility) in the applicable reserve zone or sub-zone to the total synchronized reserve assigned for that hour and then adding bilateral sales and subtracting bilateral purchases. 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. Synchronized reserve charges are then determined for both the amount of Tier 1 applied to each participant's obligation and the amount of Tier 2 each participant purchased from the market.
- PJM calculates for each hour the Tier 1 charges by allocating the total cost of Tier 1 credits to each PJM Member based on their ratio share of Tier 1 synchronized reserve allocated to obligation. The amount of Tier 1 applied to each participant's obligation is equal to the amount of Tier 1 estimated prior to the operating hour as part of the market clearing process on that participant's own resources up to the amount of obligation, plus the remaining obligation ratio share of any excess Tier 1 estimated on the resources of generation owners in excess of their individual obligations.
- PJM calculates for each hour the Tier 2 charges as follows:
 - The appropriate hourly Tier 2 clearing price times the participant's synchronized reserve obligation MW less any Tier 1 synchronized reserve applied to obligation.
 - The appropriate hourly Tier 2 clearing price for each LSE is the clearing price for the sub-zone or Reserve Zone for which the LSE's load is located. Loads located in a sub-zone will pay that sub-zone's clearing price. Loads not located in a sub-zone will pay the corresponding Reserve Zone clearing price.
 - The participant's share of any unrecovered costs incurred by assigned Tier 2 pool-schedule resources, including those Tier 2 resources assigned in addition to that which was estimated prior to a given hour, over and above the Tier 2 clearing price
 - The amount of unrecovered costs allocated to each participant is determined based on each participant's ratio share of Tier 2 synchronized reserve purchased from the market. A participant's purchases from the market equals their synchronized reserve obligation MW less any Tier 1 synchronized reserve applied to obligation, less any self-scheduled Tier 2 MW.
 - The cost of Tier 2 resources assigned by PJM during the operating hour in addition to that which resulted from the Tier 2 clearing process due to reduced availability of Tier 1 Synchronized Reserve are allocated to those entities for which less Tier 1 was available during the hour that was estimated prior to the

hour, in proportion to the reduction in Tier 1 availability. If there are no entities with a reduction in Tier 1 availability, the cost of these resources assigned during the hour is allocated based on a participant's purchases from the market as described in the preceding bullet.

- o Tier 2 resources that fail to provide assigned Tier 2 capability during a synchronized reserve event incur a retroactive obligation to refund at SRMCP the amount of the shortfall measured in MW for all of the hours the resource was assigned 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 last failed to respond with its assigned or self-scheduled Synchronized Reserve amount in response to a synchronized reserve event.
 - 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.
- o $\text{Resource Retroactive Shortfall MWh} = \text{Resource Shortfall MWh} - ((\text{Resource Shortfall MWh} / \text{Participant's Total Shortfall MWh}) * \text{Participant's Total Over Response MWh})$
- o If the Retroactive Shortfall MWh value per the above equation is less than 0 MWh, the Retroactive Shortfall MWh is equal to 0 MWh.

Note: If there are multiple Synchronized Reserve Events during a day, the maximum Resource Retroactive Shortfall MWh for the day is used to determine what the participant owes in refund charges

- o The retroactive penalty charges calculated above are allocated based on a participant's ratio share of the synchronized reserve obligation MW less any Tier 1 synchronized reserve applied to obligation on the hour(s) of the synchronized reserve event for the sub-zone or Reserve Zone for which the synchronized reserve event occurred. If the event spans multiple hours, the penalty charges will be prorated hourly based on the duration of the event within each hour. Participants that incur a penalty charge and also have an applicable synchronized reserve obligation during the hours(s) of the synchronized reserve event shall not be included in the allocation of such penalties. Additional details on verification and non-performance can be found in Manual 11: Energy &



Ancillary Services Market Operations, Section 4: Overview of the PJM Synchronized Reserve Market.

6.4 Reconciliation for Synchronized Reserve Charges

PJM will calculate reconciled Synchronized Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the “actual” usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Synchronized Reserve charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Synchronized Reserve billing determinants for that hour. The hourly Synchronized Reserve charge billing determinants (in \$/MWh) for each reserve zone and sub-zone is calculated by dividing the total hourly Synchronized Reserve charges in that reserve zone or sub-zone by the total PJM real-time load (de-rated for transmission losses) in that reserve zone or sub-zone for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Synchronized Reserve charges for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.



Section 7: Non-Synchronized Reserve Accounting

Welcome to the *Non-Synchronized Reserve Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of how Non-Synchronized Reserve are provided and accounted for in the PJM Energy Markets (see “*Non-Synchronized Reserve Accounting Overview*”).
- How credits are calculated for providers of Non-Synchronized Reserve (see “*Credits for Non-Synchronized Reserve*”).
- How the total cost of Non-Synchronized Reserve is allocated (see “*Charges for Non-Synchronized Reserve*”).
- How Non-Synchronized Reserve charge reconciliations are calculated (see “*Reconciliation for Non-Synchronized Reserve Charges*”).

7.1 Non-Synchronized Reserve Accounting Overview

Accounting for Non-Synchronized Reserve is performed on an hourly basis. Non-Synchronized Reserve shall be supplied from non-emergency generation resources located within the metered boundaries of PJM that are off-line and available to provide energy. Non-Synchronized Reserve can be provided by non-emergency generation resources that can fully convert their reserve capability into energy in 10-minutes from an offline state. PJM determines the amount of non-synchronized reserves on each resource.

There is no explicit requirement for Non-Synchronized Reserve. PJM must maintain a total quantity of 10-minute reserve (Primary Reserve) and Synchronized Reserve on the system at all times. Primary Reserves are comprised of Synchronized and Non-Synchronized Reserve. PJM maintains a total Primary Reserve requirement such that a required portion of that Primary Reserve is provided by Synchronized Reserve. The remainder between the Primary Reserve requirement and Synchronized Reserve requirement may be supplied by either additional Synchronized Reserve or Non-Synchronized Reserve, whichever is more economic. Additional details on the Primary and Synchronized Reserve requirements can be found in PJM Manual 13, Emergency Operations.

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. During hours when the Non-Synchronized Reserve Clearing Price is the same throughout the reserve zone, an LSE’s non-synchronized reserve obligation is equal to its real-time load ratio share times the amount of non-synchronized reserve assigned for the entire reserve zone. During hours when congestion causes the Non-Synchronized Reserve Clearing Price to separate, each LSE’s non-synchronized reserve obligation is equal to its real-time load ratio share within its reserve zone or sub-zone and the amount of non-synchronized reserve assigned in that reserve zone or sub-zone.



Participants may fulfill their non-synchronized reserve obligations by entering bilateral arrangements with other PJM market participants or purchasing non-synchronized reserve from the PJM Non-Synchronized Reserve Market.

7.2 Credits for Non-Synchronized Reserve

At the end of each hour, PJM calculates the credits due each PJM Member for Non-Synchronized Reserve.

PJM Actions:

- PJM retrieves the following information:
 - Non-Synchronized Reserve assignments (MWh)
 - Non-Synchronized Reserve shortfall (MWh)
 - Non-Synchronized Reserve Clearing Price (\$/MWh)
 - Non-Synchronized Reserve bilateral transactions
 - Total PJM Non-Synchronized Reserve assigned for each hour of the operating day
- PJM calculates the hourly Non-Synchronized Reserve credit for each resource as follows:
 - PJM calculates the Non-Synchronized MW supplied as the Non-Synchronized Reserve assigned MWs less the amount of Non-Synchronized Reserve MWs the resource failed to provide in response to a Non-Synchronized Reserve event (Non-Synchronized Reserve shortfall).
 - PJM calculates the Non-Synchronized Reserve Clearing Price Credit for each eligible resource by multiplying the Non-Synchronized Reserve MWs supplied by the Non-Synchronized Reserve Clearing Price (\$/MWh).
 - Non-Synchronized Reserve Clearing Price Credit = (Non-Synchronized Reserve Assigned MW – Non-Synchronized Reserve shortfall MW) * Non-Synchronized Reserve Clearing Price
 - PJM calculates a Non-Synchronized Reserve Lost Opportunity Cost Credit if the lost opportunity cost is greater than the Non-Synchronized Reserve Clearing Price Credit for the resource for the hour.
 - Non-Synchronized Reserve Lost Opportunity Cost Credit = Non-Synchronized Reserve Lost Opportunity Cost * {(Non-Synchronized Reserve Assigned MW – Non-Synchronized Reserve shortfall MW) / Non-Synchronized Reserve Assigned MW} – NSRMCP Credit, only if quantity is positive



- Non-Synchronized Reserve Lost Opportunity Cost = (LMP Desired MWh * LMP) – LMP Desired offer multiplied by the duration of the Non-Synchronized Reserve assignment.
- Since hydro units operate on a schedule and do not have an energy bid, lost opportunity costs for these units are calculated using the average of the real-time 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 a hydro unit is committed day-ahead with MW greater than zero, the lost opportunity cost is equal to (i) the Non-Synchronized Reserve assigned MW multiplied by (ii) the difference between the real-time LMP at the generator bus and the average real-time LMP (calculated as stated above). If this average real-time LMP value is higher than the real-time LMP at the generator bus, the lost opportunity cost is zero.
- If a hydro unit is not committed day-ahead, the lost opportunity cost is equal to zero.
- PJM sums the Non-Synchronized Reserve credits (both Non-Synchronized Reserve Clearing Price credits and Non-Synchronized Reserve Lost Opportunity Cost Credits) to determine the total hourly credit for each Non-Synchronized Reserve market participant, taking into account joint-ownership of generators.

7.3 Charges for Non-Synchronized Reserve

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. During hours when the Non-Synchronized Reserve Clearing Price is the same throughout the reserve zone, an LSE's non-synchronized reserve obligation is equal to its real-time load ratio share times the amount of non-synchronized reserve provided for the entire reserve zone. During hours when congestion causes the Non-Synchronized Reserve Clearing Price to separate, each LSE's non-synchronized reserve obligation is equal to its real-time load ratio share within its reserve zone or sub-zone and the amount of non-synchronized reserve provided in that reserve zone or sub-zone. The total cost of providing Non-Synchronized Reserve for each hour is the sum of the credits provided to PJM Members for supplying Non-Synchronized Reserve in that hour.

PJM Actions:

- PJM retrieves the following information:
 - Non-Synchronized Reserve bilateral transactions
 - Total PJM Non-Synchronized Reserve assigned by reserve zone and sub-zone



- Total Non-Synchronized Reserve shortfall (MWh) by reserve zone and sub-zone
- Non-Synchronized Reserve Clearing Price by reserve zone and sub-zone
- PJM calculates for each hour each participants non-synchronized reserve obligation as determined by applying the real-time load ratio share in the applicable reserve zone or sub-zone to the total non-synchronized reserve provided for that hour in the applicable reserve zone or sub-zone and then adding bilateral sales and subtracting bilateral purchases.
- Non-Synchronized Reserve Obligation = (Load Ratio Share * Total Non-Synchronized Reserve Provided) – Non-Synchronized Reserve MW Purchased + Non-Synchronized Reserve MW Sold
- PJM calculates for each hour the Non-Synchronized Reserve charges as follows:
 - The appropriate Non-Synchronized Reserve Market Clearing Price times the appropriate participant's non-synchronized reserve obligation.
- Non-Synchronized Reserve Market Clearing Price Charge = Non-Synchronized Reserve Obligation * Non-Synchronized Reserves Clearing Price
 - The appropriate hourly Non-Synchronized Reserve Market Clearing Price for each LSE is the clearing price for the sub-zone or reserve zone for which the LSE's load is located. Loads located in a sub-zone will pay that sub-zone's clearing price. Loads not located in a sub-zone will pay the corresponding reserve zone Non-Synchronized Reserve Market Clearing Price.
- If any lost opportunity cost credits for providing Non-Synchronized Reserves were credited, the total credits are allocated based on each participant's ratio share of non-synchronized reserve purchased from the market. A participant's purchases from the market equals their non-synchronized reserve obligation MW.
- Non-Synchronized Reserve Lost Opportunity Cost Charge = Total Lost Opportunity Costs Credits * (Non-Synchronized Reserve Purchase / Total PJM Non-Synchronized Reserve Purchases)
- PJM sums the Non-Synchronized Reserve charges (both Non-Synchronized Reserve Clearing Price charges and Non-Synchronized Reserve Lost Opportunity Cost Charges) to determine the total hourly Non-Synchronized Reserve charge for each market participant,



7.4 Reconciliation for Non-Synchronized Reserve Charges

PJM will calculate reconciled Non-Synchronized Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the “actual” usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Non-Synchronized Reserve charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Non-Synchronized Reserve billing determinants for that hour. The hourly Non-Synchronized Reserve charge billing determinant (in \$/MWh) for each reserve zone and sub-zone is calculated by dividing the total hourly Non-Synchronized Reserve charges in that reserve zone or sub-zone by the total PJM real-time load (de-rated for transmission losses) in that reserve zone or sub-zone for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Non-Synchronized Reserve charges for a month may be either a positive or a negative value and may even be such that the reconciled load responsibility MWh results in a negative load quantity.



Section 8: Transmission Congestion Accounting Overview

Welcome to the *Transmission Congestion Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A general description of how charges and credits are calculated when the transmission system is scheduled or operated under constrained conditions (see “*Transmission Congestion Accounting Overview*”).
- How Transmission Congestion Charges are calculated (see “*Transmission Congestion Charges*”).
- How Transmission Congestion Credits are calculated (see “*Transmission Congestion Credits*”).

8.1 Transmission Congestion Accounting Overview

When the Transmission System is scheduled day-ahead or operating real-time under constrained conditions, PJM calculates Congestion Charges for each PJM Member. The basis for the Congestion Charge is the applicable day-ahead or real-time congestion price component of LMPs. PJM calculates day-ahead and real-time locational Congestion Prices each constrained hour, as specified in **Section 2** of this PJM Manual. Every PJM Member is charged for the cost of congestion on the Transmission System, based on the difference between the congestion price at the location on the Transmission System where the PJM Member injects energy and the congestion price at the location where the PJM Member withdraws energy.

The following calculations are performed:

- Day-ahead and Balancing Transmission Congestion Charges (implicit and explicit) for each PJM Member are calculated.
- FTR Target Allocations are determined and totaled for each FTR holder for each hour.
- The Total Transmission Congestion Charges for the hour are calculated and allocated to FTR holders as Transmission Congestion Credits based on FTR Target Allocations.
- At the end of each month, any Excess Congestion Charges are distributed as additional Transmission Congestion Credits to FTR holders with Congestion Credit Deficiencies in that month or in previous months of the current planning period.
- Any revenue deficient transmission rights (ARRs or FTRs) remaining at the end of the Planning Period are satisfied through a transmission rights uplift charge which is



allocated to FTR holders on a pro-rata basis according to their net FTR target allocation position, relative to the total net FTR target allocation positions of all FTR holders in the PJM Interchange Energy Market. An entity with a net negative FTR target allocation position is not subject to transmission rights uplift allocation charges.

- Any Excess Congestion Charges that remain unallocated at the end of the planning period are used to satisfy any ARR deficiencies that may exist.
- Any Excess Congestion Charges that remain unallocated at the end of the planning period after the distribution to deficient ARR holders are allocated proportionately to FTR holders with net positive FTR target allocations for that planning period.

8.2 Transmission Congestion Charges

Transmission Congestion Charges are made up of two types:

- *Implicit* — Implicit Congestion Charges are the congestion charges associated with the congestion price differentials between the PJM Member's generation and scheduled purchases, netted out against its load (excluding losses) and scheduled sales.
- *Explicit* — Explicit Congestion Charges are the congestion charges associated with the congestion price differential from the scheduled source and sink of a transaction. The Transmission Customer pays the Congestion Charges for external transactions. The buyer pays the explicit Congestion Charges for internal transactions.

Transmission Congestion Charges can be both positive and negative.

8.2.1 Implicit Transmission Congestion Charges

Implicit Transmission Congestion Charges are the congestion charges for moving energy injections to energy withdrawals across a constrained system. They are derived by calculating an hourly Net Congestion Bill for each market participant's customer account.

The Net Congestion Bill value represents a PJM Member's total congestion obligation during a constraint, including both physical and scheduled energy. It is the difference between a PJM Member's total withdrawal congestion payment and its total injection congestion revenue. There are two primary components to the Day-ahead Net Congestion Bill.

- *Day-Ahead Injection Credits* — Day-ahead injection credits are calculated for all cleared generation and increment offers and day-ahead energy purchase transactions. Day-ahead injection credits are calculated at the generator bus congestion price, increment offer congestion price, or the congestion price at the sink of the purchase transaction, as applicable.
- *Day-Ahead Withdrawal Charges* — Day-ahead withdrawal charges are calculated for all cleared demand and decrement bids and day-ahead energy sale transactions.



Day-ahead withdrawal charges are calculated at the load bus congestion price, decrement bid congestion price, or the congestion price at the source of the sale transaction, as applicable.

Each PJM Member's hourly day-ahead implicit congestion charges (positive or negative) is that hour's day-ahead net congestion bill, which equals their day-ahead withdrawal charges minus their day-ahead injection credits for that hour.

There are two primary components to the Balancing Net Congestion Bill.

- **Balancing Injection Credits** — Balancing injection credits are calculated for all deviations between a PJM Member's real-time generation and energy purchase transactions and their day-ahead generation, increment, and energy purchase transactions. Balancing injection credits are calculated for each bus at which a real-time deviation from its day-ahead scheduled injection exists using the congestion price at that bus.
- **Balancing Withdrawal Charges** — Balancing withdrawal charges are calculated for all deviations between a PJM Member's real-time load (de-rated for transmission losses) and energy sale transactions and their day-ahead demand, decrement, and energy sale transactions. Balancing withdrawal charges are calculated for each bus at which a real-time deviation from its day-ahead scheduled withdrawal exists using the congestion price at that bus.

Each PJM Member's hourly balancing implicit congestion charges (positive or negative) is that hour's balancing net congestion bill, which equals their balancing withdrawal charges minus their balancing injection credits for that hour.

PJM Actions:

- PJM retrieves the following information:
 - demand and decrement bids cleared day-ahead (MWh)
 - generation schedules and increment offers cleared day-ahead (MWh)
 - each PJM Member's percentage of joint owned units (% ownership)
 - day-ahead and real-time external and internal energy transactions (MWh)
 - hourly state estimator MWh for each load bus (trued up to match revenue meter data from Power Meter, if available)
 - hourly state estimator MWh for each generator bus (trued-up to match revenue meter data from Power Meter, if available)
 - hourly day-ahead and real-time Congestion Prices (\$/MWh)



- PJM calculates the day-ahead withdrawal charges for each PJM Member for each of their day-ahead demand, decrement, and sale transactions as follows:

*Day-ahead withdrawal Charge = Day-ahead Demand MWh * Day-ahead Load Bus Congestion Price*

OR

*Decrement Transaction MWh * Day-ahead Congestion Price*

OR

*Day-ahead Sale Transaction MWh * Source Day-ahead Congestion Price*

- PJM calculates day-ahead injection credits for each PJM Member for each of their day-ahead generation, increment, and purchase transactions as follows:

*Day-ahead Injection Credit = Day-ahead Generation MWh * % Ownership * Day-ahead Gen Bus Congestion Price*

OR

*Increment Transaction MWh * Day-ahead Congestion Price*

OR

*Day-ahead Purchase Transaction MWh * sink Day-ahead Congestion Price*

- PJM calculates each PJM Member's hourly Day-ahead Net Congestion Bill as the sum of their day-ahead withdrawal charges minus the sum of their day-ahead injection credits.
- PJM calculates each PJM Member's hourly Day-ahead Implicit Congestion Charge as:

Day-ahead Implicit Congestion Charge = Day-ahead Net Congestion Bill

Note: Day-ahead implicit congestion charges are only calculated for market participants whose day-ahead spot market interchange includes actual or scheduled sources or sinks that reflect different congestion prices.

- PJM calculates the hourly balancing withdrawal charges for each PJM Member for each bus as follows:

*Balancing Withdrawal Charge = (Real-time loss de-rated Load MWh + Real-time Sale Transaction MWh – Day-ahead Demand MWh – Decrement Transaction MWh – Day-ahead Sale Transaction MWh) * Real-Time Bus Congestion Price*

- PJM calculates hourly balancing injection credits for each PJM Member for each bus as follows:

*Balancing Injection Credit = (Real-time Generation MWh * % Ownership + Real-time Purchase Transaction MWh – Day-ahead Generation MWh * % Ownership – Increment Transaction MWh – Day-ahead Purchase Transaction MWh) * Real-Time Bus Congestion Price*



- PJM calculates each PJM Member's hourly Balancing Net Congestion Bill as the sum of their balancing withdrawal charges minus the sum of their balancing injection credits.
- PJM calculates each PJM Member's hourly Balancing Implicit Congestion Charge as:

$$\text{Balancing Implicit Congestion Charge} = \text{Balancing Net Congestion Bill}$$

Note: Balancing implicit congestion charges are only calculated for market participants whose real-time spot market interchange includes actual or scheduled sources or sinks that reflect different congestion prices.

8.2.2 Explicit Transmission Congestion Charges

Explicit Transmission Congestion Charges are the congestion charges for moving energy across the Transmission System during a constraint. Explicit congestion charges equal the difference between the source and sink Congestion Prices of a transaction. (Explicit congestion charges are not included in the Net Congestion Bill calculations.)

- *Internal Purchases* — For internal purchases, the Explicit Congestion Charges are calculated based on the differences in Congestion Prices between their sink buses and source buses. The buyer pays the Explicit Congestion Charges associated with an internal transaction.
- *Import & Export Transactions* — For point-to-point and network secondary transmission customers, the Explicit Congestion Charges are calculated based on the difference between the sink Congestion Price and the source Congestion Price. The Transmission Customer pays the explicit Congestion Charges associated with an import or export transaction.

PJM Actions:

- PJM retrieves the following information:
 - transmission service reservations (MW, period, and source/sink)
 - day-ahead and real-time external and internal energy transactions (MWh)
 - hourly day-ahead and real-time Congestion Prices (\$/MWh)
- PJM calculates the hourly Day-ahead Explicit Congestion Charge for each transaction as:

$$\text{Day-ahead Explicit Congestion Charge} = \text{Day-ahead Transaction MWh} * (\text{Sink Day-ahead Congestion Price} - \text{Source Day-ahead Congestion Price})$$



- PJM calculates the hourly Balancing Explicit Congestion Charge for each transaction as:

$$\text{Balancing Explicit Congestion Charge} = (\text{Real-time Transaction MWh} - \text{Day-ahead Transaction MWh}) * (\text{Sink Real-time Congestion Price} - \text{Source Real-time Congestion Price})$$

8.3 Reconciliation for Transmission Congestion Charges

PJM will calculate reconciled Transmission Congestion charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the “actual” usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

Effective 6/1/2015: As part of the reconciliation process, residual metered load aggregate distribution factors are updated based on reconciliation kWh data for load responsibility InSchedules priced at nodal aggregates. An adjusted distribution congestion rate for residual metered load aggregates is then calculated as the difference between the Real-time Congestion Price that is calculated using the updated distribution factors and the original Real-time Congestion Price. This adjusted distribution congestion rate is only calculated for residual metered load aggregates.

PJM calculates the Transmission Congestion charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Real-time Congestion Price plus the adjusted distribution congestion rate at the aggregate sink bus associated with the InSchedule contract for that hour.

For those InSchedule contracts where the aggregate sink bus is a residual metered load aggregate, PJM calculates additional Transmission Congestion charge reconciliations by multiplying the scheduled Retail Load Responsibility InSchedule (in MWh) by the adjusted distribution congestion rate. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Transmission Congestion charges for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

8.4 Transmission Congestion Credits

Each market participant who holds Financial Transmission Rights receives Transmission Congestion Credits, which is a share of the Total Transmission Congestion Charges collected for each constrained hour. Each FTR holder’s Transmission Congestion Credits are calculated based upon the Financial Transmission Rights (FTRs) it holds.

8.4.1 FTRs and FTR Target Allocations

An FTR is a financial instrument that entitles the holder to receive compensation for Transmission Congestion Charges that arise when the Transmission System is congested and differences in day-ahead Congestion Prices result. The purpose of an FTR is to protect the holder from increased energy costs due to transmission congestion. Each FTR is



defined from a point of receipt to a point of delivery. For each hour in which congestion exists on the day-ahead Transmission System between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the Total Transmission Congestion Charges collected from the Market Participants. An FTR's value, therefore, is related to Transmission Congestion Charges. (See the ***PJM Manual for Financial Transmission Rights*** for more information.)

FTR Target Allocations are the amounts of credit each FTR holder should receive in each constrained hour due to the value of its FTRs. The FTR Target Allocation is calculated for each FTR in each hour by multiplying the MW value of the FTR times the sink Day-ahead Congestion Price minus the source Day-ahead Congestion Price. The total FTR Target Allocation for each FTR holder is the sum of the FTR Target Allocations for all FTRs that it holds. A market participant's net FTR Target Allocation for an hour may be either a positive or a negative value.

8.4.2 Total Transmission Congestion Charges

The Total Transmission Congestion Charges are the sum of the Day-ahead and Balancing Congestion Charges for all PJM Members, adjusted for the value of day-ahead and balancing congestion revenues due to inadvertent interchange, losses, and the MISO and NYISO joint operating agreement coordination, minus the negatively valued FTR Target Allocations.

PJM Actions:

- PJM calculates the hourly Total Transmission Congestion Charges by summing the following:
 - day-ahead and balancing implicit congestion charges (\$)
 - day-ahead and balancing explicit congestion charges (\$)
 - inadvertent interchange congestion value (\$)
 - transmission losses congestion value (\$)
 - MISO and NYISO joint operating agreement congestion value (\$)
- And then subtracting:
 - the total of all market participants' FTR Target Allocations where the net total FTR Target Allocation for that customer in the hour is a negative value (\$)

8.4.3 Hourly Allocation of Total Transmission Congestion Charges

Total Transmission Congestion Charges (including the net difference in interchange and negative Target Allocations) are allocated back to FTR holders based on their positive FTR Target Allocations. Market participants with net negative FTR Target Allocations in an hour



will always receive 100% of their FTR Target Allocations as negative Transmission Congestion Credits for that hour. The inclusion of these negative credits in the calculation of Total Transmission Congestion Charges effectively increases the amount that is available to be allocated as credits to the FTR holders with positive FTR Target Allocations.

If the Total Transmission Congestion Charges for an hour are greater than the total positive FTR Target Allocations, then there will be funds remaining in the hour after the distribution of Transmission Congestion Credits. These funds are called Excess Congestion Charges. Sometimes the calculation of Total Transmission Congestion Charges for an hour can result in a negative value. When this occurs, no positive Transmission Congestion Credits would be awarded, and the Total Transmission Congestion Charges for the hour would be treated as negative excess congestion charges. The hourly Excess Congestion Charges and the hourly negative Total Transmission Congestion Charges are accumulated for the month to be distributed in a second allocation at the end of the month.

PJM Actions:

- PJM accounting process retrieves the following information:
 - hourly Total Transmission Congestion Charge (\$)
 - each market participant's hourly FTR Target Allocations (\$)
- PJM accounting process calculates the total positive FTR Target Allocation by summing the following values:
 - sum of all market participants' FTR Target Allocations where the net total FTR Target Allocation for that customer in the hour is a positive value
- If the Total Transmission Congestion Charge is a positive value that is greater than or equal to the total positive FTR Target Allocation for the hour, the Transmission Congestion Credits for each FTR holder is equal to its FTR Target Allocations and the Congestion Credit Deficiency for each FTR holder is zero. The Excess Congestion Charge is equal to the Total Transmission Congestion Charge minus the Total positive FTR Target Allocations.
- If the Total Transmission Congestion Charge is a positive value that is less than the total positive FTR Target Allocation for the hour, then the Transmission Congestion Credit for each market participant is equal to that market participant's FTR Positive Target Allocation multiplied by the Total Transmission Congestion Charge and divided by the Total PJM positive FTR Target Allocations for the market participant's positive FTR Target Allocation, and is equal to 100% of the market participant's FTR Target Allocation for the market participant's negative FTR Target Allocation. Each market participant's hourly Congestion Credit Deficiency is calculated as its FTR Target Allocation minus its hourly Transmission Congestion Credit.



- If the Total Transmission Congestion Charge is a negative value, then the Transmission Congestion Credit for each market participant is equal to 100% of that market participant's FTR Target Allocation if the Transmission Customer's FTR Target Allocation is a negative value, and is equal to \$0.00 if the market participant's FTR Target Allocation is a positive value. Each market participant's hourly Congestion Credit Deficiency is equal to its FTR Target Allocation if the FTR Target Allocation is a positive value.

8.4.4 Monthly Allocation of Excess Congestion Charges

The objectives of the monthly Excess Congestion Charge distribution are to cover any deficiency in Transmission Congestion Credits received by each FTR holder when compared to its FTR Target Allocations, and to distribute any remaining excess at the end of the planning period first to ARR holders in proportion to ARR deficiencies and then to Network and Firm Transmission Customers. The monthly allocation is performed in five stages.

- *Stage One* — If Unscheduled Transmission Service revenues were received during the month, these charges would be allocated as additional Transmission Congestion Credits to FTR holders in proportion to, but not greater than, the total of the Congestion Credit Deficiencies in the hour to which the Unscheduled Transmission Service charge applied. Congestion Credit Deficiencies for the hour are then recalculated as a result of this allocation. Any remaining Unscheduled Transmission Service charge that cannot be allocated in the applicable hour is added to the Excess Congestion Charge for that hour. Likewise, any revenues paid to or received from MISO and NYISO for JOA market-to-market congestion relief measures are also applied to the applicable hours' congestion revenues.

PJM calculates the monthly total Excess Congestion Charge by summing the Excess Congestion Charge for each hour of the month and subtracting the Total Congestion Charge for each hour of the month in which the Total Congestion Charge was negative. PJM then distributes the monthly Total Excess Congestion Charge plus any net annual or monthly FTR Auction revenues in excess of ARR Target Allocations for that month as additional Transmission Congestion Credits to each FTR holder in proportion to, but not greater than, the sum of the hourly Congestion Credit Deficiencies in that month. If the monthly total Excess Congestion Charge is a negative value, no additional Transmission Congestion Credits can be allocated, and the negative monthly total Excess Congestion Charge would be allocated as a positive charge to Day-Ahead Operating Reserve.

PJM calculates the final monthly Congestion Credit Deficiency for each FTR holder as the difference between, the sum of the Transmission Customer's total FTR Target Allocations for the month minus the sum of all Transmission Congestion Credits distributed either hourly or monthly to that FTR holder.

- *Stage Two* — If there is any monthly total Excess Congestion Charge remaining after the stage one distribution, PJM distributes that remaining excess as additional Transmission Congestion Credits to each FTR holder in proportion to, but not greater than, the final monthly Congestion Credit Deficiencies from previous months of that



PJM planning period (June 1 to May 31). The final monthly Congestion Credit Deficiencies for each FTR holder in each month are then updated to reflect the additional Transmission Congestion Credits received.

- Stage Three — If any monthly total Excess Congestion Charge remains after the stage two distribution, that remaining excess is carried forward to be allocated to FTR holders with monthly Congestion Credit Deficiencies in future months of the PJM planning period.
- *Stage Four* — At the end of the PJM planning period, PJM distributes any Excess Congestion Charges remaining after the stage three distribution to ARR holders in proportion to any ARR deficiency that may exist over such period.
- Stage Five –
 - At the end of the PJM planning period, any Excess Congestion Charges remaining after the stage four distribution are allocated proportionately to FTR holders with net positive FTR target allocations for that planning period.
 - Any revenue deficient transmission rights (ARRs or FTRs) remaining at the end of the Planning Period are satisfied through a transmission rights uplift charge which is allocated to FTR holders on a pro-rata basis according to their net FTR target allocation position, relative to the total net FTR target allocation positions of all FTR holders in the PJM Interchange Energy Market. An entity with a net negative FTR target allocation position is not subject to transmission rights uplift allocation charges.

8.5 Reassignment of Financial Transmission Rights (FTRs)

A transitional FTR Allocation will be conducted for new zone load being added as a result of new market integration. This transitional allocation of FTRs will cover the period of time between the implementation of the new zone added and the next Annual ARR Allocation in which the new member elects to participate. The new member, at their election, will have until the second Annual FTR Auction after they join PJM to participate in the Annual FTR Auction.

For a transitional period, Network and Firm Transmission Customers that take service that sinks in new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. This transitional period covers the succeeding two Annual FTR Auctions after the integration of the new zone into the PJM interchange energy market. The election of a direct FTR Allocation shall be made prior to the commencement of each Annual FTR Auction.

Network and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights may receive allocations of Auction Revenue Rights. Network and Firm Transmission Customers in new PJM zones must choose to receive either an FTR Allocation or an ARR Allocation. A Network or Firm



Transmission Customer cannot choose to receive both an FTR Allocation and an ARR Allocation.

FTRs allocated for the transition period will be reassigned on a proportional basis within a transmission zone or load aggregation zone as load switches between LSEs within the transition period. The reassignment of FTRs is an automatic process, which is conducted by PJM on a daily basis (or as frequently as necessary). An LSE that loses load will lose a pro-rata share of their FTRs in proportion to the amount of load lost.

The total set of FTRs lost by LSEs losing load in a transmission zone or load aggregation zone will be reallocated to LSEs gaining load in the zone or load aggregation zone in proportion to each LSEs MW load gain relative to the total load shifted in the zone or load aggregation zone.



Section 9: Transmission Losses Accounting

Welcome to the *Transmission Losses Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- How transmission losses are accounted for (see “*Transmission Losses Accounting Overview*”).
- How market participants are charged for losses (see “*Transmission Loss Charges*”).
- How PJM market participants receive credits for the collected loss charges (see “*Transmission Loss Credits*”).
- How transmission loss charge reconciliations are calculated (see “*Reconciliation for Transmission Loss Charges*”).
- How transmission loss credit reconciliations are calculated (see “*Reconciliation for Transmission Loss Credits*”).

9.1 Transmission Losses Accounting Overview

Transmission losses refer to the loss of energy in the transmission of electricity from generation resources to load, which is dissipated as heat through transformers, transmission lines, and other transmission facilities. Only the losses incurred on facilities included in the PJM network model and, therefore, reflected in the PJM State Estimator are included in the PJM settlements for transmission losses.

PJM calculates Transmission Loss Charges for each PJM Member. The basis for the Loss Charge is the applicable day-ahead or real-time loss price component of LMPs. PJM calculates day-ahead and real-time locational Loss Prices each hour, as specified in **Section 2** of this PJM Manual. Every PJM Member is charged for the cost of losses on the Transmission System, based on the difference between the loss price at the location on the Transmission System where the PJM Member injects energy and the loss price at the location where the PJM Member withdraws energy.

The following calculations are performed:

- Day-ahead and Balancing Transmission Loss Charges (implicit and explicit) for each PJM Member are calculated.
- The Total PJM Loss Charges for the hour are calculated and allocated as Transmission Loss Credits based on load (excluding losses) plus export transaction ratio shares, where exports are only those that pay for transmission service and non-firm exports get a reduced allocation due to the non-firm point-to-point transmission service rate is less than the firm rate.



9.2 Transmission Loss Charges

Transmission Loss Charges are made up of two types:

- *Implicit* — Implicit Loss Charges are the loss charges associated with the loss price differentials between the PJM Member's generation and scheduled purchases, netted out against its load (excluding losses) and scheduled sales.
- *Explicit* — Explicit Loss Charges are the loss charges associated with the loss price differential from the scheduled source and sink of a transaction. The Transmission Customer pays the Loss Charges for external transactions. The buyer pays the explicit Loss Charges for internal transactions.

Transmission Loss Charges can be both positive and negative.

9.2.1 Implicit Transmission Loss Charges

Implicit Transmission Loss Charges are the loss charges for moving energy injections to energy withdrawals across the system. They are derived by calculating an hourly Net Loss Bill for each market participant's customer account.

The Net Loss Bill value represents a PJM Member's total loss obligation, including both physical and scheduled energy. It is the difference between a PJM Member's total withdrawal loss payment and its total injection loss revenue. There are two primary components to the Day-ahead Net Loss Bill.

- *Day-Ahead Injection Credits* — Day-ahead injection credits are calculated for all cleared generation and increment offers and day-ahead energy purchase transactions. Day-ahead injection credits are calculated at the generator bus loss price, increment offer loss price, or the loss price at the sink of the purchase transaction, as applicable.
- *Day-Ahead Withdrawal Charges* — Day-ahead withdrawal charges are calculated for all cleared demand and decrement bids and day-ahead energy sale transactions. Day-ahead withdrawal charges are calculated at the load bus loss price, decrement bid loss price, or the loss price at the source of the sale transaction, as applicable.

Each PJM Member's hourly day-ahead implicit loss charges (positive or negative) is that hour's day-ahead net loss bill, which equals their day-ahead withdrawal charges minus their day-ahead injection credits for that hour.

There are two primary components to the Balancing Net Loss Bill.

- *Balancing Injection Credits* — Balancing injection credits are calculated for all deviations between a PJM Member's real-time generation and energy purchase transactions and their day-ahead generation, increment, and energy purchase transactions. Balancing injection credits are calculated for each bus at which a real-time deviation from its day-ahead scheduled injection exists using the loss price at that bus.



- **Balancing Withdrawal Charges** — Balancing withdrawal charges are calculated for all deviations between a PJM Member's real-time load (de-rated for transmission losses) and energy sale transactions and their day-ahead demand, decrement, and energy sale transactions. Balancing withdrawal charges are calculated for each bus at which a real-time deviation from its day-ahead scheduled withdrawal exists using the loss price at that bus.

Each PJM Member's hourly balancing implicit loss charges (positive or negative) is that hour's balancing net loss bill, which equals their balancing withdrawal charges minus their balancing injection credits for that hour.

PJM Actions:

- PJM retrieves the following information:
 - demand and decrement bids cleared day-ahead (MWh)
 - generation schedules and increment offers cleared day-ahead (MWh)
 - each PJM Member's percentage of joint owned units (% ownership)
 - day-ahead and real-time external and internal energy transactions (MWh)
 - hourly state estimator MWh for each load bus (trued up to match revenue meter data from Power Meter, if available)
 - hourly state estimator MWh for each generator bus (trued-up to match revenue meter data from Power Meter, if available)
 - hourly day-ahead and real-time Loss Prices (\$/MWh)
- PJM calculates the day-ahead withdrawal charges for each PJM Member for each of their day-ahead demand, decrement, and sale transactions as follows:

*Day-ahead withdrawal Charge = Day-ahead Demand MWh * Day-ahead Load Bus Loss Price*

OR

*Decrement Transaction MWh * Day-ahead Loss Price*

OR

*Day-ahead Sale Transaction MWh * Source Day-ahead Loss Price*

- PJM calculates day-ahead injection credits for each PJM Member for each of their day-ahead generation, increment, and purchase transactions as follows:

*Day-ahead Injection Credit = Day-ahead Generation MWh * % Ownership * Day-ahead Gen Bus Loss Price*

OR



*Increment Transaction MWh * Day-ahead Loss Price*

OR

*Day-ahead Purchase Transaction MWh * sink Day-ahead Loss Price*

- PJM calculates each PJM Member's hourly Day-ahead Net Loss Bill as the sum of their day-ahead withdrawal charges minus the sum of their day-ahead injection credits.
- PJM calculates each PJM Member's hourly Day-ahead Implicit Loss Charge as:

Day-ahead Implicit Loss Charge = Day-ahead Net Loss Bill

9.2.2 Explicit Transmission Loss Charges

Explicit Transmission Loss Charges are the loss charges for moving energy across the Transmission System. Explicit loss charges equal the difference between the source and sink Loss Prices of a transaction. (Explicit loss charges are not included in the Net Loss Bill calculations.)

- *Internal Purchases* — For internal purchases, the Explicit Loss Charges are calculated based on the differences in Loss Prices between their sink buses and source buses. The buyer pays the Explicit Loss Charges associated with an internal transaction.
- *Import & Export Transactions* — For point-to-point and network secondary transmission customers, the Explicit Loss Charges are calculated based on the difference between the sink Loss Price and the source Loss Price. The Transmission Customer pays the explicit Loss Charges associated with an import or export transaction.

PJM Actions:

- PJM retrieves the following information:
 - transmission service reservations (MW, period, and source/sink)
 - day-ahead and real-time external and internal energy transactions (MWh)
 - hourly day-ahead and real-time Loss Prices (\$/MWh)
- PJM calculates the hourly Day-ahead Explicit Loss Charge for each transaction as:

*Day-ahead Explicit Loss Charge = Day-ahead Transaction MWh *
(Sink Day-ahead Loss Price – Source Day-ahead Loss Price)*

- PJM calculates the hourly Balancing Explicit Loss Charge for each transaction as:



$$\text{Balancing Explicit Loss Charge} = (\text{Real-time Transaction MWh} - \text{Day-ahead Transaction MWh}) * (\text{Sink Real-time Loss Price} - \text{Source Real-time Loss Price})$$

9.3 Reconciliation for Transmission Loss Charges

PJM will calculate reconciled Transmission Loss charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the “actual” usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

Effective 6/1/2015: As part of the reconciliation process, residual metered load aggregate distribution factors are updated based on reconciliation kWh data for load responsibility InSchedules priced at nodal aggregates. An adjusted distribution loss rate for residual metered load aggregates is then calculated as the difference between the Real-time Loss Price that is calculated using the updated distribution factors and the original Real-time Loss Price. This adjusted distribution loss rate is only calculated for residual metered load aggregates.

PJM calculates the Transmission Loss charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Real-time Loss Price plus the adjusted distribution loss rate at the aggregate sink bus associated with the InSchedule contract for that hour.

For those InSchedule contracts where the aggregate sink bus is a residual metered load aggregate, PJM calculates additional Transmission Loss charge reconciliations by multiplying the scheduled Retail Load Responsibility InSchedule (in MWh) by the adjusted distribution loss rate. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Transmission Loss charges for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.

9.4 Transmission Loss Credits

The total amount of both day-ahead and balancing hourly transmission losses charges, adjusted for the value of day-ahead and balancing spot market losses and loss revenues due to inadvertent interchange is allocated among the PJM market participants in proportion to their real-time load (de-rated for transmission losses) plus their real-time PJM exports (that pay for transmission service) as a percentage of the total PJM load (excluding losses) and exports. Only 31% of the non-firm export MWh are used in this allocation, since the non-firm transmission rate is 31% of the firm rate.

PJM Actions:

- PJM accounting process retrieves the following information:
 - hourly real-time load (excluding losses) for each LSE (MWh)



- hourly real-time PJM export schedules for each market participant (MWh)
- hourly non-firm export reduction factor (31%) based on the non-firm point-to-point transmission service rate divided by the firm point-to-point transmission service rate
- transmission service reservations (MW, period, type, and source/sink)
- each market participant's day-ahead and balancing loss charges (\$)
- spot market loss value (\$)
- inadvertent interchange loss value (\$)
- PJM accounting process calculates the total hourly transmission loss charges by summing the day-ahead and balancing loss charges for each market participant plus the spot market value of losses, including an adjustment for the inadvertent interchange loss value.
- PJM accounting process calculates the hourly real-time load (excluding losses) plus export ratio of each market participant.
- PJM includes only export transaction MWh that pay for transmission service. PJM compares the export transaction MWh to the linked transmission reservation capacity MW for the hour (recognizing ramping and time zone shifts) to ensure that the export transaction MWh do not exceed the linked transmission service capacity MW. Non-firm export transaction MWh are multiplied by 31% prior to including them in the allocation, since the non-firm transmission service rate is 31% of the firm transmission service rate.
- PJM accounting process allocates the total hourly loss charges as hourly transmission loss credits for each market participant based on their hourly real-time load (excluding losses) plus export (100% of firm export MWh and 31% of non-firm export MWh) ratio share.

9.5 Reconciliation for Transmission Loss Credits

PJM will calculate reconciled Transmission Loss credits for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.



PJM calculates the Transmission Loss credit reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Transmission Loss Credit billing determinant for that hour. The hourly Transmission Loss Credit billing determinants (in \$/MWh) are calculated by dividing the total day-ahead and balancing transmission loss revenues for an hour by the total PJM real-time load (de-rated for transmission losses) and exports (that pay for transmission service and using only 31% of non-firm export MWh) in that hour. These credit reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Transmission Loss credits for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.



Section 10: Emergency Energy Accounting

Welcome to the *Emergency Energy Accounting* section of the *PJM Manual for Operating Agreement Accounting*. In this section, you will find the following information:

- A description of the types of Emergency energy transactions and how they are accounted for (see “*Emergency Energy Accounting Overview*”).
- How Emergency energy purchases from other Control Areas are accounted for (see “*Emergency Energy Purchases by PJM*”).
- How Emergency energy sales to other Control Areas are accounted for (see “*Emergency Energy Sales by PJM*”).
- How Minimum Generation Emergency purchases from other Control Areas are accounted for (see “*Minimum Generation Emergency Purchases by PJM*”).
- How Minimum Generation Emergency sales to other Control Areas are accounted for (see “*Minimum Generation Emergency Sales by PJM*”).

10.1 Emergency Energy Accounting Overview

PJM may purchase energy from outside PJM as needed to alleviate or end an Emergency, and may sell energy to another Control Area as requested during Emergency conditions in that Control Area. Emergencies may be reserve deficiencies or Minimum Generation (low load) Emergencies.

Emergency energy sales to other Control Areas are priced at 150% of the real-time LMP at the bus or busses at the border of PJM at which the energy is delivered.

Minimum Generation Emergency energy sales to other Control Areas are priced at a mutually agreed upon price not to exceed the real-time LMP at the bus or busses at the border of PJM at which the energy is delivered.

10.2 Emergency Energy Purchases by PJM

The net cost in excess of real-time LMPs of Emergency energy purchased is allocated to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales.

If generator reductions are requested by PJM for reliability during hours of Emergency energy purchases, the reduced MWh are used to reduce that PJM Market Participants' charge allocation.



PJM Actions:

- PJM retrieves the following information:
 - PJM Emergency energy purchase transactions (MWh, \$)
 - each PJM Market Participant's real-time net hourly interchange (MWh)
 - each PJM Market Participant's day-ahead net hourly interchange (MWh)
 - hourly list of integrated real-time bus LMPs (\$)
 - PJM's designated interface points with adjacent Control Areas
- PJM calculates the total charges to be allocated among PJM Market Participants for each Emergency energy purchase as:

*Emergency Energy Purchase (MWh) **

(Emergency Energy Purchase Price – Real-Time Interface LMP)

- PJM allocates the total hourly charge for Emergency energy purchases to PJM Market Participants in proportion to their real-time deviation including the impact of load reconciliation MWh from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales.
- A billing adjustment is calculated, as applicable, to exempt any MWh of generator reductions requested by PJM for reliability during any hours of Emergency energy purchases.

10.3 Emergency Energy Sales by PJM

The net revenues in excess of real-time LMPs of Emergency energy sales is credited to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales, plus any energy sales from within PJM to entities outside of PJM that have been curtailed by PJM during the Emergency.

PJM Actions:

- PJM retrieves the following information:
 - PJM Emergency energy sales (\$, MWh)
 - each PJM Market Participant's real-time net hourly interchange (MWh)



- each PJM Market Participant's day-ahead net hourly interchange (MWh)
- hourly integrated real-time bus LMPs (\$)
- PJM interface points with adjacent Control Areas
- External sales that are curtailed by PJM during Emergency energy sales
- PJM calculates the total credits to be allocated among PJM Market Participants for each Emergency energy sale as:

*Emergency Energy Sale (MWh) * (Emergency Energy Sale Price – Real-Time Interface LMP)*

- PJM allocates the total hourly credit for Emergency energy sales among PJM Market Participants in proportion to their real-time deviation including the impact of load reconciliation MWh from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales, plus any energy sales from within PJM to entities outside of PJM that have been curtailed by PJM during the Emergency.

10.4 Minimum Generation Emergency Purchases by PJM

The net cost of Minimum Generation Emergency energy purchased is allocated to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation decreases their spot market purchases or increases their spot market sales.

PJM Actions:

- PJM retrieves the following information:
 - PJM Emergency energy minimum purchases (MWh, \$)
 - each PJM Market Participant's real-time net hourly interchange (MWh)
 - each PJM Market Participant's day-ahead net hourly interchange (MWh)
 - hourly integrated real-time LMPs (\$)
 - PJM interface points with adjacent control areas
- PJM calculates the total charges to be allocated among PJM Market Participants for each Minimum Generation Emergency energy purchase as:

*Minimum Generation Emergency Energy Purchase (MWh) * (Emergency Energy Purchase Price – Real-Time Interface LMP)*

PJM allocates the total hourly charge for Minimum Generation Emergency purchases to PJM Market Participants in proportion to their real-time deviation including the impact of load



reconciliation MWh from the net interchange in the day-ahead market, whenever that deviation decreases their spot market purchases or increases their spot market sales.

10.5 Minimum Generation Emergency Sales by PJM

The net revenues in connection with Minimum Generation Emergency energy sales to other Control Areas are credited to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation decreases their spot market purchases or increases their spot market sales.

PJM Actions:

- PJM retrieves the following information:
 - PJM Emergency energy minimum sales (MWh, \$)
 - each PJM Market Participant's real-time net hourly interchange (MWh)
 - each PJM Market Participant's day-ahead net hourly interchange (MWh)
 - hourly integrated real-time bus LMPs (\$)
 - PJM interface points with adjacent Control Areas
- PJM calculates the total credits to be allocated among PJM Market Participants for each Minimum Generation Emergency energy sale as:

$$\begin{aligned} & \text{Minimum Generation Emergency Energy Sale (MWh) *} \\ & (\text{Emergency Energy Sale Price} - \text{Real-Time Interface LMP}) \end{aligned}$$

- PJM allocates the total hourly credit for Minimum Generation Emergency energy sales among PJM Market Participants in proportion to their real-time deviation including the impact of load reconciliation MWh from their net interchange in the day-ahead market, whenever that deviation decreases their spot market purchases or increases their spot market sales.



Section 11: PJM Load Response Programs Accounting

Welcome to the *PJM Load Response Programs Accounting* section of the *PJM Manual for Operating Agreement Accounting*. In this section, you will find the following information:

- An overview of PJM Load Response Programs (see “*PJM Load Response Programs Overview*”).
- A description of the accounting procedure for the PJM Load Response Programs (see “*PJM Load Response Programs Accounting Procedures*”).

11.1 PJM Load Response Programs Overview

The PJM Load Response Programs are designed to provide compensation to end-use customers or curtailment service providers (“CSP”) for reduction of consumption when scheduled or dispatched by PJM and when satisfying the Net Benefits Test or when an emergency or pre-emergency event occurs. PJM offers four different types of Load Response Programs, the Full Emergency, the Full Pre-Emergency, the Emergency Energy Only, and the Economic Load Response Programs.

The Full Emergency and Full Pre-Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by reducing load during a Load Management event.

The Emergency Energy Only Program is designed to provide a method by which end-use customers may be compensated by PJM for voluntarily reducing load during an Emergency Energy Only event.

The Economic Load Response Program is designed to provide compensation to end-use customers or curtailment service providers (“CSP”) for reduction of consumption when scheduled or dispatched by PJM and when satisfying the Net Benefits Test.

11.2 PJM Load Response Programs Accounting Procedures

11.2.1 Full Emergency and Emergency Energy Only Load Response Program

Under the Full Emergency, Full Pre-Emergency, and Emergency Energy Only Load Response Programs, emergency and pre-emergency energy payment for reducing load is based on the actual kWh relief provided plus an adjustment for losses. Compensation is equal to the measured reduction adjusted for losses times the appropriate zonal or aggregate Locational Marginal Price (LMP). If, however, the sum of the hourly energy payments to a participant dispatched by PJM is not greater than or equal to the value of the standing emergency or pre-emergency energy offer price for actual, achieved reductions, then the CSP will be made whole up to the value of the standing offer for the actual, achieved reductions.

Manual 11, section 10 outlines how the energy reductions will be determined.



DR Full Emergency, Full Pre-Emergency, and Capacity only Load Response participants are subject to the Load Management Test Failure Charge and the Demand Resource Compliance Penalty Settlements as described in Manual 18: PJM Capacity Market, Section 9: Settlements.

During Emergency conditions, costs for Emergency purchases in excess of LMP are allocated to PJM Market Participants in proportion to their increase in net purchases from the PJM energy market during the hour in the real-time market compared to the day-ahead market. Consistent with this pricing methodology, all energy charges under the Full Emergency, Full Pre-Emergency, and Emergency Energy Only Load Response Program are allocated to PJM Market Participants in proportion to their real-time deviation including the impact of load reconciliation MWh from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales less any real-time dispatch reduction MWhs.

PJM Actions:

- PJM retrieves the following information:
 - each PJM Market Participant's load reduction meter data
 - EDC loss de-ration factors
 - Energy Loss factor
 - each PJM Market Participant's real-time net hourly interchange (MWh)
 - each PJM Market Participant's day-ahead net hourly interchange (MWh)
 - hourly list of integrated real-time LMPs (\$)
 - hourly real-time dispatch reduction MWh
- PJM calculates the total credits for each PJM Market Participant in the Emergency or Pre-Emergency Load Response Program as:

$$(Actual\ MWh\ relief\ provided * (1 - EDC\ loss\ de-ration\ factor) * Energy\ Loss\ factor) * \\ (Appropriate\ real-time\ zonal\ LMP\ or\ aggregate\ LMP)$$

- Actual MWh relief provided is equal to the CBL less the RT metered load. Additional details on the calculation of CBL and RT metered load can be found in Manual 11: Section 10 Overview of the Demand Resource Participation.

PJM allocates the total hourly charge for the Emergency and Pre-Emergency Load Response Program to PJM Market Participants in proportion to their real-time deviation from their net interchange in the day-ahead market, whenever that deviation increases their spot market purchases or decreases their spot market sales less any real-time dispatch reduction MWhs.



11.2.2 Economic Load Response Program

Under the Economic Load Response Program, Market Participants have the option to participate in both the Day-ahead and Real-time Energy Markets. Participation in the Real-time Energy Market consists of submitting a day-ahead offer that cleared or being dispatched by PJM.

Day-ahead Settlements:

PJM will accept demand reduction bids from an end-use customer or its representative CSP for a specific MW curtailment (in minimum increments of .1 MW or 100 kW). The demand reduction bid will include the day-ahead LMP above which the end-use customer would not consume, and could also include shut-down costs and/or the number of contiguous hours for which the load reduction must be committed.

Credits for reducing load are based on the reductions of MWh committed in the day-ahead market.

- An end-use customer or representative CSP that submits a load reduction bid day-ahead that is cleared by PJM when the applicable zonal or aggregate day-ahead LMP is less than the price determined under the Net Benefits Test for that month, will not be compensated by PJM for the reduction.
- An end-use customer or representative CSP that submits a load reduction bid day-ahead that is cleared by PJM when the applicable zonal or aggregate day-ahead LMP is greater than or equal to the price determined under the Net Benefits Test for that month, will be paid by PJM the day-ahead LMP.

The cost of payments to Economic Load Response Participants are recovered from Market Participants as follows:

- Payment is no longer made to any submitted load reduction day-ahead bid that is cleared by PJM when the day-ahead LMP is less than the price determined under the Net Benefits Test for that month,
- For any submitted load reduction day-ahead bid that is accepted by PJM when the day-ahead LMP is greater than or equal to the price determined under the Net Benefits Test for that month, PJM shall recover the costs from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and real-time loads in each Zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the Net Benefits Test for that month.

Total payments to end-use customers or their representative CSP for accepted day-ahead Economic Load Response bids that follow PJM dispatch instructions will not be less than the total value of the load response bid, including any submitted shut-down costs. Details can be found in the Day-ahead Operating Reserve Load Response Settlements Section.

End-use customers or their representative CSP that have load reductions committed in the day-ahead market that deviate from the day-ahead schedule in real-time shall be charged or credited for such variance at the real-time LMP per the Real-time Settlements section below,



plus any associated balancing operating reserve charges per the Balancing Operating Reserves Load Response Settlements Section.

PJM Actions:

- PJM retrieves the following information:
 - each PJM Market Participant's cleared day-ahead scheduled load reduction quantities
 - each PJM Market Participant's actual metered reduction
 - EDC loss de-ration factors
 - Energy Loss factor
 - associated shut-down costs
 - hourly integrated day-ahead LMPs (\$/MWh)
 - retail rate (generation and transmission)
 - monthly Net Benefits Test price
 - hourly real-time load (excluding losses) for each LSE (MWh)
 - hourly real-time PJM export schedules for each market participant (MWh)
- Payment will be made by PJM to the end-use customer or representative CSP as:

*Cleared Day-ahead MWh load reduction * Day-ahead LMP when the applicable zonal or aggregate day-ahead LMP >= Monthly Net Benefits Test*

- PJM shall recover payments for day-ahead cleared load reductions when the day-ahead LMP is greater than or equal to the price determined under the Net Benefits Test for that month as:

*Total Day-ahead Load Response Credits * { (Real-time Load in Applicable Zone(s) + Real-time Exports) / (Total Applicable Zone(s) Real-time Load + Total PJM Real-time Exports)}*

where the applicable zones are those zones for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than or equal to the Monthly Net Benefits Test Price



Real-time Settlements:

Credits for reducing load are based on the actual MWh relief provided in excess of committed day-ahead load reductions plus an adjustment for losses.

- An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is less than the threshold price established under the Net Benefits Test, will not be compensated by PJM for the reduction.
- An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJM Settlement at the real-time LMP.

In cases where load response is dispatched by PJM and follows dispatch within a 20% threshold, the total payment to end-use customers or their representative CSP will not be less than the total value of the load response bid, including any submitted shut-down costs. Details can be found in the Balancing Operating Reserve Load Response Settlements Section.

The cost of payments to Economic Load Response Participants for load reductions are recovered from Market Participants as follows:

- Payment is no longer made to any load reductions in real-time when the real-time LMP is less than the price determined under the Net Benefits Test.
- For any real-time load reductions in real-time in response to PJM dispatch, and for which the applicable real-time LMP is greater than or equal to the price determined under the Net Benefits Test for that month, PJM shall recover the costs from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and real-time loads in each Zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month.

PJM Actions:

- PJM retrieves the following information:
 - each PJM Market Participant's day-ahead scheduled load reduction quantities
 - each PJM Market Participant's actual metered reduction de-rated for transmission losses
 - associated shut-down costs
 - EDC loss de-rating factors



- o Energy Loss factor
- o hourly integrated real-time LMPs (\$/MWh)
- o retail rate (generation and transmission)
- o monthly Net Benefits Test price
- o hourly real-time load (excluding losses) for each LSE (MWh)
- o hourly real-time PJM export schedules for each market participant (MWh)
- Payment will be made by PJM to the end-use customer or representative CSP that curtails or causes the curtailment of demand in real-time in response to PJM dispatch as:

*{(Actual MWh relief provided * (1- EDC loss de-ration factor) * Energy Loss factor) – Cleared Day-ahead MWh load } * Real-Time LMP when the applicable zonal or aggregate Real-time LMP >= Monthly Net Benefits Test Price*

- Actual MWh relief provided is equal to the CBL less the RT metered load. Additional details on the calculation of CBL and RT metered load can be found in Manual 11: Section 10 Overview of the Demand Resource Participation.
- PJM shall recover payments for real-time load reductions when the real-time LMP is greater than or equal to the price determined under the Net Benefits Test for that month as:

*Total Real-time Load Response Credits * { (Real-time Load in Applicable Zone(s) + Real-time Exports) / (Total Applicable Zone(s) Real-time Load + Total PJM Real-time Exports)}*

where the applicable zones are those zones for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than or equal to the Monthly Net Benefits Test Price

Day-ahead Operating Reserve Load Response Settlements:

Total payments to Economic Load Response Participants for cleared day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid.

Day-ahead cleared load reduction resources are considered to be following dispatch instructions if the actual load reduction quantity for a given hour deviates by no more than 20% above or below the Desired MW quantity. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payments based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.



- Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid.:

*Sum[(Offer Price * Day-ahead committed MWs) + Shutdown Cost – Day-ahead Economic Load Response Credits] across all hours of the day*

- The daily total cost of Day-ahead Operating Reserve which includes Day-ahead Load Response Operating Reserve payments are allocated and charged to PJM Members in proportion to their cleared day-ahead demand and decrement bids plus their cleared day-ahead exports.

Balancing Operating Reserve Load Response Settlements:

In cases where the demand reduction follows dispatch as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid, including any submitted shut-down costs.

Real-time load reduction resources are considered to be following dispatch instructions if the actual load reduction quantity for a given hour deviates by no more than 20% above or below the Desired MW quantity. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payments based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

Balancing Operating Reserve credits are calculated by operating segment within an Operating Day. A load response resource considered to be following dispatch instructions will be made whole for the duration of the greater of the day-ahead schedule or minimum down time and made whole separately for the block of hours it is operated at PJM's direction in excess of the greater of the day-ahead schedule or minimum down time. Shutdown costs, as applicable, will be included in the segment represented by the longer of the day-ahead schedule or minimum down time.

- Total payments to Economic Load Response Participants for real-time demand reductions with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid and are calculated for each operating segment.
- The daily total cost of Balancing Load Response Operating Reserve Payments is allocated and charged to PJM Members in proportion to their real-time deviations from day-ahead schedules and generator deviations.

Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations. In the case where the Market Participant deviates by more than twenty percent of the day-ahead committed bid or the desired amount, the Market Participant will incur Balancing Operating Reserve charges:



*Abs[(Actual MWh relief provided * (1 - EDC loss de-rating factor) * Energy Loss factor) – Desired MWh] * RTO Balancing Operating Reserves Deviation Rate + Abs[(Actual MWh relief provided * (1 - EDC loss de-rating factor) * Energy Loss factor) – Desired MWh] * Locational Balancing Operating Reserves Deviation Rate (East or West depending on zone)*

- Actual MWh relief provided is equal to the CBL less the RT metered load. Additional details on the calculation of CBL and RT metered load can be found in Manual 11: Section 10 Overview of the Demand Resource Participation.



Section 12: Metering Reconciliation Accounting

Welcome to the *Metering Reconciliation Accounting* section of the PJM Manual for *Operating Agreement Accounting*. In this section, you will find the following information:

- How metering errors and corrections are reconciled and corrected (see “*Meter Correction Billing*”).

12.1 Meter Error Correction Billing

Metering errors and corrections are reconciled at the end of each month by a meter correction charge. The monthly meter error correction charge (plus/minus) is determined by the product of the positive or negative deviation in energy amounts times the load weighted average real-time LMP for all load buses in the PJM Region, as applicable for tie meter corrections; or times the generation weighted average real-time LMP for individual generation buses, [energy injections into the transmission system modeled as generators, and Pseudo Tie imports into PJM](#) for generator ~~(or for net energy injections into the transmission system modeled as generators)~~ meter corrections; or times the [Dynamic Schedule weighted average interface real-time LMP for meter corrections for Dynamic Schedule imports into PJM and non-unit specific Dynamic Schedule exports out of PJM; or RT MWh weighted average generator bus real-time LMP for Pseudo Tie exports and unit specific Dynamic Schedule exports out of PJM meter corrections.](#)

Meter error data is submitted to PJM via Power Meter no later than the last PJM business day of the month following the end of the monthly billing cycle applicable to the meter correction.

A PJM Member may not assert a claim for an adjustment in billing as a result of a meter error for any error discovered more than two years after the date on which the metering occurred. Any claim for an adjustment in billing as a result of a meter is limited to bills for transactions occurring in the most recent annual accounting period of the billing PJM Member in which the meter error occurred and the prior annual accounting period. Billing cycle accounting for PJM Mid-Atlantic 500 kV transmission losses is adjusted to account for errors in meters on those 500 kV Transmission Facilities.

12.1.1 Meter Corrections between PJM Members

If a PJM Member or PJM discovers a meter error affecting an interchange of energy with another PJM Member(s) and makes the error known to the other PJM Member(s) prior to the completion by PJM of the accounting for the interchange, and if the PJM Members are willing to adjust hourly tie readings to compensate for the error, an adjustment in tie readings may be made by the PJM Members in order to correct for the meter error, provided corrected information is provided to PJM in accordance with PJM’s accounting deadlines. No such adjustment may be made if PJM has completed the accounting for the Operating Day in which the interchange occurred. If this is not practical, the error is accounted for by a correction at the end of the billing cycle.

12.1.2 Meter Corrections between Control Areas



An error in metered interchange between a PJM Member and an entity in another Control Area is corrected by adjusting the hourly meter readings. If this is not practical, the error is accounted for by a correction at the end of the billing cycle. The PJM Member with ties [or Dynamic Transfers with](#) such other Control Area experiencing the error accounts for the full amount of the discrepancy and an appropriate debit or credit is applied proportionately among all LSEs based on load (de-rated for transmission losses). PJM adjusts the actual [or scheduled](#) interchange between PJM and the other Control Area to maintain a proper record of inadvertent energy flow.

PJM Actions:

- PJM receives meter correction data from the fully metered PJM Members.
- PJM verifies and reconciles the meter correction data to ensure data consistency.
- PJM allocates PJM Mid-Atlantic 500 kV meter corrections to all fully metered PJM Mid-Atlantic EDCs in proportion to their monthly PJM Mid-Atlantic real-time load (excluding losses), and allocates external tie line meter corrections to all PJM RTO LSEs in proportion to their monthly PJM RTO real-time load (excluding losses).
- PJM calculates ~~a~~ monthly ~~;~~ load weighted-average real-time LMP for the PJM RTO, ~~node specific and~~ generation weighted-average real-time LMPs, [and Dynamic Schedule weighted-average interface real-time LMPs](#).
- PJM calculates meter error correction charges or credits for each EDC, LSE, or generator, [or Dynamic Transfer](#) as follows:

$$\text{Meter Correction Charge (+/-)} = (\text{Tie Meter Correction MWh} * \text{PJM Monthly Load Weighted-Average LMP}) + (\text{Generation Meter Correction MWh} * \text{Applicable Monthly Generation Weighted-Average LMP}) + (\text{Dynamic Schedule Import Correction MWh} * \text{Applicable Monthly Dynamic Schedule Weighted-Average Interface LMP}) + (\text{Dynamic Schedule Non-Unit specific Export Correction MWh} * \text{Applicable Monthly Dynamic Schedule Weighted-Average Interface LMP}) + (\text{Unit Specific Dynamic Transfer Correction MWh} * (\text{Applicable Monthly Dynamic Transfer Weighted-Average Interface LMP} - \text{Applicable Monthly Generation Weighted-Average LMP}))$$

- The following table shows the market participants that receive +/- meter correction charges based on the various types of meters that require corrections.

Type of Tie Meter Correction	Mid-Atlantic 500kv?	Impacted Participant(s)	Impacted Participant(s)
PJM Internal Tie	Yes	Applicable EDC	PJM Mid-Atlantic EDCs
	No	Applicable EDC	Applicable EDC
PJM External Tie	Yes	PJM Mid-Atlantic EDCs	All PJM LSEs
	No	Applicable EDC	All PJM LSEs
Generator Tie	Yes	Generator	PJM Mid-Atlantic EDCs
	No	Generator	Applicable EDC
Pseudo Tie Generator Import	No	PJM Market Participant receiving credit	All PJM LSEs as inadvertent allocation
Pseudo Tie Generator or	Yes and No	Exporting Party	All PJM LSEs as inadvertent allocation

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Dynamic Schedule Generator Export			
Dynamic Schedule Import	No	PJM Market Participant receiving credit	All PJM LSEs as inadvertent allocation
Dynamic Schedule Export (not unit specific)	No	PJM Market Participant receiving charge	All PJM LSEs as inadvertent allocation

- For each EDC that requests PJM to further allocate their meter correction charges to all LSEs in their territory (and provides PJM with documented concurrence from all of their LSEs), that EDC's meter correction charges will be allocated to all LSEs in their territory in proportion to their monthly real-time load (excluding losses).



Section 13: Station Power Accounting

Welcome to the *Station Power Accounting* section of the *PJM Manual for Operating Agreement Accounting*. In this section, you will find the following information:

- A description of the accounting procedure for Station Power billing adjustments (see “*Station Power Accounting Procedure*”).

13.1 Station Power Accounting Procedure

In accordance with the June 28, 2001 FERC order regarding PJM’s treatment of generator station power (Docket No. ER01-1936, effective July 1, 2001), PJM performs monthly netting of hourly generator output and station power consumption to determine if the following billing adjustments are required:

- Adjustment to Spot Market Energy billing (for third-party supply of station power)
- Adjustment to Non-firm Point-to-point Transmission Service billing (for remote self-supply of station power)

The hourly net generation MWh quantities that are used in PJM energy market settlements (excluding energy consumed for pumping at pumped storage hydro facilities, for compressors at compressed air energy storage resources, for synchronous condensing, and solely for the charging of Energy Storage Resources (i.e., batteries and flywheels) for the later injection of energy) are netted over the calendar month for each generator and for each generation owner. The charging of an electric vehicle (EV) battery used for operating the vehicle would be treated as a retail transaction, even if the EV battery is also used to provide wholesale regulation or other ancillary services. Any billing adjustments required for generators or generation owners with net negative totals are calculated and included in the subsequent month’s billing cycle.

Generation MWh values are retrieved from the PJM Power Meter system for generators that report revenue meter data to PJM Power Meter. Monthly MWh data for generators not represented in PJM Power Meter must be reported to PJM by the generation owners, or by the applicable PJM Members on their behalf, by the 15th calendar day of the following month.

If a superseding arrangement for the treatment station power exists between a generation owner and the applicable electric distribution company (EDC) in whose service territory the generator resides, then hourly net station power consumption (i.e., negative net generation MWh) is not reported to PJM for settlements purposes. In this case, compensation for station power consumption is handled bilaterally between the EDCs and generation owners and PJM billing adjustments for station power are not applicable.

13.1.1 Third-Party Supply

For each individual business entity with ownership rights to one or more generators (or joint-owned shares of generators) in PJM, their net generation MWh are netted for the month to determine if a third-party retail purchase of station power occurred. If a generation owner’s monthly net generation MWh is negative, then that third-party supply of net station power



consumption is allocated to their generators that were off-line during the month based on a rank order methodology.

Starting with the generator with the most negative net MWh for the month, the entity's net MWh quantity is allocated (in 0.001 MWh increments) across all hours in the month where that generator had net negative MWh. If additional net negative MWh remains for the generation owner after being allocated to the first generator, the remaining MWh are allocated to each generator with net negative MWh based on the magnitude of the generators' net MWh (from highest to lowest) until it is all allocated.

A PJM billing adjustment will shift the financial responsibility for the wholesale value of the third-party sale of station power consumption from the generation owner to the appropriate EDC. The allocated MWh are priced at the applicable generator's hourly LMP and accumulated for the month to determine the spot market energy billing adjustment. The billing adjustment is a credit to the generation owner's billing account and a charge to the applicable EDC's billing account. The MWh allocations will be provided to the EDC and may be included in PJM's retail load reconciliation process, if desired, to facilitate the retail billing process between the EDC and the generation owner (or its designated PJM network customer).

13.1.2 Remote Self-Supply

For each generating unit (or for multiple generating units with station power requirements metered at a common source) or joint-owned share of a generating unit, the generation MWh are netted for the month to determine if station power was remotely self-supplied. If a generator's monthly net generation MWh is negative (excluding that which was determined to be supplied by a third party), then PJM non-firm point-to-point transmission service charges are determined by multiplying the net negative MWh quantity by the current discounted rate of \$0.67/MWh. Through PJM billing adjustments, the non-firm charges are assessed to the generation owner's billing account and allocated as credits to all firm point-to-point and network integration transmission customers in accordance with the PJM Open Access Transmission Tariff section 27a in proportion to their demand charges for that month.



Section 14: Unscheduled Transmission Service Accounting

Welcome to the *Unscheduled Transmission Service Accounting* section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- A description of the accounting procedure for Unscheduled Transmission Service (see “*Unscheduled Transmission Service Accounting Procedure*”).

14.1 Unscheduled Transmission Service Accounting Procedure

Prior to 1/15/2013, when PJM provides Unscheduled Transmission Service to the NYISO, the compensation received is allocated with the monthly excess congestion credit allocations. When PJM receives Unscheduled Transmission Service from the NYISO, the charges due NYISO are netted against any credits received by PJM. Effective 1/15/2013 with the implementation of NYISO JOA market-to-market congestion relief measures, any revenues paid to or received from NYISO are applied to applicable hours' congestion revenues.



Section 15: Ramapo PAR Facilities Accounting

Welcome to the *Ramapo PAR Facilities Accounting* section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- A description of the accounting procedure for Ramapo PAR facilities accounting (see "*Ramapo PAR Facilities Accounting Procedure*").

15.1 Ramapo PAR Facilities Accounting Procedure

The PJM East Transmission Owners have entered into a facility agreement with the New York ISO for the installation and operation of phase angle regulating (PAR) facilities at Ramapo. Each PJM Mid-Atlantic transmission owner pays to the NYISO its share of the carrying charges in proportion to their Transmission Revenue Requirements in effect at the time when such charges are incurred. NYISO then pays Consolidated Edison the total revenues for the Ramapo PAR.



Section 16: Financial Transmission Rights Auctions Settlement

Welcome to the *Financial Transmission Rights Auctions Settlement* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- An overview of the Financial Transmission Rights (FTR) Auctions settlement (see “*FTR Auctions Settlement Overview*”).
- How charges for FTR Auction transactions are calculated for FTR Auction buyers (see “*FTR Auction Buyers’ Charges*”).
- How credits for FTR Auction transactions are calculated for FTR Auction sellers (see “*FTR Auction Sellers’ Credits*”).
- How FTR Auction revenues are allocated (see “*Allocation of FTR Auction Revenues*”).

16.1 FTR Auctions Settlement Overview

Throughout the year, PJM oversees the process of selling and buying FTRs through FTR auctions. Market participants may purchase/sell FTRs by participating in the Long-term, Annual, and Monthly FTR auctions. The Long-term and Annual FTR auctions offer for sale the entire transmission entitlement that is available on the PJM system on a long-term basis. The Monthly FTR Auctions provide a method of auctioning the residual FTR capability that remains on the PJM Transmission System after the Annual auction is conducted. The Annual FTR auction is a multi-round auction consisting of four rounds. FTRs that are purchased in one round may be offered for sale in subsequent rounds of the Annual auction. The Monthly auctions allow FTR market participants an opportunity to offer for sale any FTRs that they currently hold and to buy the residual FTR capability that remains on the PJM Transmission System after the Annual auction is conducted. PJM conducts the monthly auctions once a month. FTRs can be in the form of an option or an obligation. For discussion purposes, FTR obligations and FTR options will be referred to as FTRs, unless otherwise noted. Each FTR acquired in the Annual FTR Auction entitles the holder to credits of Transmission Congestion Charges for one calendar year. Each FTR acquired in the monthly auctions entitles the holder to credits of Transmission Congestion Charges for one calendar month. Auction Revenue Rights (ARRs) are the mechanism by which the proceeds from the FTR auctions are allocated. An ARR holder may “self-schedule” an FTR obligation into the Annual FTR auction as a “price-taker” auction buy bid. The “self-scheduled” FTR must have exactly the same source and sink points as the ARR. This feature may only be used in Round 1 of the Annual FTR auction and must be for a 24-hour FTR obligation product.

PJM is responsible for administering the PJM FTR Auctions; including performing the following settlement functions:

- settlement of awarded auction FTRs
- allocation of FTR Auction revenues to ARR holders
- rendering bills to buyers and sellers



- receiving payments from and dispersing payments to buyers and sellers

The FTR Auctions also facilitate the trading of FTRs by PJM Members. Winning bidders pay market price for FTRs acquired in the auctions; FTR sellers are paid market price for the FTRs they surrender to PJM. The winning quotes are determined by the set of simultaneously feasible FTRs with the highest total auction value, as determined by the bids of the buyers and taking into account the reservation prices of the sellers. PJM will calculate the clearing prices for all FTR obligations at all buses, regardless of whether they are bought or sold in the auctions. PJM will calculate the clearing prices for all FTR options for all valid option paths, regardless of whether they are bought or sold in the auctions. All auction revenues, net of payments to entities selling FTRs into the auctions, are allocated among ARR holders. Additional details on the FTR Auctions can be found in the PJM Manual for **Financial Transmission Rights (M-06)**, Section, 5: FTR Auctions. Additional details on ARRs can be found in the PJM Manual for **Financial Transmission Rights (M-06)**, Section, 2: Auction Revenue Rights Overview.

16.2 FTR Auction Buyers' Charges

PJM Market buyers are charged for FTR Auction purchases based on the FTR awarded (in 0.1 MW increments) and the market clearing price. PJM calculates a market clearing price for each FTR based on the set of simultaneously feasible FTRs with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. The market clearing price for all FTRs is the difference between prices at specified pairs of receipt and delivery points as determined by the auctions. The market clearing price for an FTR obligation can be computed directly from the nodal clearing prices and can be a negative value. The market clearing price for an FTR option is a function of the shadow price of each binding constraint and cannot be computed directly from nodal prices. The market clearing price of an FTR option can never be a negative value. The FTR Auction charge is the product of the Market Buyer's FTR purchase and the market clearing price.

PJM Actions:

- PJM prepares a list of FTR Auction buyers.
- PJM accounting process retrieves the following information:
 - each participant's daily FTR Auction purchases (MW)
 - each FTR market clearing price (\$/MW)
- PJM accounting process calculates the monthly FTR Auction charge for each FTR as follows:

*FTR Auction Charge = FTR Purchased (MW) * Market Clearing Price*

- PJM accounting process sums the FTR auction charges for each FTR Auction participant to calculate the participant's total monthly FTR Auction charge.



16.3 FTR Auction Sellers' Credits

PJM Market sellers are credited for FTR Auction sales based on the FTR awarded (in 0.1 MW increments) and the market clearing price. PJM calculates a market clearing price for each FTR based on the set of simultaneously feasible FTRs with the highest net total auction value as determined by the bids of buyers and taking into account the reservation prices of the sellers. The market clearing price for all FTRs is the difference between prices at specified pairs of receipt and delivery points as determined by the auctions. The market clearing price for an FTR obligation can be computed directly from the nodal clearing prices and can be a negative value. The market clearing price for an FTR option is a function of the shadow price of each binding constraint and cannot be computed directly from nodal prices. The market clearing price of an FTR option can never be a negative value. The FTR Auction credit is the product of the Market Seller's FTR sales and the market clearing price.

PJM Actions:

- PJM prepares a list of FTR Auction sellers.
- PJM accounting process retrieves the following information:
 - each participant's FTR Auction sales (MW)
 - each FTR market clearing price (\$/MW)
- PJM accounting process calculates the monthly FTR Auction credit for each FTR as follows:

*FTR Auction Credit = FTR Sold (MW) * Market Clearing Price*

- PJM accounting process sums the FTR auction credits for each FTR Auction participant to calculate the participant's total monthly FTR Auction credit.

16.4 Allocation of FTR Auction Revenues

All auction revenues, net of payments to entities selling FTRs into the auctions, are allocated among ARR holders as ARR credits. The amount of credit that each ARR holder should receive is based on the economic value or Target Allocation of the ARR. ARR Target Allocations will be based on the FTR obligation clearing prices from each round of the Annual FTR auction. The ARR Target Allocation can be positive or negative and as such, an ARR can be either a financial benefit or a liability to the holder.

PJM Actions:

- PJM prepares a list of ARR holders.
- PJM accounting process retrieves the following information:
 - ARR Target Allocation LMP based on the nodal clearing prices for each round of the Annual FTR auction
- PJM accounting process calculates the FTR auction allocation of revenue credits to ARR holders as follows:



$ARR \text{ Target Allocation} = (ARR \text{ MW/\# of rounds}) * (LMP_{\text{Delivery}} - LMP_{\text{Receipt}})$

- PJM accounting process allocates the FTR auction allocation of revenue credits to ARR holders for a month as follows:
 - Each day, the total of all daily ARR Target Allocations are compared to the total net revenues of the applicable Monthly FTR auction (divided by the number of days in the month) plus the total net revenues of the Annual FTR auction (divided by the number of days in planning period).
 - If sufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations then total ARR credits equal total ARR Target Allocations.
 - If excess Annual and Monthly FTR Auction revenues remain after this allocation, or if no deficiencies exist, all remaining FTR auction revenue is treated as excess congestion charges and is distributed starting with Stage One as described in the “Distributing Excess Transmission Congestion Charges” Section of Section 7 Transmission Congestion Accounting in the **PJM Manual for Operating Agreement Accounting**.
 - If insufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations then ARR credits are pro-rated in proportion to ARR Target Allocations which have a positive Target Allocation value. ARRs which have a negative Target Allocation value are assigned the full Target Allocation value as a negative ARR credit. If the ARR credits are pro-rated, the difference between ARR Target Allocations and ARR credits are called ARR deficiencies. The ARR deficiencies may be funded by Annual Excess Congestion Charges starting with Stage Four as explained in the “Distributing Excess Transmission Congestion Charges” Section of Section 7 Transmission Congestion Accounting in the **PJM Manual for Operating Agreement Accounting**.



Section 17: Auction Revenue Rights Settlements

Welcome to the *Auction Revenue Rights Settlements* section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- An overview of the Auction Revenue Rights (ARR) settlements (see “*ARR Settlements Overview*”).
- How daily Reassignment of ARR occurs as load changes within a zone within the planning period (see “*Daily Reassignment of ARR as load changes*”).
- How Annual and Monthly FTR Auction revenues are allocated (see “*Allocation of Annual and Monthly FTR Auction Revenues*”).

17.1 ARR Settlements Overview

Auction Revenue Rights are financial entitlements allocated annually to PJM Network Integration and Firm Point-to-Point Transmission Service customers that entitle the holder to receive an allocation of the net revenues from the PJM Annual and Monthly FTR Auctions. ARR can be acquired by three mechanisms: 1) Annual ARR allocation where ARR requested by customers are allocated on an annual basis; 2) Daily reassignment of ARR whereby ARR that were allocated for the planning period will be reassigned on a proportional basis within a zone as load shifts between LSEs within the planning period; and 3) Firm Point-to-Point Transmission Service customers have the option to request ARR consistent with their transmission reservation. Firm Point-to-Point Transmission Service ARR requests will have the same duration as the transmission service, which may be one year, one month, one week or one day.

Network Integration Transmission Service ARR are requested via PJM eCapacity. Firm Point-to-Point Transmission Service ARR are requested via OASIS. ARR awarded must be simultaneously feasible to ensure that Annual and Monthly FTR Auction revenues are adequate to cover the economic value of all ARR.

Each holder of an ARR will be entitled to revenues from the Annual and Monthly FTR Auctions based on the economic value of the ARR. The ARR economic value or ARR Target Allocation is equal to the ARR MW amount divided by the number of rounds in the Annual FTR Auction times the price difference from the ARR sink point to the ARR source point. The LMP values used in the above calculation for settlements for annual ARR will be based on the nodal clearing prices for FTR obligations from each round of the Annual FTR auction.

The ARR Target Allocation can be a benefit or a liability. The hourly economic value of an ARR is positive (a benefit) when the nodal LMP at the sink point (point of delivery) is higher than the nodal LMP at the source point (point of receipt). The hourly economic value of an ARR is negative (a liability) when the nodal LMP at the source point (point of receipt) is higher than the nodal LMP at the sink point (point of delivery).

Transmission customers with negative ARR Target Allocations will always receive 100% of their ARR Target Allocations as negative ARR Credits. The inclusion of these negative credits effectively increases the amount that is available to be allocated as credits to the transmission customers with positive ARR Target Allocations.



If sufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations, then total ARR credits equal total ARR Target Allocations. If insufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations, then ARR credits are pro-rated in proportion to ARR Target Allocations which have a positive Target Allocation value. ARRs which have a negative Target Allocation value are assigned the full Target Allocation value as a negative ARR credit. If the ARR credits are pro-rated, the difference between ARR Target Allocations and ARR credits are called ARR deficiencies. Settlements for the Annual and Monthly FTR Auctions and the corresponding ARRs will be performed on a monthly basis.

Within the planning period, as load changes from one LSE to another within a transmission zone, a proportionate share of the ARRs defined to sink into that zone are reassigned from the old LSE to the new LSE. The reassignment of ARRs is an automatic process that is conducted on a daily basis. ARRs are only reassigned from those LSEs that have lost load in a zone and have a net positive economic ARR position in that zone. An LSE that loses load will lose ARR MWs in proportion to the amount of load lost and this same proportion will reduce each individual ARR assigned to the LSE.

Each holder of an annual ARR can convert the ARR into an FTR by “self-scheduling” the FTR into the first round of the Annual FTR auction on the exact same path as the ARR or the holder may retain the allocated ARR and receive the associated allocation of revenues from the Annual and Monthly FTR auctions.

PJM is responsible for performing the following settlement functions:

- settlement of awarded ARRs
- reassignment of ARRs
- allocation of Annual FTR Auction revenues
- allocation of Monthly FTR Auction revenues
- rendering bills to buyers and sellers
- receiving payments from and dispersing payments to buyers and sellers

17.2 Daily Reassignment of ARRs as load changes

Within the planning period, as load changes from one LSE to another within a transmission zone, a proportionate share of the ARRs defined to sink into that zone are reassigned from the old LSE to the new LSE. The reassignment of ARRs is an automatic process that is conducted on a daily basis. ARRs are only reassigned from those LSEs that have lost load in a zone and have a net positive economic ARR position in that zone. An LSE that loses load will lose ARR MWs in proportion to the amount of load lost and this same proportion will reduce each individual ARR assigned to the LSE.

PJM Actions:

On a daily basis, ARRs are reassigned using the following procedure:

- PJM compares each LSEs Network Service Peak Load in a zone to the Network Service Peak Load of the previous day.



- For each LSE losing load and having a net positive economic ARR position for that zone, the percentage of load lost for each LSE is determined. Each ARR, owned by the LSE losing load and having a net positive economic ARR position, is reduced by the percentage of load lost.
- PJM assigns that total set of forfeited ARRs to LSEs gaining load in the zone based on a percentage of the MW load gain divided by the total MWs of load shifting in the zone.

17.3 Allocation of Annual and Monthly FTR Auction Revenues

All Annual and Monthly FTR auction revenues are allocated to holders of ARRs on a proportional basis as ARR credits.

PJM Actions:

- PJM prepares a list of ARR holders.
- PJM accounting process retrieves the following information:
 - ARR target allocation LMP based on the nodal clearing prices for each round of the Annual FTR auction
- PJM accounting process calculates the FTR auction allocation of revenue credits to ARR holders as follows:

$$ARR \text{ Target Allocation} = (ARR \text{ MW} / \# \text{ of rounds}) * (LMP_{\text{Delivery}} - LMP_{\text{Receipt}})$$

- PJM accounting process allocates the net FTR auction allocation of revenue credits to ARR holders for a month as follows:
 - Each day, the total of all daily ARR Target Allocations are compared to the total net revenues of the applicable Monthly FTR auction (divided by the number of days in the month) plus the total net revenues of the Annual FTR auction (divided by the number of days in planning period).
 - If sufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations then total ARR credits equal total ARR Target Allocations.
 - If excess Annual and Monthly FTR Auction revenues remain after this allocation, all remaining FTR auction revenue is treated as excess congestion credits and is distributed starting with Stage One as described in the “Monthly Allocation of Excess Congestion Charges” Section of Section 8 Transmission Congestion Accounting in the **PJM Manual for Operating Agreement Accounting**.
 - If insufficient Annual and Monthly FTR Auction revenues are collected to satisfy ARR Target Allocations then ARR credits are pro-rated in proportion to ARR Target Allocations which have a positive Target Allocation value. ARRs which have a negative Target Allocation value are assigned the full Target Allocation value as a negative ARR credit. If the ARR credits are pro-rated, the difference



between ARR Target Allocations and ARR credits is called ARR deficiencies. The ARR deficiencies may be funded by Annual Excess Congestion Charges starting with Stage Four as explained in the “Monthly Allocation of Excess Congestion Charges” Section of Section 8 Transmission Congestion Accounting in the **PJM Manual for Operating Agreement Accounting**.



Section 18: Inadvertent Interchange Accounting

Welcome to the *Billing* section of the *PJM Manual for Operating Agreement Accounting*. In this section, you will find the following information:

- A description of the accounting procedures for determining PJM inadvertent interchange charge allocations (see “*Inadvertent Interchange Billing*”).

18.1 Inadvertent Interchange Billing

- Inadvertent Interchange is the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour. This MWh quantity may be a positive or negative value in any given hour and is priced at the PJM load weighted-average LMP for the hour. The value of this energy is allocated to all market participants based on real-time load (excluding losses) ratio shares in the PJM Region. This results in positive or negative Inadvertent Energy charges for each hour.

PJM Actions:

- PJM calculates the hourly inadvertent interchange MWh
- PJM calculates the hourly load weighted-average real-time LMP for the PJM RTO
- PJM calculates the hourly value of inadvertent interchange by multiplying the inadvertent interchange MWh by the PJM load weighted-average LMP
- PJM allocates PJM Inadvertent Interchange charges (+/-) to all PJM market participants in proportion to their hourly real-time load (excluding losses) ratio share
- Reconciliation for Inadvertent Interchange Charges
- PJM will calculate reconciled Inadvertent Interchange charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule (in MWh) and the “actual” usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.
- PJM calculates the Inadvertent Interchange charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the PJM system-wide system energy price (in \$/MWh) for that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Inadvertent Interchange charges for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.



Section 19: Day Ahead Scheduling Reserve Accounting

Welcome to the *Day-ahead Scheduling Reserve Accounting* section of the **PJM Manual for Operating Agreement Accounting**. In this section, you will find the following information:

- A description of how Day-ahead Scheduling Reserves are provided and accounted for in the PJM Energy Markets (see “*Day-ahead Scheduling Reserve Accounting Overview*”).
- How credits are calculated for providers of Day-ahead Scheduling Reserve (see “*Credits for Day-ahead Scheduling Reserve*”).
- How the total cost of Day-ahead Scheduling Reserve is allocated (see “*Charges for Day-ahead Scheduling Reserve*”).
- How Day-ahead Scheduling Reserve charge reconciliations are calculated (see “*Reconciliation for Day-ahead Scheduling Reserve Charges*”).

19.1 Day Ahead Scheduling Reserve Accounting Overview

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.

Operational conditions may occur that result in PJM increasing the Day-ahead Scheduling Reserve requirement on an hourly basis, as specified in section 11.2.1 of Manual 11: Energy and Ancillary Service Operations.

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.

19.2 Credits for Day Ahead Scheduling Reserve

At the end of each hour, PJM calculates the credits due each customer account for Day-ahead Scheduling Reserve.



PJM Actions:

- PJM retrieves the following information:
 - Day-ahead scheduled minimum and scheduled economic maximum for each resource
 - Real-time economic minimum and economic maximum for each resource
 - Real-time availability for each resource
 - Resource offer data – startup time and notification time (including real-time hourly updates)
 - Real-time generation MWh and demand resource MWh
 - Day-ahead Scheduling Reserve award quantity for each resource(MW)
 - Day-ahead Scheduling Reserve clearing price (\$/MWh)
 - Day-ahead Scheduling Reserve offer price for each resource (\$/MWh)
 - Day-ahead Scheduling Reserve bilateral transactions
 - Day-ahead Scheduling Reserve opportunity cost for each resource
- PJM determines the eligibility to receive Day-ahead Scheduling Reserve credits as follows:
 - For resources with a start time plus notification time of greater than 30 minutes, the resource is required to be online and operating at PJM's direction during the hour of the award with a real-time dispatchable range (Economic Max – Economic Min) at least as great as the day-ahead dispatchable range (Economic Max – Scheduled Min). A resource does not have a real-time dispatchable range if the real-time fixed gen flag is enabled for the hour of the award.
 - 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.
 - 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.

- Hydro resources are required to be available to the PJM operator for dispatch during the hours of the award.
- PJM calculates hourly Day-ahead Scheduling Reserve credits for each eligible generator and demand response resource as follows:

$$\text{Day-ahead Scheduling Reserve Credit} = \text{Day-ahead Cleared Day-ahead Scheduling Reserve (MW)} * \text{Day-ahead Scheduling Reserve Clearing Price \$/MW}$$

- PJM sums the Day-ahead Scheduling Reserve credits for each customer account, taking into account joint-ownership of generating units.
- If the resource's Day-ahead Scheduling Reserve offer price (plus opportunity costs, if applicable) is less than its Day-ahead Scheduling Reserve credit for that hour, the excess revenues received will offset any Balancing Operating Reserve credits received by that resource for that hour.

19.3 Charges for Day Ahead Scheduling Reserve

At the end of each hour, PJM calculates the charges due each customer account for Day-ahead Scheduling Reserve as follows:

- PJM calculates for each hour the Total Cost of Day-ahead Scheduling Reserve by summing the Day-ahead Scheduling Reserve credit for all customer accounts.
- PJM determines each load serving entity's (LSE's) hourly load ratio share based on their real-time load (excluding transmission losses).

$$\text{Load Ratio Share} = \text{Real-time Load (MWh)} / \text{Total PJM Real-time Load (MWh)}$$

- PJM calculates an hourly ratio share of the base Day-ahead Scheduling Reserve requirement and the additional requirement based on the total Day-ahead Scheduling Reserve requirement.

Base Requirement = the requirement defined in PJM Manual M-13, Section 2, plus any additional reserves scheduled to account for operational uncertainty

Additional Requirement = Max(Forecast RT load (MWh) – Adjusted Fixed Demand (MWh), 0) as defined in Manual 11, Section 11

$$\text{Base Requirement Share} = \text{Base Day-ahead Scheduling Reserve Requirement MW} / (\text{Base Day-ahead Scheduling Reserve Requirement MW} + \text{Additional Day-ahead Scheduling Reserve Requirement MW})$$

$$\text{Additional Requirement Share} = 1 - \text{Base Requirement Share}$$



- PJM calculates for each hour the Total Cost of the Base Day-ahead Scheduling Reserve and the Total Cost of the Additional Day-ahead Scheduling Reserve.

*Total Cost of Base Day-ahead Scheduling Reserve = Base Requirement Share * Total Cost of Day-Ahead Scheduling Reserve*

*Total Cost of Additional Day-ahead Scheduling Reserve = Additional Requirement Share * Total Cost of Day-Ahead Scheduling Reserve*

- PJM calculates each LSE's Base Day-ahead Scheduling Reserve obligation by multiplying their load ratio share by the total amount of Base Day-ahead Scheduling Reserve resource eligible MW.

Base Day-ahead Scheduling Reserve Obligation =

*Load Ratio Share * Total Base Day-ahead Scheduling Reserve Eligible MW*

*Total Base Day-ahead Scheduling Reserve Eligible MW = Total DASR Eligible MW * Base Requirement Share*

- PJM adjusts the Base Day-ahead Scheduling Reserve Obligations to reflect Day-ahead Scheduling Reserve bilateral transactions among participants.

Base Day-ahead Scheduling Reserve Adjusted Obligation =

Base Day-ahead Scheduling Reserve Obligation - Day-ahead Scheduling Reserve MW purchased + Day-ahead Scheduling Reserve MW sold

- PJM determines each customer account's hourly Base Day-ahead Scheduling Reserve Obligation ratio share based on their Day-ahead Scheduling Reserve Adjusted Obligation.

Base Day-ahead Scheduling Reserve Obligation ratio share =

Base Day-ahead Scheduling Reserve Adjusted Obligation / Total Base Day-ahead Scheduling Reserve Adjusted Obligation

- PJM calculates the hourly Base Day-ahead Scheduling Reserve charge for each customer account by multiplying their Base Day-ahead Scheduling Reserve Obligation ratio share by the Total Cost of Base Day-ahead Scheduling Reserve.

Base Day-ahead Scheduling Reserve Charge =

*Total Cost of Base Day-ahead Scheduling Reserve * Base Day-ahead Scheduling Reserve Obligation Ratio Share*

- For each customer account that is a net purchaser in Day-ahead, PJM calculates the hourly difference between their Day-ahead cleared demand MWh net of cleared increment and decrement transactions and their actual Real-time load MWh including the impact of load reconciliation MWh where the Day-ahead demand net of cleared increment and decrement transactions is less than the actual Real-time load.

Demand Difference (MWh) = Max (Real-time load MWh including the impact of load reconciliation MWh – Max(Day-ahead fixed demand MWh + cleared price sensitive demand MWh + cleared decrement MWh – cleared increment MWh), 0, 0)



- PJM calculates the Total Hourly Demand Difference by summing up the Demand Difference for all customer accounts.
- If the Total Hourly Demand Difference is equal to zero, then the Total Cost of Additional Day-ahead Scheduling Reserve for that hour is added to the Total Cost of Base Day-ahead Scheduling Reserve and allocated as a Base Day-ahead Scheduling Reserve Charge.
- PJM determines each customer account's ratio share of the Total Hourly Demand Difference.

Ratio Share of Demand Difference =

Demand Difference (MWh) / Total Hourly Demand Difference (MWh)

- PJM calculates the hourly Additional Day-ahead Scheduling Reserve charge for each customer account by multiplying their Ratio Share of Demand Difference by the Total Cost of Additional Day-ahead Scheduling Reserve.

Additional Day-ahead Scheduling Reserve Charge =

*Total Cost of Additional Day-ahead Scheduling Reserve * Ratio Share of Demand Difference*

19.4 Reconciliation for Day-ahead Scheduling Reserve Charges

PJM will calculate reconciled Day-ahead Scheduling Reserve charges for EDCs and Retail Load Aggregators (a.k.a. Electric Generation Suppliers) for past monthly billings on a two month lag that were based on load ratio shares. The reconciliation kWh data must be supplied to PJM by the EDCs no later than the last day of the billing month that is two months after the original billing month. For example, all reconciliation data for January must be submitted by March 31 at 23:59. The reconciliation kWh data represents the difference between the scheduled Retail Load Responsibility or Wholesale Load Responsibility InSchedule and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable InSchedule contract.

PJM calculates the Day-ahead Scheduling Reserve charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Day-ahead Scheduling Reserve billing determinant for that hour. The hourly Base Day-ahead Scheduling Reserve charge billing determinant (in \$/MWh) is calculated by dividing the total hourly Base Day-ahead Scheduling Reserve charges by the total real-time PJM load (de-rated for transmission losses) for in that hour. These charge reconciliations are then totaled for the month for each EDC or Retail Load Aggregator. Note that the reconciliation for Base Day-ahead Scheduling Reserve charges for a month may be either a positive or a negative value, and may even be such that the reconciled load responsibility MWh results in a negative load quantity.



Section 20: Billing

Welcome to the *Billing* section of the ***PJM Manual for Operating Agreement Accounting***. In this section, you will find the following information:

- A summary of the billing process for the PJM Operating Agreement Accounting (see “*Billing Process Overview*”).

20.1 Billing Process Overview

A single billing statement is issued by PJM monthly to each PJM customer account, detailing all charges and credits for the month that applies to that customer under the PJM Operating Agreement and the PJM Open Access Transmission Tariff. The billing statement presents a net amount due from the customer or due to the customer. Weekly billing statements are also issued for certain line items. The ***PJM Manual for Billing (M-29)*** describes the billing process in detail.

The Operating Agreement related billing statement line items that are described in this manual are as follows:

- Day-ahead and Balancing Spot Market Energy (charges)
- Synchronized Reserve (charges/credits)
- Non-Synchronized Reserve (charges/credits)
- Day-ahead Scheduling Reserve (charges/credits)
- Regulation (charges/credits)
- Transmission Congestion (day-ahead and balancing charges/credits)
- Transmission Losses (day-ahead and balancing charges/credits)
- Day-ahead and Balancing Operating Reserve (charges/credits)
- Synchronous Condensing (charges/credits)
- Reactive Services (charges/credits)
- Emergency Energy (charges/credits)
- Meter Correction (charges)
- Inadvertent Interchange (charges)
- Unscheduled Transmission Service (charges)
- Ramapo PAR Facilities (charges/credits)
- RPM-related (charges/credits)
- Financial Transmission Rights Auction (charges/credits)
- Auction Revenue Rights (credits)
- Reconciliation for Spot Market Energy (charges)



- Reconciliation for Transmission Congestion (charges)
- Reconciliation for Transmission Losses (charges/credits)
- Reconciliation for Regulation (charges)
- Reconciliation for Synchronized Reserve (charges)
- Reconciliation for Non-Synchronized Reserve (charges)
- Reconciliation for Inadvertent Interchange (charges)
- Reconciliation for Day-ahead Scheduling Reserve (charges)

The ***PJM Manual for Open Access Transmission Tariff Accounting (M-27)*** describes the Tariff-related line items of the billing statement in detail.



Revision History

Revision 75 (11/18/2016):

- Updated Section 3.5 to provide a description of a fully metered EDC.

Revision 74 (07/01/2016):

- Cover to Cover Periodic review clarifying changes to better describe existing rules and processes.

Revision 73 (03/31/2016):

- Revision to Section 5.2.4 and 5.3 effective 03/31/16 to provide clarification language and establish consistency with M-11 and M-15 regarding cancellation fees.

Revision 72 (12/17/2015):

- Revision to Section 5.2.1 effective 12/14/2015 for offer cap language conforming to changes related to FERC Docket No. ER16-76-000.

Revision 71 (06/01/2015):

- Effective 6/1/2015, changes to section 5 to include the impact of load reconciliation MWh in the settlement of balancing operating reserve deviation charges and section 12 to include the extension for submitting monthly meter error corrections.

Revision 70 (04/01/2015):

- Added revisions to section 19 to account for additional day-ahead scheduling reserves scheduled in response to hot or cold weather alerts or escalating emergency conditions

Revision 69 (04/01/2015):

- Removal of revisions to section 5.2.1 Credits for Pool-Scheduled Generating Resources effective 01/16/2015 – 03/31/2015 offer cap language conforming change related to Docket No. EL15-31-000.
- Administrative change updated references from eSchedule to InSchedule.

Revision 68 (01/16/2015):

- Revisions to section 5.2.1 Credits for Pool-Scheduled Generating Resources effective 01/16/2015 – 03/31/2015 offer cap language conforming change related to Docket No. EL15-31-000.

Revision 67 (01/01/2015):



- Effective 1/1/2015, changes to Sections 10 and 11 to include the impact of load reconciliation MWh in the settlement of Emergency Energy and Emergency Load Response.

Revision 66 (10/30/2014):

- Effective 10/30/2014, changes to Section 6 to compensate resources based on tier 1 estimates only when those resources can be relied upon to provide Tier 1 Synchronized Reserve per the rules in Manual 11.

Revision 65 (04/24/2014):

- Effective, 4/24/2014 changes to Section 6 to incorporate the Manual 11 aggregate response business rule for the purpose of calculating Synchronized Reserve Market retroactive penalty charges.
- Effective 5/29/2014, revisions resulting from the Settlements Formulation Review project and other clean-up items.
- Regulation Credits (Sections 4.2) – Inclusion of regulation set point definition, percentage of hour calculation, and descriptions of regulation shoulder hour calculation scenarios.
- Operating Reserve Credits (Section 5.2) – Clarified eligibility rules for resources that trip or fail to start and added reference to Manual 14D notification procedures. Clarified balancing value calculation when units operate at a lower value in Real-time than their Day-ahead commitment.
- Load Response Accounting (Section 11) – Added definition of Actual MWh relief and corrected units.
- Day-ahead Scheduling Reserve Accounting (Section 19) – clarified that resources do not have a dispatchable range if the real-time fixed gen flag is enabled during the hour of the DASR award.
- Effective 6/1/2014, unless otherwise approved by FERC based on PJM compliance filing regarding the ER14-822 proceeding (improve DR resource operational flexibility). Updated Section 11 for the inclusion of Pre-Emergency DR in the Emergency DR settlements.

Revision 64 (04/11/2014):

- Two of the eSuite Applications have been renamed. Moving forward EES will be known as ExSchedule and eMTR will be known as Power Meter.

Revision 63 (12/19/2013):

- Conforming changes to Section 6 describing how penalties are assessed to a resource that fails to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide when a synchronized event occurs as well as the allocation of these penalties. These changes are effective 1/1/2014 per Docket #ER13-297.



- Conforming changes to Section 5 per Docket #ER13-2413 clarifying the requirements that must be satisfied in order for wind resources to be eligible to receive lost opportunity cost credits, effective 11/19/2013.

Revision 62 (10/01/2012):

- Conforming changes to Section 4 outlining settlements for Performance Based Regulation Credits and Charges per Docket #ER12-1204. Specifically, the credit changes include removal of the Marginal Benefits Factor for Regulation Capability Credit and Regulation Performance Credit and the application of the Mileage Ratio Multiplier for Regulation Performance Credit. Changes for the charge include specifics around the regulation obligation. Please note per the FERC Order these changes are retroactively effective to the Performance Based Regulation implementation date of October 1, 2012.

Revision 61 (08/29/2013):

- Section 5.2.6 and Section 5.2.8: Effective 6/1/2013, conforming changes to incorporate changes to limit lost opportunity cost compensation to the lesser of a unit's economic maximum or maximum facility output as approved by FERC in Docket ER13-1200.
- Section 7.2: Incorporation of Non-Synchronized Reserve Lost Opportunity Cost calculation details (shortage pricing clean-up), effective 10/1/2012
- Section 5.3: Clarifying revisions on exempting deviations during shortage conditions and revisions for associating interfaces to the East or West BOR regions.
- Section 5.2.3: Incorporated Lost Opportunity Cost Credit for Synchronous Condensing details
- Section 5.2.6: Wind Lost Opportunity Cost: clarified language to align with Tariff language

Revision 60 (06/01/2013):

- Section 5.3: Added EKPC to Western Region BOR
- Sections 3, 8, 9, and 11: 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.

Revision 59 (04/22/2013):

Effective 4/22/2013:

- Changes to Section 2.1 required due to the elimination of the internal source and sink for Transmission Service products. Changes approved at 2/28/2013 MRC meeting.



- Incorporated changes to Section 13.1 endorsed at the 04/21/2010 MRC meeting but not included in subsequent manual versions. The approved change was to clarify Energy Storage Resources are Market Sellers excluded from the definition of Station Power.

Revision 58 (03/28/2013):

Effective 12/01/2012:

- Changes to Section 5 outlining the allocation of Day-ahead Operating Reserve Credits for resources scheduled to provide Reactive Services or transfer interface control per Docket #ER13-418.

Effective 01/15/2013:

- Changes to Section 8 and Section 14 incorporating revenues paid to or received from NYISO for JOA market-to-market congestion relief measures to the total transmission congestion charges allocated to FTR holders.

Effective 03/28/2013:

- Clean-up per settlements formulation review – Added footnote stating that diesel units types are treated liked CTs based on their similar operating characteristics.

Revision 57 (12/01/2012):

- Changes to Section 5 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
- **UPDATED 02/19/2013** – Restored portions of Section 11 that were endorsed as part of Revision 55 that had been mistakenly deleted from subsequent revisions.

Revision 56 (10/01/2012):

Conforming changes to incorporate rules for Shortage Pricing as approved by FERC in Docket (s) ER09-1063, ER12-2262, and ER12-2385, effective 10/1/2012. Conforming revisions made to sections 5 & 6. An additional section created, Section 7 – Non-Synchronized Reserve Accounting, to incorporate new rules. Revisions endorsed by Markets & Reliability Committee on 10/25/2012.

Revision 55 (10/01/2012):

Conforming tariff changes for Order 745 (ER11-4106-000), and elimination of economic DR energy compensation under Net Benefits Test threshold (ER12-1705-000) as follows:

- Section 5.1 (added note to include dispatchable resources and section 5.2, added new bullet that operating reserve credits are calculated for DR that follows dispatch signal
- Section 10.3 – includes all the new and prior rules for economic DR compensation in energy market, and associated changes for cost allocation.



Revision 54 (10/01/2012):

Based on the 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 4.1 – Regulation Accounting Overview added detail about two-part regulation settlement for capability and performance including the use of the marginal benefit factor and actual hourly performance score.
- Section 4.2 – Regulation Credits added detail about two-part regulation credit for capability and performance including the use of the marginal benefit factor and actual hourly performance score. Also added information about hydro lost opportunity cost calculation and after the fact lost opportunity cost.
- Section 4.3 – Regulation Charges added detail about two-part regulation settlement for capability and performance and regulation obligation for load.

Revision 53 (07/26/2012):

- Updated Section 3.5, 3.7, 4.4, 5.4, 6.4, 7.3, 8.3, 8.5, 11.1, 18.1, and 19.4 to reflect clarifications as recommended by the PJM Net Energy Metering Senior Task Force (NEMSTF).

Revision 52 (06/01/2012):

- Updated Section 5.2.6 to incorporate lost opportunity cost credit details for wind units per FERC Docket #ER12-1422.

Revision 51 (04/03/2012):

- Updated Section 6.1 to clarify that DR resources are compensated for shutdown costs via Operating Reserve credits.
- Updated Section 5.2.1 to clarify the applicability of 3.2.3(f-1) of the Tariff.

Revision 50 (01/01/2012):

- Updates to reflect integration of the DEOK zone

Revision 49 (09/15/2011):

- Section 2 Locational Marginal Pricing: Renamed Section 2 Interface Pricing and incorporated settlements interface pricing information. The Locational Marginal Pricing details were moved to Manual 11 in a previously approved revision.
- Section 4.2 Regulation Credits: Added details on the regulation tolerance amounts used in the calculation of regulation lost opportunity cost credits.
- Section 5.2.1 Credits for Pool-Scheduled Generating Resources: Clarified details on credits when PJM declares a Maximum Generation Emergency or a Maximum Generation Emergency Alert.



- Section 5.2.8 Credits for Resource Providing Reactive Services: Description of reactive credits for synchronous condensers corrected for consistency with the Tariff (Attachment K – Appendix Section 3.2.3B(i)).
- Section 7 Transmission Congestion Accounting – Replaced Total PJM Congestion Charges with Total Transmission Congestion Charges for consistency with Tariff terminology (Attachment K – Appendix Section 5.1.7). Clarified negative target allocations are hourly and based on net quantities.
- Section 7.4.4 Monthly Allocation of Excess Congestion Charges – Added details on the end of Planning Period ARR and FTR transmission rights uplift charges for completeness. This information was previously only documented in Manual 6 – Financial Transmission Rights.

Revision 48 (06/01/2011):

- Updates to reflect integration of ATSI zone

Revision 47 (04/01/2011)

- Correct adjusted obligation formulae in Sections 4 (Regulation) and 19 (Day-ahead Scheduling Reserve).

Revision 46 (10/01/2010)

- Revisions in Section 8, Transmission Losses Accounting, to exclude up-to congestion transaction MWh and to include a reduced amount of non-firm export MWh from the transmission loss credit allocation per FERC Order ER10-2280 effective September 17, 2010.
- Revisions in Section 12, Station Power Accounting, to exclude compressed air energy resources from the station power definition.

Revision 45 (06/23/2010)

- Revisions resulting from 2010 PJM review approved at June 16, 2010 MRC meeting.
- Revisions in Section 10, PJM Load Response Programs Accounting, for economic load response and Real-time index based contracts approved at June 16, 2010 MRC meeting.

Revision 44 (02/01/2010)

- Revised Meter Reconciliation Accounting section to reflect the changes to the Meter Correction Allocation as approved by FERC (Docket No. ER10-320).

Revision 43 (01/20/2010)

- Revised Transmission Losses Accounting section to reflect the changes to the distribution of Transmission Loss Charges as retroactively approved by FERC (EL08-14)



- Added clarifying item in the Operating Reserve Accounting section related to the Day-ahead pumped storage optimization program

Revision 42 (07/31/2009)

- Revised Operating Reserve Accounting section to reflect Balancing Operating Reserve construct change as approved by FERC (ER08-1569)
- Add several new load reconciliation charge descriptions that were recently implemented.
- Revised Regulation Accounting section 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 as approved by FERC (ER09-789)

Revision 41 (11/01/2008)

- Cleaned up to better align with new settlement system

Revision 40 (6/1/2008)

- Section 7: Revised to reflect new allocation method for any end-of-planning period excess congestion revenues

Revision 39 (1/01/2008)

- Added business rules for InSchedule and Power Meter Data Submissions

Revision 38 (06/01/2007)

- Revisions were made to reflect the implementation of Marginal Losses and for general clean-up.

Revision 37 (03/07/2007)

- Section 2: Revised to add a section titled "Calculation of Real-Time Locational Marginal Price"

Revision 36 (01/01/2007)

- Section 5: Clarified the hourly Operating Reserve deviation charge eligibility for generators not following PJM dispatch signals.
- Introduction trimmed to eliminate redundant information.
- List of PJM Manuals exhibit removed, with directions given to PJM Web site where all the manuals can be found.
- Revision History permanently moved to the end of the manual

Revision 35 (09/26/06)

- Section 4: Clarified the generator energy offer data used by PJM for Regulation lost opportunity cost credit calculations.



- Section 5: Clarified the hourly Operating Reserve credit eligibility for when a generator trips.

Revision 34 (08/28/06)

- Exhibit 1: Updated to include the new Manual 30: Alternative Collateral Program.
- Section 5: Modified rules to clarify the determination of a resource's hourly Desired MWh and no-load compensation values.
- Section 10: Modified section for revised rules for Demand Response Participation.

Revision 33 (05/01/06)

- Change to Section 4: Regulation Accounting. Add demand side response regulation charges and credits.
- Change to Section 6: Spinning Reserve Accounting. Rename spinning reserve market to synchronized reserve market and add demand side response synchronized reserve charges and credits.
- Revisions were also made to globally change "spinning" to "synchronized."

Revision 32 (03/01/06)

- Change to Section 5: Operating Reserve Agreement Accounting, "Charges for Operating Reserves". Revised to remove requirement that self-scheduled generator deviation exemptions must be requested in writing.
 - Revisions were made on the following page: 44.

Revision 31 (11/01/05)

Cleanup changes to clarify the single Regulation market and to clarify Operating Reserves charges.

Revision 30 (08/01/05)

- Cleanup changes to clarify the single Regulation market and to clarify Operating Reserves charges.
- Changes to Section 5: Operating Reserve Agreement Accounting, "Credits for Pool-Scheduled Generating Resources". Revised to include clarification on the elimination of credits during Maximum Emergency operating days.
- Changes to Section 5: Operating Reserve Agreement Accounting, "Charges for Operating Reserves", Part 6. Revised to enable generating units that trip to retain Operating Reserve eligibility for period of time the unit was running for PJM.
- Changes to Section 5: Operating Reserve Agreement Accounting, "Credits for Pool Scheduled Generating Resources", Part 4a. Revised to exempt from Balancing Operating Reserve deviation charges, generators that are self-scheduled but have a dispatchable range when following PJM dispatch above minimum.



Revision 29 (05/20/05)

- Minor changes including mention of MISO JOA market-to-market revenues in Congestion Credit section and clarifications to Operating Reserves charge and credit calculations.

Revision 28 (05/05/05)

- Charges for Operating Reserves - revised part 4A.
- Meter Correction Billing – corrected meter error data submittal timeframe.

Revision 27 (10/01/04)

- Revised to reflect the integration of AEP/Dayton.

Revision 26 (05/01/04)

- Revised to reflect the integration of ComEd.

Revision 25 (04/23/04)

- Revised Section 5: Operating Reserves Accounting to include credits to generators that adjust active power output at PJM's direction for the purpose of maintaining reactive reliability (Reactive Services). Expanded and clarified provisions regarding lost opportunity cost compensation to generators that are reduced or suspended by PJM due to a transmission constraint or for other reliability purposes. Also clarified the provisions for exempting balancing operating reserves charges and for including energy use costs in synchronous condensing credits.
- Revised Section 7: Transmission Congestion Accounting to reflect the transitional Financial Transmission Rights (FTR) Allocation and FTR reassignment process that will be conducted for new zone load being added as a result of market growth.
- Revised Section 7: Transmission Congestion Accounting to adjust the allocation period for excess congestion revenues from a calendar year basis to a PJM planning period basis.

Revision 24 (07/01/03)

- Revised Section 5: Operating Reserves Accounting to reflect the credits for resources performing an annual scheduled Black Start test.
- Revised Section 7: Transmission Congestion Accounting Overview to reflect the updated allocation procedures for Transmission Congestion Credits.
- Revised Section 16: Financial Transmission Rights Auctions Settlement to reflect the PJM Annual and Monthly FTR Auctions settlement.
- Added Section 17: Auction Revenue Rights Settlements.

Revision 23 (02/01/03)



- Revised Section 11: Meter Reconciliation Accounting to reflect the updated meter error data submission requirement.

Revision 22 (12/01/02)

- Revised Section 5: Operating Reserves. Revision coincides with the inclusion of the Spinning Reserve Section.
- Added new Section 6: Spinning Reserve Accounting. All remaining sections re-numbered respectively.

Revision 21 (10/01/02)

- Added new Section 9: PJM Load Response Programs Accounting.
- All remaining sections re-numbered respectively.

Revision 20 (06/01/02)

- Revised to reflect the new Emergency Energy allocation procedures.
- Revision 19 (04/01/02)
- Revised to reflect the changes to incorporate the PJM West Region and Rockland Electric Company.

Revision 18 (07/01/01)

- Added new Section 10: Station Power Accounting.
- Renumbered Sections 10 through 14 to 11 through 15 respectively.

Revision 17 (06/01/01)

- Revised to reflect the implementation of the PJM Power Meter System.

Revision 16 (05/17/01)

- Revisions have been made to Section 6: Transmission Congestion Accounting. Revised to include additional detail to further clarify excess congestion allocation procedures.

Revision 15 (12/01/00)

- This revision contains the removal of Attachment A: Definitions and Abbreviations. Attachment A is being developed into a 'new' PJM Manual for **Definitions and Abbreviations (M-35)**.

Revision 14 (06/01/00)

- Section 5: Operating Reserves Accounting
- Revised subsection "Credits for Pool-Scheduled Generating Resources." Corrected to remove the description of a credit adjustment during Max Emergency conditions.



Revision 13 (06/01/00)

- All Sections updated to reflect Two Settlement implementation of a Day-Ahead Energy Market and the new Regulation Market.

Revision 12 (01/03/00)

- Section 5: Operating Reserves Accounting was updated to reflect a short run solution (effective 01/01/00) to correct for a market design flaw related to bidding constraints.

Revision 11 (09/23/99)

- Section 5: Operating Reserves Accounting was updated to reflect the FERC approval of the application of operating reserves charges on all export transactions and approval of the new opt out procedures (dynamic scheduling) for those that want to opt out of spot market backup.

Revision 10 (08/02/99)

- Section 2: Locational Marginal Price was expanded to include a new sub-section containing information on PJM's Locational Marginal Price verification procedure.

Revision 09 (06/01/99)

- Added new Section 13: Fixed Transmission Rights Auction Settlements
- Billing section re-numbered as Section 14

Revision 08 (04/01/99)

- Section 03: Spot Market Energy Accounting
 - Addition of Reconciliation Billing
- Section 4: Regulation Accounting
 - Addition of Reconciliation Billing
- Section 5: Operating Reserves Accounting
 - Addition of Reconciliation Billing and updated Market-based Pricing in the calculation of Operating Reserves credits
- Section 7: Transmission Losses Accounting
 - Addition of Reconciliation Billing

Revision 07 (01/01/99)

- Section 03: Spot Market Energy Accounting
 - 5% penalty for self-scheduled resources no longer in effect. Elimination of Non-Delivery Charges
- Section 12: Capacity Credit Market Accounting
 - New section which replaces Emergency Reliability Service Accounting



Revision 06 (12/07/98)

- Section 06: Transmission Congestion Accounting
 - Modifications were made to “Transmission Congestion Charges.” A note, explaining calculation of implicit congestion charges when a radial transmission limitation exists, was also added to “Transmission Congestion Charges.”

Revision 05 (10/13/98)

- Section 05: Operating Reserves Accounting
 - Modifications made to “Charges for Operating Reserves” reflecting all Market Participants having the opportunity to buy and sell power in the Spot Market on an hourly basis

Revision 04 (07/01/98)

- Section 01: Market Overview
 - Corrections made to “Market Accounting Overview.”
- Section 03: Spot Market Energy Accounting
 - Corrections made to “PJM Actions” of “Interchange Seller’s Credits.”
- Section 05: Operating Reserves Accounting
 - Corrections made to “PJM Actions” of “Credits for Canceled Pool-Scheduled Resources” under “Credits for Operating Reserves.”
 - Corrections made to “PJM Actions” of “Credits for Pool-Scheduled Aggregate Resources” under “Credits for Operating Reserves.”
 - Corrections made to “PJM Actions” of “Cost of Operating Reserves.”
 - Corrections made to “PJM Actions” of “Charges for Operating Reserves.”
 - Section 13: Billing
 - Corrections made to “Billing Process Overview.”

Revision 03 (06/15/98)

- Section 03: Spot Market Energy Accounting
 - Corrections made to Non-Delivery Charges formulas
- Section 08: Emergency Energy Accounting
 - Corrections made to Emergency Energy Purchases by PJM and Minimum Generation Emergency Purchases by PJM formulas

Revision 02 (05/01/98)



- All sections revised for change from “Market Clearing Price” to “Locational Marginal Price.”
- Deleted Attachments B, C, and D

Revision 01 (01/06/98)

- Section 4: Regulation Accounting
 - Added “(6) PJM calculates the Average Cost of Regulation dispatched by PJM from all Generating Market Buyers and Market Sellers supplying excess Regulation at the direction of PJM” under “Regulation Credits.”
 - Added “(7) If according to the Regulation log, PJM is deficient of its Control Area Regulation requirement for the hour, additional credits (Total PJM Regulation MW Deficiency * Average Cost of Regulation) are allocated to Market Buyers and Market Sellers based on their percentage of total Regulation supplied” under “Regulation Credits.”
 - Deleted “(2) PJM calculates the average cost of Regulation dispatched by PJM from all Generating Market Buyers and Market Sellers supplying excess Regulation at the direction of PJM” under “Regulation Charges.”
 - Added “(4) If according to the Regulation log, PJM is deficient of its Control Area Regulation requirement for the hour, additional charges for any remaining regulating deficiency (not satisfied by self-scheduled, allocated pool-scheduled, or allocated self-scheduled excess regulation) are assessed to Internal Market Buyers and Market Sellers, that are also Internal Market Buyers, at the Average Cost of Regulation” under “Regulation Charges.”

Revision 00 (09/02/97)

- This revision is the preliminary draft of the PJM Manual for Operating Agreement Accounting.