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 PJM Manual 11. 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 eSchedules and eMTR Data Submissions

Unilateral Corrections to eSchedules Load Responsibility Data

- For load responsibility eSchedules 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 eSchedules data submission deadline in order for them to accurately calculate load responsibilities for all other LSEs in their territory by the eSchedules deadline.

- These LSEs must submit their data two hours prior to the established PJM eSchedules 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 eSchedules data submission deadline as the official data to be used for settlements.
- Any discrepancies remaining after the eSchedules deadline may be resolved via the EDC load reconciliation data submissions.

Unilateral Corrections to eMTR 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 eMTR data prior to the PJM eSchedules data submission deadline in order for them to accurately calculate load responsibilities for all other LSEs in their territory by the eSchedules 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 eMTR data submission deadline as the official data to be used for settlements.
- Any discrepancies remaining after the eMTR 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 eSchedule transactions, and including any eSchedule transactions that were priced day-ahead) in which the customer account is involved.

3.4 Transmission Loss De-ration 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-ration factors are applied to the total EDC load and to individual LSE load responsibilities. In general, these loss de-ration 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-ration 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:

EDC total state-estimated Loss MWh / 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:

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

These EDC hourly loss de-ration factors are applied to the LSE load responsibility eSchedule 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:

Loss De-rated Load MWh = (1 – EDC Loss De-ration Factor) x eScheduled, 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 eMTR.

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 metered tie lines to PJM via eMTR and for which all generators within that EDC's territory report revenue meter data for their hourly net energy delivered via eMTR, the total 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 EDC's load buses calculated by the PJM State Estimator is then adjusted, in proportion to its share of the total load of that EDC, in order that the total amount of load across all of the EDC's load buses matches its total revenue meter calculated load.

3.6 Residual Metered EDC Load Determination

Load within a fully metered EDC's territory is assigned to non-metered entities by submitting hourly load data in the eSchedules system. Nodal priced load (e.g., municipals, co-ops, qualified retail access load) is defined as any hourly load eSchedule that is priced at an aggregate. The hourly nodal load amounts submitted in eSchedules are multiplied by the nodal fixed aggregates definitions to calculate the nodal priced load at each bus. Residual metered EDC load at each bus is defined as the bus load (adjusted revenue meter calculated load) less nodal priced load at each bus.

3.7 Residual Metered EDC Pricing Definitions

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

Residual metered EDC pricing is represented in the Day-ahead LMPs, Real-time LMPs, and FTR Credit Target Allocations as follows:

- Final hourly real-time residual metered EDC distribution factors are calculated using eSchedule submitted nodal MWs. Preliminary real-time residual metered EDC LMPs are not calculated.
- Day-ahead residual metered EDC distribution factors default to the final real-time distribution factors for the residual metered EDC 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 zones, the definition applies to all hours in the day.
- Residual metered EDC distribution factors for FTR Credit Target Allocations are fixed for the planning period (June 1st – May 31st). Consistent with physical zones, the residual metered EDC distributions for FTRs are initially determined using the hourly individual residual load bus contribution to the total residual load at the time of the PJM annual peak from the previous year. In cases where there are new nodal load requests pursuant to the nodal pricing rules in Manual 27, the initial residual metered EDC definition for FTRs 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 EDC distribution.

3.7.1 Residual Metered EDC Pricing Business Rules

- Once an EDC elects to switch load from physical zone to residual metered EDC pricing, there cannot be a combination of residual metered EDC and physical zone pricing for load within a zone. In cases where the fully metered EDC's territory differs from the physical zone and at least one fully metered EDC is using physical zone pricing, residual metered EDC pricing cannot be elected for other EDCs in the zone.
- The effective date for switching load from physical zone pricing to residual metered EDC pricing is June 1 of each year to coincide with the PJM planning year.

- Prior to switching load from physical zone pricing to residual metered EDC pricing, EDCs must confirm via a PJM form that all LSEs will be priced at the residual metered EDC and will continue to be priced at the residual metered EDC in the future. This form must be provided to PJM by January 15th or at least 30 days prior to the start of PJM's annual ARR/FTR allocation process, whichever is later. Implementation will be delayed one year to the following June 1 if all notifications and forms have not been received according to the business rules.
- Once a fully metered EDC has elected residual metered EDC pricing for load within its territory, physical zone pricing for load will no longer be available.

3.~~6~~ 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:

*Day-ahead Spot Market Energy Charge = (Day-ahead Net Interchange) **

(Day-ahead System Energy Price)

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

*Balancing Spot Market Energy Charge = (Real-time Net Interchange – Day-ahead Net Interchange) **
(Real-time System Energy Price)

3.~~7~~ 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 months' billings. The reconciliation kWh data must be supplied to PJM by the EDCs, and represents the difference between the scheduled Retail Load Responsibility eSchedules (in MWh) and the "actual" usage based on metered data. This hourly kWh data must be reported separately for each applicable eSchedules 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.