

## 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-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 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:

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

### 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 a fixed weighted 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 1<sup>st</sup> – May 31<sup>st</sup>). 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 15<sup>th</sup> 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.
- Fully metered EDCs with nodally priced load in their territory should immediately use residual metered EDC pricing upon implementation unless contractual obligations prevent them from doing so.

### **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:

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

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

*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.

## Section 7: Transmission Congestion Accounting

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*”).

### 7.1 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 PJM 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 remaining Congestion Credit Deficiencies (for ARRS and FTRs) remaining at the end of the planning period are satisfied by a reallocation of congestion credits that were provided in previous months of the planning period such that all months of the planning period are equal in their resulting deficiency percentages.
- 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.

## 7.2 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.

### 7.2.1 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 eMTR, if available)
  - hourly state estimator MWh for each generator bus (trued-up to match revenue meter data from eMTR, 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:

$$\text{Day-ahead withdrawal Charge} = \text{Day-ahead Demand MWh} * \text{Day-ahead Load Bus Congestion Price}$$

OR

$$\text{Decrement Transaction MWh} * \text{Day-ahead Congestion Price}$$

OR

$$\text{Day-ahead Sale Transaction MWh} * \text{Source Day-ahead Congestion Price}$$

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

$$\text{Day-ahead Injection Credit} = \text{Day-ahead Generation MWh} * \% \text{ Ownership} * \text{Day-ahead Gen Bus Congestion Price}$$

OR

$$\text{Increment Transaction MWh} * \text{Day-ahead Congestion Price}$$

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:

*Balancing Implicit Congestion Charge = 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.

## 7.2.2 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:

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

## **7.3 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 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 Transmission Congestion charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Real-time Congestion Price, or revised Real-time Congestion Price, at the aggregate sink bus associated with the eSchedules contract for that hour. Residual metered EDC aggregate distribution factors are updated based on nodal reconciliation kWh data. A revised Real-time Congestion Price for residual metered EDC aggregates is calculated using the updated distribution factors to determine the Transmission Congestion charge reconciliations.

For those eSchedules where the aggregate sink bus is a residual metered EDC aggregate, PJM calculates additional Transmission Congestion charge reconciliations by multiplying the scheduled Retail Load Responsibility eSchedules (in MWh) by the difference between the revised Real-time Congestion Price and the original Real-time Congestion Price. 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.

## Section 8: 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*”).

### 8.1 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.

## 8.2 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.

### 8.2.1 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 eMTR, if available)
  - hourly state estimator MWh for each generator bus (trued-up to match revenue meter data from eMTR, 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:

$$\text{Day-ahead withdrawal Charge} = \text{Day-ahead Demand MWh} * \text{Day-ahead Load Bus Loss Price}$$

OR

$$\text{Decrement Transaction MWh} * \text{Day-ahead Loss Price}$$

OR

$$\text{Day-ahead Sale Transaction MWh} * \text{Source Day-ahead Loss Price}$$

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

$$\text{Day-ahead Injection Credit} = \text{Day-ahead Generation MWh} * \% \text{ Ownership} * \text{Day-ahead Gen Bus Loss Price}$$

OR

$$\text{Increment Transaction MWh} * \text{Day-ahead Loss Price}$$

OR

$$\text{Day-ahead Purchase Transaction MWh} * \text{sink Day-ahead Loss Price}$$

- 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:

$$\text{Day-ahead Implicit Loss Charge} = \text{Day-ahead Net Loss Bill}$$

## 8.2.2 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:

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

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

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

## 8.3 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 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 Transmission Loss charge reconciliations by multiplying the kWh data (de-rated for transmission losses) by the Real-time Loss Price, or revised Real-time Loss Price, at the aggregate sink bus associated with the eSchedules contract for that hour. Residual metered EDC aggregate distribution factors are updated based on nodal reconciliation kWh data. A revised Real-time Loss Price for residual metered EDC

aggregates is calculated using the updated distribution factors to determine the Transmission Loss charge reconciliations.

For those eSchedules where the aggregate sink bus is a residual metered EDC aggregate, PJM calculates additional Transmission Loss charge reconciliations by multiplying the scheduled Retail Load Responsibility eSchedules (in MWh) by the difference between the revised Real-time Loss Price and the original Real-time Loss Price. 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.

## 8.4 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.

## 8.5 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 months' billings that were based on load ratio shares. 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 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.