Market Settlements
(MS-301)

Fall 2009
It is assumed the student is familiar with the following concepts:

- Locational Marginal Price and how it is calculated
- Financial Transmission Rights and FTR Auctions
- PJM Capacity markets
- PJM Regulation market
- PJM Synchronized Reserve market
- Transmission Service and Interchange scheduling
- PJM e-Tools and their operation

This course will **NOT** provide training in market rules or tools.
Disclaimer:

PJM has made all efforts possible to accurately document all information in this presentation. The information seen during this presentation does not supersede the PJM Operating Agreement or the PJM Tariff both of which can be found by accessing:


For additional detailed information on any of the topics discussed, please refer to the appropriate PJM manual which can be found by accessing:

• All materials contained within this presentation are from PJM training/development systems and are not representative of any particular members business philosophies and strategies nor should they be used to suggest or promote particular business philosophies or strategies.

• Examples, prices and reports are for demonstrative purposes and are not intended to be representative of actual market clearing prices and results, trading volumes, generation and load characteristics and business strategies.

• Before performing any type of business in PJM, members should adequately research PJM manuals, documents, agreements and website for detailed information.
• This training will be conducted in two primary segments:

  – Market Settlements Primer

  – MS-301
At the end of the training session it is anticipated that you will be able to:

• Understand the terminology used for Market Settlements
• Analyze the various components of a PJM Billing Statement and the supporting reports through a detailed line item walkthrough
• Understand the eligibility requirements and impacts of PJM Operating Reserves
• Describe the various sources for more detailed Settlements information
• Market Settlements Terminology
• Line Items on a PJM Billing Statement
  • Spot Market Energy
  • Congestion
  • Losses/Transmission Service
  • Ancillary Services
  • Miscellaneous
• Review
• Market Settlements Terminology
• Line Items on a PJM Billing Statement
  • Spot Market Energy
  • Marginal Losses
  • Congestion
  • Transmission Service
  • Ancillary Services
  • Miscellaneous
  • Review
Zero-Sum

Total PJM charges = Total PJM credits + PJM/FERC/OPSI/NERC/RFC Expenses

Terminology

- **Charge**
  - Payments or obligations to PJM from the Market Participant
- **Credit**
  - Payments or obligations from PJM to the Market Participant
Summary of Charges and Credits

CHARGES

Members Using a Service/Buying a Product

Charges may be “positive” or “negative”

PJM

CREDITS

Members Providing a Service/Selling a Product

Credits may be “positive” or “negative”

PJM Expenses
• **Load-ratio Share**
  
  - A Market Participant’s portion of a total obligation or charge based on their “load”
  
  - “Load” could be lossless load, load plus losses, or actual peak load
  
  - \( \frac{\text{(LSE load)}}{\text{(PJM Total Load)}} \)

  
  **PJM Total Load = 50,000 MW**

<table>
<thead>
<tr>
<th>LSE #1</th>
<th>LSE #2</th>
<th>LSE #3</th>
<th>LSE #4</th>
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<tbody>
<tr>
<td>Load = 5000</td>
<td>Load = 500</td>
<td>Load = 1000</td>
<td>Load = 3000</td>
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<tr>
<td>LRS = 10%</td>
<td>LRS = 1%</td>
<td>LRS = 2%</td>
<td>LRS = 6%</td>
</tr>
</tbody>
</table>

  **Total of Load Ratio Shares = 100%**
“Average LMP” vs. “Load-weighted Average LMP”

- Average LMP:
  \[
  \frac{($10 + $20)}{2} = $15
  \]

- Load Weighted Average LMP:
  
  - 200 MW x $10 = $2000
  - 5 MW x $20 = $100
  
  Total $ / Total MW = $2100/205 = $10.24

- Zonal Weighted Average LMPs are Load Weighted LMPs
• Zonal LMPs are Load-weighted LMPs
  • Correspond to PJM Transmission zones
• Hub LMPs use equal weighting at each bus included in the Hub
• Interface LMPs are dynamically weighted based on flow on each tie-line of the interface
  • More accurately reflects physical flow
• Aggregate LMPs can be generation or load weighted
  • Use fixed weightings for each bus
  • Can be requested by LSE or Generation owner
• Detailed definitions of Zones, Hubs, Interfaces and Aggregates can be found at:
Day-Ahead LMP Components

\[ \text{DALMP} = \text{DASEP} + \text{DACP} + \text{DALP} \]

DALMP = Day-ahead Locational Marginal Price

DASEP = Day-ahead System Energy Price
- Used to price Day-ahead Spot Market Interchange

DACP = Day-ahead Congestion Price
- Used to price Day-ahead Transmission Congestion

DALP = Day-ahead Loss Price
- Used to price Day-ahead Transmission Losses
Real-time LMP Components

RTLMP = RTSEP + RTCP + RTLP

RTLMP = Real-time Locational Marginal Price

RTSEP = Real-time System Energy Price
- Used to price Real-time Spot Market Interchange based on deviation from Day-ahead Spot Market Interchange

RTCP = Real-time Transmission Congestion Price
- Used to price Real-time Congestion based on deviation from Day-ahead values

RTLP = Real-time Transmission Loss Price
- Used to price Real-time Transmission Losses based on deviation from Day-ahead values
**Spot Market Interchange**

- A measure of the “imbalance” in a Market Participant’s resources and loads
- Defines a participant’s “Net Position” (i.e. buyer or seller) relative to the PJM Spot Energy Market
- Net Interchange = Load - Resources

**Positive Net Interchange** = Buyer From Spot Market

**Negative Net Interchange** = Seller To Spot Market

---

**Market Participant #1**

- **Load** = 400 MW
- **Export** = 50 MW
- **Import** = 300 MW
- **Resources**
  - Generator 1 = 100 MW
  - Generator 2 = 200 MW
  - 300 MW (Import)

**Load**

- 400 MW (Load w/out losses)
- 200 MW (Gen 2)
- 50 MW (Export)

**Spot Market Interchange** = 450 - 600 = - 150

(Net Seller to Spot Market)
• **Spot Market Interchange**
  - A measure of the “imbalance” in a Market Participant’s resources and loads
  - Defines a participant’s “Net Position” (i.e. buyer or seller) relative to the PJM Spot Energy Market
  - Net Interchange = Load - Resources

### Import = 300 MW  
### Export = 50 MW

<table>
<thead>
<tr>
<th><strong>Resources</strong></th>
<th><strong>Load</strong></th>
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<tbody>
<tr>
<td>100 MW (Gen 1)</td>
<td>950 MW (Load w/out losses)</td>
</tr>
<tr>
<td>200 MW (Gen 2)</td>
<td>50 MW (Export)</td>
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<td>300 MW (Import)</td>
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</table>

**Market Participant #1**

- Generator 1 = 100 MW
- Generator 2 = 200 MW
- Load = 950 MW

**Spot Market Interchange = 1000 - 600 = 400**  
(Net Buyer from Spot Market)
Exercise 1

- Calculate the “Day-ahead Spot Market Interchange” for the Market Participant shown below:

- Export = 600 MW
- Import = 700 MW
- Generator 1 = 500 MW
- Generator 2 = 400 MW
- Fixed Load = 800 MW
- Cleared Dec Bid = 75 MW
- Cleared Inc Offer = 50 MW
- Cleared Price-sensitive Load = 100 MW
- Cleared Inc Offer = 50 MW

“Generation” = ?
“Load” = ?
“Spot Market Interchange” = ?
• Market Settlements Terminology
• Line Items on a PJM Billing Statement
  • Spot Market Energy
  • Marginal Losses
  • Congestion
  • Transmission Service
  • Ancillary Services
  • Miscellaneous
  • Review
Customers receive monthly charges/credits for:

**Energy Markets** (Day-ahead and Real-time)
- Day-ahead and Balancing Spot Market Energy
- Day-ahead and Balancing Transmission Congestion (Implicit and Explicit)
- Day-ahead and Balancing Transmission Losses (Implicit and Explicit)

**Transmission Service** (Network and Point-to-Point)

**Ancillary Services**
- Scheduling, System Control, & Dispatch
- Reactive Supply and Voltage Control from Generation Sources
- Regulation and Synchronized Reserve Markets
- Day-ahead Scheduling Reserve
- Black Start Service
- Operating Reserves

**RPM Markets** (and deficiency charges and allocations)

**Miscellaneous Categories**
The purpose of this presentation is to provide a quick, consolidated reference of the potential charges and credits for which a participant typically may be responsible for conducting various types of PJM transactions.

Although this list is meant to be as inclusive as possible, based upon various types of activities, business philosophies and strategies, from time to time, some charges and credits may not apply or may apply in addition to those referenced.

More detailed information on PJM charges, credits and market settlements can be located in the PJM Guide to Billing, the PJM Open Access Transmission Tariff, the PJM Operating Agreement and the PJM Manuals as posted on the PJM website at www.pjm.com

Emergency energy potentially applies to all types of transactions.
Imports – Point of Delivery Other Than External Interface

- Firm or Non-Firm Transmission Service
- Spot Market Energy
- Congestion (Relative to the interface)
- Losses (Relative to the interface)
- Operating Reserves (If scheduled real-time or deviation in real-time from day-ahead)
- Reactive (Schedule 2)
- Black-start (Schedule 6A)
- Control Area Administration (Schedule 9-1)
- Market Support (Schedule 9-3)
- FERC Annual Charge Recovery (Schedule 9-FERC)
- Organization of PJM States, Inc. Funding (Schedule 9-OPSI)
- MMU Funding (Schedule 9-MMU)
- Advanced Second Control Center AC² (Schedule 9-AC²)
- Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)
No Firm or Non-Firm Transmission Service (However, “Spot In” must be reserved on OASIS)
Spot Market Energy
Congestion (Relative to the interface)
Losses (Relative to the interface)
Operating Reserves (If scheduled real-time or deviation in real-time from day-ahead)
Market Support (Schedule 9-3)
Advanced Second Control Center AC² (Schedule 9-AC²)
MMU Funding (Schedule 9-MMU)
Exports – Point of Delivery Not MISO

- Firm or Non-Firm Transmission Service
- Spot Market Energy
- Congestion (Relative to the interface)
- Losses (Relative to the interface)
- Day-ahead Operating Reserve (If scheduled Day-ahead)
- Balancing Operating Reserve (If deviation from Day-ahead, Reliability)
- Synchronous Condensing
- Reactive (Schedule 2)
- Black Start (Schedule 6A)
- Control Area Administration (Schedule 9-1)
- Market Support (Schedule 9-3)
- FERC Annual Charge Recovery (Schedule 9-FERC)
- Organization of PJM States, Inc. Funding (Schedule 9-OPSI)
- MMU Funding (Schedule 9-MMU)
- Advanced Second Control Center AC² (Schedule 9-AC²)
- Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)

- Real-time exports loss surplus credit allocation (for those transactions paying for transmission service only)
Exports – Point of Delivery MISO

- Firm or Non-Firm Transmission Service (No charge for this service)
- Spot Market Energy
- Congestion (Relative to the interface)
- Losses (Relative to the interface)
- Day-ahead Operating Reserve (If scheduled Day-ahead)
- Balancing Operating Reserve (If deviation from Day-ahead, Reliability)
- Synchronous Condensing
- Reactive (Schedule 2)
- Black Start (Schedule 6A)
- Control Area Administration (Schedule 9-1)
- Market Support (Schedule 9-3)
- FERC Annual Charge Recovery (Schedule 9-FERC)
- Organization of PJM States, Inc. Funding (Schedule 9-OPSI)
- MMU Funding (Schedule 9-MMU)
- Advanced Second Control Center AC² (Schedule 9-AC²)
- Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)
- Firm or Non-Firm Transmission Service
- Congestion
- Losses
- Reactive (Schedule 2)
- Black Start (Schedule 6A)
- Control Area Administration (Schedule 9-1)
- FERC Annual Charge Recovery (Schedule 9-FERC)
- Organization of PJM States, Inc. Funding (Schedule 9-OPSI)
- Advanced Second Control Center AC² (Schedule 9-AC²)
- Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)
Firm or Non-Firm Transmission Service (No charge for this service)
Congestion
Losses
Reactive (Schedule 2)
Black Start (Schedule 6A)
Control Area Administration (Schedule 9-1)
FERC Annual Charge Recovery (Schedule 9-FERC)
Organization of PJM States, Inc. Funding (Schedule 9-OPSI)
Advanced Second Control Center AC² (Schedule 9-AC²)
Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)
Wheel – Point of Delivery Not MISO

- Firm or Non-Firm Transmission Service
- Congestion
- Losses
- Reactive (Schedule 2)
- Black Start (Schedule 6A)
- Control Area Administration (Schedule 9-1)
- FERC Annual Charge Recovery (Schedule 9-FERC)
- Organization of PJM States, Inc. Funding (Schedule 9-OPSI)
- Advanced Second Control Center AC² (Schedule 9-AC²)
- Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)
Up-To-Congestion Transaction

- Firm or Non-Firm Transmission Service (If POD is not MISO)
- Congestion (-$50.00 to $50.00/MWh Cap Applies)
- Losses
- Market Support (Schedule 9-3)
- MMU Funding (Schedule 9-MMU)
- Advanced Second Control Center AC\(^2\) (Schedule 9-AC\(^2\))
- Reactive (Schedule 2)
- Black Start (Schedule 6A)

If transaction flows in Real-Time:
- Spot Market Energy
- Balancing Operating Reserves (Deviations, [Reliability-Exports])
- Synchronous Condensing (Exports)
- Control Area Administration (Schedule 9-1)
- FERC Annual Charge Recovery (Schedule 9-FERC)
- Organization of PJM States, Inc. Funding (Schedule 9-OPSI)
- Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)

- Loss Surplus Allocation (for those up-to-congestion transactions paying for transmission service only)
- Spot Market Energy
- Congestion
- Losses
- Balancing Operating Reserve Charges (Deviations)
- Market Support (Schedule 9-3)
- MMU Funding (Schedule 9-MMU)
- Advanced Second Control Center AC² (Schedule 9-AC²)
Decrement Bid

- Spot Market Energy
- Congestion
- Losses
- Day-ahead Operating Reserve Charges
- Balancing Operating Reserve Charges (Deviations)
- Market Support (Schedule 9-3)
- MMU Funding (Schedule 9-MMU)
- Advanced Second Control Center AC$^2$ (Schedule 9-AC$^2$)
- Spot Market Energy
- Congestion (Buyer pays explicit charges)
- Congestion (Buyer credited implicit at sink, Seller charged implicit at source)
- Losses (Buyer pays explicit charges)
- Losses (Buyer credited implicit at sink, seller charged implicit at source)
- Balancing Operating Reserve Charges (Deviations)
- Network Integration Transmission Service
- Spot Market Energy
- Congestion
- Losses
- Day-ahead Operating Reserve (If scheduled Day-ahead)
- Balancing Operating Reserve (If deviation from Day-ahead, Reliability)
- Day-ahead Scheduling Reserve
- Synchronous Condensing
- Reactive (Schedule 2)
- Regulation (Schedule 3)
- Black Start (Schedule 6A)
- Synchronized Reserve (Schedule 5)
- Inadvertent Interchange
- Meter Error Correction
Control Area Administration (Schedule 9-1)
Market Support (Schedule 9-3)
Regulation and Frequency Response Administration (Schedule 9-4)
Capacity Resource and Obligation Management (Schedule 9-5)
FERC Annual Charge Recovery (Schedule 9-FERC)
Organization of PJM States, Inc. Funding (Schedule 9-OPSI)
MMU Funding (Schedule 9-MMU)
Advanced Second Control Center AC² (Schedule 9-AC²)
North American Electric Reliability Corp. Charge (Schedule 10-NERC) (excludes Dominion and Duquesne zones)
Reliability First Corp. Charge (Schedule 10-RFC) (excludes Dominion and Duquesne zones)
Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)
- RPM Auction (Resource make-whole payments allocated to LSE in applicable LDA)
- Locational Reliability Charge
- RTO Start-up Cost Recovery (ComEd and AEP Zones)
- Expansion Cost Recovery (except Dominion)
- Generation Deactivation (Affected Transmission Zones)
- Transmission Enhancement
- Load Response
- Loss Surplus Credit Allocation (Real-time Load)
- Auction Revenue Rights
- Capacity Transfer Rights Credits
- Demand Resource and ILR Compliance Penalty Credits (Revenues above cap)
- Capacity Resource Deficiency Credits*
- Generation Resource Rating Test Failure Credits*
- Qualifying Transmission Upgrade Compliance Penalty Credits*
- Peak Season Maintenance Compliance Penalty Credits*
- Peak Hour Period Availability Credits*

* Allocated to LSEs that paid a Locational Reliability Charge
- Spot Market Energy
- Losses
- Congestion
- Reactive
- Regulation
- Day-ahead Scheduling Reserve
- Synchronized Reserve
- Operating Reserve (Day-ahead, Balancing)
- Black Start Service (Approved Black Start Revenue Requirements)
- RPM Auction
- Generation Deactivation
- Meter Error Correction
- Balancing Operating Reserve (Deviations Not Following Dispatch)
- Market Support (Schedule 9-3)
- Regulation and Frequency Response Administration (Schedule 9-4)
- Capacity Resource and Obligation Management (Schedule 9-5)
- Advanced Second Control Center AC² (Schedule 9-AC²)
- MMU Funding (Schedule 9-MMU)
- Capacity Resource Deficiency
- Generation Resource Rating Test Failure
- Peak Season Maintenance Compliance Penalty
- Peak Hour Period Availability Charge*

*Capped credits apply to resources with peak period excess MW
• Market Settlements Terminology
• Line Items on a PJM Billing Statement
  • Spot Market Energy
    • Marginal Losses
    • Congestion
    • Transmission Service
    • Ancillary Services
    • Miscellaneous
    • Review
• **Day-ahead Energy Market Settlement**
  - Hourly net energy market position priced at *Day-ahead System Energy Price*
  - Net position based on cleared increment and generation offers, decrement, demand, and load response bids, imports, exports, and bilateral energy transactions in the day-ahead market

• **Balancing Settlement of Real-time Energy Market**
  - Hourly deviation between real-time and day-ahead net spot market energy positions priced at the *Real-time System Energy Price*
  - Real-time net energy position based on real-time generation, load (w/out losses), imports, exports, and bilateral energy transactions

**PJM Operating Agreement Reference - Schedule 1-3.2.1 and 3.3.1**
Day-ahead Spot Market Energy

1200 Day-ahead Spot Market Energy

• Buyer Charges
  
  System Energy Price component of day-ahead LMP

• Seller Charges (negative)
  
  System Energy Price component of day-ahead LMP

System Energy Price will be the same for all participants at all buses!
Balancing Spot Market Energy Calculation*

- Real-time Load MWh - Losses
- Real-time Sale Transaction MWh
- Real-time Generation MWh
- Real-time Purchase Transaction MWh

\[
\text{Real-time Spot Market Energy} = \text{Real-time Load MWh - Losses} - \text{Real-time Sale Transaction MWh} + \text{Real-time Generation MWh} - \text{Real-time Purchase Transaction MWh}
\]

* Net metered interchange (minus SE losses) used from eMTR
Balancing Spot Market Energy

- **Buyer Deviation** = Real-time Spot Market Energy - Day-ahead Spot Energy Purchase
- **Buyer Charge** = Real-time System Energy Price component of LMP
- **Seller Deviation** = Real-time Spot Market Energy - Day-ahead Spot Energy Sale
- **Seller Charge** (negative) = Real-time System Energy Price component of LMP

System Energy Price will be the same for all participants at all buses!
Calculation of Spot Market Interchange-Review

**Spot Market Interchange** is the difference between a participant’s total energy resources and its energy demand

- **Interchange Buyers’ Charge**
  - pay System Energy Price for spot market purchases

- **Interchange Sellers’ Charge (negative)**
  - receive System Energy Price for spot market sales
Spot Market Interchange Review - Net Buyer

LSE Net Buyer of 10 MW

S.M. Energy Charge = 10MW ($25) = $250

Prices shown are System Energy Price component of LMP

SMI = 10 MW
Spot Market Interchange Review - Net Seller

20 MW @ $35
30 MW @ $35
20 MW @ $35
40 MW @ $35
15 MW @ $35
10 MW @ $35

Prices shown are System Energy Price component of LMP

Net Seller of 45 MW
S.M. Energy Charge = -45MW ($35) = -$1575

SMI = -45 MW
Infamous 5 Bus Transmission Grid

Note: Some generator references from this 5 Bus Model appear in the following examples.
## Business Example – Day-Ahead Spot Market Energy

<table>
<thead>
<tr>
<th>Energy Market Withdrawals</th>
<th>Energy Market Injections</th>
</tr>
</thead>
<tbody>
<tr>
<td>200 MW (DA Demand)</td>
<td>100 MW (eSchedule purchase)</td>
</tr>
<tr>
<td>10 MW (Decrement Bid)</td>
<td>110 MW (Alta day-ahead schedule)</td>
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<tr>
<td></td>
<td>10 MW (Increment Offer)</td>
</tr>
<tr>
<td></td>
<td>0 MW (Solitude day-ahead schedule)</td>
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<tr>
<td>210 MW</td>
<td>220 MW</td>
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</tbody>
</table>

210 MW – 220 MW = -10 MW * $10.00 = -$100 charge

(Note that charge is negative)

**Day-Ahead System Energy Price**
## Business Example – Balancing Spot Market Energy

<table>
<thead>
<tr>
<th>Real-Time Energy Withdrawals</th>
<th>Real-Time Energy Injections</th>
</tr>
</thead>
<tbody>
<tr>
<td>220 MW (RT Load excluding losses)</td>
<td>100 MW (eSchedule purchase)</td>
</tr>
<tr>
<td></td>
<td>110 MW (Alta actual generation)</td>
</tr>
<tr>
<td></td>
<td>37 MW (Solitude actual generation)</td>
</tr>
</tbody>
</table>

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
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<tbody>
<tr>
<td>220 MW</td>
<td>247 MW</td>
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</table>

\[
220 \text{ MW} - 247 \text{ MW} = -27 \text{ MW}
\]

\[
-27 \text{ MW} - (-10 \text{ MW}) = -17 \text{ MW} ($11.75) = -$199.75 \text{ charge}
\]

(Note that charge is negative)

- **Real-Time Net Interchange**
- **Day-Ahead Net Interchange**
- **Real-Time System Energy Price**
Exercise 2

- Calculate the “Day-ahead Spot Market Energy” for the participant shown below:

  **Generator 1** = 100 MW @ LMP = $10
  **Generator 2** = 200 MW @ LMP = $10
  **Load** = 400 MW @ LMP = $10
  **Export** = 100 MW LMP = $10 (Source)
  **eSchedule purchase at zone** = 20 MW @ $10 (Sink)
  **“Dec bid” 50 MW @** LMP = $10

“Net Spot Market Interchange” = ?
“Day-ahead charges or credits” = ?

LMPs shown are DA System Energy Price component of LMP
Exercise 3

- Calculate the “Balancing Spot Market Energy” for the participant shown below:

Generator 1 = 205 MW @ LMP = $15
Generator 2 = 305 MW @ LMP = $15
Load = 500 MW @ LMP=$15
Export = 100 MW LMP = $15 (Source)
eSchedule purchase at zone = 20 MW @ $15 (Sink)

“Balancing Net Interchange” = (Metered Interchange – Losses) + Scheduled Sales - Scheduled Purchases
Balancing Charge or Credit = Balancing Net Interchange - DA Net Interchange * RT LMP

Hint: Assume 10 MW losses; Metered Interchange – Losses = 0 MW

LMPs shown are Real-time System Energy Price component of LMP
### MSRS - Spot Market Energy Charge Summary

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<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
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<td>GMT Hour Ending</td>
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<td>DA Net Interchange (MWh)</td>
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<td>DA PJM Energy Price ($/MWh)</td>
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### Supporting Calculations

\[
\text{DA Spot Market Energy Charge (1200.01)} = \text{DA Net Interchange (3000.28)} \times \text{DA PJM Energy Price (3000.01)}
\]

\[
\text{Bal Net Interchange (3000.30)} = \text{RT Net Interchange (3000.29)} - \text{DA Net Interchange (3000.28)}
\]

\[
\text{Bal Spot Market Energy Charge (1205.01)} = \text{Bal Net Interchange (3000.30)} \times \text{RT PJM Energy Price (3000.02)}
\]
# MSRS – Day-Ahead Daily Energy Transactions

## Supporting Calculations

**Day-Ahead Net Interchange** = \( \text{SUM (all MWh values)} \) for each hour, excluding transactions whose Up to Congestion flag = \( Y \).

## Data Granularity: Hourly

## Frequency: Updated Daily

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**Possible Transaction Type values:** Demand, Decrement, Load Response, Generation, Increment, Internal Bilateral, Import, Export, Wheel In, Wheel Out, Total DA Net Interchange.
### MSRS – Real-Time Daily Energy Transactions

**Supporting Calculations**

Real-Time Net Interchange = SUM (all MWh values) for each hour

---

**Data Granularity:** Hourly Frequency: Updated Daily

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### MSRS – Real-Time Daily Energy Transactions

**Possible Transaction Type Values:** Internal Bilateral, Retail Load Responsibility, Wholesale Load Responsibility, Generation Responsibility, Import, Export, Wheel In, Wheel Out, Adjusted Net Metered Interchange, eMTR Allocated EHV Losses, De-rated Losses, Default Supplier Load, Total RT Net Interchange.

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End of Report
Report displays the load MWh with and without losses for each load eSchedule (WLRs and RLRs) applicable to the customer account.

**Possible Transaction Type values:** Wholesale Load Responsibility, Retail Load Responsibility

**Possible Status values:** Load with Losses, Load without Losses

* Hours 3 through 23 Hidden Due to Space Considerations.
• Market Settlements Terminology
• Line Items on a PJM Billing Statement
  • Spot Market Energy
  • Marginal Losses
  • Congestion
  • Transmission Service
  • Ancillary Services
  • Miscellaneous
• Review
• Settlement for losses reflected in LMP calculation

• **Implicit Loss Charge**
  • Day-ahead and balancing locational net loss bill calculated hourly
    • Represents the marginal loss price difference between a participant’s injections and withdrawals
    • Calculated using the *Loss Price* component of LMP

• **Explicit Loss Charge**
  • Calculated using source and sink of transaction using *Loss Price* component of LMP

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Implicit vs Explicit Loss Calculations

**Generation**
- **Gen** credited Losses at A
- **Gen** charged Losses at B

**Load**
- **Load** credited Losses at C
- **Load** charged Losses at D
- **Load** as buyer in the internal bilateral transaction pays explicit losses C - B

**$Actual Generation Loss Credit**

**$Scheduled Load Loss Charge**

**Internal Bilateral Transaction Gen Sells To Load**

**$Scheduled Generation Loss Credit**

**$Actual Generation Loss Credit**

** Implicit**

$Actual Load Loss Charge
Calculation of Locational Net Loss Bill (Implicit Losses)

**Locational Net Loss Bill is the difference in Loss Price components of LMP between a participant’s “load” and “generation”**

Net Loss Bill (Implicit Loss Charge):
Load Loss Charges - Generation Loss Credits

**Load Loss Charges**:  
Load: Load Bus MWh x Loss Price Component of Load Bus LMP  
Energy Sales: Sale MWh x Loss Price Component of Source LMP  
Decrement Bids: Dec Bid MWh x Loss Price Component of Bus LMP

**Generation Loss Credits**:  
Generation: Generation Bus MWh x Loss Price Component of Generation Bus LMP  
Energy Purchases: Purchase MWh x Loss Price Component of Sink LMP  
Increment Offers: Inc Offer MWh x Loss Price Component of Bus LMP

* deviations are used for balancing market calculations
Day-ahead Explicit Losses Charge

Day-ahead Transaction MWh *
(Loss Price Component of Day-ahead Sink LMP - Loss Price Component of Day-ahead Source LMP)

- Transmission customer pays losses for external transactions
- Buyer pays losses for internal transactions (network customer)
- Explicit loss charges are not included in the net loss bill calculations.
Balancing Explicit Loss Charge

Real-time Transaction MWh – Day-ahead Transaction MWh * 
(Loss Price Component of Real-time Sink LMP - Loss Price Component of Real-time Source LMP)

- Transmission customer pays losses for external transactions
- Buyer pays losses for internal transactions (network customer)
- Explicit loss charges are not included in the net loss bill calculations.
# MSRS-Transmission Loss Charge Summary

## Supporting Calculations

**DA Implicit Loss Charge (1220.01)** = **DA Loss Withdrawal Charge (1220.11)** - **DA Loss Injection Credit (1220.12)**

**Bal Implicit Loss Charge (1225.01)** = **Bal Loss Withdrawal Charge (1225.11)** - **Bal Loss Injection Credit (1225.12)**

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# MSRS-Implicit Congestion and Loss Charge Details

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<th>Bal Congestion Withdrawal Energy Deviation (MWh)</th>
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## Report Content Summary

This report displays the customer account's net position by PNODE for each hour of a specified range of dates where the customer account has DA Congestion Withdrawal Energy, DA Loss Withdrawal Energy, DA Congestion Injection Energy, DA Loss Injection Energy, RT Congestion Withdrawal Energy, RT Loss Withdrawal Energy, RT Congestion Injection Energy OR RT Loss Injection Energy for that hour. This report lists DA and RT injection and withdrawal MWh on an hourly basis for each bus at which the account had activity. MWhs at aggregates have been distributed to individual bus PNODEs based on aggregate distribution factors.
MSRS-Implicit Congestion and Loss Charge Details

Supporting Calculations

DA Congestion Withdrawal Charge (from Congestion Charge Summary) = \( \text{SUM} (\text{PNODE DA Congestion Price} \times \text{DA Congestion Withdrawal Energy}) \) for all PNODEs

DA Congestion Injection Credit (from Congestion Charge Summary) = \( \text{SUM} (\text{PNODE DA Congestion Price} \times \text{DA Congestion Injection Energy}) \) for all PNODEs

DA Loss Withdrawal Charge (from Loss Charge Summary) = \( \text{SUM} (\text{PNODE DA Loss Price} \times \text{DA Loss Withdrawal Energy}) \) for all PNODEs

DA Loss Injection Credit (from Loss Charge Summary) = \( \text{SUM} (\text{PNODE DA Loss Price} \times \text{DA Loss Injection Energy}) \) for all PNODEs


Bal Congestion Injection Energy Deviation = RT Congestion Injection Energy - DA Congestion Injection Energy


Bal Loss Injection Energy Deviation = RT Loss Injection Energy - DA Loss Injection Energy

Bal Congestion Withdrawal Charge (from Congestion Charge Summary) = \( \text{SUM} (\text{PNODE RT Congestion Price} \times \text{Bal Congestion Withdrawal Energy Deviation}) \) for all PNODEs

Bal Congestion Injection Credit (from Congestion Charge Summary) = \( \text{SUM} (\text{PNODE RT Congestion Price} \times \text{Bal Congestion Injection Energy Deviation}) \) for all PNODEs

Bal Loss Withdrawal Charge (from Loss Charge Summary) = \( \text{SUM} (\text{PNODE RT Loss Price} \times \text{Bal Loss Withdrawal Energy Deviation (MWh)}) \) for all PNODEs

Bal Loss Injection Credit (from Loss Charge Summary) = \( \text{SUM} (\text{PNODE RT Loss Price} \times \text{(MWh)} \times \text{Bal Loss Injection Energy Deviation (MWh)}) \) for all PNODEs
### MSRS-Explicit Loss Charges

**Supporting Calculations**

DA Explicit Loss Charge (1220.13) = DA Transaction MWh (3000.72) * (DA Sink Loss Price (3000.16) - DA Source Loss Price (3000.17))

Bal Transaction Deviation (3000.74) = RT Transaction MWh (3000.73) - DA Transaction MWh (3000.72)

Bal Explicit Loss Charge (1225.13) = Bal Transaction Deviation (3000.74) * (RT Sink Loss Price (3000.19) - RT Source Loss Price (3000.20))
Loss Credit Allocation
• Money collected from Marginal Losses will be approximately twice that collected from average losses

• More money collected from load than is paid to generation
  – Results in a loss surplus
  – Distributed to Transmission Users based on load + exports (paying for transmission service) + Up-To-Congestion Transactions (paying for transmission service) ratio shares
Loss Surplus Allocation

• Loss surplus is allocated to Transmission Users:
  – Real-time Load
  – Real-time Exports (paying for transmission service)
  – Up-To-Congestion Transactions (paying for transmission service)

Customer total MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service

Total PJM MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service

Loss Credit = Total Loss Surplus ($)

2220 | Transmission Losses
Loss Surplus - Example

Energy LMP = 13.83 $/MWh
Congestion LMP = 0.00 $/MWh
Losses LMP = 0.00 $/MWh
Total LMP = 13.83 $/MWh
PF = 1.00

Brighton
Bid = $10
600 MW
AGC ON

Energy LMP = 13.83 $/MWh
Congestion LMP = 0.00 $/MWh
Losses LMP = 0.17 $/MWh
Total LMP = 14.00 $/MWh
PF = 0.99

Area Load = 669 MW
Area Losses = 17 MW
Area Generation = 686 MW

98%
MVA

225 MW

D

O

AGC ON

0 MW

Sundance
Bid = $30

149 MW

223 MW

Energy LMP = 13.83 $/MWh
Congestion LMP = 0.00 $/MWh
Losses LMP = 0.51 $/MWh
Total LMP = 14.33 $/MWh
PF = 0.96

Energy LMP = 13.83 $/MWh
Congestion LMP = 0.00 $/MWh
Losses LMP = 0.86 $/MWh
Total LMP = 14.69 $/MWh
PF = 0.94

Energy LMP = 13.83 $/MWh
Congestion LMP = 0.00 $/MWh
Losses LMP = 0.79 $/MWh
Total LMP = 14.61 $/MWh
PF = 0.95

www.pjm.com
## Loss Surplus - Example

### Load Bus MWh | Loss Price + System Energy Price | Load Charges
---|---|---
B | 223 | $14.61 | $3258.03
C | 223 | $14.69 | $3275.87
D | 223 | $14.33 | $3195.59

PJM collects $9729.49 in energy + loss charges from load.

### Generator Payments

<table>
<thead>
<tr>
<th>Generator</th>
<th>Bus</th>
<th>MWh</th>
<th>Loss Price + System Energy Price</th>
<th>Generator Payments</th>
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<tbody>
<tr>
<td>Brighton</td>
<td>E</td>
<td>600</td>
<td>$13.83</td>
<td>$8298</td>
</tr>
<tr>
<td>Alta</td>
<td>A</td>
<td>86</td>
<td>$14.00</td>
<td>$1204</td>
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<tr>
<td>Park City</td>
<td>A</td>
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<td>$14.00</td>
<td>$0</td>
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<tr>
<td>Solitude</td>
<td>C</td>
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<td>$14.69</td>
<td>$0</td>
</tr>
<tr>
<td>Sundance</td>
<td>D</td>
<td>0</td>
<td>$14.33</td>
<td>$0</td>
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</tbody>
</table>

Surplus of $227.49 is the Loss Revenues.

PJM pays $9502 in energy + loss credits to generation.

$9729.49 - $9502 = $227.49

PJM collects $9729.49 in energy + loss charges from load.

PJM pays $9502 in energy + loss credits to generation.

Surplus of $227.49 is the Loss Revenues.
## Loss Surplus Allocation

### Load Bus | MWh | LSE | Loss Surplus Allocation
---|---|---|---
B | 223 | ABC | $(223/669)(227.49) = $75.83$
C | 223 | XYZ | $(446/669)(227.49) = $151.66$
D | 223 | | 

Total MWh: 669
Loss Surplus Allocation: $227.49$

---

**Formula:**

\[
\text{Loss Surplus Allocation} = \frac{\text{Load MWh}}{\text{Total MWh}} \times \text{Loss Surplus}\]

**Note:**
- Load MWh: MWh delivered to load + exports, paying for transmission service.
- Total MWh: MWh delivered to load + exports, paying for transmission service + up-to-congestion transactions.
### MSRS - Transmission Loss Credit Summary

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<th>B</th>
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<th>D</th>
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<td>EPR Hour Ending</td>
<td>GMT Hour Ending</td>
<td>Total PJM Loss Revenues ($)</td>
<td>RT Load (MWh)</td>
<td>RT Exports (MWh)</td>
<td>Up-To Congestion Transactions (MWh)</td>
<td>Total PJM RT Load plus Exports plus Up-To Congestion Transactions (MWh)</td>
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### Supporting Calculations

Transmission Loss Credit (2220.01) = Total PJM Loss Revenues (2220.11) * ((RT Load (3000.38) + RT Exports (3000.48) + Up-To Congestion Transactions (2220.12)) / Total PJM RT Load plus Exports plus Up-To Congestion Transactions (3000.49))

### Data Granularity: Hourly

### Frequency: Updated Daily
Example Case (Unconstrained)

Let's see an example!
Example - Day-ahead and Spot Market Energy

- **Case 1**
  - *Unconstrained* Day-ahead Market
  - *Unconstrained* Balancing Market
<table>
<thead>
<tr>
<th>Participant</th>
<th>Role</th>
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<tbody>
<tr>
<td>EDC 1</td>
<td>Metered entity that owns generation &amp; serves load in PJM</td>
</tr>
<tr>
<td>LSE 2</td>
<td>Retail load aggregator that serves portion of LSE 1’s metered load</td>
</tr>
<tr>
<td>EDC 3</td>
<td>Metered entity that owns generation &amp; serves load in PJM</td>
</tr>
<tr>
<td>EDC 4</td>
<td>Metered entity that owns generation &amp; serves load in PJM</td>
</tr>
<tr>
<td>Park City</td>
<td>Merchant generation plant that sells to PJM Spot Market</td>
</tr>
<tr>
<td>Alta</td>
<td>Merchant generation plant that sells to PJM Spot Market &amp; enters bilateral contracts with other PJM Members</td>
</tr>
</tbody>
</table>
Example - System Conditions

Unconstrained Day-ahead Schedule
- Total scheduled system demand of 669 MW

Unconstrained Actual Operations
- Total system actual load w/out losses of 683 MW
- Mechanical failure of generator scheduled to operate in day-ahead schedule

Resulting Effect:
Increase in marginal price between day-ahead schedule & real time operations
Example - Day-Ahead Market Demand Bids

Bus B
EDC 1: Fixed Demand Bid for 200 MW at Bus B
LSE 2: Decrement Bid for 23 MW at Bus B ($25)

Bus C
EDC 3: Price Sensitive Demand Bid for 223 MW at Bus C ($25)

Bus D
EDC 4: Fixed Demand Bid for 223 MW at Bus D

Total Demand = 669 MW
## Example - Day-Ahead Market Generator Offers

### Scheduled Generation

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<th>Owner</th>
<th>Offer Price</th>
<th>MWh Scheduled</th>
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<td>$10/MWh</td>
<td>600</td>
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<tr>
<td>A</td>
<td>Alta</td>
<td>110</td>
<td>Merchant Generator Company X</td>
<td>$14/MWh</td>
<td>86</td>
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<td>A</td>
<td>Park City</td>
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<td>$30/MWh</td>
<td>0</td>
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<tr>
<td>D</td>
<td>Sundance</td>
<td>200</td>
<td>100% EDC 4</td>
<td>$30/MWh</td>
<td>0</td>
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</table>
Example - Day-Ahead Market Transaction Schedules

Alta schedules internal bilateral transaction in eSchedules for 5 MW on path A to D

Alta is seller; EDC 4 is buyer.

Looks like 5 MW load for Alta at A

Looks like 5 MW generation for EDC 4 at D
Example – Day-Ahead Schedule

LMPs

- **Brighton**
  - 600 MW
  - $10/MWh
  - Energy = $13.83
  - Loss = $0.00
  - Congestion = $0
  - Total LMP = $13.83

- **Alta**
  - 110 MW
  - $14/MWh
  - Energy = $13.83
  - Loss = $0.17
  - Congestion = $0
  - Total LMP = $14.00

- **Park City**
  - 100 MW
  - $15/MWh
  - Energy = $13.83
  - Loss = $0.79
  - Congestion = $0
  - Total LMP = $14.61

- **Sundance**
  - 223 MW
  - $30/MWh
  - Energy = $13.83
  - Loss = $0.51
  - Congestion = $0
  - Total LMP = $14.33

- **Solitude**
  - 520 MW
  - $30/MWh
  - Energy = $13.83
  - Loss = $0.86
  - Congestion = $0
  - Total LMP = $14.69

**Thermal Limit**

- 240 MW

**Marginal Generator**

- **E**
  - 225 MW

- **B**
  - 305 MW

- **C**
  - 77 MW

- **D**
  - 146 MW

- **223 MW**

Energy = $13.83
Loss = $0.00
Congestion = $0
Total LMP = $13.83

Energy = $13.83
Loss = $0.51
Congestion = $0
Total LMP = $14.33

Energy = $13.83
Loss = $0.86
Congestion = $0
Total LMP = $14.69

Energy = $13.83
Loss = $0.79
Congestion = $0
Total LMP = $14.61

Energy = $13.83
Loss = $0.17
Congestion = $0
Total LMP = $14.00
Example – Day-Ahead Settlements

Net Spot Market MWh = DA Load + Energy Sale Transactions + Decrement Transactions

Generator + Energy Purchase Transactions + Increment Transactions

-200 = 200 (load @B) - 400 (66.7% of Brighton @E)

23 = 23 (Dec bid @ B) - 0

23 = 223 (P.S. Demand bid @ C) - 200 (33.3% of Brighton @E)

218 = 223 (load @D) - 5 (purchase @D)

0 = 0 - 0

-81 = 5 (sale @D) - 86 (Alta generation @A)

-17 (losses)

for EDC 1
for LSE 2
for EDC 3
for EDC 4
for Park City
for Alta
Example - Day-Ahead Spot Market Charges

\[
\text{Total Spot Market Charges} = \text{Positive Net Interchange (MWh)} \times \text{System Energy Price Component of DA LMP ($/MWh)}
\]

\[
\text{Total Spot Market Negative Charges} = \text{Negative Net Interchange (MWh)} \times \text{System Energy Price Component of DA LMP ($/MWh)}
\]
Example – Day Ahead Spot Market Charges

($2766) = -200 \text{ MWh} \times 13.83/\text{MWh} \quad \text{for EDC 1}

$318 = 23 \text{ MWh} \times 13.83/\text{MWh} \quad \text{for LSE 2}

$318 = 23 \text{ MWh} \times 13.83/\text{MWh} \quad \text{for EDC 3}

$3015 = 218 \text{ MWh} \times 13.83/\text{MWh} \quad \text{for EDC 4}

$0 = 0 \text{ MWh} \times 13.83/\text{MWh} \quad \text{for Park City}

($1120.23) = -81 \text{ MWh} \times 13.83/\text{MWh} \quad \text{for Alta}

($235.23)

This negative charge is due to losses and it is allocated, along with implicit and explicit loss revenues, as an offset to the credits provided to all PJM load and exports.
## Example – Day Ahead Implicit Loss Charges - Load

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Day-ahead Load</th>
<th>Bus</th>
<th>Loss Price ($/MWh)</th>
<th>DA Load Loss Charge ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>200</td>
<td>B</td>
<td>0.79</td>
<td>158.00</td>
</tr>
<tr>
<td>LSE 2</td>
<td>23</td>
<td>B</td>
<td>0.79</td>
<td>18.17</td>
</tr>
<tr>
<td>EDC 3</td>
<td>223</td>
<td>C</td>
<td>0.86</td>
<td>191.78</td>
</tr>
<tr>
<td>EDC 4</td>
<td>223</td>
<td>D</td>
<td>0.51</td>
<td>113.73</td>
</tr>
<tr>
<td>Alta</td>
<td>5</td>
<td>A</td>
<td>0.17</td>
<td>0.85</td>
</tr>
</tbody>
</table>

**Total** 482.53
### Example – Day Ahead Implicit Loss Charges - Generation

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Day-ahead Generation</th>
<th>Bus</th>
<th>Loss Price ($/MWh)</th>
<th>DA Generation Loss Credit ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>400</td>
<td>E</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>LSE 2</td>
<td>0</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>EDC 3</td>
<td>200</td>
<td>E</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>EDC 4</td>
<td>5</td>
<td>D</td>
<td>0.51</td>
<td>2.55</td>
</tr>
<tr>
<td>Alta</td>
<td>86</td>
<td>A</td>
<td>0.17</td>
<td>14.62</td>
</tr>
</tbody>
</table>

**Example – Day Ahead Implicit Loss Charges**

- **Loss Price ($/MWh)**
- **DA Generation Loss Credit ($)**

**Note:**

- * indicates a specific scenario or calculation.
## Example – Day Ahead Implicit Loss Charge

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>DA Loss Charge ($)</th>
<th>DA Loss Credit ($)</th>
<th>DA Implicit Loss Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>158.00</td>
<td>0</td>
<td>158.00</td>
</tr>
<tr>
<td>LSE 2</td>
<td>18.17</td>
<td>0</td>
<td>18.17</td>
</tr>
<tr>
<td>EDC 3</td>
<td>191.78</td>
<td>0</td>
<td>191.78</td>
</tr>
<tr>
<td>EDC 4</td>
<td>113.73</td>
<td>2.55</td>
<td>111.18</td>
</tr>
<tr>
<td>Alta</td>
<td>.85</td>
<td>14.62</td>
<td>(13.77)</td>
</tr>
</tbody>
</table>

Total DA Implicit Loss Charge: 465.36
Example – Day-Ahead Explicit Loss Charge

Day-ahead Explicit Loss Charge = Day-Ahead Transaction MWh \times (DA Sink Loss Price - DA Source Loss Price)

EDC 4: 5 \times (0.51 - 0.17) = $1.70
No Congestion Charges from Day Ahead Schedule
Example - Actual Operations (Real Time)

- Actual load higher than day-ahead scheduled load
  - Total System Load (minus losses) = 683 MW
    - Bus B Load = 210 MW (223 MW day-ahead)
    - Bus C Load = 250 MW (223 MW day-ahead)
    - Bus D Load = 223 MW (223 MW day-ahead)
  - Details of Bus B Load
    - 20 MW is being served by LSE 2 (entered in eSchedules as Retail Load Responsibility Transaction)
      - 20 MW following PJM removal of EHV losses
      - Remaining load of 190 MW is served by EDC 1
  - Alta Generator fails
    - Park City brought on to replace
## Example - Actual Operations: Generator Bids

### Generation Operating

<table>
<thead>
<tr>
<th>BUS</th>
<th>Generator</th>
<th>MWh Available</th>
<th>Owner</th>
<th>Offer Price</th>
<th>MWh Dispatched</th>
</tr>
</thead>
<tbody>
<tr>
<td>E</td>
<td>Brighton</td>
<td>600</td>
<td>33.3 % EDC 3</td>
<td>$10/MWh</td>
<td>600</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>66.7 % EDC 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>Alta</td>
<td>0</td>
<td>Merchant Gen – Company X</td>
<td>$14/MWh</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>Park City</td>
<td>100</td>
<td>Merchant Gen – Company Y</td>
<td>$15/MWh</td>
<td>100</td>
</tr>
<tr>
<td>C</td>
<td>Solitude</td>
<td>520</td>
<td>15 % EDC 1</td>
<td>$30/MWh</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>42.5 % EDC 3</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>42.5 % EDC 4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>D</td>
<td>Sundance</td>
<td>200</td>
<td>100 % EDC 4</td>
<td>$30/MWh</td>
<td></td>
</tr>
</tbody>
</table>
Since Alta scheduled internal bilateral transaction in eSchedules for 5 MW on path A to D in day-ahead market, schedule also applies to balancing market.

Altair is seller; EDC 4 is buyer.

Looks like 5 MW load for Alta at A.

Looks like 5 MW generation for EDC 4 at D.
Example - Balancing Settlements

Net Interchange MWh = Metered Interchange – State Estimator Losses (incl. PJM-East 500kV loss allocation, as applicable) + Scheduled Load + Energy Sale Transactions - Scheduled Generation + Energy Purchase Transactions

-210 = -190 (400 Brighton gen @E + 210 load @B) + 0 -20 (esched retail load transfer to LSE 2)

20 = 0 + 20 (esched retail load transfer to LSE 2) - 0

50 = 50 (-200 Brighton gen @E + 250 load @C) + 0 - 0

218 = 223 (223 load @D) + 0 - 5 (esched purchase from Alta @D)

-100 = -100 (100 gen @A) + 0 - 0

5 = 0 + 5 (esched sale to LSE 4 @A) - 0

for EDC 1

for LSE 2

for EDC 3

for EDC 4

for Park City

for Alta
Example - Balancing Spot Market Charges

Balancing Spot Market Charges = Real Time Net Interchange (MWh) - Day Ahead Net Interchange (MWh) * System Energy Price Component of Real-time LMP ($/MWh)

Balancing Spot Market Negative Charges = Real Time Net Interchange (MWh) - Day Ahead Net Interchange (MWh) * System Energy Price Component of Real-time LMP ($/MWh)
Example - Balancing Spot Market Charges

\[
\begin{align*}
($148.1) &= (-210 - (-200 \text{ MWh})) \times \$14.81/\text{MWh} \quad \text{for EDC 1} \\
($44.43) &= (20 - 23 \text{ MWh}) \times \$14.81/\text{MWh} \quad \text{for LSE 2} \\
$399.87 &= (50 - 23 \text{ MWh}) \times \$14.81/\text{MWh} \quad \text{for EDC 3} \\
$0 &= (218 - 218 \text{ MWh}) \times \$14.81/\text{MWh} \quad \text{for EDC 4} \\
($1481) &= (-100 - 0) \text{ MWh} \times \$14.81/\text{MWh} \quad \text{for Park City} \\
$1273.66 &= (5 - -81) \text{ MWh} \times \$14.81/\text{MWh} \quad \text{for Alta} \\
0
\end{align*}
\]
## Example - Summary of Day-Ahead & Balancing Settlements

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Day Ahead Spot Market Payments</th>
<th>Balancing Spot Market Payments</th>
<th>Total Spot Market Payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>($2766)</td>
<td>($148.1)</td>
<td>($2914.10)</td>
</tr>
<tr>
<td>LSE 2</td>
<td>$318</td>
<td>($44.43)</td>
<td>$273.57</td>
</tr>
<tr>
<td>EDC 3</td>
<td>$318</td>
<td>$399.87</td>
<td>$717.87</td>
</tr>
<tr>
<td>EDC 4</td>
<td>$3015</td>
<td>$0</td>
<td>$3015</td>
</tr>
<tr>
<td>Park City</td>
<td>$0</td>
<td>($1481.00)</td>
<td>($1481.00)</td>
</tr>
<tr>
<td>Alta</td>
<td>($1120.23)</td>
<td>$1273.66</td>
<td>$153.43</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>($235.23)</strong></td>
</tr>
</tbody>
</table>
### Example - Summary of Day-Ahead & Balancing Settlements

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Day Ahead Spot Market Payments</th>
<th>Balancing Spot Market Payment</th>
<th>Total Spot Market Payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>$318</td>
<td>$399.87</td>
<td>$717.87</td>
</tr>
<tr>
<td>LSE 1</td>
<td></td>
<td></td>
<td>$273.57</td>
</tr>
<tr>
<td>EDC 3</td>
<td></td>
<td></td>
<td>$3015</td>
</tr>
<tr>
<td>EDC 4</td>
<td></td>
<td>$0</td>
<td>$1481.00</td>
</tr>
<tr>
<td>Park City</td>
<td>($1120.23)</td>
<td>($1481.00)</td>
<td>($235.23)</td>
</tr>
<tr>
<td>Alta</td>
<td></td>
<td></td>
<td>$153.43</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>($235.23)</td>
</tr>
</tbody>
</table>

**Credit offsets the total amount of loss surplus revenues to be distributed to LSEs and Exports.**

Where is this residual credit supplied from?
### Example – Balancing Implicit Losses – Load Loss Charges

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Real-time Load</th>
<th>DA Load</th>
<th>Bus</th>
<th>Balancing Loss Price ($/MWh)</th>
<th>Balancing Loss Charge ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>190</td>
<td>200</td>
<td>B</td>
<td>0.85</td>
<td>(8.50)</td>
</tr>
<tr>
<td>LSE 2</td>
<td>20</td>
<td>23</td>
<td>B</td>
<td>0.85</td>
<td>(2.55)</td>
</tr>
<tr>
<td>EDC 3</td>
<td>250</td>
<td>223</td>
<td>C</td>
<td>0.94</td>
<td>25.38</td>
</tr>
<tr>
<td>EDC 4</td>
<td>223</td>
<td>223</td>
<td>D</td>
<td>0.56</td>
<td>0</td>
</tr>
<tr>
<td>Alta</td>
<td>5</td>
<td>5</td>
<td>A</td>
<td>0.19</td>
<td>0</td>
</tr>
<tr>
<td>Park City</td>
<td>0</td>
<td>0</td>
<td>A</td>
<td>0.19</td>
<td>0</td>
</tr>
</tbody>
</table>

↑ - ↑ * = ↑
## Example – Balancing Implicit Losses – Generation Loss Credits

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Real-time Generation</th>
<th>DA Generation</th>
<th>Bus</th>
<th>Balancing Loss Price ($/MWh)</th>
<th>Balancing Loss Credit ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>400</td>
<td>400</td>
<td>E</td>
<td>0.85</td>
<td>0</td>
</tr>
<tr>
<td>LSE 2</td>
<td>0</td>
<td>0</td>
<td>-</td>
<td>0.85</td>
<td>0</td>
</tr>
<tr>
<td>EDC 3</td>
<td>200</td>
<td>200</td>
<td>E</td>
<td>0.94</td>
<td>0</td>
</tr>
<tr>
<td>EDC 4</td>
<td>5</td>
<td>5</td>
<td>D</td>
<td>0.56</td>
<td>0</td>
</tr>
<tr>
<td>Alta</td>
<td>0</td>
<td>86</td>
<td>A</td>
<td>0.19</td>
<td>(16.34)</td>
</tr>
<tr>
<td>Park City</td>
<td>100</td>
<td>0</td>
<td>A</td>
<td>0.19</td>
<td>19.00</td>
</tr>
</tbody>
</table>

$\uparrow - \uparrow \ast \quad = \quad \uparrow$
# Example - Implicit Losses Charge

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Balancing Loss Charge ($)</th>
<th>Balancing Loss Credit ($)</th>
<th>Balancing Implicit Loss Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>(8.50)</td>
<td>0</td>
<td>(8.50)</td>
</tr>
<tr>
<td>LSE 2</td>
<td>(2.55)</td>
<td>0</td>
<td>(2.55)</td>
</tr>
<tr>
<td>EDC 3</td>
<td>25.38</td>
<td>0</td>
<td>25.38</td>
</tr>
<tr>
<td>EDC 4</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Alta</td>
<td>0</td>
<td>(16.34)</td>
<td>16.34</td>
</tr>
<tr>
<td>Park City</td>
<td>0</td>
<td>19.00</td>
<td>(19.00)</td>
</tr>
</tbody>
</table>

Total: 11.67
Example – Balancing Explicit Loss Charge

Balancing Explicit Loss Charges = Transaction Deviation (RT – DA) MWh \* Real Time Sink Loss Price LMP = Real Time Source Loss Price LMP

EDC 4: 0 \* (0.56 - 0.19) = $0
### Example – Total Loss Surplus

<table>
<thead>
<tr>
<th>Market</th>
<th>Implicit Loss Charge ($)</th>
<th>Explicit Loss Charge ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day Ahead</td>
<td>465.36</td>
<td>1.70</td>
</tr>
<tr>
<td>Balancing</td>
<td>11.67</td>
<td>0</td>
</tr>
</tbody>
</table>

**Total Loss Surplus = $478.73**
### Example – Total Loss Surplus Distribution

**Total Loss Surplus** = \( \$478.73 \)

**Spot Market Credit** = \(-\$235.23\)

**Loss Surplus for Distribution** = \( \$243.50 \)

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Real-time Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>190mw@Bus B</td>
</tr>
<tr>
<td>LSE 2</td>
<td>20mw@Bus B</td>
</tr>
<tr>
<td>EDC 3</td>
<td>250mw@Bus C</td>
</tr>
<tr>
<td>EDC 4</td>
<td>223mw@Bus D</td>
</tr>
<tr>
<td>Park City</td>
<td>0</td>
</tr>
<tr>
<td>Alta</td>
<td>0</td>
</tr>
</tbody>
</table>

**Total Real-time Load** = 683mw
## Example – Total Loss Surplus Distribution

<table>
<thead>
<tr>
<th>EDC 1</th>
<th>$67.74 = $243.50 * 190 / 683</th>
</tr>
</thead>
<tbody>
<tr>
<td>LSE 2</td>
<td>$7.13 = $243.50 * 20 / 683</td>
</tr>
<tr>
<td>EDC 3</td>
<td>$89.13 = $243.50 * 250 / 683</td>
</tr>
<tr>
<td>EDC 4</td>
<td>$79.50 = $243.50 * 223 / 683</td>
</tr>
</tbody>
</table>
No Congestion Charges from Actual Operations
• Market Settlements Terminology
• Line Items on a PJM Billing Statement
  • Spot Market Energy
  • Marginal Losses
  • Congestion
  • Transmission Service
  • Ancillary Services
  • Miscellaneous
• Review
Transmission Congestion Charges

- **Implicit**
  - charge incurred from moving generation to load across a constrained system
  - associated with price differences in congestion component of LMP between generation and purchases, netted against its load and sales

- **Explicit**
  - associated with price differences in congestion component of LMP between the source and sink of a transaction

<table>
<thead>
<tr>
<th>1210</th>
<th>Day-ahead Transmission Congestion</th>
</tr>
</thead>
<tbody>
<tr>
<td>1215</td>
<td>Balancing Transmission Congestion</td>
</tr>
</tbody>
</table>

- PJM Operating Agreement Reference - Schedule 1-3.2.4 and 3.4.1
Transmission Congestion Charges

Day-ahead Charge Calculations
- Locational Net Congestion Bill
  - Implicit Congestion Charge
- Explicit Congestion Charge
  - Associated with internal and external transactions

Balancing Charge Calculations
- Locational Net Congestion Bill
  - Implicit Congestion Charge
- Explicit Congestion Charge
  - Associated with internal and external transactions

Calculations utilize the *Congestion Price* component of LMP
Calculation of Locational Net Congestion Bill
(Implicit Congestion)

Locational Net Congestion Bill is the difference in Congestion Price components of LMP between a participant’s “load” and “generation”

Load Congestion Charges:
- Load: Load Bus MWh \times \text{Congestion Price Component of Load Bus LMP}
- Energy Sales: Sale MWh \times \text{Congestion Price Component of Source LMP}
- Decrement Bids: Dec Bid MWh \times \text{Congestion Price Component of Bus LMP}

Generation Congestion Credits:
- Generation: Gen Bus MWh \times \text{Congestion Price Component of Gen Bus LMP}
- Energy Purchases: Purchase MWh \times \text{Congestion Price Component of Sink LMP}
- Increment Offers: Offer Bid MWh \times \text{Congestion Price Component of Bus LMP}

* deviations are used for balancing market calculations
Implicit Congestion Calculations

An **LSE** pays the difference between equivalent load prices and generation price - all congestion implicit in delivering their resources to their loads.

**Interchange Charge** = $500
= \((50 \text{ MW} \times \$10)\)

**Losses Charge** = $55
= \((100)(.8) - (50)(.5)\)

**Implicit Congestion Charge** = $1000
= \((100)(10) - (50)(0)\)

**Total charge** = 100 \((\$20.8) - 50(\$10.5) = \$1555\)

---

**System Energy Price LMP** = $10

**Loss Price** component of LMP = $.5

**Congestion Price** component of LMP = $0

Total LMP = $10.5

**System Energy Price LMP** = $10

**Loss Price** component of LMP = $.8

**Congestion Price** component of LMP = $10

Total LMP = $20.8
Day-ahead Explicit Congestion Charge

Transaction MWh *
(Congestion Price Component of Day-ahead Sink LMP
Congestion Price Component of Day-ahead Source LMP)

- Transmission customer pays congestion for external transactions
- Buyer pays congestion for internal transactions (network customer)
Balancing Explicit Congestion Charge

Transaction MWh Deviation *
(Congestion Price Component of Real-time Sink LMP
Congestion Price Component of Real-time Source LMP)

• Transmission customer pays congestion for external transactions
• Buyer pays congestion for internal transactions (network customer)
Explicit Generation Load  Source $Actual Generation Creditolla  $Actual Load Charge  Sink
Implicit
Implicit
Implicit $Scheduled Load Charge
Scheduled Generation Credit
Transaction

Calculated Congestion
LMP  [(D-C)+(C-B)+(B-A)] = LMP (D-A)
Example – Spot Market Interchange w/ Bilateral

LMPs shown are **System Energy Price** component of LMP.

Generator sells to entity at agreed to location (source) and entity delivers to load at agreed to location (sink)

**Spot Market Interchange = 0 MW**
50 MW Generation
50 MW “Load” (Sale)

**Spot Market Interchange = 50 MW Purchase**
100 MW Load
50 MW “Generation” (Purchase)
SMI Charge = $2750 = $55 x 50 MW

Generator Spot Market Interchange

LSE Spot Market Interchange
Example - Loss Calculation w/ Bilateral

Generator sells to entity at agreed to location (source) and entity delivers to load at agreed to location (sink)

LMPs shown are **Loss Price** component of LMP.

Implicit Losses = $50
50 MW ($1.2) - 50 MW ($0.5)

**Implicit Losses**

Transmission Customer Charge = $35
50 MW * ($1.9 - $1.2)

“**Explicit Losses**”

Transmission Customer Explicit Loss Charge

Implicit Losses = $135
100 MW ($2.3) – 50 MW ($1.9)

LSE Implicit Loss Charge
Example - Congestion Calculation w/ Bilateral

Generator sells to entity at agreed to location (source) and entity delivers to load at agreed to location (sink)

LMPs shown are *Congestion Price* component of LMP.

Implicit Congestion = $125
50 MW ($12.5) - 50 MW ($10)

Generator Implicit Congestion Charge

Transmission Customer Charge = $250
50 MW* ($17.5 - $12.5)

“Explicit Congestion”

Transmission Customer Explicit Congestion Charge

Implicit Congestion = $1125
100 MW ($20) – 50 MW ($17.5)

LSE Implicit Congestion Charge
Congestion Calculation Steps

1. Calculate congestion charges
   - day-ahead market
   - balancing market

2. Determine FTR target allocations based on *Congestion Price* component of day-ahead LMPs

3. Allocate congestion charges based on target allocations

4. Distribute excess
## MSRS – Transmission Congestion Charge Summary

<p>| | | | | | | | | | | | | | | | |</p>
<table>
<thead>
<tr>
<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>B</td>
<td>C</td>
<td>D</td>
<td>E</td>
<td>F</td>
<td>G</td>
<td>H</td>
<td>I</td>
<td>J</td>
<td>K</td>
<td>L</td>
<td>M</td>
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### Supporting Calculations

**DA Implicit Congestion Charge (1210.01) = DA Congestion Withdrawal Charge (1210.11) - DA Congestion Injection Credit (1210.12)**

**Bal Implicit Congestion Charge (1215.01) = Bal Congestion Withdrawal Charge (1215.11) - Bal Congestion Injection Credit (1215.12)**

(Note: See MSRS Customer Report Documentation for Implicit Congestion and Loss Charge Details for related DA Congestion Withdrawal Charge, DA Congestion Injection Credit, Bal Congestion Withdrawal Charge and Bal Congestion Injection Credit calculations)
## MSRS – Explicit Congestion Charges

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### MSRS Table

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<td>DA Explicit Congestion Charge ($)</td>
<td>RT Transaction MWh</td>
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End of Report

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Supporting Calculations

DA Explicit Congestion Charge (1210.13) = DA Transaction MWh (3000.72) * (DA Sink Congestion Price (3000.07) - DA Source Congestion Price (3000.08))

Bal Transaction Deviation (3000.74) = RT Transaction MWh (3000.73) - DA Transaction MWh (3000.72)

Bal Explicit Congestion Charge (1215.13) = Bal Transaction Deviation (3000.74) * (RT Sink Congestion Price (3000.10) - RT Source Congestion Price (3000.11))
## MSRS-Implicit Congestion and Loss Charge Details

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<th>PNODE ID</th>
<th>PNODE DA Congestion Price ($/MWh)</th>
<th>DA Congestion Withdrawal Energy (MWh)</th>
<th>DA Congestion Injection Energy (MWh)</th>
<th>PNODE DA Loss Price ($/MWh)</th>
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### Report Content Summary

This report displays the customer account's net position by PNODE for each hour of a specified range of dates where the customer account has DA Congestion Withdrawal Energy, DA Loss Withdrawal Energy, DA Injection Energy, RT Congestion Injection Energy, RT Loss Withdrawal Energy, RT Congestion Injection Energy OR RT Loss Injection Energy for that hour. This report lists DA and RT injection and withdrawal MWh on an hourly basis for each bus at which the account had activity. MWhs at aggregates have been distributed to individual bus PNODEs based on aggregate distribution factors.
**Supporting Calculations**

**DA Congestion Withdrawal Charge (from Congestion Charge Summary)** = \( \text{SUM} (\text{PNODE DA Congestion Price} \times \text{DA Congestion Withdrawal Energy for all PNODEs}) \)

**DA Congestion Injection Credit (from Congestion Charge Summary)** = \( \text{SUM} (\text{PNODE DA Congestion Price} \times \text{DA Congestion Injection Energy for all PNODEs}) \)

\( \text{DA Loss Withdrawal Charge (from Loss Charge Summary)} = \text{SUM} (\text{PNODE DA Loss Price} \times \text{DA Loss Withdrawal Energy}) \) for all PNODEs

\( \text{DA Loss Injection Credit (from Loss Charge Summary)} = \text{SUM} (\text{PNODE DA Loss Price} \times \text{DA Loss Injection Energy}) \) for all PNODEs

**Bal Congestion Withdrawal Energy Deviation** = \( \text{RT Congestion Withdrawal Energy} - \text{DA Congestion Withdrawal Energy} \)

**Bal Congestion Injection Energy Deviation** = \( \text{RT Congestion Injection Energy} - \text{DA Congestion Injection Energy} \)

\( \text{Bal Loss Withdrawal Energy Deviation} = \text{RT Loss Withdrawal Energy} - \text{DA Loss Withdrawal Energy} \)

\( \text{Bal Loss Injection Energy Deviation} = \text{RT Loss Injection Energy} - \text{DA Loss Injection Energy} \)

**Bal Congestion Withdrawal Charge (from Congestion Charge Summary)** = \( \text{SUM} (\text{PNODE RT Congestion Price} \times \text{Bal Congestion Withdrawal Energy Deviation}) \) for all PNODEs

**Bal Congestion Injection Credit (from Congestion Charge Summary)** = \( \text{SUM} (\text{PNODE RT Congestion Price} \times \text{Bal Congestion Injection Energy Deviation}) \) for all PNODEs

\( \text{Bal Loss Withdrawal Charge (from Loss Charge Summary)} = \text{SUM} (\text{PNODE RT Loss Price} \times \text{Bal Loss Withdrawal Energy Deviation}) \) for all PNODEs

\( \text{Bal Loss Injection Credit (from Loss Charge Summary)} = \text{SUM} (\text{PNODE RT Loss Price} \times \text{Bal Loss Injection Energy Deviation}) \) for all PNODEs
Day-ahead Congestion Credit

Allocation based on day-ahead target congestion allocation

\[ FTR \text{ MW} \times (DA \text{ Congestion Price Sink LMP} - DA \text{ Congestion Price Source LMP}) \]

Day-ahead Transmission Congestion Charges

Balancing Transmission Congestion Charges

Transmission Congestion Credit

FTR Holders

2210 Transmission Congestion
### Congestion Credit Allocation

<table>
<thead>
<tr>
<th>If total Day-ahead &amp; Balancing Transmission Congestion Charges are …</th>
<th>Then …</th>
<th>And the hourly congestion credit for the participants is …</th>
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</thead>
<tbody>
<tr>
<td>Greater than or equal to Day-ahead Target Allocations</td>
<td>All allocations are satisfied,</td>
<td>The participant’s target allocation</td>
</tr>
<tr>
<td>Less than the Total Day-ahead Target Allocations,</td>
<td>Target Allocations cannot be satisfied,</td>
<td>Reduced proportionately.</td>
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</table>

- Excess congestion charges (including ARR and FTR Auction net revenues remaining after initial distribution to any ARR deficiencies) are distributed by
  - Covering hourly FTR deficiencies within month
    - Remaining monthly excess allocated to previous and future deficient months of the Planning Period year (ending May 31)
      - Remaining planning period year-end excess allocated proportionately to FTR holders with net positive FTR target allocations for that planning period.
      - Deficiencies remaining at end of planning period are eliminated by reallocating all planning period FTR congestion revenues among FTR holders to yield a uniform ratio of deficiency.
Distributing Excess Transmission Congestion Charges

Object of the monthly excess Transmission Congestion Charge distribution is to cover any deficiency in the share of Transmission Congestion Credits received by each FTR holder during the month compared to their target allocations for the month.

Excess Transmission Congestion Charges are distributed in five stages:

**Stage One** – PJM distributes excess Transmission Congestion Charges accumulated during the month to each holder of FTRs in proportion to, but not greater than any deficiency in the share of Transmission Congestion Charges received by the FTR holder during that month as compared to its total target allocations for the month.

**Stage Two** – Any remaining excess after the stage one distribution will be used to satisfy any FTR deficiency from previous months within the Planning Period (June 1 to May 31) on a pro-rata basis up to the full FTR Target Allocation value.
Stage 3 – Any remaining excess after the Stage 2 distribution will be carried forward to the next month as excess congestion charges.

Stage 4 – At the end of the planning period, any remaining Excess Congestion Charges will first be used to satisfy any ARR deficiency that may exist. If insufficient funds exist to honor all ARR revenue shortfalls then the funds would be distributed by ratio of the ARR deficiency.

Stage 5 – PJM distributes any excess Transmission Congestion Charges remaining after the Stage 4 distribution to all FTR holders on a pro-rata basis according to the total target allocations for all FTRs held at any time during the relevant planning period.
### Table 8-7 - Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

#### Congestion Revenue

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<th>Load Payments</th>
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<td>100</td>
<td>$1,000</td>
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<tr>
<td>B</td>
<td>$15</td>
<td>$750</td>
<td>0</td>
<td>$0</td>
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<tr>
<td>C</td>
<td>$20</td>
<td>$1,000</td>
<td>100</td>
<td>$2,000</td>
<td></td>
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<tr>
<td>D</td>
<td>$25</td>
<td>$1,250</td>
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<td>$0</td>
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#### FTR Target Allocations

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#### Congestion Accounting

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The data on this report is preliminary until the end of the billing cycle. Final results are based on month-end calculations that could significantly change the preliminary results that are displayed throughout the month.

The Hourly FTR Target Credit on this report may include the effect of settlement adjustments for reasons such as FTR forfeiture.

### Supporting Calculations

**If Hourly FTR Target Credit < 0,**

\[
\text{Hourly FTR Credit}(2210.01) = \text{Hourly FTR Target Credit}(2210.13)
\]

**Else (Hourly FTR Target Credit >= 0),**

\[
\text{Hourly FTR Credit}(2210.01) = \frac{\text{Hourly FTR Target Credit}(2210.13)}{\text{Total PJM FTR Target Credits}(2210.11) \times \text{Total PJM FTR Revenues}(2210.12)}
\]
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<td>PALCO</td>
<td>1/31/2008</td>
<td>33333333</td>
<td>20</td>
<td>1 MIKE24 KKV A-2</td>
<td>12345678</td>
<td>KATE18 KKV KC2</td>
<td>87654321</td>
<td>OBLIGATION</td>
<td>1</td>
</tr>
</tbody>
</table>

### Supporting Calculations

For each hour, Target Credit = (Sink DA Congestion Price - Source DA Congestion Price) * FTR MW * FTR Ownership Share

<table>
<thead>
<tr>
<th></th>
<th>L</th>
<th>M</th>
<th>AK</th>
<th>AL</th>
<th>AM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>2210.14</td>
<td>3011.01</td>
<td>3011.24</td>
<td>3011.26</td>
<td>4000.07</td>
</tr>
</tbody>
</table>

* Data Granularity: Hourly
* Frequency: Updated Daily

* HE 02 through HE 23 hidden due to space considerations
The FTR Uplift Credit, ARR Holder Excess Congestion Credit, ARR Uplift Credit and Transmission Customer Excess Congestion Credit that appear on this report are calculated at the end of the planning year and allocated back to each month within the planning year. The Planning Period Excess Congestion Credits and Planning Period Congestion Uplift Credits that appear on the billing statement reflect the sum of the credits stored for each month in the annual planning period (June - May). To view all details supporting the end of period credit, please retrieve this report for all months that fall within the applicable planning period.
Supporting Calculations

FTR Deficiency (2217.13) = Monthly FTR Target Credit (2217.11) – Monthly FTR Credit (2217.12)

ARR Deficiency (2217.16) = Monthly ARR Target Credit (2217.14) – Monthly ARR Credit (2217.15)

At the end of the planning period:

FTR Uplift Credit (2218.01) = FTR Deficiency (2217.13) – FTR Holder Excess Congestion Credit (2217.01)

ARR Uplift Credit (2218.02) = ARR Deficiency (2217.16) – ARR Holder Excess Congestion Credit (2217.02)
Example Case (Constrained)
Unconstrained Day-ahead Schedule
- Total day-ahead demand of 669 MW

Constrained Actual Operations
- Total actual demand of 900 MW
<table>
<thead>
<tr>
<th>Participant</th>
<th>Role</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>Metered entity that owns generation &amp; serves load in PJM</td>
</tr>
<tr>
<td>LSE 2</td>
<td>Retail load aggregator that serves portion of LSE 1’s metered load</td>
</tr>
<tr>
<td>EDC 3</td>
<td>Metered entity that owns generation &amp; serves load in PJM</td>
</tr>
<tr>
<td>EDC 4</td>
<td>Metered entity that owns generation &amp; serves load in PJM</td>
</tr>
<tr>
<td>Park City</td>
<td>Merchant generation plant that sells to PJM Spot Market</td>
</tr>
<tr>
<td>Alta</td>
<td>Merchant generation plant that sells to PJM Spot Market &amp; enters bilateral contracts with other PJM Members</td>
</tr>
</tbody>
</table>
Example - Day-Ahead Market: Demand Bids

**Bus B**
- **EDC 1:** Fixed Demand Bid for 200 MW at Bus B
- **LSE 2:** Decrement Bid for 23 MW at Bus B ($25)

**Bus C**
- **EDC 3:** Price Sensitive Demand Bid for 223 MW at Bus C ($25)

**Bus D**
- **EDC 4:** Fixed Demand Bid for 223 MW at Bus D

**Total Demand = 669 MW**
## Example - Day-Ahead Market: Generator Offers

### Scheduled Generation

<table>
<thead>
<tr>
<th>Bus</th>
<th>Generator</th>
<th>MWh Available</th>
<th>Owner</th>
<th>Offer Price</th>
<th>MWh Scheduled</th>
</tr>
</thead>
<tbody>
<tr>
<td>E</td>
<td>Brighton</td>
<td>600</td>
<td>33.3 % EDC 3</td>
<td>$10/MWh</td>
<td>600</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>66.7 % EDC 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>Alta</td>
<td>110</td>
<td>Merchant Generator Company X</td>
<td>$14/MWh</td>
<td>86</td>
</tr>
<tr>
<td>A</td>
<td>Park City</td>
<td>100</td>
<td>Merchant Generator Company Y</td>
<td>$15/MWh</td>
<td>0</td>
</tr>
<tr>
<td>C</td>
<td>Solitude</td>
<td>20</td>
<td>15% EDC 1</td>
<td>$30/MWh</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>42.5% EDC 3</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>42.5% EDC 4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>D</td>
<td>Sundance</td>
<td>200</td>
<td>100% EDC 4</td>
<td>$30/MWh</td>
<td>0</td>
</tr>
</tbody>
</table>
Example - Day-Ahead Market Results: Transaction Schedules

Alta schedules internal bilateral transaction in eSchedules for 5 MW on path A to D

*Alta is seller; EDC 4 is buyer.*

*Looks like 5 MW load for Alta at A*

*Looks like 5 MW generation for EDC 4 at D*
Example - Day Ahead Schedule

LMPs

Brighton
600 MW
$10/MWh

600 MW

600 MW

$10/MWh

Alta
110 MW
$14/MWh

Park City
100 MW
$15/MWh

E

225

240 MW
Thermal Limit

Solitude

Alta

373

223 MW

154

223 MW

305

223 MW

77

223 MW

146

223 MW

E

= Marginal Generator

Energy = $13.83
Loss = $0.00
Congestion = $0
Total LMP = $13.83

Energy = $13.83
Loss = $0.51
Congestion = $0
Total LMP = $14.33

Energy = $13.83
Loss = $0.79
Congestion = $0
Total LMP = $14.61

Energy = $13.83
Loss = $0.86
Congestion = $0
Total LMP = $14.69

Sundance

D

200 MW
$30/MWh

Solitude

520 MW
$30/MWh

Energy = $13.83
Loss = $0.17
Congestion = $0
Total LMP = $14.00
Example - Day Ahead Settlements

Net Spot MWh = DA Load + Energy Sale Transactions + Decrements Transactions - Generator + Energy Purchase Transactions + Increments Transactions

-200 = 200 (load @B) - 400 (66.7% of Brighton @E)  
23 = 23 (Dec bid @ B) - 0  
23 = 223 (P.S. Demand bid @ C) - 200 (33.3% of Brighton@E)  
218 = 223 (load @D) - 5 (purchase @D)  
0 = 0 - 0

-81 = 5 (sale @D) - 86 (Alta generation @A)

-17 (losses)
Example - Day-Ahead Spot Market Charges & Credits

Total Spot Market Charges = Positive Net Interchange (MWh) \times System Energy Price Component of DA LMP ($/MWh)

Total Negative Spot Market Charges = Negative Net Interchange (MWh) \times System Energy Price Component of DA LMP ($/MWh)
Example – Day Ahead Spot Market
Charges & Credits

($2766) = -200 MWh * $13.83/MWh  for EDC 1
$318 = 23 MWh * $13.83/MWh  for LSE 2
$318 = 23 MWh * $13.83/MWh  for EDC 3
$3015 = 218 MWh * $13.83/MWh  for EDC 4
$0 = 0 MWh * $13.83/MWh  for Park City
($1120.23) = -81 MWh * $13.83/MWh  for Alta

($235.23)

Credit offsets the total amount of loss surplus revenues to be distributed to LSEs and Exports
### Example – Day Ahead Implicit Losses – Load Loss Charges

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Day-ahead Load</th>
<th>Bus</th>
<th>Loss Price ($/MWh)</th>
<th>Loss Charge ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>200</td>
<td>B</td>
<td>0.79</td>
<td>158.00</td>
</tr>
<tr>
<td>LSE 2</td>
<td>23</td>
<td>B</td>
<td>0.79</td>
<td>18.17</td>
</tr>
<tr>
<td>EDC 3</td>
<td>223</td>
<td>C</td>
<td>0.86</td>
<td>191.78</td>
</tr>
<tr>
<td>EDC 4</td>
<td>223</td>
<td>D</td>
<td>0.51</td>
<td>113.73</td>
</tr>
<tr>
<td>Alta</td>
<td>5</td>
<td>A</td>
<td>0.17</td>
<td>0.85</td>
</tr>
</tbody>
</table>

\[ \sum \text{Loss Charge} = 482.53 \]
### Example – Day Ahead Implicit Losses – Generator Loss Credits

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Day-ahead Generation</th>
<th>Bus</th>
<th>Loss Price ($/MWh)</th>
<th>DA Generation Loss Credit ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>400</td>
<td>E</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>LSE 2</td>
<td>0</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>EDC 3</td>
<td>200</td>
<td>E</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>EDC 4</td>
<td>5</td>
<td>D</td>
<td>0.51</td>
<td>2.55</td>
</tr>
<tr>
<td>Alta</td>
<td>86</td>
<td>A</td>
<td>0.17</td>
<td>14.62</td>
</tr>
</tbody>
</table>

**Total Loss Credit:** 17.17
### Example – Day Ahead Implicit Losses Charge

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>DA Loss Charge ($)</th>
<th>DA Loss Credit ($)</th>
<th>DA Implicit Loss Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>158.00</td>
<td>0</td>
<td>158.00</td>
</tr>
<tr>
<td>LSE 2</td>
<td>18.17</td>
<td>0</td>
<td>18.17</td>
</tr>
<tr>
<td>EDC 3</td>
<td>191.78</td>
<td>0</td>
<td>191.78</td>
</tr>
<tr>
<td>EDC 4</td>
<td>113.73</td>
<td>2.55</td>
<td>111.18</td>
</tr>
<tr>
<td>Alta</td>
<td>.85</td>
<td>14.62</td>
<td>(13.77)</td>
</tr>
</tbody>
</table>
Example – Day Ahead Explicit Loss Charge

Day-ahead Explicit Loss Charges = Day Ahead Transaction MWh * DA Sink Loss Price LMP - DA Source Loss Price LMP

EDC 4: 5 * (0.51 - 0.17) = $1.70
Example - Transmission Congestion Charges

*No* Congestion Charges from Day Ahead Schedule
Example - Actual Operations

• Actual load > Day-ahead scheduled load
  – Total System Load (minus losses) = 900 MW
    • Bus B Load = 300 MW (223 MW day-ahead)
    • Bus C Load = 300 MW (223 MW day-ahead)
    • Bus D Load = 300 MW (223 MW day-ahead)
  – Details of Bus B Load
    • 31 MW is being served by LSE 2 (entered in eSchedules as Retail Load Responsibility Transaction)
      – 30 MW following PJM removal of EHV losses
      – Remaining load of 270 MW is served by EDC 1
## Example - Actual Operations: Generator Bids

### Generation Operating

<table>
<thead>
<tr>
<th>BUS</th>
<th>Generator</th>
<th>MWh Available</th>
<th>Owner</th>
<th>Offer Price</th>
<th>MWh Dispatched</th>
</tr>
</thead>
<tbody>
<tr>
<td>E</td>
<td>Brighton</td>
<td>600</td>
<td>33.3% EDC 3, 66.7% EDC 1</td>
<td>$10/MWh</td>
<td>600</td>
</tr>
<tr>
<td>A</td>
<td>Alta</td>
<td>110</td>
<td>Merchant Gen – Company X</td>
<td>$14/MWh</td>
<td>110</td>
</tr>
<tr>
<td>A</td>
<td>Park City</td>
<td>100</td>
<td>Merchant Gen – Company Y</td>
<td>$15/MWh</td>
<td>75</td>
</tr>
<tr>
<td>C</td>
<td>Solitude</td>
<td>520</td>
<td>15% EDC 1, 42.5% EDC 3, 42.5% EDC 4</td>
<td>$30/MWh</td>
<td>0</td>
</tr>
<tr>
<td>D</td>
<td>Sundance</td>
<td>200</td>
<td>100% EDC 4</td>
<td>$30/MWh</td>
<td>138</td>
</tr>
</tbody>
</table>
Since Alta scheduled internal bilateral transaction in eSchedules for 5 MW on path A to D in day-ahead market, this schedule also applies to balancing market.

*Alta is seller; while EDC 4 is buyer.*
Example 2 – Actual Operations

LMPs

<table>
<thead>
<tr>
<th>Location</th>
<th>Capacity (MW)</th>
<th>Price ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brighton</td>
<td>600</td>
<td>10</td>
</tr>
<tr>
<td>Alta</td>
<td>110</td>
<td>14</td>
</tr>
<tr>
<td>Park City</td>
<td>100</td>
<td>15</td>
</tr>
<tr>
<td>Sundance</td>
<td>200</td>
<td>30</td>
</tr>
<tr>
<td>Solitude</td>
<td>520</td>
<td>30</td>
</tr>
</tbody>
</table>

Energy = $10.43
Loss = $0.00
Congestion = $0
Total LMP = $10.43

Energy = $10.43
Loss = $0.38
Congestion = $19.19
Total LMP = $30.00

Energy = $10.43
Loss = $0.73
Congestion = $10.90
Total LMP = $22.06

Energy = $10.43
Loss = $0.13
Congestion = $4.44
Total LMP = $15.00

= Marginal Generators
Example - Balancing Settlements


-130 = -100 (400 Brighton gen @E + 300 load @B) + 0 -30 (esched retail load transfer to LSE 2)

30 = 0 + 30 (esched retail load transfer from EDC1) - 0

100 = 100 (-200 Brighton gen @E + 300 load @C) + 0 - 0

157 = 162 (-138 Sundance gen @D + 300 load @D) + 0 - 5 (esched purchase from Alta @D)

-75 = -75 (75 gen @A) + 0 – 0

-105 = -110 (110 Alta gen) + 5 (esched sale to LSE 4 @A) - 0

-23 (losses)

for EDC 1
for LSE 2
for EDC 3
for EDC 4
for Park City
for Alta
Example - Balancing Spot Market Charges & Credits

Balancing Spot Market Charges = Real Time Net Interchange (MWh) - Day Ahead Net Interchange (MWh) * System Energy Price Component of Real-time LMP ($/MWh)

Balancing Spot Market Credits = Real Time Net Interchange (MWh) - Day Ahead Net Interchange (MWh) * System Energy Price Component of Real-time LMP ($/MWh)
Example - Balancing Spot Market Charges & Credits

**Real-time Net Interchange**

$730.1 = (-130 - (-200 \text{ MWh}) \times $10.43/\text{MWh}$

$73.01 = (30 - 23 \text{ MWh}) \times $10.43/\text{MWh}$

$803.11 = (100 - 23 \text{ MWh}) \times $10.43/\text{MWh}$

($636.23) = (157 - 218 \text{ MWh}) \times $10.43/\text{MWh}$

($782.25) = (-75 - 0) \text{ MWh} \times $10.43/\text{MWh}$

($250.32) = (-105 - (-81)) \text{ MWh} \times $10.43/\text{MWh}$

(62.58)

**Day-ahead Net Interchange**

**System Energy Price Component of Real-time LMP**

for EDC 1

for LSE 2

for EDC 3

for EDC 4

for Park City

for Alta
Example - Summary of Day Ahead & Balancing Settlements

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Day Ahead Spot Market Payments</th>
<th>Balancing Spot Market Payments</th>
<th>Total Spot Market Payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>($2766)</td>
<td>730.1</td>
<td>($2035.9)</td>
</tr>
<tr>
<td>LSE 2</td>
<td>$318</td>
<td>73.01</td>
<td>$391.01</td>
</tr>
<tr>
<td>EDC 3</td>
<td>$318</td>
<td>$803.11</td>
<td>$1121.11</td>
</tr>
<tr>
<td>EDC 4</td>
<td>$3015</td>
<td>($636.23)</td>
<td>$2378.77</td>
</tr>
<tr>
<td>Park City</td>
<td>$0</td>
<td>($782.25)</td>
<td>($782.25)</td>
</tr>
<tr>
<td>Alta</td>
<td>($1120.23)</td>
<td>($250.32)</td>
<td>($1370.55)</td>
</tr>
</tbody>
</table>

Total ($297.81)
## Example – Balancing Implicit Losses – Load Loss Charges

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Balancing Load</th>
<th>DA Load</th>
<th>Bus</th>
<th>Balancing Loss Price ($/MWh)</th>
<th>Balancing Loss Charge ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>270</td>
<td>200</td>
<td>B</td>
<td>0.73</td>
<td>51.10</td>
</tr>
<tr>
<td>LSE 2</td>
<td>30</td>
<td>23</td>
<td>B</td>
<td>0.73</td>
<td>5.11</td>
</tr>
<tr>
<td>EDC 3</td>
<td>300</td>
<td>223</td>
<td>C</td>
<td>0.80</td>
<td>61.60</td>
</tr>
<tr>
<td>EDC 4</td>
<td>300</td>
<td>223</td>
<td>D</td>
<td>0.38</td>
<td>29.26</td>
</tr>
<tr>
<td>Alta</td>
<td>5</td>
<td>5</td>
<td>A</td>
<td>0.13</td>
<td>0</td>
</tr>
<tr>
<td>Park City</td>
<td>0</td>
<td>0</td>
<td>A</td>
<td>0.13</td>
<td>0</td>
</tr>
</tbody>
</table>

↑ - ↑ * = ↑
### Example – Balancing Implicit Losses – Generation Loss Credits

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Balancing Generation</th>
<th>DA Generation</th>
<th>Bus</th>
<th>Balancing Loss Price ($/MWh)</th>
<th>Balancing Loss Credit ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>400</td>
<td>400</td>
<td>E</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>LSE 2</td>
<td>0</td>
<td>0</td>
<td>-</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>EDC 3</td>
<td>200</td>
<td>200</td>
<td>E</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>EDC 4</td>
<td>143</td>
<td>5</td>
<td>D</td>
<td>0.38</td>
<td>52.44</td>
</tr>
<tr>
<td>Alta</td>
<td>110</td>
<td>86</td>
<td>A</td>
<td>0.13</td>
<td>3.12</td>
</tr>
<tr>
<td>Park City</td>
<td>75</td>
<td>0</td>
<td>A</td>
<td>0.13</td>
<td>9.75</td>
</tr>
</tbody>
</table>

↑ - ↑ * = ↑
## Example - Implicit Losses Charge

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Balancing Loss Charge ($)</th>
<th>Balancing Loss Credit ($)</th>
<th>Balancing Implicit Loss Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>51.10</td>
<td>0</td>
<td>51.10</td>
</tr>
<tr>
<td>LSE 2</td>
<td>5.11</td>
<td>0</td>
<td>5.11</td>
</tr>
<tr>
<td>EDC 3</td>
<td>61.60</td>
<td>0</td>
<td>61.60</td>
</tr>
<tr>
<td>EDC 4</td>
<td>29.26</td>
<td>52.44</td>
<td>(23.18)</td>
</tr>
<tr>
<td>Alta</td>
<td>0</td>
<td>3.12</td>
<td>(3.12)</td>
</tr>
<tr>
<td>Park City</td>
<td>0</td>
<td>9.75</td>
<td>(9.75)</td>
</tr>
</tbody>
</table>

81.76
Example – Balancing Explicit Loss Charge

Balancing Explicit Loss Charges = Transaction Deviation (RT – DA) MWh \times \text{Real Time Sink Loss Price LMP} - \text{Real Time Source Loss Price LMP}

EDC 4: \( 0 \times (0.38 - 0.13) = 0 \)
### Example – Total Loss Surplus

<table>
<thead>
<tr>
<th>Market</th>
<th>Implicit Loss Charge ($)</th>
<th>Explicit Loss Charge ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day Ahead</td>
<td>465.36</td>
<td>1.70</td>
</tr>
<tr>
<td>Balancing</td>
<td>81.76</td>
<td>0</td>
</tr>
</tbody>
</table>

**Total Loss Surplus = $548.82**
### Example – Total Loss Surplus Distribution

**Total Loss Surplus** = $548.82  
**Spot Market Credit** = -$297.81  
**Loss Surplus for Distribution** = $251.01

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Real-time Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>270mw@Bus B</td>
</tr>
<tr>
<td>LSE 2</td>
<td>30mw@Bus B</td>
</tr>
<tr>
<td>EDC 3</td>
<td>300mw@Bus C</td>
</tr>
<tr>
<td>EDC 4</td>
<td>300mw@Bus D</td>
</tr>
<tr>
<td>Park City</td>
<td>0</td>
</tr>
<tr>
<td>Alta</td>
<td>0</td>
</tr>
</tbody>
</table>

**Total Real-time Load** = 900mw
# Example – Total Loss Surplus Distribution

Loss Credit = \( \text{Total Loss Surplus (\$)} \times \frac{270}{900} \)

<table>
<thead>
<tr>
<th>EDC 1</th>
<th>$75.30</th>
<th>=</th>
<th>$251.01</th>
<th>*</th>
<th>270 / 900</th>
</tr>
</thead>
<tbody>
<tr>
<td>LSE 2</td>
<td>$8.37</td>
<td>=</td>
<td>$251.01</td>
<td>*</td>
<td>30 / 900</td>
</tr>
<tr>
<td>EDC 3</td>
<td>$83.67</td>
<td>=</td>
<td>$251.01</td>
<td>*</td>
<td>300 / 900</td>
</tr>
<tr>
<td>EDC 4</td>
<td>$83.67</td>
<td>=</td>
<td>$251.01</td>
<td>*</td>
<td>300 / 900</td>
</tr>
</tbody>
</table>

Customer total MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service

Total PJM MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service
Transmission Losses Credit

Day-ahead Transmission Loss Charges

Balancing Transmission Loss Charges

Transmission Losses Credit

LSEs & Exporters

Allocation based on hourly real-time load + export ratio shares
Example - Balancing Implicit Congestion

Balancing Implicit Congestion Charges =

Total Balancing Load Deviation Congestion Charges - Total Balancing Generator Deviation Congestion Credits

"Locational Net Congestion Bill"

Calculated using Congestion Price Component of LMP
### Example – Balancing Implicit Congestion – Load Congestion Charges

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Balancing Load</th>
<th>DA Load</th>
<th>Bus</th>
<th>Balancing Congestion Price ($/MWh)</th>
<th>Balancing Congestion Charge ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>270</td>
<td>200</td>
<td>B</td>
<td>10.90</td>
<td>763.00</td>
</tr>
<tr>
<td>LSE 2</td>
<td>30</td>
<td>23</td>
<td>B</td>
<td>10.90</td>
<td>76.3</td>
</tr>
<tr>
<td>EDC 3</td>
<td>300</td>
<td>223</td>
<td>C</td>
<td>13.19</td>
<td>1015.63</td>
</tr>
<tr>
<td>EDC 4</td>
<td>300</td>
<td>223</td>
<td>D</td>
<td>19.19</td>
<td>1477.63</td>
</tr>
<tr>
<td>Alta</td>
<td>5</td>
<td>5</td>
<td>A</td>
<td>4.44</td>
<td>0</td>
</tr>
<tr>
<td>Park City</td>
<td>0</td>
<td>0</td>
<td>A</td>
<td>4.44</td>
<td>0</td>
</tr>
</tbody>
</table>

The formula for calculating the Balancing Congestion Charge is: `Balancing Congestion Charge = (Balancing Load - DA Load) * Balancing Congestion Price`
# Example – Balancing Implicit Congestion – Generation Congestion Credits

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Balancing Generation</th>
<th>DA Generation</th>
<th>Bus</th>
<th>Balancing Congestion Price ($/MWh)</th>
<th>Balancing Congestion Credit ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>400</td>
<td>400</td>
<td>E</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>LSE 2</td>
<td>0</td>
<td>0</td>
<td>-</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>EDC 3</td>
<td>200</td>
<td>200</td>
<td>E</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>EDC 4</td>
<td>143</td>
<td>5</td>
<td>D</td>
<td>19.19</td>
<td>2648.22</td>
</tr>
<tr>
<td>Alta</td>
<td>110</td>
<td>86</td>
<td>A</td>
<td>4.44</td>
<td>106.56</td>
</tr>
<tr>
<td>Park City</td>
<td>75</td>
<td>0</td>
<td>A</td>
<td>4.44</td>
<td>333.00</td>
</tr>
</tbody>
</table>

↑ - ↑ * = ↑
### Example - Implicit Congestion Charge

<table>
<thead>
<tr>
<th>Market Participant</th>
<th>Balancing Congestion Charge ($)</th>
<th>Balancing Congestion Credit ($)</th>
<th>Balancing Implicit Congestion Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDC 1</td>
<td>763.00</td>
<td>0</td>
<td>763.00</td>
</tr>
<tr>
<td>LSE 2</td>
<td>76.30</td>
<td>0</td>
<td>76.30</td>
</tr>
<tr>
<td>EDC 3</td>
<td>1015.63</td>
<td>0</td>
<td>1015.63</td>
</tr>
<tr>
<td>EDC 4</td>
<td>1477.63</td>
<td>2648.22</td>
<td>(1170.59)</td>
</tr>
<tr>
<td>Alta</td>
<td>0</td>
<td>106.56</td>
<td>(106.56)</td>
</tr>
<tr>
<td>Park City</td>
<td>0</td>
<td>333.00</td>
<td>(333.00)</td>
</tr>
</tbody>
</table>

\[
\text{\textbf{Total:}} \ 244.78
\]
Example – Balancing Explicit Congestion Charge

EDC 4: 0 * (19.19 – 4.44) = $0
<table>
<thead>
<tr>
<th>Market</th>
<th>Implicit Congestion Charge ($)</th>
<th>Explicit Congestion Charge ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day Ahead</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Balancing</td>
<td>244.78</td>
<td>0</td>
</tr>
</tbody>
</table>

**Total Congestion Revenue = $244.78**
Example - Congestion Credits

FTR Target Allocation = FTR MW (0) = $0

No congestion in Day-ahead!

$244.78 congestion charges applied proportionately to eliminate target deficiencies in other hours of month
• This report that provides the hourly energy, transmission congestion and transmission loss charges for each unit. Details in report do not reflect share of joint ownership. All owners will see complete generator data information.
Supporting Calculations

DA Spot Market Energy Charge (1200.11) =
  DA Scheduled MWh (3000.32) * DA PJM Energy Price (3000.01)

DA Transmission Congestion Charge (1210.18) =
  DA Scheduled MWh (3000.32) * PNODE DA Congestion Price (3000.06)

DA Transmission Loss Charge (1220.18) =
  DA Scheduled MWh (3000.32) * PNODE DA Loss Price (3000.15)

Bal Generation (3000.91) = RT Generation (3000.33) - DA Scheduled MWh (3000.32)

Bal Spot Market Energy Charge (1205.11) =
  Bal Generation (3000.91) * RT PJM Energy Price (3000.02)

Bal Transmission Congestion Charge (1215.20) =
  Bal Generation (3000.91) * PNODE RT Congestion Price (3000.09)

Bal Transmission Loss Charge (1225.20) =
  Bal Generation (3000.91) * PNODE RT Loss Price (3000.18)
Day-ahead Market
DA System Energy Price = $10

Exercise 4

Export = 20 MW
Source DALP = $1; DACP = $10
Sink DALP = $3; DACP = $20

Load
Generation

LSE

Hint:
Spot Market Charges = SMI * “DA System Energy Price”
Implicit Congestion = Load Charges – Generator Credits using DACP
Explicit Congestion = Schedule MW (Sink DACP - Source DACP)
Implicit Losses = Load Charges – Generator Credits using DALP
Explicit Losses = Schedule MW (Sink DALP – Source DALP)

Calculate:
- DA Spot Market Charges
- DA Implicit Congestion
- DA Explicit Congestion
- DA Implicit Losses
- DA Explicit Losses

SMI = 30 MW (Net buyer)
Exercise 5

Balancing Market
RT System Energy Price = $20

Export = 0 MW
Source RTLP = $1; RTCP = $15
Sink RTLP = $3; RTCP = $28

30 MW
RTLP = $1.5; RTCP = $5

20 MW
RTLP = $1; RTCP = $10

10 MW
RTLP = $1; RTCP = $0

20 MW
RTLP = $0.5; RTCP = $15

30 MW
RTLP = $2; RTCP = $20

DEC Bid
0 MW
RTLP = $2; RTCP = $5

SMI = 10 MW (Net buyer)

Calculate:
- Balancing Spot Market Charges
- Balancing Implicit Congestion
- Balancing Explicit Congestion
- Balancing Implicit Losses
- Balancing Explicit Losses

Hint:
Calculate Deviations from DA
Spot Market Charges = SMI (deviation) * “RT System Energy Price”
Implicit Congestion = Load Charges – Generator Credits using RTCP (based on deviations from DA schedules)
Explicit Congestion = Transaction deviations (Sink RTCP - Source RTCP)
Implicit Losses = Load Charges – Generator Credits using RTLP (based on deviations from DA schedules)
Explicit Losses = Transaction deviations (Sink RTLP – Source RTLP)
• Market Settlements Terminology
• Line Items on a PJM Invoice
  • Spot Market Energy
  • Marginal Losses
  • Congestion
  • Transmission Service
• Ancillary Services
• Miscellaneous
• Review
Transmission Service

• **Network Integration**
  – Network customers pay daily demand charges based on zonal coincident peak load (including losses) priced at zonal rates
  – Transmission Owners receive their zonal revenues
  – Used for serving load

• **Firm Point-to-Point**
  – Point to Point customers pay demand charges based on transmission reservations priced at PJM border rates
  – Revenues allocated to transmission owners
  – Designated source and sink used for exports, wheels and imports

• **Non-Firm Point-to-Point**
  – Point to Point customers pay discounted rate ($0.67 per MWh reserved)
  – Revenues allocated to Network and Firm customers
  – Designated source and sink used for exports, wheels and imports
Network Integration Transmission Service

- **Charges**
  - Daily Demand Charge
  - \( \text{Network Customer Daily Peak Load Contribution} \)
  - \( \frac{1}{365} \)
  - Applicable Zonal rate

  - Coincident with metered zonal peak (including losses) for 12 months ending October of previous year

- **Credits**
  - Allocated to Transmission Owners in that zone on a transmission revenue requirement basis

PJM Tariff Reference - Section 34, Attachments H-1 through H-17, Section 5.4 of Transmission Owner Agreement

<table>
<thead>
<tr>
<th>1100</th>
<th>Network Integration Transmission Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>2100</td>
<td>Network Integration Transmission Service</td>
</tr>
</tbody>
</table>
### PJM Network Transmission Service Peak Loads for 2010

(Metered Demand Coincident with Zonal Peak Load Hour for Period 11/1/08-10/31/09)

<table>
<thead>
<tr>
<th>Zone</th>
<th>Zonal Peak (MW)</th>
<th>Hour Ending (Eastern Prevailing Time)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>24,421.9</td>
<td>1/16/2009 8</td>
</tr>
<tr>
<td>Allegheny Power</td>
<td>8,526.7</td>
<td>1/16/2009 19</td>
</tr>
<tr>
<td>Atlantic Electric</td>
<td>2,706.6</td>
<td>8/10/2009 18</td>
</tr>
<tr>
<td>Baltimore Gas &amp; Electric</td>
<td>6,596.0</td>
<td>8/10/2009 17</td>
</tr>
<tr>
<td>ComEd</td>
<td>21,217.9</td>
<td>6/25/2009 16</td>
</tr>
<tr>
<td>Dayton</td>
<td>3,338.5</td>
<td>6/25/2009 17</td>
</tr>
<tr>
<td>Delmarva</td>
<td>3,843.4</td>
<td>8/21/2009 15</td>
</tr>
<tr>
<td>Dominion</td>
<td>18,137.0</td>
<td>8/10/2009 17</td>
</tr>
<tr>
<td>Duquesne</td>
<td>2,732.2</td>
<td>8/17/2009 16</td>
</tr>
<tr>
<td>Jersey Central</td>
<td>5,738.4</td>
<td>8/10/2009 18</td>
</tr>
<tr>
<td>Metropolitan Edison</td>
<td>2,839.3</td>
<td>8/10/2009 17</td>
</tr>
<tr>
<td>PECO</td>
<td>7,993.0</td>
<td>8/10/2009 17</td>
</tr>
<tr>
<td>Pennsylvania Electric</td>
<td>2,865.6</td>
<td>12/22/2008 19</td>
</tr>
<tr>
<td>Potomac Electric Power</td>
<td>6,325.0</td>
<td>8/10/2009 18</td>
</tr>
<tr>
<td>PPL</td>
<td>7,608.7</td>
<td>1/16/2009 18</td>
</tr>
<tr>
<td>PSE&amp;G</td>
<td>9,686.7</td>
<td>8/21/2009 15</td>
</tr>
<tr>
<td>Rockland</td>
<td>371.1</td>
<td>8/17/2009 17</td>
</tr>
</tbody>
</table>
Network Integration Transmission Service

Effective: January 1, 2010

<table>
<thead>
<tr>
<th>Transmission Owner (Transmission Zone)</th>
<th>Annual Transmission Revenue Requirement</th>
<th>Network Integration Transmission Service Rate ($/MW-Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AE (AECO)</td>
<td>$65,798,896</td>
<td>$24,939</td>
</tr>
<tr>
<td>AEP (AEP)</td>
<td>$613,384,744</td>
<td>$25,339.25</td>
</tr>
<tr>
<td>AP (APS)</td>
<td>$128,000,000</td>
<td>$17,895</td>
</tr>
<tr>
<td>BC (BGE)</td>
<td>$107,536,202</td>
<td>$15,519</td>
</tr>
<tr>
<td>ComEd (CE)</td>
<td>$439,537,877</td>
<td>$20,982</td>
</tr>
<tr>
<td>Dayton (DAY)</td>
<td>$40,100,000</td>
<td>$13,296</td>
</tr>
<tr>
<td>Duquesne (DLCO)</td>
<td>$82,110,545</td>
<td>$29,096.58</td>
</tr>
<tr>
<td>Dominion (DOM)</td>
<td>$314,792,000</td>
<td>$17,356.08</td>
</tr>
<tr>
<td>DPL, ODEC (DPL)</td>
<td>$59,798,401</td>
<td>$14,984</td>
</tr>
<tr>
<td>FE (JCPL, METED, PENELEC)</td>
<td>$141,000,000</td>
<td>$15,112</td>
</tr>
<tr>
<td>PE (PECO)</td>
<td>$151,703,000</td>
<td>$20,942</td>
</tr>
<tr>
<td>PPL, AECoop, UGI (PPL)</td>
<td>$130,367,258</td>
<td>$17,487</td>
</tr>
<tr>
<td>PEPCO (PEPCO)</td>
<td>$89,310,733</td>
<td>$13,229</td>
</tr>
<tr>
<td>PS (PSEG)</td>
<td>$251,064,988</td>
<td>$25,919</td>
</tr>
<tr>
<td>Rockland (RECO)</td>
<td>$11,785,928</td>
<td>$32,114</td>
</tr>
<tr>
<td>TrAILCo</td>
<td>$47,262,046</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Rates as of 1/1/10
See OATT Attachment H-1 through H-17 for details
Facilities Charges

Direct Assignment Facilities:
- If through a System Impact Study, PJM determines the transmission system is not capable of providing Firm or Non-Firm Point-to-Point Transmission Service, the Transmission Owner is obligated to expand or upgrade the transmission system.

- Transmission customers must agree to compensate the transmission owner for any transmission facility additions.

- These charges may also apply to existing Network Customers based on the specifications in their network service agreements.

Other Supporting Facilities:
- The Transmission Customer shall also pay charges based on a case-by-case basis for facilities necessary to provide Transmission Service at voltages lower than those shown in Attachment H of the Open Access Transmission Tariff.
Charges

Monthly Demand Charge = Reserved Transmission Capacity * Applicable Tariff rate

<table>
<thead>
<tr>
<th>Yearly Charge ($/kW)</th>
<th>Monthly Charge ($/kW)</th>
<th>Weekly Charge ($/kW)</th>
<th>Weekday Charge ($/kW)</th>
<th>Weekend/NE RC Holiday($/kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>18.888</td>
<td>1.574</td>
<td>0.3632</td>
<td>0.0726</td>
<td>0.0519</td>
</tr>
</tbody>
</table>

Credits

- Total firm transmission service revenues collected are allocated to PJM Transmission Owners based on transmission revenue requirement ratio shares
- ComEd, Dominion and AEP shares further allocated to their respective zonal customers based on demand charge ratios

PJM Tariff Reference - Section 13.7, Schedule 7, Attachment R, Section 5.4 of Transmission Owner Agreement

Firm Point-to-Point Transmission Service requested on or after November 17, 2003 with a Point of Delivery (POD) at a MISO interface is not charged.
Non-Firm Point-to-Point Transmission Service

- **Charges**
  \[
  \text{Hourly Non-firm Demand Charge} = \left( \text{Reserved Transmission Capacity (MW Reserved – MW Curtailed)} \right) \times \text{Discounted Rate}
  \]
  - Hourly congestion charge if congestion > 0  
  
- **Credits**
  - Rebates for transaction MWh curtailed by PJM
  - Total Non-firm transmission service revenues are allocated to network and firm transmission service customers in proportion to their monthly demand charges for transmission service

Non-Firm Point-Point service requested on or after November 17, 2003 with a Point of Delivery (POD) at a MISO interface is not charged.

PJM Tariff Reference - Section 14.5, Section 27a, Schedule 8

<table>
<thead>
<tr>
<th></th>
<th>Non-Firm Point-to-Point Transmission Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>1140</td>
<td></td>
</tr>
<tr>
<td>2140</td>
<td></td>
</tr>
</tbody>
</table>
Non-Firm Point-to-Point Transmission Service

• For Non-firm – Willing to pay Congestion
  – If congestion is positive
    • Transmission Customer pays higher of
      – Transmission Congestion charge OR
      – Applicable non-firm tariff rate
      – (Rebate can only go as high as $.67)
  – If congestion is negative
    • Pay or be credited (congestion) the sum of
      – Transmission Congestion Charge
      – Applicable non-firm tariff rate
      – (No Rebate Applied)

  – Purchase of Non-firm Service cannot result in a credit.
Regional Through and Out Rate (RTOR) Elimination

- PJM will not charge for a transmission reservation with a Point of Delivery in MISO requested on or after November 17, 2003

- PJM will charge for a transmission reservation with a Point of Delivery not in MISO (including PJM imports)

- PJM will charge for firm transmission reservations redirected from having a Point of Delivery in MISO to having a Point of Delivery not in MISO

- PJM will charge for firm transmission reservations redirected from a non-exempt path to an exempt path based on the initial reservation

- PJM will charge for applicable ancillary services.
Regional Through and Out Rate (RTOR) Elimination

Combined Region

MISO

PJM

Chargeable

RTOR eliminated*

www.pjm.com

PJM©2009
Regional Through and Out Rate (RTOR) Elimination

Combined Region

MISO

PJM

Chargeable

RTOR eliminated*

www.pjm.com
# MSRS – Network Integrated Transmission Service Charge Summary

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
<th>H</th>
<th>I</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Network Integration Transmission Service Charge Summary</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Customer Ac PJM Interc Report Crc</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Start Date: 1/31/2008 End Date: 1/31/2008</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>4000.01</td>
<td>4000.02</td>
<td>4000.04</td>
<td>4000.32</td>
<td>3000.47</td>
<td>1100.11</td>
<td>1102.01</td>
<td>1100.01</td>
</tr>
<tr>
<td>5</td>
<td>Customer ID</td>
<td>Customer Code</td>
<td>Date</td>
<td>Zone</td>
<td>Daily Peak Load (MW)</td>
<td>Network Rate ($/MW per day)</td>
<td>Network Service Exempt Charge ($)</td>
<td>Network Service Charge ($)</td>
</tr>
<tr>
<td>6</td>
<td>1234</td>
<td>PALCO</td>
<td>1/31/2008</td>
<td>AECO</td>
<td>50</td>
<td>54.631148</td>
<td>0</td>
<td>2731.56</td>
</tr>
<tr>
<td>7</td>
<td>1234</td>
<td>PALCO</td>
<td>1/31/2008</td>
<td>JCPL</td>
<td>71</td>
<td>41.289617</td>
<td>0</td>
<td>2931.56</td>
</tr>
<tr>
<td>8</td>
<td>End of Report</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Data Granularity:** Daily  
**Frequency:** Updated Daily

## Supporting Calculations

Network Service Charge (1100.01) = Daily Peak Load (3000.32) * Network Rate (1100.11)

Network Service Exempt Charge (1102.01) = Daily Peak Load (3000.32) * Network Rate (1100.11) (applies only to those transmission owners that do not pay themselves for use of their own facilities)
MSRS – Network Integrated Transmission Service Credit Summary

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
<th>H</th>
<th>I</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Network Integration Transmission Service Credit Summary</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Customer Ac PJM Interconne Report Cred</td>
<td></td>
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<td>4000.01</td>
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<td>2100.11</td>
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<td>Customer ID</td>
<td>Customer Code</td>
<td>Date</td>
<td>Zone</td>
<td>Total Zone Network Service Charge ($)</td>
<td>Zone Revenue Requirement Share ($/MW per day)</td>
<td>Network Service Exempt Credit ($)</td>
<td>Network Service Credit ($)</td>
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</tbody>
</table>

Data Granularity: Daily
Frequency: Updated Daily

Supporting Calculations

\[
\text{Network Service Credit (2100.01) = Total Zone Charge (2100.11) \times Zone Revenue Requirement Share (2100.12)}
\]

\[
\text{Network Service Exempt Credit (2102.01) = Network Service Exempt Charge (1102.01) from the Network Integration Transmission Service Charge Summary report}
\]

(Exempt credit applies only to those transmission owners that do not pay themselves for use of their own facilities)
### Supporting Calculations

Firm PTP Transmission Service Daily Charge (1130.01) = Firm PTP Rate (1130.11) * Reservation Capacity (3000.52)
## MSRS – Firm Point-to-Point Transmission Service Credit Summary

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
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<th>K</th>
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<tr>
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<td>Firm Point-to-Point Transmission Service Credit Summary</td>
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<td>Customer Code</td>
<td>Month</td>
<td>Total PJM Firm Charges ($)</td>
<td>Transmission Revenue Requirement Share</td>
<td>Zone</td>
<td>Zone Peak Load (MW-days)</td>
<td>Total Zone Peak Load (MW-days)</td>
<td>Firm Credit ($)</td>
<td>Total Zone PTP Load Firm Charge ($)</td>
<td>PTP Load Firm Credit ($)</td>
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</tr>
</tbody>
</table>

### Supporting Calculations

Firm Credit (2130.01) = Total PJM Firm Charge (2130.11) \times \text{Transmission Revenue Requirement Share (3000.85)} \text{unless further allocation}

If further allocation:
Firm Credit (2130.01) = \text{Total PJM Firm Charge (2130.11)} \times \text{Transmission Revenue Requirement Share (3000.85)} \times \left( \frac{\text{Zone Peak Load (3000.88)}}{\text{Total Zone Peak Load (3000.89)}} \right)

PTP Load Firm Credit (2132.01) = \text{Total Zone PTP Load Firm Charge (2132.11)} \text{unless further allocation}

If further allocation:
PTP Load Firm Credit (2132.01) = \text{Total Zone PTP Load Firm Charge (2132.11)} \times \left( \frac{\text{Zone Peak Load (3000.88)}}{\text{Total Zone Peak Load (3000.89)}} \right)
## MSRS – Non-Firm Point-to-Point Transmission Service Charge Summary

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
<th>H</th>
<th>I</th>
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<th>K</th>
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<tr>
<td>1</td>
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<td>Non-Firm Point-to-Point Transmission Service Charges</td>
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<td>Start Date: 1/31/2008</td>
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<td>4000.1</td>
<td>4000.15</td>
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<td>1140.11</td>
<td>3013.01</td>
<td>3013.24</td>
</tr>
</tbody>
</table>

### Supporting Calculations

Non-Firm PTP Transmission Service Charge = (Hourly Non-Firm PTP Rate * Billable Capacity) - Congestion Adjustment

Data Granularity: Hourly  
Frequency: Updated Daily

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## MSRS – Non-Firm Point-to-Point Transmission Service Credit Summary

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
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<td>Customer Account</td>
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<td>Start Month: January, 2008</td>
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<td>5</td>
<td>Customer ID</td>
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<td>Total PJM Non-Firm Charges ($)</td>
<td>Network and Firm Demand Charge ($)</td>
<td>Total PJM Network and Firm Demand Charge ($)</td>
<td>Non-Firm Credit ($)</td>
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<td>6</td>
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</tbody>
</table>

The data on this report is preliminary until the end of the billing cycle. Final results are based on month-end calculations that could significantly change the preliminary results that are displayed throughout the month.

### Data Granularity: Monthly
Frequency: Updated monthly

### Supporting Calculations

Non-Firm Credit (2140.01) = Total PJM Non-Firm Charges (2140.11) \times (Network and Firm Demand Charge (2140.12) \div Total PJM Network and Firm Demand Charge (2140.13))
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. The MWh quantity may be positive or negative in any given hour.

- Allocated as +/- charges directly to all LSEs
- Based on real-time load ratio shares
- Priced at the PJM load-weighted-average LMP

  - Total LMP (All 3 Components)
  - Details: PJM Operating Agreement Schedule 1-3.7

- Positive inadvertent interchange typically results in a charge
- Negative inadvertent interchange typically results in a negative charge (ultimately a credit)
Inadvertent interchange posted on the PJM website at:

## MSRS - Inadvertent Interchange Charge Summary

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
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<th>J</th>
<th>K</th>
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<td>Start Date: 1/31/2008</td>
<td>End Date: 1/31/2008</td>
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<td>3000.02</td>
<td>3000.12</td>
<td>3000.21</td>
<td>3000.38</td>
<td>3000.41</td>
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<td>1230.03</td>
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<td>5</td>
<td>Customer ID</td>
<td>Customer Code</td>
<td>EPT Hour Ending</td>
<td>GMT Hour Ending</td>
<td>Total PJM Inadvertent Interchange (MWh)</td>
<td>RT PJM Energy Price ($/MWh)</td>
<td>RT PJM Congestion Price ($/MWh)</td>
<td>RT PJM Loss Price ($/MWh)</td>
<td>RT Load (MWh)</td>
<td>Total PJM RT Load (MWh)</td>
<td>Inadvertent Energy Charge ($)</td>
<td>Inadvertent Congestion Charge ($)</td>
<td>Inadvertent Loss Charge ($)</td>
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### Supporting Calculations

Inadvertent Energy Charge (1230.01) = \( (\text{Total PJM Inadvertent Interchange (3000.5)} \times (\text{RT Load (3000.38)} / \text{Total PJM RT Load (3000.41)})) \times \text{RT PJM Energy Price (3000.02)} \)

Inadvertent Congestion Charge (1230.02) = \( (\text{Total PJM Inadvertent Interchange (3000.5)} \times (\text{RT Load (3000.38)} / \text{Total PJM RT Load (3000.41)})) \times \text{RT PJM Congestion Price (3000.12)} \)

Inadvertent Loss Charge (1230.03) = \( (\text{Total PJM Inadvertent Interchange (3000.5)} \times (\text{RT Load (3000.38)} / \text{Total PJM RT Load (3000.41)})) \times \text{RT PJM Loss Price (3000.21)} \)

**Data Granularity:** Hourly  
**Frequency:** Updated Daily

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• Market Settlements Terminology
• Line Items on a PJM Billing Statement
  • Spot Market Energy
  • Marginal Losses
  • Congestion
  • Transmission Service
• Ancillary Services
• Miscellaneous
• Review
Customers receive monthly charges/credits for:

• Energy Markets (Day-ahead and Real-time)
  – Day-ahead and Balancing Spot Market Energy
  – Day-ahead and Balancing Transmission Congestion
  – Point-to-Point Transmission Losses
• Transmission Service (Network and Point-to-Point)
• Ancillary Services
  – Scheduling, System Control & Dispatch
  – Reactive Supply and Voltage Control from Generation Sources
  – Black Start Service
  – Regulation and Synchronized Reserve Markets
  – Operating Reserves
• Capacity Credit Markets (and deficiency charges and allocations)
• Miscellaneous Categories
### “Load” for Market Settlements Billing Items – Summary

<table>
<thead>
<tr>
<th>Billing Item Based on “Load + Losses”</th>
<th>Billing Item Based on “Lossless Load”</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network Transmission Service</td>
<td>Spot Market Energy (DA and Balancing)</td>
</tr>
<tr>
<td>Capacity Obligation</td>
<td>Congestion (DA and Balancing)</td>
</tr>
<tr>
<td>Schedule 1A- Trans Owner Scheduling, System Control and Dispatch</td>
<td>Regulation Obligation</td>
</tr>
<tr>
<td>Schedule 2 – Reactive</td>
<td>Synchronized Reserve Obligation</td>
</tr>
<tr>
<td>Schedule 6A – Black Start</td>
<td>DA Scheduling Reserve</td>
</tr>
<tr>
<td>Schedule 9-1 PJM Control Area Administration</td>
<td>Balancing Operating Reserve (Load deviations)</td>
</tr>
<tr>
<td>Schedule 9-3 PJM Market Support</td>
<td>Synchronous Condensing (for load following and post-contingency operation)</td>
</tr>
<tr>
<td>Schedule 9-FERC</td>
<td>Reactive Services (units reduced to provide more reactive power)</td>
</tr>
<tr>
<td>Schedule 9-OPSI</td>
<td>Load Response</td>
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<tr>
<td>Schedule 9-MMU</td>
<td>Inadvertent Interchange</td>
</tr>
<tr>
<td>Schedule 10-NERC</td>
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<tr>
<td>Schedule 10-RFC</td>
<td></td>
</tr>
</tbody>
</table>
Schedule 1-A Transmission Owner Scheduling, System Control and Dispatch Service

- Charges for operation of Transmission Owner control centers

  - Pt-Pt customers

  \[ \text{Monthly Charge} = \text{Energy Deliveries (MWh)} \times 0.1019/\text{MWh} \]

  Including Losses

* Rate as of 1/1/10
Schedule 1-A Transmission Owner Scheduling, System Control and Dispatch Service

- Network customers and customers using Point-to-Point Transmission Service to serve load

\[
\text{Monthly Charge} = \text{Real-time MWh monthly load} \times \text{Schedule 1A zonal rates (Including Losses)}
\]

<table>
<thead>
<tr>
<th>Zone</th>
<th>Rate (S/MWh)</th>
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<tbody>
<tr>
<td>Atlantic City Electric Company</td>
<td>0.0781</td>
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<tr>
<td>Baltimore Gas and Electric Company</td>
<td>0.0430</td>
</tr>
<tr>
<td>Delmarva Power &amp; Light Company</td>
<td>0.0743</td>
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<tr>
<td>PECO Energy Company</td>
<td>0.1189</td>
</tr>
<tr>
<td>PP&amp;L, Inc. Group</td>
<td>0.0618</td>
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<tr>
<td>Potomac Electric Power Company</td>
<td>0.0186</td>
</tr>
<tr>
<td>Public Service Electric and Gas Company</td>
<td>0.1030</td>
</tr>
<tr>
<td>Jersey Central Power &amp; Light Company</td>
<td>0.0796</td>
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<tr>
<td>Metropolitan Edison Company</td>
<td>0.0796</td>
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<tr>
<td>Pennsylvania Electric Company</td>
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<td>Rockland Electric Company</td>
<td>0.2475</td>
</tr>
<tr>
<td>Commonwealth Edison Company</td>
<td>0.2223</td>
</tr>
<tr>
<td>AEP East Operating Companies</td>
<td>Rate updated annually Per Attachment H-14</td>
</tr>
<tr>
<td>The Dayton Power and Light Company</td>
<td>0.0797</td>
</tr>
<tr>
<td>Duquesne Light Company</td>
<td>0.0520</td>
</tr>
</tbody>
</table>
Schedule 1-A Transmission Owner Scheduling, System Control and Dispatch Service

• Credits
  – Charges collected from Network customers provided to applicable transmission owner
  – Charges collected from Pt to Pt customers are allocated to transmission owners on a fixed % basis:

<table>
<thead>
<tr>
<th>Transmission Owner</th>
<th>Share (%)</th>
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<tbody>
<tr>
<td>Atlantic City Electric Company</td>
<td>0.50</td>
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<tr>
<td>Baltimore Gas and Electric Company</td>
<td>0.80</td>
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<tr>
<td>Delmarva Power &amp; Light Company</td>
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<td>PECO Energy Company</td>
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<tr>
<td>PP&amp;L, Inc. Group</td>
<td>1.36</td>
</tr>
<tr>
<td>Potomac Electric Power Company</td>
<td>0.33</td>
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<td>Public Service Electric and Gas Company</td>
<td>2.64</td>
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<td>AEP East Operating Companies</td>
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<td>The Dayton Power and Light Company</td>
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<tr>
<td>Duquesne Light Company</td>
<td>0.45</td>
</tr>
</tbody>
</table>

PJM Tariff Reference – Schedule 1A
Schedule 9 PJM Scheduling, System Control and Dispatch Service

- How PJM pays its bills
- Unbundled
  - Those who use the service, pay for it
  - 6 categories plus FERC, NERC, OPSI charges
  - Charges equal monthly usage multiplied by rate
  - Stated Rates began in 2006
  - Fixed rates determined annually based on budgeted costs and forecast usage associated with category
  - Quarterly refund rates to account for prior year’s over or under collection (Schedules 9-1 through 9-5)
Schedule 9 PJM Scheduling, System Control and Dispatch Service

- **Control Area Administration Service**
- (Schedule 9-1)
  - Reliability and transmission service related expenses
  - Charged to transmission customers
    - Network *(Real-time load including losses)*
    - Point-To-Point *(Scheduled Energy Transactions)*
  - Includes Losses
  - Fixed yearly rate
  - Charge equals total transmission use for the month multiplied by the applicable Control Area Administration Service Rate

<table>
<thead>
<tr>
<th>1301</th>
<th>Control Area Administration</th>
</tr>
</thead>
<tbody>
<tr>
<td>1308</td>
<td>Control Area Administration Refund</td>
</tr>
</tbody>
</table>
• **Fixed Transmission Rights Administration Service**

• (Schedule 9-2)
  – FTR administration and eFTR expenses
  – Two Components
  1) Sum of the FTR holder’s hourly FTR MWs for each hour of the month that the FTR is in effect, regardless of the dollar value of the FTR - Charged to FTR Holders

  2) The number of hours associated with all bids to buy FTR Obligations submitted by the market participant plus five times the number of hours associated with all bids to buy FTR Options submitted by each market participant for a month
     - This charge is applicable to all bids submitted into any round of the Annual FTR auction (billed monthly) and to all bids submitted into the applicable monthly FTR auctions. - Charged to FTR Auction Participants

<table>
<thead>
<tr>
<th>1302</th>
<th>FTR Administration</th>
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<tbody>
<tr>
<td>1309</td>
<td>FTR Administration Refund</td>
</tr>
</tbody>
</table>
Schedule 9 PJM Scheduling, System Control and Dispatch Service

• Fixed Transmission Rights Administration Service

• (Schedule 9-2)
  – Rates updated annually based on budgeted costs, forecast FTR MWh and FTR bid/offer hours
Schedule 9 PJM Scheduling, System Control and Dispatch Service

- Market Support Service
- (Schedule 9-3)
  - Energy Market, Market Settlements, eSchedules expenses
  - Charged to load (including losses), transmission customers and generation
    - Generation, Load, and cleared bid/offers
    - Each energy bid/offer segment price/quantity pair submitted or changed in eMKT

<table>
<thead>
<tr>
<th>1303</th>
<th>Market Support</th>
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<tbody>
<tr>
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</table>
Schedule 9 PJM Scheduling, System Control and Dispatch Service

- Market Support Service
- (Schedule 9-3)
  - Energy Market, Market Settlements, eSchedules expenses
  - Two Components
    1) Charged to Transmission Customers and Generation using the PJM Transmission System and to market participants that submit offers to sell or bids to buy energy in the PJM energy market
    - Usage for Transmission Customers defined as:
      - Sum of the Network Transmission Customer’s hourly energy delivered to serve load including losses in PJM
      - Network Transmission Customer’s hourly energy imported into PJM
      - Point-to-Point Transmission Customer’s hourly energy exported out of PJM (excluding wheels) for all hours of the month
      - Point-to-Point Transmission Customer’s hourly energy imported in PJM (excluding wheels)
Schedule 9 PJM Scheduling, System Control and Dispatch Service

- Market Support Service
- (Schedule 9-3)
  - Component 1 (continued)
  - Usage for Generation Provider’s defined as the sum of the hourly energy input into the PJM Transmission System from generation facilities within PJM
  - Market Seller’s hourly energy delivered for import to the boundaries of PJM for sale to the PJM Spot Market for all hours of the month
  - Market Participants total quantity in MWh of all cleared Increment Offers, Decrement Bids and “Up To” Congestion Bids during the month
2) Defined as the number of bid/offer segments submitted by the market participant
   - A bid/offer segment equals each price/quantity pair submitted into the day-ahead energy market and is **computed hourly** for each Network Transmission Customer’s fixed or price sensitive demand bid, each Market Seller’s Increment Offer and each Market Buyer’s Decrement Bid and **computed daily** for each generation offer (including offers submitted into the generation rebidding period).
   - In addition, bid/offer segments to schedule day-ahead Point-to-Point energy transactions into, out of or through PJM including “Up To” congestion bids, may be in single hour or multi-hour periods provided that the submitted MW value remains unchanged for the duration of the period and that the period does not cross from one day into another.
Schedule 9 PJM Scheduling, System Control and Dispatch Service

- Market Support Service
- (Schedule 9-3)

- All rates are updated annually and are based on budgeted costs, forecast energy MWh and forecast number of bid/offers and may include Mitigation Factor adjustments
• Regulation and Frequency Response Administration Service (Schedule 9-4)
  – Regulation and Frequency response service expenses
  – Charged to LSEs and regulating generators
  – Usage of this service is defined as the sum of the member’s regulation obligation (in MWh) plus the member’s regulation scheduled (pool-scheduled and self-scheduled) from all generating units qualified to supply regulation in the PJM regulation market for each hour of the month
  – Rate updated annually based on budgeted costs and forecast regulation usage

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<tr>
<th>1304</th>
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<tbody>
<tr>
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• **Capacity Resource and Obligation Management Service (Schedule 9-5)**
  
  – RAA, RPM markets, Processing Network Transmission Service
  – Charged to LSEs, generators
  – Usage of this service is defined as the sum of the Load-Serving Entity’s monthly accounted for obligations during the month including FRRs and the Capacity Resource Owner’s Unforced Capacity measured in MWd
  – Rates updated annually based on budgeted costs and forecast usage
  – Member’s charge is the total usage for the month multiplied by that month’s service rate

| 1305 | Capacity Resource/Obligation Mgmt. |
Advanced Second PJM Control Center Cost (Schedule 9-6)

- Recovery of the actual monthly costs of owning, leasing and operating AC²
  - PJM’s parallel control or second control center
- Monthly accrued actual costs related to AC²
- Collected across all users of Schedules 9-1 through 9-5
- Based on usage shares with costs allocated to applicable schedules
- Each PJM member’s schedule 9-6 charge is equal to that member’s usage share of total PJM usage for the month multiplied by the following cost shares allocated to each of the schedules:
  - Schedule 9-1 = 62.2%
  - Schedule 9-2a = 1.4%
  - Schedule 9-2b = .9%
  - Schedule 9-3a = 32.9%
  - Schedule 9-3b = .4%
  - Schedule 9-4 = 1.5%
  - Schedule 9-5 = .7%
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<tr>
<th>Effective Date</th>
<th>9-1 Control Area Administration Service (per MWh)</th>
<th>9-2 Financial Transmission Rights (FTR) Administration Service</th>
<th>9-3 Market Support (MS) Service</th>
<th>9-4 Regulation &amp; Frequency Response Administration Service (per MWh)</th>
<th>9-5 Capacity Resource &amp; Obligation Management Service (per MWh)</th>
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• FERC Annual Charge Recovery (Schedule 9-FERC)
  – PJM must recover charges assessed by FERC in accordance with Part 382 of FERC regulations
  – PJM charge based on total MWh of transmission of electric energy used in interstate commerce
  – Charged to Load (plus losses)
  – $0.0558/MWh charged to transmission customers based on usage of the PJM transmission system for 2009
    • Network customer’s real-time load plus losses
    • Point-To-Point customers’ real-time energy transactions
• OPSI Annual Charge Recovery (Schedule 9-OPSI)
  – OPSI is the regional state committee in the PJM region
    • Comprised of regulatory commissions of states in the PJM footprint
  – Rate is intended to recover costs to support OPSI
  – $0.00063 MWh charged to transmission customers based on usage of the PJM transmission system for 2009
    • Network customer’s real-time load plus losses
    • Point-To-Point customers’ real-time energy transactions

OPSIs = Organization of PJM States, Inc.
Market Monitoring Unit Funding (Schedule 9-MMU)

- Recovers costs of providing market monitoring functions as specified in PJM Open Access Transmission Tariff Attachment M

- 2009 rate $.0053/MWh charged to transmission customers based on network load (including losses) and exports, generation providers, imports and to day-ahead energy market participants based on accepted increment offers, decrement bids and up-to congestion bids

- 2009 rate $.0054 is charged for each energy bid/offer segment price/quantity pair submitted including those submitted during the rebidding period
North American Electric Reliability Corporation (NERC)
(Schedule 10-NERC)

- NERC is the Electric Reliability Organization certified by FERC
- Purpose is to ensure the reliability of the interconnected bulk power system
- Recovers a share of NERC’s cost of operations
- Based on energy delivered to load (excluding load in Dominion and Duquesne zones)
- $0.0068/MWh for 2009
- Over and under collections trued up in December billing cycle
• Reliability First Corporation (RFC)
  • (Schedule 10-RFC)
    – RFC is a Regional Reliability Organization (RRO) of NERC
    – This schedule recovers RFC’s statutory costs of operations
    – Based on energy delivered to load (Excludes Load in the Dominion and Duquesne zones)
    – $0.0087/MWh for 2009
    – Actual costs trued up in December billing cycle

1318 | Reliability First Corporation (RFC)
### MSRS - Schedule 9 and 10 Charge Details

#### Data Granularity: Daily
#### Frequency: Updated Daily

This report does not have any calculated values that are supported purely by other columns on this report.

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### Advanced Second Control Center Charge Detail Report

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- Report identifies the AC2 charges as they relate to Schedule 9-1 through Schedule 9-5

This report does not have any calculated values that are supported purely by other columns on this report.
Schedule 2 Reactive Supply and Voltage Control from Generation Sources Service

- All Transmission customers purchase this service from PJM
- Required to maintain transmission voltages within acceptable PJM reliability limits
- Annual Revenue Requirements filed with FERC
  - NOT Market-based

PJM Tariff Reference – Schedule 2
Schedule 2 Reactive Supply and Voltage Control from Generation Sources Service

- **Credits**
  - Monthly credits are provided to generation and transmission owners with FERC-approved reactive revenue requirements
  - 1/12 of annual reactive revenue requirement monthly

- **Charges**
  - Allocated to point-to-point customers based on monthly transmission service reserved
  - Remaining revenue requirements not allocated for each zone are allocated to network customers based on monthly peak load (including losses)

<table>
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<tr>
<th>1330</th>
<th>Reactive Supply and Voltage Control from Generation and Other Sources Service</th>
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<tr>
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<td>Reactive Supply and Voltage Control from Generation and Other Sources Service</td>
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Schedule 2 Reactive Supply and Voltage Control from Generation Sources Service

Effective June 2009

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<th>Zone</th>
<th>Generator or Other Source</th>
<th>Annual Reactive Revenue Requirement</th>
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<td>Brookfield Power Pinny &amp; Deep Creek LLC</td>
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<td></td>
<td>York Generation Company, LLC (Marcal)</td>
<td>$333,159.00</td>
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</tbody>
</table>

**PJM TOTAL** $241,493,345.56
Additional Compensation for Reactive Support

• Generators that reduce MW output to provide additional reactive support (at PJM request) may be eligible for Lost Opportunity Cost if Real-time LMP is greater than offer price at requested reduced MW output level
  – More MVAR available at lower MW output levels
    • PJM will monitor reactive performance of these redispatched units and may withhold compensation if reactive support is not provided
• Daily Charges for these reactive services allocated to Network Service customers in the zone where redispatch exists for increased reactive support (Losses not included)

PJM Operating Agreement – Schedule 1 Section 3.2.3B
Supporting Calculations

Reactive Services Charge (1378.01) = 
Total Zone Reactive Services Credit (1378.11) * 
(RT Zone Load (3000.46) / Total RT Zone Load (3000.35))
Schedule 6A Black Start Service

- All Transmission customers purchase this service from PJM
- Required to ensure power grid could restart following complete system blackout
- Critical units for System Restoration compensated for their costs incurred in maintaining blackstart capability
- Annual Revenue Requirements approved by PJM Market Monitoring Unit
  - NOT Market-based

PJM Tariff Reference – Schedule 6A
Schedule 6A Black Start Service

• Credits

  – Monthly credits are provided to critical blackstart generation based on annual revenue requirements
  – 1/12 of annual black Start revenue requirement monthly
  – Annual Revenue requirements based on standard formula
    • See Schedule 6A or Black Start Business Rules for details of calculation

\[ \{(\text{Fixed Blackstart Costs}) + (\text{Variable Blackstart Costs}) + (\text{Training Costs}) + (\text{Fuel Storage & Carrying Costs})\} \times (1 + \text{Incentive Factor}) \]

2380 Black Start Service
Schedule 6A Black Start Service

• Charges
  • Zonal rates based on black Start capability within zone
  • Allocated to point-to-point customers based on monthly peak usage
  • Remaining revenue requirement in each zone is allocated to network customers serving load in that zone based on monthly peak loads (including losses)
  • Charge allocation identical to Reactive Support and Voltage Control Service

1380 Black Start Service
# Schedule 6A Black Start Service

<table>
<thead>
<tr>
<th>Transmission Zone</th>
<th>Annual Black Start Revenue Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>AECO</td>
<td>$430,610.62</td>
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<tr>
<td>AEP</td>
<td>$852,966.20</td>
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<td>APS</td>
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<td>COMED</td>
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<td>DAYTON</td>
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<td>DPL</td>
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<td><strong>PJM TOTAL</strong></td>
<td><strong>$10,694,754.43</strong></td>
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Effective: January 1, 2010
# Black Start Service Charge Summary

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<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
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<th>J</th>
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<th>L</th>
<th>M</th>
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<tbody>
<tr>
<td>Start Month: January, 2008</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Customer ID</th>
<th>Customer Code</th>
<th>Month</th>
<th>Zone</th>
<th>Zone Black Start Revenue Requirement ($)</th>
<th>Revenue Requirement Effective Date</th>
<th>Black Start Zone Peak Transmission Use (MW)</th>
<th>Black Start Non-Zone Peak Transmission Use (MW)</th>
<th>Black Start Total Zone Peak Transmission Use (MW)</th>
<th>Black Start Total PJM Zone Peak Transmission Use (MW)</th>
<th>Black Start Total PJM Non-Zone Peak Transmission Use (MW)</th>
<th>Black Start Charge ($)</th>
<th>Version</th>
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<tbody>
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</table>

## Supporting Calculations

- **Zones:**

  \[
  \text{Black Start Charge (1380.01) = Zone Black Start Revenue Requirement (1380.11) * (Black Start Zone Peak Transmission Use (1380.12) / Black Start Total Zone Peak Transmission Use (1380.14)) * (Black Start Total PJM Zone Peak Transmission Use (1380.15) / (Black Start Total PJM Zone Peak Transmission Use (1380.15) + Black Start Total PJM Non-Zone Peak Transmission Use (1380.16)))}
  \]

- **Non-Zones:**

  \[
  \text{Black Start Charge (1380.01) = Zone Black Start Revenue Requirement (1380.11) * (Black Start Non-Zone Peak Transmission Use (1380.13) / (Black Start Total PJM Zone Peak Transmission Use (1380.15) + Black Start Total PJM Non-Zone Peak Transmission Use (1380.16)))}
  \]
What is Regulation?

- **Definition**
  - A variable amount of generation energy under automatic control which is independent of economic cost signal and is obtainable within five minutes
  - 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

- Generating units that provide fine tuning that is necessary for effective system control
- Governors respond to minute-to-minute changes in load
- Regulating units correct for small load changes that cause the power system to operate above and below 60 Hz for sustained period of time
• Regulation Ancillary Service is Market-based
• PJM conducts a single Regulation market
• Details of Regulation Market not covered in this training
  – Covered in Detail in Market Operations Center (MOC) Training

PJM Operating Agreement Reference – Schedule 1-3.2.2, 3.2.2A, 3.3.2 and 3.3.2A.
• Generation owners receive hourly credits
  – Pool-scheduled or Self-scheduled regulation MWh priced at Regulation Market Clearing Price
  – Additional revenue for any portion of regulation bid plus lost opportunity cost not recovered by regulation market clearing price revenues
  – Additional revenue for any other unrecovered costs incurred by a unit called on by PJM solely for providing Regulation
    • I.e. Startup costs

2340 Regulation and Frequency Response Service
Regulation Charges

• Obligation is based on real-time load ratio share (lossless load) of applicable PJM regulation obligation
• Adjusted obligation is original obligation plus bilateral sales minus bilateral purchases
• Shares of Opportunity Costs and Unrecovered Costs is based on amount of Regulation purchased from the market

\[
\text{(RMCP} \times \text{Adjusted Obligation)} + \text{Share of Opportunity Cost Above RMCP} + \text{Share of Unrecovered Costs}
\]

1340 Regulation and Frequency Response Service
### Supporting Calculations

**Adjusted Reg Obligation** (1340.14) = Reg Obligation (1340.11) + Bilateral Reg Sales (1340.12) + Bilateral Reg Purchases (1340.13)  
RMCP Charge (1340.01) = Adjusted Reg Obligation (1340.14) * RMCP (3000.57)

Reg Purchase (1340.15) = MAX (Adjusted Reg Obligation (1340.14) - Self-Scheduled Reg (2340.14), 0)  
Reg Lost Opportunity Cost Charge (1340.02) = Total PJM Reg Lost Opportunity Cost Credit (1340.17) * (Reg Purchase (1340.15) / Total PJM Reg Purchase (1340.16))

RMCP Credit (2340.15) = (PJM-Assigned Reg (2340.13) + Self-Scheduled Reg (2340.14)) * RMCP (3000.57)

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<tr>
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<th>Q</th>
<th>R</th>
<th>S</th>
<th>T</th>
<th>U</th>
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**Data Granularity:** Hourly  
**Frequency:** Updated daily
### MSRS - Regulation Credits

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<td>RMCP ($/MWh)</td>
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<td>RT Generator LMP ($/MWh)</td>
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</table>

**Supporting Calculations**

- \[ \text{RMCP Credit}(2340.19) = (\text{PJM-Assigned Reg}(2340.17) + \text{Self-Scheduled Reg}(2304.18)) \times \text{RMCP}(3000.57) \]
- \[ \text{Reg Offer Amount}(2340.22) = \text{PJM-Assigned Reg}(2340.17) \times \text{Reg Offer Price}(2340.21) \]
- \[ \text{Regulation Lost Opportunity Cost Credit}(2340.24) = \max((\text{Regulation Lost Opportunity Cost}(2340.23) + \text{Reg Offer Amount}(2340.22) - (\text{PJM-Assigned Reg}(2340.17) \times \text{RMCP}(3000.57))), 0) \]

**Data Granularity:** Hourly  
**Frequency:** Updated daily
The Day-ahead Scheduling Reserve Market is an offer-based market that will clear existing reserve requirements on a forward basis. The market is designed to create an explicit value for an additional reserve product in the PJM markets on a short-term basis. The market provides a pricing method and price signals to encourage generation and demand resources to provide day-ahead scheduling reserves, and to encourage the deployment of new resources with the capability to provide such reserves.

- Day-ahead Scheduling Reserve (DASR) market was implemented on June 1, 2008.
Day-ahead Scheduling Reserve Billing Line Items

- DASR Billing Line Items
  - Day-ahead Scheduling Reserve Credit
    - DASR Credit = DASR Cleared Offer MWh * DASR Hourly Clearing Price (assuming real-time criteria are met)
    - Lost opportunity cost credit is also calculated, as applicable
    - Any revenue above offer will offset Balancing Operating Reserve credits
  - Day-ahead Scheduling Reserve Charge
    - Hourly DASR Obligation MWh = Customers’ Real-time load ratio share of Total PJM DASR Cleared MWh
    - DASR Charge = Total DASR Credits (including lost opportunity cost payments) allocated on a DASR Obligation ratio share
    - Day-ahead Operating Reserve Charges should decrease due to this market
Day-ahead Scheduling Reserve Reports

- Day-ahead Scheduling Reserve Summary
  - Account-level charges and credits
- Day-ahead Scheduling Reserve Credits
  - Unit-level credits
- Load Response for Day-ahead Scheduling Reserve Credits
  - Resource-level credits
- Day-ahead Scheduling Reserve Preliminary Billing Data
  - Preliminary data posted to pjm.com (currently available)

Additional DASR market information available at:
http://www.pjm.com/markets/energy-market/day-ahead-scheduling-reserve-market.html
This report displays the customer account's hourly Day-ahead Scheduling Reserve Charges and Credits where the account's DASR Charge or DASR Credit is not equal to 0. The credits summarized on this report are reflective of credits received by the customer account’s generation units and demand side resources that participate in the DASR market.

### Supporting Calculations

\[
\text{DASR Obligation (1365.14)} = \text{Total PJM Cleared DASR MWh (1365.11)} \times \left[ \frac{\text{RT Load (1365.12)}}{\text{Total PJM RT Load (1365.13)}} \right]
\]

\[
\text{Adjusted DASR Obligation (1365.17)} = \text{MAX} \left[ \text{DASR Obligation (1365.14)} + \text{Bilateral DASR Sales (1365.15)} - \text{Bilateral DASR Purchases (1365.16)} \right], 0 \]

\[
\text{DASR Charge (1365.01)} = \text{Total PJM DASR Credits (1365.19)} \times \left[ \frac{\text{Adjusted DASR Obligation (1365.17)}}{\text{Total PJM Adjusted DASR Obligation (1365.18)}} \right]
\]

\[
\text{DASR Credit (2365.20)} = \text{DASRMCP (2365.18)} \times \text{Cleared DASR MWh (2365.19)}
\]
This report displays the customer account’s hourly Day-ahead Scheduling Reserve for each unit that is eligible for Day-ahead Scheduling Reserve Credits, for each hour the unit is eligible. The credits in this report do not reflect the customer account’s share of jointly owned units. All owners will see the full credit assigned to the unit.

**Supporting Calculations**

**DASR Credit (2365.14) = DASRMCP (2365.12) * Cleared DASR MWh (2365.13)**

**DASR Operating Reserve Offset (2520.17) = MAX [DASR Credit (2365.14) – ((Cleared DASR MWh (2365.13) * DASR Offer Price (2520.15)) + DASR Opportunity Cost (2520.16)), 0]**
**Synchronized Reserve Market**

**Definition:** 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 reserves

- Synchronized Reserve (10-minute reserve) Service is Market-based
- Ensures PJM can respond to sudden loss of generation and maintain system control
- Details of Synchronized Reserve Market not covered in this training
  - Covered in Detail in GEN-301 Training

| 1360 | Synchronized Reserve |
| 2360 | Synchronized Reserve |

**PJM Operating Agreement Reference** – Schedule 1-3.2.3, 3.3.3.
**PJM OATT Reference** – Schedule 5
Schedule 5 Synchronized Reserve Service

- Zero sum calculation based on Synchronized Reserve provided by generation owners or demand resources and purchased by load serving entities
- Obligation determined hourly based on real time load ratio share (lossless load)
- Broken into Tier 1 / Tier 2 charges and credits
<table>
<thead>
<tr>
<th>Tier 1 – Economic</th>
<th>Marginal, partially loaded units - online, following economic dispatch and able to increase output in response to a Spinning event</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tier 2 – Non-economic</td>
<td>Condensers (CTs and hydro), steam reduced to provide spinning, CTs on at min – operating at a point that deviates from economic dispatch</td>
</tr>
</tbody>
</table>
Synchronized Reserve Market Areas

RFC Synchronized Reserve Zone

ComEd
AEP
AP
DAY

Mid Atlantic Synchronized Reserve Sub-zone

Southern Synchronized Reserve Zone

DOM

Control Zone
Ancillary Service Region
Energy delivered by Tier 1 resource in response to a Synchronized Reserve request will be compensated based on a “premium” over and above LMP.

Premium will be calculated using the average LMP over a synchronized reserve event plus an adder:
- Initially set at $50

Compensation for Tier 1 will therefore be the Synchronized Event Average LMP plus $50, minus the hourly integrated LMP for the hour(s) in which an event occurred.

Tier 1 credits paid only in the event units respond to a synchronized reserve event.
• Hourly Integrated LMP = $30
• Synchronized Reserve Event LMP = $40
• Unit’s Integrated MW Increase over the Synchronized Event = 20 MW

Compensation for Spinning = (20 MW) [($50 + $40) - $30]
= (20 MW) ($60) = $1,200
Tier 2 Compensation

- Self-scheduled Tier 2 credits equal the SRMCP (for the correct location) times the amount of Tier 2 Self-Scheduled.

- Assigned Tier 2 will be credited the higher of:
  1. \((\text{SRMCP}) \times (\text{Assigned Synchronized Capability})\)
  2. \((\text{Synchronized offer}) \times (\text{Assigned synchronized capability}) + (\text{Opportunity Cost in Real time}) + (\text{Energy use incurred in Real time}) + \text{Startup costs}\)

SRMCP = Synchronized Reserve Market Clearing Price
Tier 1 Charges

- Total Synchronized Obligation is LSE real-time load ratio share (lossless load) of PJM Obligation
- Tier 1 charges for each participant equal to percentage share of total Tier 1 credits paid to all generators
- Percentage share of credits determined by:
  - Tier 1 provided from that participant’s own resources up to the amount of obligation
  - remaining load ratio share of any excess Tier 1 provided by generation owners in excess of their individual obligations
- Tier 1 charges will only exist if a synchronized event occurs within a given hour
Tier 2 charges for each participant are the obligation share of:

- all Tier 2 self-scheduled towards the participant’s obligation plus that which is purchased from the market times the respective SRMCP
- the total costs incurred by assigned Tier 2 above the SRMCP
- costs of Tier 2 resources assigned in addition to those estimated before the operating hour
Hierarchical Charge

- Obligation share is determined hourly by load ratio share (lossless load) within each reserve zone.

- Costs of resources assigned after the market clearing are allocated to entities whose available Tier 1 in real-time was less than estimated.
<table>
<thead>
<tr>
<th></th>
<th>A</th>
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Data Granularity: Hourly
Frequency: Updated daily

If there is not a split zone (the price for subzones within a synchronized reserve zone are equal) the Total Subzone Obligation, Total Subzone Load, Total Subzone Remaining Bilateral Adjusted Obligation and Total Subzone Tier 1 Excess columns will display values for the whole Synchronized Reserve Zone total, rather than the Subzone total.
MSRS – Synchronized Reserve Obligation Details

Supporting Calculations

Synch Reserve Obligation (1360.24) = Total Subzone Obligation (1360.21) * (Subzone Load (1360.22) / Total Subzone Load (1360.23)) + Tier 2 Shortfall (1360.32)

Adjusted Synch Reserve Obligation (1360.27) = Synch Reserve Obligation (1360.24) + Bilateral Synch Reserve Sales (1360.25) - Bilateral Synch Reserve Purchases (1360.26)

Remaining Bilateral Adjusted Obligation (1360.29) = MAX (Adjusted Synch Reserve Obligation (1360.27) - Tier 1 Estimate MWh (1360.28), 0)

Obligation Ratio Share of Excess Tier 1 (1360.31) = Total Subzone Tier 1 Excess (1360.30) * (Remaining Bilateral Adjusted Obligation (1360.29) / Total Subzone Remaining Bilateral Adjusted Obligation (1360.33))

Tier 1 Allocation to Obligation (1360.12) = MIN(Remaining Bilateral Adjusted Obligation (1360.29), Obligation Ratio Share of Excess Tier 1 (1360.31)) + MIN(Adjusted Synch Reserve Obligation (1360.27), Tier 1 Estimate MWh (1360.28))

Above Obligation Tier 1 Adjustment (1360.14) = Adjusted Synch Reserve Obligation (1360.27) - Tier 1 Allocation to Obligation (1360.12)

Synch Reserve Purchases (1360.15) = MAX (Above Obligation Tier 1 Adjustment (1360.14) - Tier 2 Self-Scheduled MWh (3000.63), 0)
# MSRS – Synchronized Reserve Tier 1 Charge Summary

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## Supporting Calculation

Tier 1 Charge (1360.01) = Total Zone Tier 1 Credit (1360.11) * (Tier 1 Allocation to Obligation (1360.12) / Total Zone Tier 1 Allocation to Obligation (1360.13))

Data Granularity: Hourly  
Frequency: Updated daily
## MSRS – Synchronized Reserve Tier 2 Charge Summary

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### Data Granularity: Hourly

**Frequency: Updated daily**

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Supporting Calculations

SRMCP Charge (1360.02) = Above Obligation Tier 1 Adjustment (1360.14) * SRMCP (3000.61)

If Total Zone Tier 1 Lost (1360.20) > 0, then:

Synch Reserve Lost Opportunity Cost Charge Cleared (1360.03) = Total Zone Synch Reserve Lost Opportunity Cost Credit Cleared (1360.17) * (Synch Reserve Purchases (1360.15) / Total Zone Synch Reserve Purchases (1360.16))

Synch Reserve Lost Opportunity Cost Charge Added (1360.04) = Total Zone Synch Reserve Lost Opportunity Cost Credit Added (1360.18) * (Tier 1 Lost (1360.19) / Total Zone Tier 1 Lost (1360.20))
### MSRS – Synchronized Reserve Credit Summary

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### Supporting Calculation

SRMCP Credit (2360.17) = SRMCP (3000.61) * (Tier 2 PJM-Scheduled MWh (2360.14) + Tier 2 PJM-Added MWh (2360.15) + Tier 2 Self-Scheduled MWh (3000.63) - Tier 2 Shortfall (2360.48))
## Supporting Calculations

If Tier 1 Synch Reserve Response (2360.20) is LESS THAN OR EQUAL TO Synch Reserve Capability (2350.21) then:

\[
\text{Tier 1 Credit MWh (2360.23) = Tier 1 Synch Reserve Response (2360.20) + Tier 1 Adjustment (2360.22)}
\]

If Tier 1 Synch Reserve Response (2360.20) is GREATER THAN Synch Reserve Capability (2350.21) then:

\[
\text{Tier 1 Credit MWh (2360.23) = Synch Reserve Capability (2350.21) + Tier 1 Adjustment (2360.22)}
\]

Tier 1 Credits (2360.24) = Tier 1 Credit MWh (2360.23) * (Tier 1 Premium Price (3000.64) – RT Generator LMP (3000.25))

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**MSRS – Synchronized Reserve Tier 1 Credits**

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**Data Granularity:** Hourly  
**Frequency:** Updated daily
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<td>Unit ID</td>
<td>Unit Name</td>
<td>Unit Ownership Share</td>
<td>SRMCP ($/MWh)</td>
<td>Tier 2 PJM-Scheduled MWh</td>
<td>Tier 2 PJM-Added MWh</td>
<td>Tier 2 Self-Scheduled MWh</td>
<td>Tier 2 Shortfall (MWh)</td>
<td>SRMCP Credit ($)</td>
</tr>
<tr>
<td>6</td>
<td>1234</td>
<td>PALCO</td>
<td>03/29/2008 01</td>
<td>03/29/2008 05</td>
<td>87654321</td>
<td>DAVIDC 02</td>
<td>0.3333</td>
<td>8.62</td>
<td>36</td>
<td>0</td>
<td>72</td>
<td>0</td>
<td>930.96</td>
</tr>
</tbody>
</table>

### Data Granularity: Hourly

### Frequency: Updated daily
MSRS – Synchronized Reserve Tier 2 Credits

Supporting Calculations

SRMCP Credit (2360.29) = SRMCP (3000.61) * (Tier 2 PJM Scheduled MWh (2360.25) + Tier 2 PJM Added MWh (2360.26) + Tier 2 Self Scheduled MWh (2360.27) – Tier 2 Shortfall (2360.28))

Condenser Energy Use Cost (2360.31) = Condenser Energy Use (2360.30) * RT Generator LMP (3000.25)

Synch Reserve Offer Amount (2360.33) = (Tier 2 PJM Scheduled MWh (2360.25) + Tier 2 PJM-Added MWh (2360.26) – Tier 2 Shortfall (2360.28)) * Spin Price

Synch Reserve Lost Opportunity Cost Credit Cleared (2360.35) = MAX (0, (Synch Reserve Lost Opportunity Cost (2360.32) + Synch Reserve Offer Amount (2360.33) + Condenser Start Up Cost (2360.34) – SRMCP Credit (2360.29)) * (Tier 2 PJM-Scheduled MWh (2360.25) + Tier 2 PJM-Added MWh (2360.26) / ((Tier 2 PJM-Scheduled MWh (2360.25) + Tier 2 PJM-Added MWh (2360.26))))

Synch Reserve Lost Opportunity Cost Credit Added = MAX (0, (Synch Reserve Lost Opportunity Cost (2360.32) + Synch Reserve Offer Amount (2360.33) + Condenser Start Up Cost (2360.34) – SRMCP Credit (2360.29)) * (Tier 2 PJM-Added MWh (2360.26) / ((Tier 2 PJM-Scheduled MWh (2360.25) + Tier 2 PJM-Added MWh (2360.26)))))
<table>
<thead>
<tr>
<th>Schedule</th>
<th>Ancillary Service</th>
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<td>Schedule 1A</td>
<td>Synchronized Reserve Service</td>
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<td>Trans Owner Scheduling, System Control and Dispatch Service</td>
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<td>Schedule 9</td>
<td>Black Start Service</td>
</tr>
</tbody>
</table>
Operating Reserves
What are Operating Reserves?

- **“Operations”** Definition of Operating Reserves
  - “Extra” available generation that is scheduled on a day-ahead basis and maintained in real-time.
  - Defined in
    - PJM Pre-Scheduling Manual (M-10)
    - PJM Emergency Ops Manual (M-13)

- **“Accounting”** Definition of Operating Reserves
  - “Make-whole” payments to pool-scheduled generation and transactions.
  - Defined in Operating Agreement
    - Schedule 1-3.2.3 & 3.3.3

- Following presentation deals with the **Accounting Definition**
Operating Reserves

- Preserves incentive for demand and supply to bid and offer into the day-ahead market based on their actual expectations.
- Preserves incentive for generation to follow real-time dispatch signals:
  - Generation guaranteed to make bid.
- Performed on a daily basis.
- Somewhat complex and volatile.
Day-ahead Operating Reserves Credits

- Pool scheduled generators, demand response and transactions scheduled for PJM are eligible.
- For each eligible resource, daily credit is day-ahead offer amount in excess of day-ahead market revenue.
  - Calculation uses day-ahead scheduled MWh, offer data, and day-ahead LMPs.
- Total offered price for start-up and no-load costs and energy determined on the resources scheduled output shall be compared to the value of the resource’s energy determined by the Day-ahead Energy Market.
Day-ahead Operating Reserves Charges

• Day-ahead Operating Reserves payments are allocated proportionately by MW to:
  – all cleared day-ahead demand
  – cleared decrement bids
  – exports that submit day-ahead schedules (not including dynamically scheduled transactions)

Rates posted on PJM website at:
Balancing Operating Reserve Credits

- Daily credits for specified operating period segments provided to:
  - Pool-scheduled generators
  - Demand response
  - Import transactions

- Credits are for any portion of their offer amount in excess of:
  - Scheduled MWh times day-ahead bus LMP
  - MWh deviation from day-ahead schedule times real-time bus LMP
  - Any day-ahead operating reserve credits
  - Any day-ahead scheduling reserve market revenues in excess of offer
  - Any synchronized reserve market revenues in excess of offer plus opportunity, energy use and startup costs
  - Any applicable reactive services credits

- Cancellation and quick start reserve credits are based on actual costs submitted to PJM market settlements

- Credits for lost opportunity costs are also provided to generators reduced or suspended by PJM for reliability purposes
Balancing Operating Reserve Charges

- Total daily costs of balancing operating reserve related to resources identified as **Credits for Deviations** is allocated based on regional shares of real-time locational deviations from following the day-ahead scheduled quantities of:
  - Cleared generation offers (only for generating units not following PJM dispatch instructions and not assessed deviations based on their real-time desired MWh
  - Cleared increment offers and purchase transactions
  - Cleared demand bids, decrement bids and sale transactions

- Total daily cost of operating reserve in the balancing market related to resources identified as **Credits for Reliability** is allocated based on regional shares of real-time load (without losses) plus exports.
Balancing Operating Reserve BOR Terminology

**Total Cost:**
- Total credit amount paid to generators to supply RT Operating Reserves
- Total “Bucket”

**Rate:**
- $ per MW charge that is derived from Total Cost
- Calculated daily

**Charge:**
- *Allocation* of the Total Cost to the participant based on deviations, BORCA rules, netting by location, etc.
- Charged **weekly** per the daily Rate

- \[
  \text{Total Cost} \div \text{Charge} = \text{Rate}
  \]
## The “Package” of BOR Changes

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<th>Impact</th>
<th>Description</th>
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<td><strong>Segmented Make-Whole Payments</strong></td>
<td>Generator Credits</td>
<td>Segment Make-Whole Payments as a function of the greater of the DA Schedule, or Min Run Time</td>
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<tr>
<td><strong>Minimum Generator Operating Parameters – Parameter Limited Schedules</strong></td>
<td>Generator Credits</td>
<td>Define operator objectives and the associated relevant market for solutions. Apply the defined market power test to the defined market. Apply market power mitigation rules only when the test indicates the potential to exercise market power.</td>
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<tr>
<td><strong>Use Ramp-Limited Desired MW to determine deviations</strong></td>
<td>Generator Deviations</td>
<td>PJM will determine whether a generator is following dispatch and calculate the deviation based on a new calculation incorporating ramp limited desired MW</td>
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<tr>
<td><strong>Supplier Netting at the Bus (Plant)</strong></td>
<td>Generator Deviations</td>
<td>Generators that deviate from RT dispatch may offset deviations by another generator at the same bus.</td>
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<tr>
<td><strong>Regional Balancing Operating Reserve Allocation</strong></td>
<td>Charge Allocation</td>
<td>Allocate OR charges that were accrued for local constraints to the regions, creating “regional” rates for Balancing Operating Reserve charges.</td>
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<tr>
<td><strong>Netting (by Zone, Interface, Hub)</strong></td>
<td>Charge Allocation</td>
<td>Demand bucket should be netted locationally by zone, hub, or interface. Supply bucket should be netted locationally by zone, hub, or interface.</td>
</tr>
<tr>
<td><strong>Balancing Operating Reserve Cost Allocation</strong></td>
<td>Charge Allocation</td>
<td>For the purposes of allocation of Balancing Operating Reserve charges, PJM will determine and identify the reasons for which operating reserve credits are earned. The results of this determination will identify the resources for which Balancing Operating Reserve credits will be allocated to Real-time deviations from Day-Ahead schedules and identify the resources for which Balancing Operating Reserve credits will should be allocated to real-time load share plus export</td>
</tr>
</tbody>
</table>
Segmented Make-Whole Payments

- Segment Make-Whole Payments as a function of the greater of the DA Schedule, or Min Run Time

- A resource will be made whole for two periods for each synchronized start. The two periods are as follows:
  1. greater of the DA Schedule or Min Run time
  2. hours in excess of #1 (above)

- Segment does not “carry over” to the next day

- Start-up costs (and applicable no-load costs) will be in the segment “greater of the DA Schedule or Min Run Time”

- Segmented Make-Whole Payments are an overall benefit to resources
Example 1: Unit was extended in real time for two hours beyond its day ahead schedule. (LMP is less than offer during extended period)

Example 1: Unit was extended in real time for two hours beyond its day ahead schedule. (LMP is less than offer during extended period)

Explanation:

**Segment 1: Day Ahead Schedule**
- DA Energy = (4 hours * $100 * 150 MW) = $60,000
- DA Offer = (4 hours * $75 * 150 MW) = $45,000
- Day Ahead OR Credit: $0
- Balancing OR Credit: $0

**Segment 2: Extended Period**
- RT Energy = (2 hours * $50 * 150 MW) = $15,000
- RT Offer = (2 hours * $75 * 150 MW) = $22,500
- Balancing OR Credit: $7,500
Example 2: Unit was extended in real time through the midnight period. The unit was uneconomic for most of the extended period.

**Explanation:**

**Segment 1: Day Ahead Schedule**
- DA Energy = (16 hours * $100 * 150 MW) = $240,000
- DA Offer = (16 hours * $75 * 150 MW) = $180,000
- DA OR Credit: $0
- Balancing OR Credit: $0

**Segment 2: Extended Period**
- RT Energy = (4 hours * $25 * 150 MW) + (3 hours * $50 * 150 MW) + (1 hour * $110 * 150 MW) = $54,000
- RT Offer = (8 hours * $75 * 150 MW) = $90,000
- Balancing OR Credit: $36,000
Example 3: Unit was extended in real time for four hours beyond its min run time. (LMP is less than offer during extended period)

Explanation:

**Segment 1: Min Run Time**
- RT Energy = (4 hours * $80 * 150 MW) = $48,000
- RT Offer = (4 hours * $75 * 150 MW) = $45,000
- Balancing OR Credit: $0

**Segment 2: Extended Period**
- RT Energy = (4 hours * $50 * 150 MW) = $30,000
- RT Offer = (4 hours * $75 * 150 MW) = $45,000
- Balancing OR Credit: $15,000
Segmented Make-Whole Payments

Example 4 – Unit Y Extended Beyond Min Run Time

Example 4: Unit was extended in real time for four hours beyond its min run time. (LMP is less than offer during extended period)

**Explanation:**

**Segment 1: Min Run Time**
- RT Energy = (2 hours * $100 * 150 MW) + (2 hours * $25 * 150 MW) = $37,500
- RT Offer = (4 hours * $75 * 150 MW) = $45,000
- Balancing OR Credit: $7,500

**Segment 2: Extended Period**
- RT Energy = (2 hours * $75 * 150 MW) + (2 hours * $100 * 150 MW) = $52,500
- RT Offer = (4 hours * $75 * 150 MW) = $45,000
- Balancing OR Credit: $0
Desired Outcome

Issues with current construct include:

*inflexible operating parameters* during times of transmission constrained operations and/or maximum generation conditions

*potential of generation resources to exercise market power* by altering operating parameters in order to increase operating reserves credits.

Solution

- Apply market power mitigation rules only when a market power test indicates the potential to exercise market power.
What are Parameter-Limited Schedules?

Parameter-Limited Schedules are limitations that could be imposed on the parameters that generators submit as part of their offer.

These pre-determined limits are used when certain operational circumstances exist.
Parameter Limited Schedules

• For each unit class, minimum acceptable operating parameters include:
  - Turn Down Ratio (Ratio of Eco Max MW to Eco Min MW)
  - Minimum Down Time
  - Minimum Run Time
  - Maximum Daily Starts
  - Maximum Weekly Starts

Future parameters MAY include:
Hot Start Notification Time, Warm Start Notification Time, Cold Start Notification Time

Some parameters will be set based on operating history of the unit compared to % of PJM-defined unit class

i.e.

The initial Minimum Down Time for each unit is based on the minimum of the Minimum Down Times submitted over the prior 24 months, if the resultant minimum down time is less than or equal to 110 percent of the PJM-defined unit class Minimum Down Time. If Minimum Down Time submitted for a unit is more than 110 percent of the PJM-defined unit class Minimum Down Time, then the unit’s Minimum Down Time will be set equal to 110 percent of the PJM defined unit class Minimum Down Time.
When are Parameter-Limited Schedules used?

Units will be committed on Parameter-Limited Schedules when:

1) The Three Pivotal Supplier (TPS) Test is failed

   -- OR --

2) PJM:
   - declares a Maximum Generation Emergency
   - issues a Maximum Generation Emergency Alert
   - schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert for all or any part of such Operating Day
Normal Operations

- Generators continue on their Price Schedule and non-limited parameters

Generator fails the Three Pivotal Supplier Test (TPS)

- Generators are placed on their cost schedule as well as their Parameter-Limited Schedules

Max Emergency Alert, loading, etc.

- Generators continue on their price schedule but placed on their Parameter-Limited Schedules (note: Scarcity Pricing rules may apply)
Parameter-Limited Schedules – example for Min Run Time

Without Parameter-Limited Schedules in effect:

A 150MW Combustion Turbine (CT) submits a 20-hour Minimum Run Time

HE 1  HE 20

This parameter could have substantial impacts to BOR credits if LMP prices fall below the unit offer prior to the end of the min-run time

With Parameter-Limited Schedules in effect:

PJM implements the parameter-limited schedule based on submitted value or unit class (in this case, 5 hours or less)

HE 1  HE 5

Business Rule 14: The submitted Minimum Run Time may not exceed the defined Minimum Run Time for the PJM defined unit class.

See Appendix for complete list of PJM-defined values
Daily Exception Process – Business Rules

• On a daily basis, the generation supplier may submit notification to PJM that changed physical operational limitations at the unit require a temporary exception to the unit’s parameters.

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

• Each generation supplier will provide a date on which the exception period will end. Exceptions granted may not continue past the beginning of the next period. Such exceptions will be accepted, but will be subject to after-the-fact review by PJM and the MMU. If physical conditions at the unit change such that the exception is no longer required, the generation supplier is obligated to inform PJM and the exception will be terminated.

• If an exception request is denied by PJM, the generation supplier may choose to dispute the decision via the PJM Dispute Resolution Process per the OA. While under dispute, the generation supplier will be required to submit parameter-limited schedules for the period as determined during the exception process.
Multiple Fuels / Nuclear Units Business Rules

• Multiple-fuel units may submit a parameter-limited schedule (PLS) associated with each fuel type. All PLS’s must be submitted via eMKT seven days prior to the beginning of each period. The generation supplier will be required to indicate to PJM which of the parameter-limited schedules are available each day. The exception process (as previously described) for any of the PLS’s submitted for multiple-fuel units will be in effect.

• Nuclear Units are excluded from eligibility for Operating Reserve payments except in cases where PJM requests that nuclear units reduces output at PJM’s direction. Other specific circumstances will be evaluated on a case-by-case basis by PJM and the MMU.
Create greater incentive for generators to follow PJM real-time dispatch instruction rather than day-ahead schedule

Determination of generation deviations will be made using new criteria:
1. Ramp-Limited Desired MW
2. % Off Dispatch
3. MW Off Dispatch

Once a generator is deemed “deviating,” charges will be based on operational characteristics of the generator and of one of the following calculations:
1. Real Time MWh – Ramp Limited Desired MWh
2. Real Time MWh – UDS LMP Desired MWh
3. Real Time MWh – Day-Ahead MWh
Ramp Limited Desired (RLD) – Getting Started

Definitions, Acronyms, and New Terms applicable to RLD

- **UDS Basepoint** – time weighted individual generator dispatch point (this value is ramp limited)
- **Ramp Limited Desired (RLD) MW** – achievable MW based on UDS requested ramp rate (this value is ramp-limited)
- **UDS LMP Desired MWh** - calculated by comparing the hourly integrated UDS LMP to the unit’s bid curve to determine a corresponding MW value (this value is not ramp-limited)
- **Day-Ahead MWh** – the participants DA market position
- **% Off Dispatch** – percentage off dispatch using the lesser of the difference between the actual output and the UDS basepoint or the actual output and Ramp Limited Desired MW (new calculation)
- **MW Off Dispatch** – MW off dispatch using the lesser of the difference between the actual output and the UDS basepoint or the actual output and Ramp Limited Desired MW (new calculation)
- **% Off Dispatch & MW Off Dispatch** time-weight the values over the hour

Which units will this apply to?

- DA Scheduled units
- RA Run (2nd pass) Scheduled units
- Must-Run units that are dispatchable and dispatched above Eco Min

![Diagram](image_url)
Operating Scenarios with Ramp Limited Desired MW

Operating scenarios of the generator will determine if and how a deviation is calculated:

- No Deviation Calculation?
- Real Time MWh – Ramp Limited Desired MWh?
- Real Time MWh – UDS LMP Desired MWh?
- Real Time MWh – Day-Ahead MWh?

See Business Rules for more details.
BR 39: A pool-scheduled or dispatchable self-scheduled generator is considered to be “following dispatch” if its actual output is between its Ramp Limited Desired MW and UDS Basepoint, (or its % off dispatch is <= 10) or it’s hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated Ramp Limited Desired MW. A self-scheduled generator must also be dispatched above economic minimum.

(Dotted line represents Ramp-Limited Desired MW)

No Deviation Calculation

No Deviation Calculation

< = 5% or 5MW
BR 40: A dispatchable self-scheduled resource that is not dispatched above economic minimum will be assessed deviations using |hourly integrated Real-time MWh – Day-Ahead MWh|

Economic Maximum – 200 MW

Unit is Self Scheduled

RT Unit Output – 175 MW (Ramps 1 MW / min)

Economic Minimum – 100 MW

The RT dispatch lambda is $50, which translates to 100 MW (Eco Min)

Deviation based on Hourly Integrated RT MWh – Day-Ahead MWh
BR 41: A unit that is dispatchable Day-Ahead but is Fixed Gen in real-time will have deviations assessed using $|\text{hourly integrated Real-time MWh} - \text{UDS LMP Desired MW}|$.

____________ DA Economic Maximum – 200 MW

Unit is dispatchable in DA
Fixed Gen in RT

____________ DA Economic Minimum – 100 MW

------------ RT Fixed Gen Unit Output – 150 MW (Ramps 1 MW / min)

In RT, participant flags eMKT as Fixed Gen with 150 MW output

Deviation based on RT MWh - UDS LMP Desired
In Summary:

If the Real-Time ratio of Eco Min / Eco Max become more restrictive than what was submitted in the Day-Ahead, then the deviation is calculated as:

\[
\text{Real Time MWh} - \text{UDS LMP Desired MWh}
\]

If the Real-Time ratio of Eco Min / Eco Max is equal to (or less restrictive) what was submitted in the Day-Ahead, then the deviation is calculated as:

\[
\text{Real Time MWh} - \text{Ramp Limited Desired MWh}
\]
The RT dispatch lambda increases to $150, which translates to above 200 MW (Eco Max)
In this case using a 20 minute UDS Look-Ahead:
Ramp-Limited Desired = 145 MW
UDS Basepoint = 200  UDS LMP Desired= 200

If RT Eco Max = 200 and RT Eco Min = 100
then,
Deviation based on Ramp-Limited Desired (145 – 125) if unit does not respond to lambda increase
(note: % off Dispatch is < 20%)  

If RT Eco Max = 200 and RT Eco Min = 125
then,
Deviation based on UDS LMP Desired (200 – 125) if unit does not respond to lambda increase
BR 48: If the unit is deemed “not following dispatch” and its % Off Dispatch is $\leq 20\%$, the deviation will be calculated as the $|\text{hourly integrated Real-time Mwh} - \text{hourly integrated Ramp Limited Des MW}|$.

As mentioned earlier, if deviation value is within $5\%$ or $5\text{ MW (whichever is greater)}$ of Ramp Limited Desired MW, no deviations will be calculated.

Deviation based on RT MWh – Ramp-Limited Desired MW

BR 49: If the unit is deemed to be “not following dispatch” and its % off Dispatch is $> 20\%$, the unit’s deviations will be calculated as $|\text{hourly integrated Real time MWh} - \text{UDS LMP Desired MWh}|$.

Deviation based on RT MWh – UDS LMP Desired MWh

% Off Dispatch – percentage off dispatch using the lesser of the difference between the actual output and the UDS basepoint or the actual output and Ramp Limited Desired MW.
BR 50: If a unit is deemed to be “not following dispatch” and has tripped, the deviation MW for the hour it tripped and the hours it remains offline throughout its DA Schedule will be calculated as |hourly integrated Real time MWh – Day-Ahead MWh|

Deviation based on Hourly Integrated RT MWh – Day-Ahead MWh
Supplier Netting at the Bus

– Recognize that generator injections at the same bus are electrically equivalent as far as their impact on the system.
– Generators that deviate from RT dispatch may offset deviations by another generator at the same bus.
– For deviations purposes, these two units will look like one unit.
Generators A and B are located at the same bus. Both generators are deemed to be “not following dispatch” for a given hour.

<table>
<thead>
<tr>
<th></th>
<th>Station A 138KV ST1</th>
<th>Station A 138KV ST2</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT Desired MW</td>
<td>100</td>
<td>200</td>
</tr>
<tr>
<td>RT Output (MW)</td>
<td>112</td>
<td>178</td>
</tr>
<tr>
<td>Deviation (MW)</td>
<td>12</td>
<td>-22</td>
</tr>
</tbody>
</table>

Deviation MW at the Bus:
12MW + (-22MW) = 10MW **

(**5% or 5 MW of Desired is calculated at the individual generator level prior to netting the two deviations. Therefore, both units are considered deviating.)

Total MWs subject to BOR charges:
10MW

** Note: Ramp Limited Desired MW calculation could also be applicable
Balancing Operating Reserve Charges Applied to:

- **Day-Ahead**
  - Cleared Decrement, DA Load, Sales/Export
    - By Zone, by Hub, by Interface
  - Net Deviation of total

- **Real-Time**
  - RT Load, Sales/Export
    - By Zone, by Hub, by Interface

- **Bucket 1**
  - Net Deviation of total

- **Bucket 2**
  - Cleared Increments, Purchases/Imports
    - By Zone, by Hub, by Interface
  - Net Deviation of total

- **Bucket 3**
  - DA Scheduled Generation
  - Individual deviation on each generator not following dispatch
  - RT Generation
LSE “EnerWave”
Serves load in two zones in different PJM regions

Zone A
- DA Fixed Demand = 100
- RT Load Served = 0

Zone B
- DA Fixed Demand = 0
- RT Load Served = 100

Deviation calculation = 100 (Zone A) + 100 (Zone B) = 200 MW Total Dev

Does not change total COST of BORs. Allocates cost to increased participant base with possible impact to CHARGES.
Some hubs are wholly-contained inside a zone (nested). Netting is allowed across areas that are nested.

Deviation calculation = 0 MW Total Dev (DA position in ComEd Zone offsets RT position in ComEd Gen Hub)
Balancing Operating Reserve Cost Allocation (BORCA)

Certain Balancing OR costs are incurred for reasons other than differences between Day-Ahead schedules and actual conditions. The desire is to recognize this split in cost causation and allocate the portion of Balancing OR incurred to maintain system reliability to the beneficiaries of those costs.

Solution

For the purposes of allocation of Balancing Operating Reserve charges, PJM will determine and identify the reasons for which operating reserve credits are earned.

This determination will be conducted by PJM in two stages:
- 1) those resources called on during the Reliability Analysis and
- 2) those resources called on to operate during the operating day.

The results of this determination will identify the resources for which Balancing Operating Reserve credits will be allocated to Real-time deviations from Day-Ahead schedules and identify the resources for which Balancing Operating Reserve credits should be allocated to real-time load share plus exports.
Differentiating the reasons why operators are making decisions into the following categories:
  a) Reliability
  b) Managing Deviations from DA positions

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<th>Reliability</th>
<th>Managing Deviations</th>
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<td>Collect system costs (BOR) due to reliability decisions</td>
<td>Collect system costs (BOR) due to changes (deviations) from DA schedules on a System–wide &amp; Local basis</td>
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<tr>
<td><strong>Denominator</strong></td>
<td>RT Load and Exports</td>
<td>All Deviations (Including Incs &amp; Decs)</td>
</tr>
</tbody>
</table>
Reliability Analysis (RA) BOR Cost Allocation

**RA BOR Credits for Reliability**
Units committed due to extenuating conditions that warrant conservative actions to ensure the maintenance of system reliability (i.e. – to provide reserves over and above the quantity determined by the real time load forecast)

**RA BOR Credits for Deviations**
Units committed to operate in real time in order to augment the physical units committed in the Day-Ahead Market to meet the forecasted real time load plus the operating reserve requirement

Real- Time (RT) BOR Cost Allocation

**RT BOR Credits for Reliability**
Units called on by PJM to operate during the operating day for which the LMP at the unit’s bus does not meet or exceed the unit’s applicable offer (cost or price) for at least four, 5-minute intervals of at least one clock hour during which the unit was running at PJM’s direction

**RT BOR Credits for Deviations**
All other units operated at PJM’s direction in real time

Load Ratio Share plus exports

Real- Time Deviations from Day-Ahead Schedules
Balancing Operating Reserve Cost Allocation - Regional

• **Former Rule**
  – All balancing operating reserve credits are divided equally among all deviations (Supply Bucket, Demand Bucket, and Generator Bucket), to create a single Balancing Operating Reserve Rate across the PJM RTO.

• **Outcome**
  – Recognize that some Balancing OR credits are accrued to manage local constraints

• **Change**
  – Allocate OR charges that were accrued for local constraints to the regions, creating “regional” rates for Balancing Operating Reserve charges.
As determined during Real Time (RT) or during the Reliability Analysis (RA), Balancing Operating Reserve Credits will be identified for either:

- **a) Reliability** or **b) Deviations**: and
  - will be collected for the RTO and/or each Region based on whether units were committed for transmission constraints and if so, for which constraints they were committed.

PJM will post the aggregate amount of MWs committed that meet this criteria in all the respective buckets.

BORs that are associated with a constraint of <345kV will be allocated regionally.
Balancing Operating Reserve Cost Allocation - Regional

Reliability Analysis (RA) BOR Cost Allocation

**RA BOR Credits for Reliability**
- Regional Credits for Reliability
- RTO Credits for Reliability

**RA BOR Credits for Deviations**
- Regional Credits for Deviations
- RTO Credits for Deviations

Real-Time (RT) BOR Cost Allocation

**RT BOR Credits for Reliability**
- Regional Credits for Reliability
- RTO Credits for Reliability

**RT BOR Credits for Deviations**
- Regional Credits for Deviations
- RTO Credits for Deviations

Load Ratio Share plus exports By Region

Real-Time Deviations from Day-Ahead Schedules By Region
BORs for Reliability are allocated by Load Ration Share plus Exports:

\[ \text{Participant’s Reliability Allocation (by RTO or Region)} = \frac{\text{Total BORs for Reliability (by RTO or Region)}}{\text{Total PJM MWh of energy delivered to load + exports (by RTO or Region)}} \times \text{Customer total MWh of energy delivered to load + exports (by RTO or Region)}} \]
BORs for Deviations are allocated by participants based on deviations from Day-Ahead scheduled quantities:

\[
\text{RTO Rate for BORs for Deviations} = \frac{\text{Total $ Cost of BORs in RTO for Deviations}}{\text{Total MW Deviations Across RTO (after netting by zone, hub, interface)}}
\]

\[
\text{Participants Deviation Allocation} = \frac{\text{RTO Rate for BORs for Deviations}}{\text{Total MW Deviations of Participant}}
\]

This example shows the calculation for deviations across RTO (not regional).
This BORCA process determines the TOTAL COST (credits) of BORs.

Balancing Operating Reserve Cost Allocation

When is Unit Being Called On?

- Why is Unit Being Called On?
- Is LMP >= Offer for at least 4 Intervals for at least an hour?

Reliability Analysis

Operating Day

Conservative Operations

Load + Reserves

RA BOR Credits for Reliability A1

RA BOR Credits for Deviations B1

RT BOR Credits for Reliability A2

RT BOR Credits for Deviations B2

Is Unit being called on for Tx Constraint <= 345 kv?

Regional RA BOR Credits for Reliability A1-R

Regional RA BOR Credits for Deviations B1-R

Regional RT BOR Credits for Reliability A2-R

Regional RT BOR Credits for Deviations B2-R

RTO RA BOR Credits for Reliability A1-T

RTO RA BOR Credits for Deviations B1-T

RTO RT BOR Credits for Reliability A2-T

RTO RT BOR Credits for Deviations B2-T
This BORCA process determines the ALLOCATION of the total costs.
“Reliability” allocated to real-time load plus exports and “Deviations” allocated to deviations across RTO including those who might have charges from the regional bucket.

The rate for this bucket will be the RTO rate.

Regional costs allocated regionally

RTO costs are allocated globally

Separate buckets:
The costs of Regional BORs are not contained in the costs of the RTO BORs.

No “Double Dipping” of costs.
Regional BOR Rates will be calculated for the following two OR regions:

**Western Region:** AEP, APS, COMED, DUQ, DAYTON

**Eastern Region:** BGE, DOM, PENELEC, PEPCO, METED, PPL, JCPL, PECO, DPL, PSEG, RECO, AE

For regions that do not have Regional Adders, the Regional BOR Rate for Deviations and/or Reliability will equal the RTO BOR Rate for Deviations and/or Reliability.
### Balancing Operating Reserve (BOR) Quick Reference

<table>
<thead>
<tr>
<th>Day-Ahead Operating Reserve Rates</th>
<th>RTO Balancing Operating Reserve Rates</th>
<th>East Balancing Operating Reserve Rates</th>
<th>West Balancing Operating Reserve Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>DA Operating Reserve Rate</td>
<td>RTO Bal Operating Reserve for Reliability Rate</td>
<td>East Bal Operating Reserve for Reliability Rate</td>
<td>West Bal Operating Reserve for Reliability Rate</td>
</tr>
<tr>
<td>$/MWh of cleared DA Demand, Decrements, Load Response, and Exports</td>
<td>$/MWh of RT Load plus Exports</td>
<td>$/MWh of RT Load plus Exports</td>
<td>$/MWh of RT Load plus Exports</td>
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<tr>
<td></td>
<td>$/MWh of RT Deviations</td>
<td>$/MWh of RT Deviations</td>
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<table>
<thead>
<tr>
<th>East Zones</th>
<th>East Interfaces</th>
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<tr>
<td>BC</td>
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<td>AE</td>
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- BORs that are associated with a constraint of <345kV will be allocated regionally
**Base Case**

- **LSE “Enerwave”** serves load in the ComEd and BGE zones, HE 16

- **The Load Ratio Share of Enerwave is:**
  - ComEd – 30% \(\text{Western Region} – 2\%\)  \(\text{RTO} – 1\%\) \(\rightarrow 3\%\) Total RTO
  - BGE – 40% \(\text{Eastern Region} – 4\%\)  \(\text{RTO} – 2\%\) \(\rightarrow \text{Total RTO}\)

- **Cleared Day Ahead Market Bids:**
  - ComEd – 1000 MW Fixed Demand, 50 Dec, 10 MW Inc
  - BGE – 1500 MW Fixed Demand

### Daily BOR Rates:
- **RTO Rate for Reliability:** $3
- **Regional Adder for Reliability (East):** $2
- **Regional Adder for Reliability (West):** $1
- **RTO Rate for Deviations:** $2
- **Regional Adder for Deviations (East):** $2
- **Regional Adder for Deviations (West):** n/a
Scenario #1 – BOR Cost Allocation

- Additional generation is picked up in the RA case due to an increased RTO load forecast (not for constraint control)
- The total cost of Operating Reserves for this additional unit commitment is $200,000
- The real time load for Enerwave is 900MW in ComEd and 1300MW in BGE

What is the correct BOR rate category for this unit commitment?

A) RTO BOR Rate for Reliability
B) Regional BOR Rate for Reliability (East & West)
C) RTO BOR Rate for Deviations
D) Regional BOR Rate for Deviations (East & West)

How will PJM allocate the BOR charges?

A) Load Ratio Share plus Exports by RTO
B) Load Ratio Share Plus Exports by Region
C) Real Time Deviations from Day-Ahead Schedules by RTO
D) Real Time Deviations from Day-Ahead Schedules by Region
Scenario #1 – BOR Cost Allocation (cont)

• Additional generation is picked up in the RA case due to an increased RTO load forecast (not for constraint control)
• The total cost of Operating Reserves for this additional unit commitment is $200,000
• The real time load for Enerwave is 900MW in ComEd and 1300MW in BGE

What are the BOR costs for Enerwave for this unit commitment?

In ComEd:
100MW X $2 = $200 (Load dev)
50MW X $2 = $100 (Dec dev)
10MW X $2 = $20 (Inc dev)

In BGE:
200MW X $2 = $400 (Load dev)

Total BOR charges for Enerwave $720

The RTO BOR Rate for Deviations will incorporate the participants deviation from DA position and will be the vehicle for the calculation.
Scenario #2 – BOR Cost Allocation

- Additional generation is picked up in the RA case due to an increased RTO load forecast (not for constraint control)
- The total cost of Operating Reserves for this additional unit commitment is $200,000
- The real time load for Enerwave is 900MW in ComEd and 1650MW in BGE

(Note: new netting rule nets Load / Dec deviations by zone)

What is the correct BOR rate category for this unit commitment?

A) RTO BOR Rate for Reliability
B) Regional BOR Rate for Reliability (East & West)
C) RTO BOR Rate for Deviations
D) Regional BOR Rate for Deviations (East & West)

How will PJM allocate the BOR charges?

A) Load Ratio Share plus Exports by RTO
B) Load Ratio Share Plus Exports by Region
C) Real Time Deviations from Day-Ahead Schedules by RTO
D) Real Time Deviations from Day-Ahead Schedules by Region
Scenario #2 – BOR Cost Allocation (cont)

- Additional generation is picked up in the RA case due to an increased RTO load forecast (not for constraint control)
- The total cost of Operating Reserves for this additional unit commitment is $200,000
- The real time load for Enerwave is 900MW in ComEd and 1650MW in BGE

**What are the BOR costs for Enerwave for this unit commitment?**

<table>
<thead>
<tr>
<th>In ComEd:</th>
<th>Total BOR charges for Enerwave</th>
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<tbody>
<tr>
<td>100MW X $2 = $200 (Load dev)</td>
<td>$620 ***</td>
</tr>
<tr>
<td>50MW X $2 = $100 (Dec dev)</td>
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<tr>
<td>10MW X $2 = $20 (Inc dev)</td>
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</table>

<table>
<thead>
<tr>
<th>In BGE:</th>
</tr>
</thead>
<tbody>
<tr>
<td>150MW X $2 = $300 (Load dev)</td>
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</table>

The RTO BOR Rate for Deviations incorporate the participants deviation from DA position and will be the vehicle for the calculation.
Scenario #3 – BOR Cost Allocation

• PJM RTO is in a Cold Weather Alert. PJM requests 3 additional units on in addition to what was requested by the RA case
• The total cost of Operating Reserves for this additional unit commitment is $200,000

What is the correct BOR rate category for this unit commitment?

A) RTO BOR Rate for Reliability
B) Regional BOR Rate for Reliability (East & West)
C) RTO BOR Rate for Deviations
D) Regional BOR Rate for Deviations (East & West)

How will PJM allocate the BOR charges?

A) Load Ratio Share plus Exports by RTO
B) Load Ratio Share Plus Exports by Region
C) Real Time Deviations from Day-Ahead Schedules by RTO
D) Real Time Deviations from Day-Ahead Schedules by Region
What are the BOR costs for Enerwave for this unit commitment?

In ComEd:
$200,000 \times 0.01 = $2,000

In BGE:
$200,000 \times 0.02 = $4,000

Total BOR charges for Enerwave
$6,000

The RTO BOR Rate for Reliability will incorporate the Load Ratio Share and will be the vehicle for the calculation.
Scenario #4 – BOR Cost Allocation

- PJM RTO is in a Cold Weather Alert. Steam generation that was to be cycled, is run through the midnight period to ensure it’s availability the next morning
- The total cost of Operating Reserves for this additional unit commitment is $100,000

What is the correct BOR rate category for this unit commitment?

A) RTO BOR Rate for Reliability
B) Regional BOR Rate for Reliability (East & West)
C) RTO BOR Rate for Deviations
D) Regional BOR Rate for Deviations (East & West)

How will PJM allocate the BOR charges?

A) Load Ratio Share plus Exports by RTO
B) Load Ratio Share Plus Exports by Region
C) Real Time Deviations from Day-Ahead Schedules by RTO
D) Real Time Deviations from Day-Ahead Schedules by Region
Scenario #4 – BOR Cost Allocation (cont)

- PJM RTO is in a Cold Weather Alert. Steam generation that was to be cycled, is run through the midnight period to ensure it’s availability the next morning.
- The total cost of Operating Reserves for this additional unit commitment is $100,000

What are the BOR costs for Enerwave for this unit commitment?

In ComEd:
$100,000 \times 0.01 = $1,000

In BGE:
$100,000 \times 0.02 = $2,000

Load Ratio Share by Zone (totals 3%)

Total BOR charges for Enerwave
$3,000

The RTO BOR Rate for Reliability will incorporate the Load Ratio Share and will be the vehicle for the calculation.
Scenario #5 – BOR Cost Allocation

- Generation is requested in the RA Case for a 230 kV transmission constraint located in PSEG
- The total cost of Operating Reserves for this additional unit commitment is $100,000
- The real time load for Enerwave is 900MW in ComEd and 1300MW in BGE

What is the correct BOR rate category for this unit commitment?

A) RTO BOR Rate for Reliability
B) Regional BOR Rate for Reliability (East & West)
C) RTO BOR Rate for Deviations
D) Regional BOR Rate for Deviations (East & West)

How will PJM allocate the BOR charges?

A) Load Ratio Share plus Exports by RTO
B) Load Ratio Share Plus Exports by Region
C) Real Time Deviations from Day-Ahead Schedules by RTO
D) Real Time Deviations from Day-Ahead Schedules by Region
Scenario #5 – BOR Cost Allocation (cont)

- Generation is requested in the RA Case for a 230 kV transmission constraint located in PSEG
- The total cost of Operating Reserves for this additional unit commitment is $100,000.
- The real time load for Enerwave is 900MW in ComEd and 1300MW in BGE

What are the BOR costs for Enerwave for this unit commitment?

In BGE:
200MW X $2 = $4,000 (Load dev)

$2 Regional Adder (East)

Total BOR charges for PSEG constraint:
$4,000

Total BOR charges for Enerwave:
something greater than $4,000 for RTO BORs (calculation depends on scenario of additional BORs)

The Regional Adder for Deviations will incorporate the participants deviation from DA position and will be the vehicle for the calculation.
Scenario #6 – BOR Cost Allocation

• A CT is called on by the Power Dispatcher in real-time to alleviate a 230kv transmission constraint in the AEP Zone
• Throughout the operating day, the LMP never exceeded the unit’s offer (in any of the five-minute intervals)
• The cost of Operating Reserves for this additional unit commitment is $300,000. (The cost of Operating Reserves for the RTO is $700,000.)

What is the correct BOR rate category for this additional unit commitment?

A) RTO BOR Rate for Reliability
B) Regional BOR Rate for Reliability (East & West)
C) RTO BOR Rate for Deviations
D) Regional BOR Rate for Deviations (East & West)

How will PJM allocate the BOR charges?

A) Load Ratio Share plus Exports by RTO
B) Load Ratio Share Plus Exports by Region
C) Real Time Deviations from Day-Ahead Schedules by RTO
D) Real Time Deviations from Day-Ahead Schedules by Region
Scenario #6 – BOR Cost Allocation (cont)

- A CT is called on by the Power Dispatcher in real-time to alleviate a 230kv transmission constraint in the AEP Zone
- Throughout the operating day, the LMP never exceeded the unit’s offer (in any of the five-minute intervals)
- The cost of Operating Reserves for this additional unit commitment is $300,000. (The cost of Operating Reserves for the RTO is $700,000.)

In ComEd: $300,000 \times 0.02 = $6,000

Total BOR charges for CT in AEP: $6,000

Total BOR charges for Enerwave: something greater than $6,000 (calculation depends on scenario of additional BORs)

The Regional Adder for Reliability will incorporate the Load Ratio Share and will be the vehicle for the calculation:

- RTO Rate for Reliability: $3
- Regional Adder for Reliability (West): $1
- Enerwave’s Total Rate for Reliability: $4

Charged for BORs across RTO
Charged for BORs for CT in AEP
Enerwave’s total charge for all BORs
### MSRS Operating Reserve Reports

<table>
<thead>
<tr>
<th>Operating Reserve</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator Credit Summary</td>
</tr>
<tr>
<td>Generator Portfolio Credit Summary (Operating Reserve Credit Summary)</td>
</tr>
<tr>
<td>Operating Reserve Deviation Summary</td>
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<tr>
<td>Operating Reserve Deviation Summary (pre-12/1/2008)</td>
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<tr>
<td>Operating Reserve Generator Deviations</td>
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<td>Operating Reserve Generator Deviations (pre-12/1/2008)</td>
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<tr>
<td>Operating Reserve Generator Credit Details</td>
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<tr>
<td>Operating Reserve Generator Credit Details (pre-12/1/2008)</td>
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<tr>
<td>Operating Reserve Charge Summary</td>
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<tr>
<td>Regional Balancing Operating Reserve Charge Summary</td>
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<td>Operating Reserve for Load Response Charge Summary</td>
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<td>Operating Reserve Lost Opportunity Cost Credits</td>
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<td>Operating Reserve Transaction Credits</td>
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<td>Reactive Services Charge Summary</td>
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<td>Reactive Services Credits</td>
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<tr>
<td>Synchronous Condensing Charge Summary</td>
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<td>Synchronous Condensing Credits</td>
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# MSRS Operating Reserve Charge Summary

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## Supporting Calculations

- **DA Operating Reserve Charge (1370.01)** = Total PJM DA Operating Reserve Credit (1370.11) * ((DA Load (3000.37) + DA Operating Reserve Exports (1370.12)) / Total PJM DA Load Plus Exports (1370.13))

- **Bal Operating Reserve for Reliability Charge (1375.36)** = Sum of the following columns from the Regional Balancing Operating Reserve Charge Summary: RTO Bal OpRes for Reliability Charge (1375.41) + East Bal OpRes for Reliability Charge (1375.45) + West Bal OpRes for Reliability Charge (1375.49)
### MSRS Generator Credit Summary

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
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</table>

#### Supporting Calculations

This report does not have any calculated values that are supported purely by other columns on this report.

This report displays the following daily ancillary service credits for each unit that the customer account owns or jointly owns and where at least one of the credits is greater than 0:

- Day-ahead and Balancing Operating Reserve Credits
- Synchronous Condensing Credits
- Reactive Services Credits
- Regulation Credits
- Synchronized Reserve Credits
- Day-ahead Scheduling Reserve Credits
This report displays the customer account’s hourly generator deviation and also provides the hourly values for the components used in calculating withdrawal and injection deviation MWh which are used in calculating the Balancing Operating Reserve Charge. These values are displayed by balancing operating reserve location.
**Supporting Calculations**

- **DA Operating Reserve Injection (1365.19) =** DA Increment Offers (1365.16) + DA Operating Reserve Imports (1365.17) + DA Internal Bilateral Purchases (1365.18)

- **RT Operating Reserve Injection (1375.22) =** RT Operating Reserve Imports (1365.20) + RT Internal Bilateral Purchases (1375.21)

- **Operating Reserve Injection Deviation (1375.23) =** ABS \{(RT Operating Reserve Injection (1375.22) - DA Operating Reserve Injection (1365.19))\}

- **DA Operating Reserve Withdrawal (1375.29) =** DA Decrement Bids (1375.24) + DA Demand Bids (1375.25) + DA Load Response Bids (1375.26) + DA Operating Reserve Exports (1375.27) + DA Internal Bilateral Sales (1375.28)

- **RT Operating Reserve Withdrawal (1375.32) =** RT Load (3000.38) + RT Operating Reserve Exports (1375.30) + RT Internal Bilateral Sales (1375.31)

- **Operating Reserve Withdrawal Deviation (1375.33) =** ABS \{(RT Operating Reserve Withdrawal (1375.32) - DA Operating Reserve Withdrawal (1375.29))\}

- **Operating Reserve Generator Deviation (1375.44) =** SUM(Supplier Netted Deviation MWh from Operating Reserve Generator Deviations report) for all supplier netted groups that fall within the transmission zone displayed.

  - Please note that the Supplier Netted Deviation MWh value appears on the Operating Reserve Generator Deviations report for each generator that belongs to the supplier netted group. In order to properly recalculate the Operating Reserve Generator Deviation at the customer account-level, the Supplier Netted Deviation MWh should only be added once for each group, rather than once for each generator.

- **Locational Total Deviation (1375.35) =** Operating Reserve Injection Deviation (1375.23) + Operating Reserve Withdrawal Deviation (1375.33) + Operating Reserve Generator Deviation (1375.34)
MSRS Operating Reserve Generator Credit Details

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</table>

This report displays the hourly values used in calculating the customer account’s Operating Reserve Generator Credits (Balancing Operating Reserve Generator, Local Constraint and Cancellation Credits). The details in this report do not reflect the customer account’s share of jointly owned units. All owners will see the full values associated with the unit.

Supporting Calculations

Day-ahead Operating Reserve Credit = MAX ((DA Energy Offer + DA No-Load Cost + DA Startup Cost − DA Value), 0)

If Segment ID = 1
Balancing Operating Reserve Credit = MAX((RT Energy Offer + RT No-Load Cost + RT Startup Cost + RT Additional Startup Cost - Bal Value - Operating Reserve Offsetting Synch Reserve Revenue - Operating Reserve Offsetting Reactive Services Revenue - Operating Reserve Offsetting DASR Revenue - DA Value - DA Credit), 0)

Else, for all other segments
Balancing Operating Reserve Credit = MAX((RT Energy Offer + RT No-Load Cost + RT Startup Cost + RT Additional Startup Cost - Bal Value - Operating Reserve Offsetting Synch Reserve Revenue - Operating Reserve Offsetting Reactive Services Revenue - Operating Reserve Offsetting DASR Revenue), 0)

Daily Balancing Operating Reserve Credit = Sum(Balancing Operating Reserve Credit) for all segments in the day

Data Granularity: Hourly
Frequency: Updated daily
This report displays the customer account’s hourly operating reserve lost opportunity cost credit for each generation unit that the customer owns or jointly owns. Data will display on this report when the unit has DA Scheduled MWh or RT Generation MWh and the unit is eligible for lost opportunity cost credits.
MSRS Operating Reserve
Lost Opportunity Cost Credits

Supporting Calculations

If the unit is a CT or Diesel unit and is scheduled for PJM Day-ahead and not called on in Real-time, then:

MWh Reduced (3000.96) = 0

Operating Reserve Lost Opportunity Cost Credit (2375.18) = \text{MAX} ((\text{RT Generator LMP} (3000.25) - \text{DA Generator LMP} (3000.24)) * \text{DA Scheduled MWh} (3000.32), (\text{RT Generator LMP} (3000.25) - \text{Offer at DA MWh} (3000.92)) * \text{DA Scheduled MWh} (3000.32), 0)

Else:

MWh Reduced (3000.96) = \text{RT LMP Desired MWh}(3000.34) - \text{RT Generation} (3000.33) - \text{Reg MWh Adj} (3000.94) - \text{Synch Reserve MWh Adj} (3000.95) - \text{Reg High < LMP Desired} (3000.99)

Operating Reserve Lost Opportunity Cost Credit (2375.18) = MWh Reduced (3000.96) * (\text{max(\text{RT Generator LMP} (3000.25) - \text{Offer at RT MWh} (3000.93)), 0})
<table>
<thead>
<tr>
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<th>A</th>
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<td>5</td>
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<td>Date</td>
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<td>Sink PNODE ID</td>
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<td>DA Offer ($)</td>
<td>DA Revenue ($)</td>
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<td>RT Transaction MWh</td>
<td>RT Offer ($)</td>
<td>Bal Revenue ($)</td>
<td>Bal Operating Reserve Transaction Credit ($)</td>
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</tbody>
</table>

This report displays the customer account’s daily Day-ahead and Balancing Operating Reserve Transaction Credit for each transaction that received a day-ahead and/or balancing credit.

### Supporting Calculations

**DA Operating Reserve Transaction Credit**

\[ \text{DA Operating Reserve Transaction Credit (2370.14)} = \max(\text{DA Offer (2370.12)} - \text{DA Revenue (2370.13)}, \ 0) \]

**Bal Operating Reserve Transaction Credit**

\[ \text{Bal Operating Reserve Transaction Credit (2375.17)} = \max(\text{RT Offer (2375.15)} - \text{Bal Revenue (2375.16)} - \text{DA Revenue (2370.13)} - \text{DA Operating Reserve Transaction Credit (2370.14)}, \ 0) \]
# MSRS Regional Balancing Operating Reserve Charge Summary

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
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<tbody>
<tr>
<td>5</td>
<td>Customer ID</td>
<td>Customer Code</td>
<td>Date</td>
<td>Total RTO BalOpRes for Reliability Credit ($)</td>
<td>PJM RT Load plus Exports (MWh)</td>
<td>Total PJM RT Load plus Exports (MWh)</td>
<td>RTO Bal OpRes for Reliability Charge ($)</td>
<td>Total East Bal OpRes for Reliability Credit ($)</td>
<td>East RT Load plus Exports (MWh)</td>
<td>Total East RT Load plus Exports (MWh)</td>
<td>East Bal OpRes for Reliability Charge ($)</td>
<td>Total West Bal OpRes for Reliability Credit ($)</td>
<td>West RT Load plus Exports (MWh)</td>
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Data Granularity: Daily  
Frequency: Updated daily
Supporting Calculations

RTO Bal OpRes for Reliability Charge (1375.41) = Total RTO Bal OpRes for Reliability Credit (1375.38) * (PJM RT Load plus Exports (1375.39) / Total PJM RT Load plus Exports (1375.40))

East Bal OpRes for Reliability Charge (1375.45) = Total East Bal OpRes for Reliability Credit (1375.42) * (East RT Load plus Exports (1375.43) / Total East RT Load plus Exports (1375.44))

West Bal OpRes for Reliability Charge (1375.49) = Total West Bal OpRes for Reliability Credit (1375.46) * (West RT Load plus Exports (1375.47) / Total West RT Load plus Exports (1375.48))

RTO Bal OpRes for Deviations Charge (1375.53) = Total RTO Bal OpRes for Deviations Credit (1375.50) * (PJM Deviations (1375.51) / Total PJM Deviations (1375.52))

East Bal OpRes for Deviations Charge (1375.57) = Total East Bal OpRes for Deviations Credit (1375.54) * (East Deviations (1375.55) / Total East Deviations (1375.56))

West Bal OpRes for Deviations Charge (1375.61) = Total West Bal OpRes for Deviations Credit (1375.58) * (West Deviations (1375.59) / Total West Deviations (1375.60))
Synchronous Condensing

Credits:

• Daily credits for condensing and energy use costs are provided to eligible synchronous condensers dispatched by PJM for purposes other than synchronized reserve, post-contingency or reactive services

Charges:

• Total daily cost of synchronous condensing (not for synchronized reserve or reactive services) is allocated based on real-time load (without losses) plus export ratio shares
## MSRS Synchronous Condensing Charge Summary

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</tr>
<tr>
<td>5</td>
<td>Customer ID</td>
<td>Customer Code</td>
<td>Date</td>
<td>Total PJM Synchronous Condensing Credit ($)</td>
<td>RT Load (MWh)</td>
<td>RT Operating Reserve Exports (MWh)</td>
<td>Total PJM RT Load plus Operating Reserve Exports (MWh)</td>
<td>Synchronous Condensing Charge ($)</td>
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<tr>
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<td>End of Report</td>
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Data Granularity: Daily
Frequency: Updated daily

This report displays the customer account’s daily Synchronous Condensing Charge where the RT Load value or RT Operating Reserve Exports value is greater than zero and where the Total PJM Synchronous Condensing Credit for the day is greater than 0.

**Supporting Calculations**

Synchronous Condensing Charge (1377.01) = (RT Load (3000.39) + RT Operating Reserve Exports (3177.12)) / Total PJM RT Load plus Operating Reserve Exports (1377.13) * Total PJM Synchronous Condensing Credit (1377.11)
This report displays the customer account’s hourly Synchronous Condensing Credits and Reactive Condensing Credits where their synchronous condensing credit for the hour is not null or where their reactive services condensing credit for the hour is not null.

The credits in this report do not reflect the customer account’s share of jointly owned units. All owners will see the full credit assigned to the unit.
Supporting Calculations

Synchronous Condensing Credit (2377.18) = (Condensing Duration (2377.13) * Energy Use (2377.15) * RT Generator LMP (3000.25)) + (Condensing Duration (2377.13) * Condensing Offer (2377.14)) + Condensing Start Up Cost (2377.17)

Reactive Services Condensing Credit (2378.18) = MAX (Economic Max (3000.98) * SRMCP (3000.61) * Condensing Duration (2377.13)) + ((Condensing Duration (2377.13) * Energy Use (2377.15) * RT Generator LMP (3000.25)) + (Condensing Duration (2377.13) * Condensing Offer (2377.14)) + Condensing Start Up Cost (2377.17))

Synchronous Condensing Lost Opportunity Cost Credit (2377.19) = MAX (MAX (Economic Max (3000.98) - MAX (RT Generation MWh (3000.33), 0), 0)) * (MAX (RT Generator LMP (3000.25) - Offer at RT LMP Desired MWh (2377.16), 0)) - Synchronous Condensing Credit (2377.18), 0

Reactive Services Condensing Lost Opportunity Cost Credit (2378.19) = MAX (MAX (Economic Max (3000.98) - MAX (RT Generation (3000.33), 0), 0)) * (MAX (RT Generator LMP (3000.25) - Offer at RT LMP Desired MWh (2377.16), 0)) - Reactive Services Condensing Credit (2378.18), 0
• Market Settlements Terminology
• Line Items on a PJM Billing Statement
  • Spot Market Energy
  • Marginal Losses
  • Congestion
  • Transmission Service
• Ancillary Services
  • Miscellaneous
• Review
RPM Settlements

(Reliability Pricing Model)
What is RPM?

- Reliability Pricing Model (RPM) is PJM’s resource adequacy construct.
- The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP).
- RPM adds stability and a locational nature to the pricing signal.
Participation in RPM

• Participation by LSEs for load served in PJM region is mandatory, except for those LSEs that have elected Fixed Resource Requirement (FRR) Alternative
  – Each LSE shall be responsible for paying a Locational Reliability Charge
  – May choose to hedge Locational Reliability Charges

• Supply in RPM:
  Generation Resources, Load Management Products, Demand Resources (DR), Bilateral Transactions, Interruptible Load for Reliability (ILR), Energy Efficiency Resources Qualified Transmission Upgrades
Summary of RPM Activities

Pre-Delivery Year Activity
- RPM Auctions
  - Base Residual Auction
  - 1st Incremental Auction
  - 2nd Incremental Auction
  - 3rd Incremental Auction
- Interruptible Load for Reliability Nomination

Delivery Year Activity
- Auction Credits/Charges
- ILR Credits
- Daily Unforced Capacity Obligations & Locational Reliability Charges
- CTR Credits
- Resource Performance Assessments
- Deficiency & Penalty Charges/Credits
- Non-Unit Specific Capacity Transactions Charges/Credits

On-going Bilateral Market
# PJM Billing Statement Line Item Mapping

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<th>CHARGES</th>
<th>ID#</th>
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<td>Interruptible Load for Reliability</td>
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<td>Demand Resource and ILR Compliance Penalty</td>
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<td>Capacity Resource Deficiency</td>
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<td>Peak-Hour Period Availability</td>
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<td>Peak-Hour Period Availability</td>
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</table>
**Locational Reliability Charges**

\[
\text{Locational Reliability Charges} = \frac{\text{Daily Unforced Capacity Obligation in Zone}}{\text{Final Zonal Capacity Price}}
\]

- Each LSE that serves load in a PJM Zone or load outside PJM using PJM resources (i.e., Non-Zone Network Load) during the Delivery Year must pay a Locational Reliability Charge.

- The Locational Reliability Charge Summary displays the participant’s Locational Reliability Charge **for each zone** where the participant has an unforced capacity obligation.

1610 Locational Reliability Charge
If cleared Buy Bid in an Incremental Auction, Market Buyer will receive an Auction Charge (i.e., Resource Substitution Charge).

Charges calculated daily and billed weekly during the Delivery Year.
RPM Auction Credit =

MW Amount Cleared* × Applicable Resource Clearing Price

• If cleared Sell Offer in an RPM Auction, Market Seller will receive an Auction Credit.

• Credits calculated daily and billed weekly during the Delivery Year.

*MW Amount Cleared will be adjusted for Unit Specific Bilaterals for Cleared MW

2600 RPM Auction Credits
Daily Capacity Resource Deficiency Charge =

Daily Deficiency Rate * MW Amount of Shortage

Daily Deficiency Rate = RCP + the higher of (.2 * RCP or $20)

*Effective the 3/26/09FERC Order

- Party’s Weighted Average Resource Clearing Price is determined by calculating the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by a party’s cleared and makewhole MWs in the LDA.
- Capacity Resource Deficiency Charges assessed daily and billed weekly.
• Penalties are allocated on a pro-rata basis to those LSEs who were charged a Daily Locational Reliability Charge based on their Daily UCAP Obligation.

Capacity Resource Deficiency Credit =

\[
\frac{\text{Total PJM Capacity Deficiency Charge}}{\text{Total PJM UCAP Obligation}} \times \frac{\text{UCAP Obligation}}{\text{UCAP Obligation}}
\]
ILR Reliability Credit =

\[
\text{ILR Reliability Credit} = \frac{\text{Final Zonal ILR Price}}{\text{Zonal MWs Certified}}
\]

- Each ILR Resource Provider will receive an ILR Reliability Credit.
- Credits calculated daily and billed weekly during Delivery Year.

2620 Interruptible Load for Reliability
Capacity Transfer Rights Credits

- CTR’s allocate the economic value of transmission import capability that exists into a constrained Locational Deliverability Area (LDA)

Zonal CTR Credit =

- Zonal CTRs Owned
- Zonal CTR Settlement Rate

Each zonal CTR owner will receive a daily Zonal CTR Credit

Credits will be calculated daily and billed weekly during the Delivery Year.

2630 Capacity Transfer Rights
Incremental Capacity Transfer Rights Credits

- Incremental Capacity Transfer Rights are allocated to a new service customer obligated to fund a transmission facility or upgrade that increases the import capability into an LDA.

Incremental CTR Credit =

- Incremental CTRs Owned
- Zonal Incremental CTR Credit Rate
- Each incremental CTR owner will receive a daily Incremental CTR Credit

Credits will be calculated daily and billed weekly during the Delivery Year.

2640 Incremental Capacity Transfer Rights
Non-Unit Specific Capacity Transactions

- Non-Unit Specific Capacity Transactions in eRPM are treated as financial settlements only in RPM.
- Non-Unit Specific Capacity Transactions will not change the resource position or load obligation of any entity.
- Non-Unit Specific Capacity Transactions are not eligible to be offered into an RPM auction or used to meet the region’s UCAP obligation.
Non-Unit Specific Capacity Transaction Charges

Seller of a Non-Unit Specific Capacity Transaction will receive a Charge =

\[ \text{Charge} = \text{Price Applicable to Pricing Point} \times \text{Transaction Amount} \]

Non-Unit Specific Capacity Transaction Charges/Credits will be calculated daily and billed weekly for the duration of the transaction during the Delivery Year.

1650 Non-Unit Specific Capacity Transaction
Non-Unit Specific Capacity Transaction Credits

Buyer of a Non-Unit Specific Capacity Transaction will receive a Credit =

\[ \text{Price Applicable to Pricing Point} \times \text{Transaction Amount} \]

Non-Unit Specific Capacity Transaction Charges/Credits will be calculated daily and billed weekly for the duration of the transaction during the Delivery Year.

2650 Non-Unit Specific Capacity Transaction
Non-Unit Specific Capacity Transaction
Hedging Example

Example:
• Party A has 500 MW load obligation in PSEG zone
• Party A buys 500 MW from Party B @ PSEG_Net Load pricing point
PSEG Final Zonal Capacity Price = $12
• PSEG Final Zonal CTR Credit Rate = $2
• (Final Zonal Capacity Price – Final Zonal CTR Credit Rate) of PSEG zone = $10

Party A Settlement:
Locational Reliability Charge
(500MW * $12)
($6000)
Zonal CTR Credit
500 MW * $2
$1000
Non-Unit Specific
Capacity Transaction Credit
500MW * $10
$5000
Net $0

Party B Settlement:
Non-Unit Specific Capacity Transaction Charge
500MW *$10
($5000)
Load Management Event Compliance Penalty Charge

**Load Management Event Compliance Penalty Charge =**

- Load Management Compliance Penalty charges are assessed to those DR and ILR resources that under-complied during an event.
- Load Management Compliance Rate = higher of (1/ #events or \( \frac{1}{2} \) * Weighted Annual Revenue Rate)
- Annual Revenue Rate = \{Resource Clearing Price (DR) or Final Zonal ILR Price\} * 365 days/year
- Assessed on event basis the third billing month after the event occurs (e.g., June events will be included in September bill)

| 1660 | Demand Resource and ILR Compliance Penalty |

www.pjm.com
Load Management Compliance Penalty Credit

Total PJM DR and ILR Compliance Penalty Charge

Over Complying Resource

Calculations are per event

Not to exceed 20% of resource annual revenue

Shared by all LSE’s
Based on average daily UC Obligation during the month of the event

If there are excess dollars

2660 Demand Resource and ILR Compliance Penalty
**Generation Resource Rating Test Failure Charge**

- Assessed if Summer and Winter generator capability testing does not certify full delivery of the Total Unit ICAP Commitment Amount.

**Generation Resource Rating Test Failure Charge =**

\[
\text{Deficiency MW} \times (\text{Resource Clearing Price} + \text{The higher of } (0.2 \times \text{RCP} \text{ or } $20))
\]

| 1662 | Generation Resource Rating Test Failure |
• Assessed if a provider of a Qualifying Transmission Upgrade is cancelled or delayed and does not commence interconnection service prior to the start of the delivery year

**Qualifying Transmission Upgrade Compliance Penalty Charge**

\[
\text{Deficiency MW} \times \text{Resource Clearing Price} + \text{The higher of} (.2\times\text{RCP or }$20) = \text{1663 Qualifying Transmission Upgrade Compliance Penalty Charge}
\]
Peak Season Maintenance Compliance Penalty Charge

- Assessed if the provider committed a generation resource to RPM and the resource was not available due to a planned or maintenance outage that occurred during the peak season without the approval of PJM.

Peak Season Maintenance Compliance Penalty Charge =

1664 Peak Season Maintenance Compliance Penalty

**Deficiency MW**

**Resource Clearing Price**

The higher of (.2*RCP or $20)
• Generation Resource Rating Test Failure Charges collected by PJM are allocated on a pro-rata basis to Load Serving Entities who were charged a Daily Locational Reliability Charge based on their Daily UCAP Obligation

**Generation Resource Rating Test Failure Credit** =

\[
\text{Total PJM Gen Resource Rating Test Failure Charge} \times \frac{\text{UCAP Obligation}}{\text{Total PJM UCAP Obligation}}
\]

| 2662 | Generation Resource Rating Test Failure |
Qualifying Transmission Upgrade Compliance Credit

• Qualifying Transmission Upgrade Compliance Charges collected by PJM are allocated on a pro-rata basis to Load Serving Entities who were charged a Daily Locational Reliability Charge based on their Daily UCAP Obligation

Qualifying Transmission Upgrade Compliance Penalty Charge =

\[
\text{Qualifying Transmission Upgrade Compliance Penalty Charge} = \frac{\text{Total PJM Qualifying Transmission Upgrade Charge}}{\text{UCAP Obligation}} \times 2663
\]
Peak Season Maintenance Compliance Penalty Credit

- Peak Season Maintenance Compliance Penalty Charges collected by PJM are allocated on a pro-rata basis to Load Serving Entities who were charged a Daily Locational Reliability Charge based on their Daily UCAP Obligation.

Peak Season Maintenance Compliance Penalty Credit =

\[
\text{Total PJM Peak Season Maintenance Compliance Penalty Charge} \times \frac{\text{UCAP Obligation}}{\text{Total PJM UCAP Obligation}}
\]

2664 Peak Season Maintenance Compliance Penalty
### Deficiency & Penalty Charges

**Charge = Rate * MW Amount**

<table>
<thead>
<tr>
<th>Charge</th>
<th>Rate</th>
<th>MW Amount</th>
<th>Assessed</th>
<th>Billed</th>
<th>Allocated</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Peak-Hour Period Availability Charge</strong></td>
<td>Daily Peak-Hour Period Availability Charge Rate = ( RCP + \text{higher of } (0.2 \times RCP \text{ or }$20) )</td>
<td>Net Peak Period Capacity Shortfall for RPM Resource Commitments in LDA</td>
<td>Daily</td>
<td>Retroactively for entire DY in September bill after conclusion of DY</td>
<td>Resource providers that have negative Net Peak Period Capacity Shortfalls (capped at excess shortfall * Daily Peak-Hour Availability Charge Rate). Remaining Charges to LSEs based on their Daily UCAP Obligation</td>
</tr>
<tr>
<td></td>
<td>Daily Peak-Hour Period Availability Charge Rate = ( \text{Weighted average RCP in a LDA} )</td>
<td>Net Peak Period Capacity Shortfall for FRR Capacity Plan Commitments in LDA</td>
<td>Daily</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Capacity Resource Deficiency Charge</strong></td>
<td>Daily Deficiency Rate = ( RCP + \text{higher of } (0.2 \times RCP \text{ or }$20) )</td>
<td>MW Amount of Shortage</td>
<td>Daily</td>
<td>Monthly during DY</td>
<td>Pro-rata basis to those LSEs who were charged Daily Locational Reliability Charge based on their Daily UCAP Obligation</td>
</tr>
<tr>
<td><strong>Qualifying Transmission Upgrade Delay Penalty</strong></td>
<td>QTU Delay Penalty Rate = ( RCP + \text{higher of } (0.2 \times RCP \text{ or }$20) )</td>
<td>Cleared MW Amount of Incremental Import Capability Not Delivered</td>
<td>Daily</td>
<td>Monthly during DY</td>
<td>Pro-rata basis to those LSEs who were charged Daily Locational Reliability Charge based on their Daily UCAP Obligation</td>
</tr>
</tbody>
</table>
# Deficiency & Penalty Charges

## Charge = Rate * MW Amount

<table>
<thead>
<tr>
<th>Charge</th>
<th>Rate</th>
<th>MW Amount</th>
<th>Assessed</th>
<th>Billed</th>
<th>Allocated</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generation Resource Rating Test Failure Charge</strong></td>
<td>Daily Deficiency Rate = RCP + higher of (.2 X RCP or $20)</td>
<td>Daily ICAP Shortfall for RPM Resource Commitments * (1-Effective EFORd)</td>
<td>Daily</td>
<td>Retroactively for entire DY in June bill after conclusion of DY</td>
<td>Pro-rata basis to those LSEs who were charged Daily Locational Reliability Charge based on their Daily UCAP Obligation</td>
</tr>
<tr>
<td><strong>See Attachment A For FRR Calculation</strong></td>
<td>Daily ICAP Shortfall for FRR Capacity Plan Commitments * (1-Effective EFORd)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>PSM Compliance Penalty Charge</strong></td>
<td>Daily Deficiency Rate = RCP + higher of (.2 X RCP or $20)</td>
<td>Daily PSM Shortfall for RPM Resource Commitments * (1-Effective EFORd)</td>
<td>Daily</td>
<td>Retroactively for entire DY in June bill after conclusion of DY</td>
<td>Pro-rata basis to those LSEs who were charged Daily Locational Reliability Charge based on their Daily UCAP Obligation</td>
</tr>
<tr>
<td><strong>See Attachment A For FRR Calculation</strong></td>
<td>Daily PSM Shortfall for FRR Capacity Plan Commitments * (1-Effective EFORd)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Load Management (DR and ILR) Compliance Charge</strong></td>
<td>LM Compliance Penalty Rate = higher of (1/ #events or ½ * Weighted Annual Revenue Rate)</td>
<td>Net Zonal Under-Compliance MW in a Category</td>
<td>LM Event basis</td>
<td>Third billing month after the LM event occurs</td>
<td>DR &amp; ILR Resource Providers that over-complied (capped at MW amount of over-compliance * 1/5 Annual Revenue Rate). Remaining Charges to LSEs based on Average Daily UCAP Obligation during month of LM event.</td>
</tr>
</tbody>
</table>
FRR Deficiency and Penalty Calculations

1. **Peak Hour Period Availability**: equal to a PJM Weighted Average Resource Clearing Price in an LDA.

2. **Rating Test Penalty Rate**: equal to 1.2 times the weighted average of the resource clearing prices across all RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

3. **PSM Penalty Rate**: equal to 1.2 times the weighted average of the resource clearing prices across all RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.
MSRS RPM Reports

- Capacity Transfer Rights Credit Summary
- Deficiency Credit Summary
- Demand Resource and ILR Compliance Penalty Charges and Credits
- Demand Resource and ILR Compliance Penalty Residual Credit Summary
- Non-Unit Specific Capacity Transaction Charges and Credits
- Incremental Capacity Transfer Rights Credits
- Interruptible Load for Reliability Credit Summary
- Locational Reliability Charge Summary
- Non-Compliance Charge Summary
- RPM Auction Charges and Credits
- RPM Auction Make-Whole Charge Summary
This report displays the account’s CTR credit for each zone where the CTR credit is greater than $0.

**Supporting Calculations**

CTR Credit (2630.01) = (CTR MW (2630.11) * (UCAP Obligation (3001.23) / Total Zone UCAP Obligation (3001.31)) + Traded CTR MW (2630.12)) * Zonal CTR Rate (2630.13)
This report displays the account’s daily capacity resource deficiency credit, generation resource rating test failure credit, qualifying transmission upgrade compliance penalty credit and peak season maintenance compliance penalty credit for each day where at least one of the credits is greater than $0.
<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
<th>G</th>
<th>H</th>
<th>I</th>
<th>J</th>
<th>K</th>
<th>L</th>
<th>M</th>
<th>N</th>
<th>O</th>
<th>P</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Deficiency Credit Summary</td>
<td>Customer ID</td>
<td>Customer Code</td>
<td>Start Date</td>
<td>End Date</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>7</td>
<td>8</td>
<td>9</td>
<td>10</td>
<td>11</td>
</tr>
<tr>
<td>2</td>
<td>Customer ID</td>
<td>Customer Code</td>
<td>Start Date</td>
<td>End Date</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>7</td>
<td>8</td>
<td>9</td>
<td>10</td>
<td>11</td>
<td>12</td>
</tr>
<tr>
<td>3</td>
<td>Start Date</td>
<td>End Date</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>7</td>
<td>8</td>
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<td>12</td>
<td>13</td>
<td>14</td>
</tr>
<tr>
<td>4</td>
<td>4000.01</td>
<td>4000.02</td>
<td>4000.04</td>
<td>1651.11</td>
<td>1652.11</td>
<td>1663.11</td>
<td>1664.11</td>
<td>2566.11</td>
<td>3001.29</td>
<td>3001.3</td>
<td>2661.01</td>
<td>2662.01</td>
<td>2663.01</td>
<td>2664.01</td>
<td>2666.01</td>
</tr>
</tbody>
</table>

**Supporting Calculations**

Capacity Resource Deficiency Credit (2661.01) = Total PJM Capacity Resource Deficiency Charge (1661.11) * (UCAP Obligation (3001.29) / Total PJM UCAP Obligation (3001.30))

Gen Resource Rating Test Failure Credit (2662.01) = Total PJM Gen Resource Rating Test Failure Charge (1662.11) * (UCAP Obligation (3001.29) / Total PJM UCAP Obligation (3001.30))

Qualifying Transmission Upgrade Compliance Penalty Credit (2663.01) = Total PJM Qualifying Transmission Upgrade Compliance Penalty Charge (1663.11) * (UCAP Obligation (3001.29) / Total PJM UCAP Obligation (3001.30))

Peak Season Maintenance Compliance Penalty Credit (2664.01) = Total PJM Peak Season Maintenance Compliance Penalty Charge (1664.11) * (UCAP Obligation (3001.29) / Total PJM UCAP Obligation (3001.30))
This report displays the account’s demand resource and ILR compliance penalty charge for each resource or zone that undercomplied during a load management event and where the resulting charge is greater than $0. It also displays the account’s demand resource and ILR compliance penalty credit for each resource or zone that overcomplied during a load management event and where the resulting credit is greater than $0.
### Supporting Calculations

1. **DR and ILR Compliance Penalty Charge**
   \[
   \text{DR and ILR Compliance Penalty Charge} (1660.01) = \text{DR and ILR Compliance Charge Penalty Rate (1660.11)} \times \text{Under Compliance (1660.12)}
   \]

2. **DR and ILR Compliance Penalty Credit**
   \[
   \text{DR and ILR Compliance Penalty Credit (2660.01)} = \min(\text{Total PJM DR and ILR Compliance Penalty Charge (2660.11)} \times (\text{Over Compliance (2660.12)} / \text{Total PJM Over Compliance (2660.13)}), \text{DR and ILR Compliance Credit Penalty Rate (2660.17)} \times \text{Over Compliance (2660.12)})
   \]

   *The total DR and ILR Compliance Penalty charge assessed in a planning year is capped at the annual revenue rate the Demand Resource or ILR resource would receive.*
This report displays the account’s ILR Credit for each zone where the account’s ILR MW is greater than 0 MW.

**Supporting Calculations**

\[
\text{ILR Reliability Credit (}2620.01) = \text{ILR MW (}3001.25) \times \text{Final Zonal ILR Price (}2620.11)\]

This report displays the account’s locational reliability charge for each zone where the account’s UCAP obligation is greater than 0.

**Supporting Calculations**

Locational Reliability Charge (1610.01) = UCAP Obligation (3001.23) * Final Zonal Capacity Price (3001.24)
This report displays the account’s daily capacity resource deficiency charge, generation resource rating test failure charge, qualifying transmission upgrade compliance penalty charge and peak season maintenance compliance penalty charge for each day, for each resource where at least one of the charges is greater than $0.

**Supporting Calculations**

\[
\text{Deficiency Rate (3001.35)} = \text{Wtd-Avg Resource Clearing Price (3001.34) + MAX(0.2 * Wtd-Avg Resource Clearing Price, 20)}
\]

\[
\text{Deficiency Charge (3001.28)} = \text{Deficiency MW (3001.26) * Deficiency Rate (3001.35)}
\]
This report displays the account’s daily RPM auction charges and credits, for each resource or buy bid, for each auction round. Data will appear for each resource or buy bid bid that has cleared capacity greater than 0 MW.

### Supporting Calculations

\[
\text{RPM Auction Charge (1600.01)} = \text{Cleared Capacity (1600.11)} \times \text{Capacity Price (3001.22)} \quad \text{when Buy Bid ID is populated}
\]

\[
\text{RPM Auction Charge (2600.01)} = \text{Cleared Capacity (1600.11)} \times \text{Capacity Price (3001.22)} \quad \text{when Resource ID is populated}
\]
This report displays the account’s non-unit specific capacity transaction charge for each non-unit specific capacity transaction where the account is the seller on the transaction and the charge is greater than $0. It also displays the account’s non-unit specific capacity transaction credit for each non-unit specific capacity transaction where the account is the buyer on the transaction and the credit is greater than $0.

**Supporting Calculations**

Non-Unit Specific Capacity Transaction Charge (1650.01) = Transaction MW (1650.11) * Transaction Price (1650.12) when the customer account is the seller on the transaction

Non-Unit Specific Capacity Transaction Credit (2650.01) = Transaction MW (1650.11) * Transaction Price (1650.12) when the customer account is the buyer on the transaction
• **Charges**
  – Monthly on/off peak charges calculated as:
    • \((FTR \text{ purchased}) \times (\text{Applicable FTR Market Price})\)

• **Credits**
  – Monthly on/off peak credits calculated as:
    • \((FTR \text{ sold}) \times (\text{Applicable FTR Market Price})\)
  – Net auction revenue allocated to ARR (Auction Revenue Rights) holders
    • Any excess distributed to FTR holders as excess congestion revenues

PJM Operating Agreement Reference – Schedule 1-7.3.8

<table>
<thead>
<tr>
<th>Financial Transmission Rights Auction</th>
</tr>
</thead>
<tbody>
<tr>
<td>1500</td>
</tr>
<tr>
<td>2500</td>
</tr>
</tbody>
</table>
Auction Revenue Rights

- Auction Revenue Rights (ARRs) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers.

Credits:

- Annual FTR auction net revenues are allocated as hourly credits based on ARR target allocations which equal the ARR MW (divided by the number of auction rounds) times the difference between auction clearing prices at the ARR sink and source.

- ARR target deficiencies may be proportionately eliminated by any monthly FTR auction net revenues and excess congestion revenues in that planning period.
Supporting Calculations

ARR Total Target Credit (2510.12) = ARR MW (3000.54) * ARR Rate (2510.11)

ARR Target Credit (2510.01) = ARR Total Target Credit (2510.12) * ARR Ownership Share (3000.82)

- Zonal Peak Load MW and Load Shift MW can be verified via the Network Integration Transmission Service Charge Summary report.
ARR Reassignment Methodology

• New methodology will reassign ownership of the ARR, rather than just the ARR dollar value. This provides customers with additional data for more detailed ARR tracking while the results remain financially identical to today’s method.

• If one customer holds a net negative ARR Portfolio and loses load in the zone, customers picking up that load will not be burdened.

• Results will be reported in the ARR Target Credits report.
## Current ARR Reassignment Methodology

### June 10th

**ARR 1234**  
Zone A  
Customer A = 100% Ownership

<table>
<thead>
<tr>
<th>Sink Locational Price</th>
<th>Source Locational Price</th>
<th>MW</th>
<th>Annual Value</th>
<th>Daily Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$70.00</td>
<td>$50.00</td>
<td>20</td>
<td>$400.00</td>
<td>$1.10</td>
</tr>
</tbody>
</table>

**ARR 5678**  
Zone A  
Customer A = 20% Ownership  
Customer E = 80 % Ownership

<table>
<thead>
<tr>
<th>Sink Locational Price</th>
<th>Source Locational Price</th>
<th>MW</th>
<th>Annual Value</th>
<th>Daily Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$50.00</td>
<td>$40.00</td>
<td>20</td>
<td>$200.00</td>
<td>$0.55</td>
</tr>
</tbody>
</table>

### Load Value Calculation

<table>
<thead>
<tr>
<th>Customer</th>
<th>MW</th>
<th>Value Calculation</th>
<th>June 10th Portfolio Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer A</td>
<td>100 MW</td>
<td>($1.10 * 100% + $0.55 * 20%)</td>
<td>$1.21</td>
</tr>
<tr>
<td>Customer E</td>
<td>100 MW</td>
<td>($0.55 * 80%)</td>
<td>$0.44</td>
</tr>
</tbody>
</table>
Current ARR Reassignment Methodology

June 11th

Customer A – 80 MW Load → 20% Decrease
Customer C – Gains ¼ of Customer A Load
Customer D – Gains ¾ of Customer A Load
Customer E – Remains at Same Load = 100 MW

<table>
<thead>
<tr>
<th></th>
<th>June 11th Value Calculation</th>
<th>June 11th Portfolio Value</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NOT PROVIDED IN CURRENT REPORTING SYSTEM</td>
<td></td>
</tr>
<tr>
<td>Customer A</td>
<td>80% * $1.21</td>
<td>$0.968</td>
</tr>
<tr>
<td>Customer C</td>
<td>25% * $1.21 * 20%</td>
<td>$0.0605</td>
</tr>
<tr>
<td>Customer D</td>
<td>75% * $1.21 * 20%</td>
<td>$0.1815</td>
</tr>
<tr>
<td>Customer E</td>
<td>100% * $0.44</td>
<td>$0.44</td>
</tr>
</tbody>
</table>

In current methodology, ARR Reassignment values are calculated by dollar amount of the ARR. Customers are not able to determine which ARRs are changing the portfolio value.
### ARR Reassignment Example

**New ARR Reassignment Methodology:**

#### ARR 1234

<table>
<thead>
<tr>
<th></th>
<th>June 10(^{th}) Load</th>
<th>June 10(^{th}) Ownership</th>
<th>June 11(^{th}) Load</th>
<th>Ownership Shift</th>
<th>June 11(^{th}) Ownership</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Account A</td>
<td>100</td>
<td>100%</td>
<td>80</td>
<td>-20%</td>
<td>80%</td>
</tr>
<tr>
<td>Customer Account B</td>
<td>100</td>
<td>0%</td>
<td>80</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Customer Account C</td>
<td>100</td>
<td>0%</td>
<td>110</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Customer Account D</td>
<td>100</td>
<td>0%</td>
<td>130</td>
<td>15%</td>
<td>15%</td>
</tr>
<tr>
<td>Customer Account E</td>
<td>100</td>
<td>0%</td>
<td>100</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>500</strong></td>
<td><strong>100%</strong></td>
<td><strong>500</strong></td>
<td><strong>0%</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

#### ARR 5678

<table>
<thead>
<tr>
<th></th>
<th>June 10(^{th}) Load</th>
<th>June 10(^{th}) Ownership</th>
<th>June 11(^{th}) Load</th>
<th>Ownership Shift %</th>
<th>June 11(^{th}) Ownership</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Account A</td>
<td>100</td>
<td>20%</td>
<td>80</td>
<td>-4%</td>
<td>16%</td>
</tr>
<tr>
<td>Customer Account B</td>
<td>100</td>
<td>0%</td>
<td>80</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Customer Account C</td>
<td>100</td>
<td>0%</td>
<td>110</td>
<td>1%</td>
<td>1%</td>
</tr>
<tr>
<td>Customer Account D</td>
<td>100</td>
<td>0%</td>
<td>130</td>
<td>3%</td>
<td>3%</td>
</tr>
<tr>
<td>Customer Account E</td>
<td>100</td>
<td>80%</td>
<td>100</td>
<td>0%</td>
<td>80%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>500</strong></td>
<td><strong>100%</strong></td>
<td><strong>500</strong></td>
<td><strong>0%</strong></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>
**New ARR Reassignment Methodology:**

Portfolio Value Calculation = Ownership % * Daily Value of ARR

<table>
<thead>
<tr>
<th>June 10th</th>
<th>ARR 1234</th>
<th>ARR 5678</th>
<th>Total June 10th Portfolio Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Account A</td>
<td>100% * $1.10 = $1.10</td>
<td>20% * $.55 = $0.11</td>
<td>$1.21</td>
</tr>
<tr>
<td>Customer Account B</td>
<td>No Ownership</td>
<td>No Ownership</td>
<td>$0.00</td>
</tr>
<tr>
<td>Customer Account C</td>
<td>No Ownership</td>
<td>No Ownership</td>
<td>$0.00</td>
</tr>
<tr>
<td>Customer Account D</td>
<td>No Ownership</td>
<td>No Ownership</td>
<td>$0.00</td>
</tr>
<tr>
<td>Customer Account E</td>
<td>No Ownership</td>
<td>80% * $0.55 = $0.44</td>
<td>$0.44</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>June 11th</th>
<th>ARR 1234</th>
<th>ARR 5678</th>
<th>Total June 11th Portfolio Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Account A</td>
<td>80% * $1.10 = $.88</td>
<td>16% * $0.55 = $0.088</td>
<td>$.968</td>
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<tr>
<td>Customer Account B</td>
<td>0% * $ 1.10 = $0.00</td>
<td>0% * $0.55 = $0.00</td>
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<td>Customer Account C</td>
<td>5% * $ 1.10 = $0.055</td>
<td>1% * $0.55 = $0.0055</td>
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<tr>
<td>Customer Account D</td>
<td>15% * $ 1.10 = $0.165</td>
<td>3% * $0.55 = $0.0165</td>
<td>$0.1815</td>
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<tr>
<td>Customer Account E</td>
<td>0 * $ 1.10 = $0.00</td>
<td>80% * $0.55 = $0.44</td>
<td>$0.44</td>
</tr>
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</table>
• PJM may purchase energy from outside PJM as needed to alleviate or
dend an emergency or may sell energy to another control area as
requested during emergencies 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.
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 day-ahead market net interchange 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 market participants charge allocation

- Total charges to be allocated among market participants for each emergency energy purchase are calculated as:

  \[ \text{Emergency Energy Purchase (MWh)} \times (\text{Emergency Energy Purchase Price - Real-time Interface LMP}) \]
The net revenues in excess of real-time LMPs of emergency energy sales is credited to market participants in proportion to their real-time deviation from their day-ahead net interchange whenever that deviation:

- Increases their spot market purchases
- Decreases their spot market sales, plus any sales from within PJM to entities outside of PJM that have been curtailed by PJM during the emergency

PJM calculates the total credits to be allocated among PJM market participants for each emergency energy sale as:

\[
\text{Emergency Energy Sale (MWh)} \times (\text{Emergency Energy Sale Price} - \text{Real-time Interface LMP})
\]
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 day-ahead market net interchange when that deviation:
  
  – Decreases their spot market purchases
  
  OR
  
  – Increases their spot market sales

• PJM calculates the total charges to be allocated among PJM market participants for each Minimum Generation Emergency energy purchase as:

\[ \text{Min Gen Emergency Energy Purchase (MWh)} \times (\text{Emergency Energy Purchase Price} - \text{Real-time Interface LMP}) \]
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 day-ahead market net interchange when that deviation:
  - Decreases their spot market purchases
    OR
  - Increases their spot market sales

- PJM calculates the total credits to be allocated among PJM market participants for each Minimum Generation Emergency energy sale as:

  \[ \text{Min Gen Emergency Energy Sale (MWh)} \times (\text{Emergency Energy Sale Price} - \text{Real-time Interface LMP}) \]
Load Response Accounting

• **Credits:**

  • Day-ahead and real-time economic and real-time emergency load response credits are provided to Curtailment Service Providers (CSP) equal to the reduced MWh times LMP (minus retail rate, as applicable)

• **Charges:**

  • For day-ahead and real-time economic load response:

    • The CSP’s Load Serving Entity (LSE) is charged the difference between the LMP and the retail rate, as applicable times the MWh reduction

  • For emergency load response:

    • All balancing energy market participants are allocated charges using the same method as for PJM emergency energy purchases
This report displays a customer account's hourly CSP load response credits and directly allocated LSE load response charges for each end use customer for all hours processed within the selected month where the Day-Ahead Load Response Credit, DA Load Response Charge, RT Load Response Credit or RT Load Response Charge is not zero for the hour.
**Supporting Calculations**

**DA Load Response Charge (1240.01)** = \( \text{DA Load Response MWh} \times 3001.14 \times \max(\text{DA LMP} - \text{DA Retail Rate Used}) \)

**DA Load Response Credit (2240.01)** = \( \text{DA Load Response MWh} \times 3001.14 \times \max(\text{DA LMP} - \text{DA Retail Rate Used}) \)

**RT Load Response MWh (3001.15)** = \( \text{Load Response Loss Factor} \times (1 - \text{EDC Loss De-ration Factor} \times (\text{CBL} - \text{Metered Load}) / 1000) \)

If \( \text{RT Load Response MWh} \geq 0 \),

\[ \text{RT Load Response Charge (1241.01)} = (\text{RT Load Response MWh} - \text{DA Load Response MWh}) \times \max(\text{RT LMP} - \text{RT Retail Rate Used}), 0) \]

Else,

\[ \text{RT Load Response Charge (1241.01)} = (\text{RT Load Response MWh} - \text{DA Load Response MWh}) \times \max(0, \text{RT LMP} - \text{MIN (RT Retail Rate Used) - RT LMP (3002.25)}), 0) \]

If \( \text{RT Load Response MWh} \geq 0 \)

\[ \text{RT Load Response Credit (2241.01)} = (\text{RT Load Response MWh} - \text{DA Load Response MWh}) \times \max(\text{RT LMP} - \text{RT Retail Rate Used}), 0) \]

Else,

\[ \text{RT Load Response Credit (2241.01)} = (\text{RT Load Response MWh} - \text{DA Load Response MWh}) \times \max(0, \text{DA LMP} - \text{MIN (RT Retail Rate Used) - RT LMP (3002.25)}), 0) \]

Else, \( \text{RT Load Response Credit (2241.01)} = 0 \)
This report displays a customer account's hourly day-ahead and real-time load response charge allocations for each zone for all hours processed within the selected month.

**Supporting Calculations**

DA Load Response Charge Allocation (1240.02) = Total DA Load Response Zone Charge (1240.12) * (DA Demand (3001.11) / Total Zone DA Demand (1240.13))

RT Load Response Charge Allocation (1241.02) = Total RT Load Response Zone Charge (1241.15) * (RT Load (3001.12) / Total Zone RT Load (3001.13))
**Temporary Charges**

- **RTO Start-up Recovery for ComEd**
  - **Expected to end May 2014**
  - **Charges**
    - Monthly charges to ComEd zonal network customers
      - $72.71/MW/year based on network service peak load (plus losses) contributions (2009 Rate)
  - **Credits**
    - Allocated to ComEd
      - **OATT Attachment H-13**

<table>
<thead>
<tr>
<th>1720</th>
<th>RTO Start-up Cost Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>2720</td>
<td>RTO Start-up Cost Recovery</td>
</tr>
</tbody>
</table>
• **RTO Startup Recovery for AEP**

  – **Expected to end May 2015**

  – **Charges**
    - Monthly charges to AEP zonal network and Point to Point customers
      - $97.56/MW/year based on network service peak load (plus losses) contributions and point-to-point load serving transmission reservations (2009 Rate)

  – **Credits**
    - Allocated to AEP
      - **OATT Attachment H-14**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td>1720</td>
<td>RTO Start-up Cost Recovery</td>
</tr>
<tr>
<td>2720</td>
<td>RTO Start-up Cost Recovery</td>
</tr>
</tbody>
</table>
Temporary Charges

• Expansion Cost Recovery

  – Charges
    • Monthly charges to all customers using Pt-Pt and Network Transmission Service to serve load in any PJM zone (except in Dominion Virginia Power zone)
      – $5.29 * (average of network service peak load (including losses) contributions across all days in applicable month)
        » For Network and Pt-Pt load serving customers in AEP, Dayton and ComEd zones
      – $2.54 * (average of network service peak load (including losses) contributions across all days in applicable month)
        » For Network and Pt-Pt load serving customers in all other zones (except Dominion)

  – Credits
    • Total revenues allocated to ComEd, AEP and Dayton Transmission Owners in accordance with Schedule 13

  ─ OATT Schedule 13

    Expected to continue through April 2015

    | 1730       | Expansion Cost Recovery |
    | 2730       | Expansion Cost Recovery |
Temporary Charges

• Generation Deactivation

  – Charges
  – Revenues are collected for generation requesting retirement where PJM studies find reliability issues that require the generation to continue operating.
  – Network transmission customers in affected transmission zones pay a share of the Deactivation Avoidable Cost Rate or the FERC-approved Cost of Service Recovery Rate
  – Costs determined on a generator by generator basis

  – Credits
    • Generation Owners requesting retirement annual cost allocation
    – Billed/Credited Monthly
    – OATT Part V

| 1930 | Generation Deactivation |
| 2930 | Generation Deactivation |
• Transmission Enhancement
  – Charges
  – All network and merchant transmission owners pay certain transmission owners for required enhancement projects in accordance with zonal cost responsibility allocations.
  – All network customers serving load in a responsible zone pay for that zone’s applicable projects’ revenue requirements in proportion to their network service peak load share in that zone.
  – Responsible merchant transmission owners pay their share of applicable revenue requirements
  – ComEd bears their zone’s Illinois CPP suppliers charges
  – Credits
    • Total revenues allocated to applicable transmission enhancement project owners or applicable transmission zone customers for zonal transmission owners that include these rates in their network rates. Currently TrAILCo, PATH, BG&E and Dominion receive credits
  – OATT Schedule 12

<table>
<thead>
<tr>
<th></th>
<th>Transmission Enhancement</th>
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<tr>
<td>1108</td>
<td>Transmission Enhancement</td>
</tr>
<tr>
<td>2108</td>
<td>Transmission Enhancement</td>
</tr>
</tbody>
</table>
Settlement Topics
Default Supplier Settlement Service

• A service offered by PJM settlements to automatically allocate any MWh of load responsibility remaining in an EDC’s account to designated default suppliers based on specified percentages agreed to by all parties.

• This service is intended for use by EDCs with default suppliers whereby the EDC itself has no load responsibility, including those EDCs with POLR suppliers, full requirements contracts with one or more parties, or operating under the NJ BGS or the IL CPP retail load auction programs.
Default Supplier Settlement Service

• The former settlement system requires EDCs to attempt to carve-out their load down to zero and employs a monthly financial “sweep” adjustment for all final billing line item amounts related to any load MWh that remain in their account (semi-manual process not very flexible in handling variations among the EDCs’ contractual specifications nor handling changes of suppliers or responsibility shares mid-Planning Period).

• The new system will replace the existing process with a method where PJM will allocate all hourly MWh of an EDC’s remaining load responsibility directly to their default suppliers based on monthly allocation percentages.
Billing Line Items related to Default Supplier Load MWh

- Balancing Spot Market Energy Charges
- Balancing Transmission Congestion Charges
- Balancing Transmission Losses Charges
- Transmission Losses Credits
- Regulation Charges
- Synchronized Reserve Charges
- Balancing Operating Reserve Charges
- Reactive Services and Synchronous Condensing Charges
- Inadvertent Interchange Charges
- Emergency Load Response Charges
- Meter Correction Charges (inadvertent portion only)
- Schedule 9-1, 9-3, 9-4, 9-FERC, and 9-OPSI Charges
- Schedule 10-NERC and 10-RFC Charges
- Schedule 1-A Charges
- Emergency Energy Charges and Credits
Default Supplier Methodology Changes

• PJM allocates all remaining load in an EDC’s account, so the EDC will no longer need to carve-out their load responsibility to 0.000 MWh. If an EDC still wishes to employ this process, load cannot be carved-out below zero.

• All reconciliation billing for these line items will also be automatically applied to the default suppliers. No reconciliation billing line items nor reports will appear for the EDC.
  – EDCs will continue to have access to their submitted reconciliation data via the eSchedules report for upload verification.
Default Supplier Methodology Changes

- Meter Error Correction Charges (except for the inadvertent component for external tie corrections) will not be automatically applied to default suppliers. Some EDCs currently have all of these charges being allocated.

- Schedule 10-NERC and RFC charges will be automatically applied to default suppliers. Some EDCs currently do not have these charges being allocated.

- Documentation is required to show agreement among the EDC and the applicable default suppliers (including exact PJM account names and specified allocation shares) preferably via a Declaration of Authority.
EDCs and Default Suppliers can see the MWh that were allocated from the EDC to the Default Supplier on the Real-Time Daily Energy Transactions report.

### Real-Time Daily Energy Transactions

<table>
<thead>
<tr>
<th>Customer Code</th>
<th>Date</th>
<th>Transaction Type</th>
<th>Transaction ID: NERC Tag</th>
<th>EPT HE 01</th>
<th>EPT HE 02</th>
<th>EPT HE 02*</th>
<th>EPT HE 03</th>
<th>Source PNODE Name</th>
<th>Source PNODE ID</th>
<th>Sink PNODE Name</th>
<th>Sink PNODE ID</th>
<th>Seller</th>
<th>Buyer</th>
</tr>
</thead>
<tbody>
<tr>
<td>101 EDCA</td>
<td>2/1/2008</td>
<td>Retail Load Responsibility</td>
<td>57149</td>
<td>-40</td>
<td>-40</td>
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<td>ZONIEA</td>
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<td>COMPB</td>
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<tr>
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<tr>
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<td>Default Supplier Load</td>
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<td>101 EDCA</td>
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<td>Total RT Not Interchange</td>
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<td>100</td>
<td>ZONIEA</td>
<td>100</td>
<td>COMPB</td>
<td>EDCA</td>
</tr>
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</table>
Default Supplier Access to Reconciliation Data

• Default suppliers will receive reconciliation billing reports for billing related to reconciliation data submitted for the EDC’s eSchedules

• All reconciliation line items will be reported at the account level, rather than at the eSchedule level, with the exception of load reconciliation for congestion and loss charges

• The Congestion and Loss Load Reconciliation Charges report requires eSchedule-level granularity due to the locational nature of these charges
  – On this report, default suppliers will see their share of reconciled MWh and delivery point, but they will not see the EDC’s LSE counterparty, which is masked for data confidentiality
Real-Time Daily Energy Transaction Report for EDC A

- 40 MWh RLR with Company B for HE 1-3
- Allocates 70% of residual load to Company A
- Allocates 30% of residual load to Company B

<table>
<thead>
<tr>
<th>Real-Time Daily Energy Transactions</th>
</tr>
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<tbody>
<tr>
<td>Customer Account: EDC A, LLC Report Creation Timestamp (EPT): 02/05/2008 9:56:48 AM</td>
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<tr>
<td>Start Date: 2/1/2008 End Date: 2/1/2008</td>
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</table>

EDC A submits the following reconciliation data for RLR with Company B

- Scheduled MWh = 40, Actual MWh = 45
- Reconciliation Energy = -5MWh (5MWh more load for LSE, 5MWh less for EDC default suppliers)
Congestion Reconciliation Report Example

Congestion Reconciliation Charge report for Company A

- Company A is only a default supplier for EDC A. They are not party to the eSchedule being reconciled; therefore, the seller column is left blank in order to protect confidential information.

<table>
<thead>
<tr>
<th>Customer ID</th>
<th>Customer Code</th>
<th>Billing Month</th>
<th>EPT Hour Ending</th>
<th>GMT Hour Ending</th>
<th>eSchedules ID</th>
<th>Seller</th>
<th>Buyer</th>
<th>Load Reconciliation Energy (MWh)</th>
<th>PNODE ID</th>
<th>PNODE RT Congestion Price ($/MWh)</th>
<th>Congestion Load Reconciliation Charge ($)</th>
<th>PNODE RT Loss Price ($/MWh)</th>
<th>Loss Load Reconciliation Charge ($)</th>
</tr>
</thead>
<tbody>
<tr>
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</table>
Congestion Reconciliation Charge report for Company B

- Company B is a default supplier for EDC A as well as the seller on the RLR eSchedule being reconciled; therefore the eSchedule will appear twice

<table>
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<th>Customer ID</th>
<th>Customer Code</th>
<th>Billing Month</th>
<th>EPT Hour Ending</th>
<th>GMT Hour Ending</th>
<th>eSchedules ID</th>
<th>Seller</th>
<th>Buyer</th>
<th>Load Reconciliation Energy (MWh)</th>
<th>PNODE RT Congestion Price</th>
<th>PNODE RT Loss Price</th>
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<th>Loss Load Reconciliation Charge ($)</th>
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<tbody>
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</tbody>
</table>
Billing Line Item Transfer Settlement Service

- A service offered by PJM settlements to automatically transfer specified billing line items, and the associated report details, from one customer account to another as agreed to by both parties.

- This service is mainly used by EDCs and LSEs operating under the MD/DE/VA/DC SOS and IL CPP retail load programs.
Billing Line Item Transfer Settlement Service

- The existing settlement system employs a monthly financial transfer of all specified final billing line item amounts from one customer account to another customer account (semi-manual process not very flexible in handling variations among the EDCs’ contractual specifications nor handling line item changes mid-Planning Period)
- The new system will replace the existing process with a similar (but more flexible) method which will also allow both parties to the transfer to have access to the applicable detailed settlement report data
- Billing line item transfers may change line items and/or parties to the transfer on a monthly basis, if required
Typical Billing Line Items Transferred

• MD/DE/VA/DC SOS Programs (from supplier to EDC)
  – Network Integration Transmission Service Charges
  – Network Integration Transmission Service Offset Charges (AP only)
  – Non-Firm Point-to-Point Transmission Service Credits
  – Transmission Enhancement Charges (Delmarva only)

• IL CPP Program (from supplier to EDC)
  – Network Integration Transmission Service Charges
  – Non-Zone Network Integration Transmission Service Credits
  – Firm Point-to-Point Transmission Service Credits
  – Non-Firm Point-to-Point Transmission Service Credits
  – Transmission Enhancement Charges
  – Expansion Cost Recovery Charges
  – RTO Start-up Cost Recovery Charges
Billing Line Item Transfer Details

• PJM directly transfers 100% of each specified billing line item from one customer account to another. No longer are equal and opposite billing adjustment line items necessary.

• Since the entire billing line item amount is transferred, activity related to a specific generator or load cannot be transferred unless the “from” account consists solely of the applicable activity of that generator or load.

• All billing adjustments made to the line items specified for transfer will also be transferred.
Billing Line Item Transfer Details

• Customer settlement reports applicable to the transferred line items will be made available to both parties to the transfer (there are some exceptions to this, since some reports reflect multiple line items’ detailed data)

• Documentation is required to show agreement among the two parties involved in the billing line item transfer (including exact PJM account names and specified line items) preferably via a Declaration of Authority

• Note that reports that support more than one billing line item will not display billing line item transfer details due to data confidentiality constraints
Billing Line Item Transfer

• In MSRS reports, the data supporting the transferred BLI will display on the applicable settlement report(s) of both the “Transfer From” and the “Transfer To” account.

• On the “Transfer From” account’s report, the data will appear as normal.

• On the “Transfer To” account’s report, the data supporting the line item being transferred from the other account will appear on a separate line(s) beneath the account’s own data. The data will be differentiated through the use of the account identifiers on the report (customer ID, customer code).
Billing Line Item Transfer - Example

- Customer A transfers BLI 2630 (Capacity Transfer Rights credit) to Customer B for the month of September, 2006

- This BLI is displayed on the Capacity Transfer Rights Credit Summary Report

- Customer A will see its credit on the September CTR Credit Summary

- Customer B will see both its credit and Customer A’s credit on the September CTR Credit Summary

Customer A  
BLI 2630  
Customer B
# Billing Line Item Transfer - Example

**Customer Account:** Customer A

**Start Date:** 09/01/2006  
**End Date:** 09/30/2006

### Capacity Transfer Rights Credit Summary

<table>
<thead>
<tr>
<th>Customer ID</th>
<th>Customer Code</th>
<th>Date</th>
<th>Zone</th>
<th>CTR MW</th>
<th>UCAP Obligation (MW)</th>
<th>Total Zone UCAP Obligation (MW)</th>
<th>Traded CTR MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>123</td>
<td>Customer A</td>
<td>09/10/2006</td>
<td>AEP</td>
<td>12.0</td>
<td>1.000</td>
<td>6.500</td>
<td>5.0</td>
</tr>
<tr>
<td>123</td>
<td>Customer A</td>
<td>09/14/2006</td>
<td>PJM</td>
<td>15.0</td>
<td>1.000</td>
<td>6.500</td>
<td>5.0</td>
</tr>
</tbody>
</table>

**Date Range Total**

---

**Customer A is the Transfer From organization**  
The report will display Customer A’s data only
### Capacity Transfer Rights Credit Summary

**Customer Account:** Customer B

Start Date: 09/01/2006

End Date: 09/30/2006

<table>
<thead>
<tr>
<th>Customer ID</th>
<th>Customer Code</th>
<th>Date</th>
<th>Zone</th>
<th>CTR MW</th>
<th>UCAP Obligation (MW)</th>
<th>Total Zone UCAP Obligation (MW)</th>
<th>Traded CTR MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>456</td>
<td>Customer B</td>
<td>09/01/2006</td>
<td>DOM</td>
<td>120.0</td>
<td>1.000</td>
<td>6.500</td>
<td>5.0</td>
</tr>
<tr>
<td>123</td>
<td>Customer A</td>
<td>09/10/2006</td>
<td>AEP</td>
<td>12.0</td>
<td>1.000</td>
<td>6.500</td>
<td>5.0</td>
</tr>
<tr>
<td>123</td>
<td>Customer A</td>
<td>09/14/2006</td>
<td>PJM</td>
<td>15.0</td>
<td>1.000</td>
<td>6.500</td>
<td>5.0</td>
</tr>
</tbody>
</table>

**Report Creation Timestamp (EPT):** 03/04/2008 10:50:06AM

**Date Range Total**

Customer B is the Transfer To organization. The report will display Customer B’s data first, then the data transferred from Customer A.
Billing Line Item Transfer Summary Report

• This report displays all billing line item transfers included in the billing statement for the selected billing period, where the customer account is either the “transferred from” customer account or the “transferred to” customer account and where an amount was transferred for the billing period.

• Applies to transfers that are effective for the selected billing period, as well as transfers that were effective for the source billing period of adjustments included in the selected billing period.
## Billing Line Item Transfer Summary

**Customer Account:** Power and Light Co.

**Report Creation Timestamp (EPT):** 04/15/2008 12:44:38AM

**Billing Period Start:** 04/14/2008

### Billing Period Start Date | Source Billing Period Start Date | Billing Line Item ID | Billing Line Item Name | Transfer Amount ($) | Transferred From (Customer Account) | Transferred To (Customer Account) | Version
---|---|---|---|---|---|---|---
4001.03 | 4001.04 | 4001.05 | 4001.06 | 2008.07 | 4002.90 | 4002.91 | 4002.92 | 4002.97

www.pjm.com
Review and Additional Resources
• Market Settlements Terminology
• Line Items on a PJM Billing Statement
  • Spot Market Energy
  • Marginal Losses
  • Congestion
  • Transmission Service
  • Ancillary Services
• Miscellaneous
• Review
Additional Resources

- PJM Manuals
  - OATT Accounting M-27
  - Operating Agreement Accounting M-28
  - Billing M-29
  - PJM Capacity Market Manual M-18
- PJM OATT
- PJM Operating Agreement
Important Phone Numbers

- Member Relations Hotline
  - General Questions
    - 610-666-8980
    - Toll free – 1-866-400-8980
    - http://www.pjm.com/about/contact/form-contact.html
- Market Settlements Hotline
  - Specific questions about individual bill
    - 610-666-8825
    - mrkt_settlement_ops@pjm.com
- Market Operations Hotline
  - Specific Markets-related questions
    - 610-666-8998
Questions ?
Appendix
• Calculate the “Day-ahead Spot Market Interchange” for the Market Participant shown below:

- **Generation** = 700 (Import) + 500 (Gen 1) + 400 (Gen 2) + 50 (Inc offer) = 1650 MW
- **Load** = 600 (Export) + 800 (Fixed) + 100 (Price-sensitive) + 75 (Dec Bid) = 1575 MW
- **Spot Market Interchange** = 1575 MW - 1650 MW = -75 MW (Net Seller to Spot Market)
Exercise 2 - Answer

- Calculate the “Day-ahead Spot Market Energy” for the participant shown below:

“Load” = 400 + 50 + 100 = 550 MW

“Gen” = 100 + 200 + 20 = 320 MW

“Net Spot Market Interchange” = 550 MW - 320 MW = 230 MW

“Day-ahead charges or credits” = (230 MW)($10) = $2300 charge
Calculate the “Balancing Spot Market Energy” for the participant shown below:

Generator 1 = 200 MW @ LMP = $15
Generator 2 = 300 MW @ LMP = $15
Load = 500 MW @ LMP = $15
Export = 100 MW LMP = $15 (Source)

eSchedule purchase at zone = 20 MW @ $15 (Sink)

“Balancing Net Interchange” = (Metered Interchange – losses) + Scheduled Sales - Scheduled Purchases

= 0 + 100 MW - 20 MW = 80 MW

Balancing Charge or Credit = Balancing Net Interchange - DA Net Interchange * Energy component of RT LMP

= (80 MW - 230 MW) * $15 = $2,250 credit

DA charge - Balancing Credit = 2300 - 2250 = $50 charge
### Exercise 3 - Answer

- **Calculated Individually**

<table>
<thead>
<tr>
<th></th>
<th>Day-ahead</th>
<th>Balancing</th>
<th>Net</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Export</strong></td>
<td>-1000</td>
<td>0</td>
<td>-1000</td>
</tr>
<tr>
<td><strong>eSched</strong></td>
<td>200</td>
<td>0</td>
<td>200</td>
</tr>
<tr>
<td><strong>Dec Bid</strong></td>
<td>-500</td>
<td>750</td>
<td>250</td>
</tr>
<tr>
<td><strong>Gen 1</strong></td>
<td>1000</td>
<td>1500</td>
<td>2500</td>
</tr>
<tr>
<td><strong>Gen 2</strong></td>
<td>2000</td>
<td>1500</td>
<td>3500</td>
</tr>
<tr>
<td><strong>Load</strong></td>
<td>-4000</td>
<td>-1500</td>
<td>-5500</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>-2300</td>
<td>2250</td>
<td>-50</td>
</tr>
</tbody>
</table>
Day - ahead Market
DA System Energy Price = $10

Export = 20 MW
Source DALP = $1; DACP = $10
Sink DALP = $3; DACP = $20

DA Spot Market Charges:
30 MW * $10 = $300

DA Implicit Congestion:
($300+$300+$50) - ($0+$75+$100) = $475

DA Explicit Congestion:
20 ($20-$10) = $200

DA Implicit Losses:
($20+$30+$20) - ($10+$10+(-$20)) = $70

DA Explicit Losses:
20 ($3-$1) = $40

Hint:
Spot Market Charges = SMI * “DA System Energy Price”
Implicit Congestion = Load Charges – Generator Credits using DACP
Explicit Congestion = Schedule MW (Sink DACP - Source DACP)
Implicit Losses = Load Charges – Generator Credits using DALP
Explicit Losses = Schedule MW (Sink DALP – Source DALP)
Balancing Market
RT System Energy Price = $20

Export = 0 MW
Source RTLP = $1; RTCP = $15
Sink RTLP = $3; RTCP = $28

30 MW
RTLP = $1.5; RTCP = $5

10 MW
RTLP = $1; RTCP = $0

20 MW
RTLP = $1; RTCP = $10

DEC Bid
0 MW
RTLP = $2; RTCP = $5

20 MW
RTLP = $0.5; RTCP = $15

30 MW
RTLP = $2; RTCP = $20

Balancing Spot Market Charges:
(10 MW – 30 MW) * $20 = ($400)

Balancing Implicit Congestion:
($50+$300-$50) - ($0+$150+$0) = $150

Balancing Explicit Congestion:
-20 ($28-$15) = ($260)

Balancing Implicit Losses:
($15+$30-$20) – ($0+$15+$0) = $10

DA Explicit Losses:
-20 ($3-$1) = ($40)

Hint:
Calculate Deviations from DA
Spot Market Charges = SMI (deviation) * “RT System Energy Price”
Implicit Congestion = Load Charges – Generator Credits using RTCP (based on deviations from DA schedules)
Explicit Congestion = Transaction deviations (Sink RTCP - Source RTCP)
Implicit Losses = Load Charges – Generator Credits using RTLP (based on deviations from DA schedules)
Explicit Losses = Transaction deviations (Sink RTLP – Source RTLP)
Match the OATT Schedule to the Ancillary Service

- **Schedule 1A**: Synchronized Reserve Service
- **Schedule 2**: Reactive Supply Service
- **Schedule 3**: Trans Owner Scheduling, System Control and Dispatch Service
- **Schedule 5**: Regulation and Frequency Response Service
- **Schedule 6A**: PJM Administrative Services
- **Schedule 9**: Black Start Service