Market Settlements (MS-301)

Fall 2009

Pre-requisite Knowledge

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:
http://www.pjm.com/documents/agreements.aspx

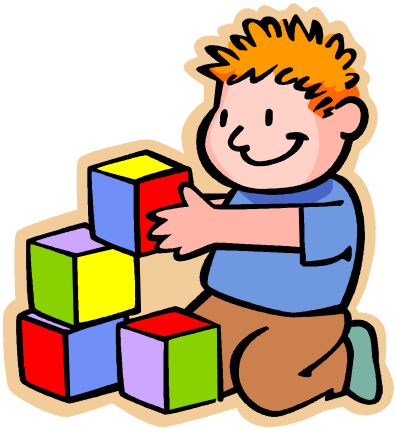
For additional detailed information on any of the topics discussed, please refer to the appropriate PJM manual which can be found by accessing:
http://www.pjm.com/documents/manuals.aspx

⚠ WARNING

- 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.

Market Settlements Training Segments

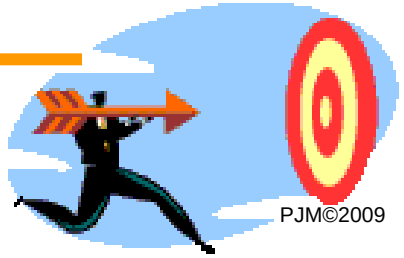
- This training will be conducted in two primary segments:
  - Market Settlements Primer
  - MS-301



Objectives

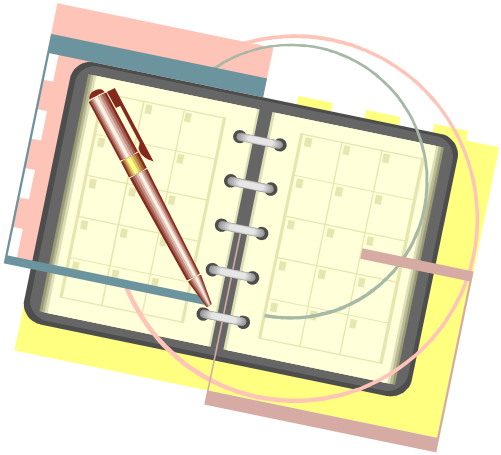
At the end of the training session
it is anticipated that you will be able to:

- 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 walk-through
- Understand the eligibility requirements and impacts of PJM Operating Reserves
- Describe the various sources for more detailed Settlements information



Agenda

- Market Settlements Terminology
- Line Items on a PJM Billing Statement
  - Spot Market Energy
  - Congestion
  - Losses/Transmission Service
  - Ancillary Services
  - Miscellaneous
  - Review



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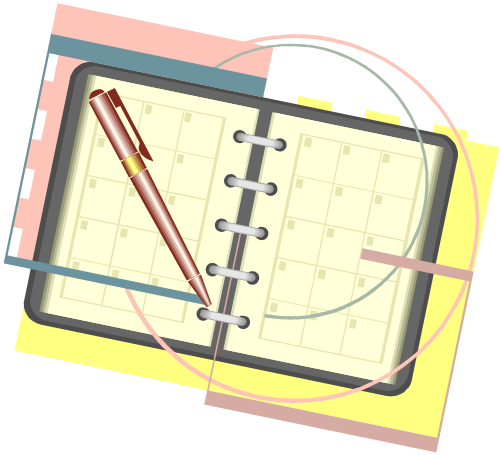
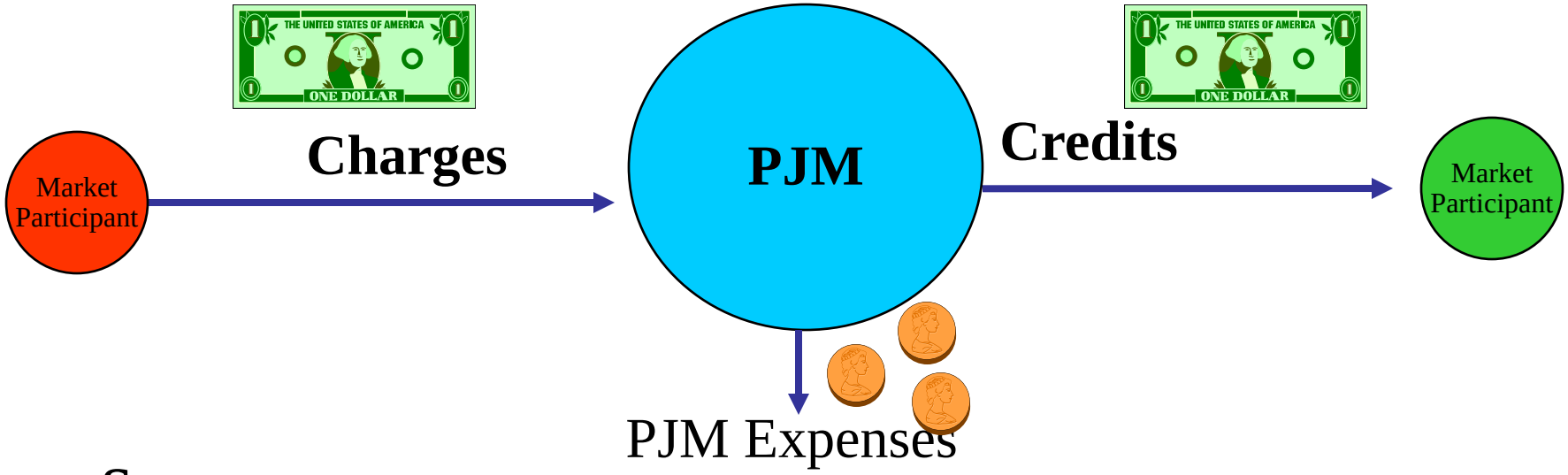


Terminology

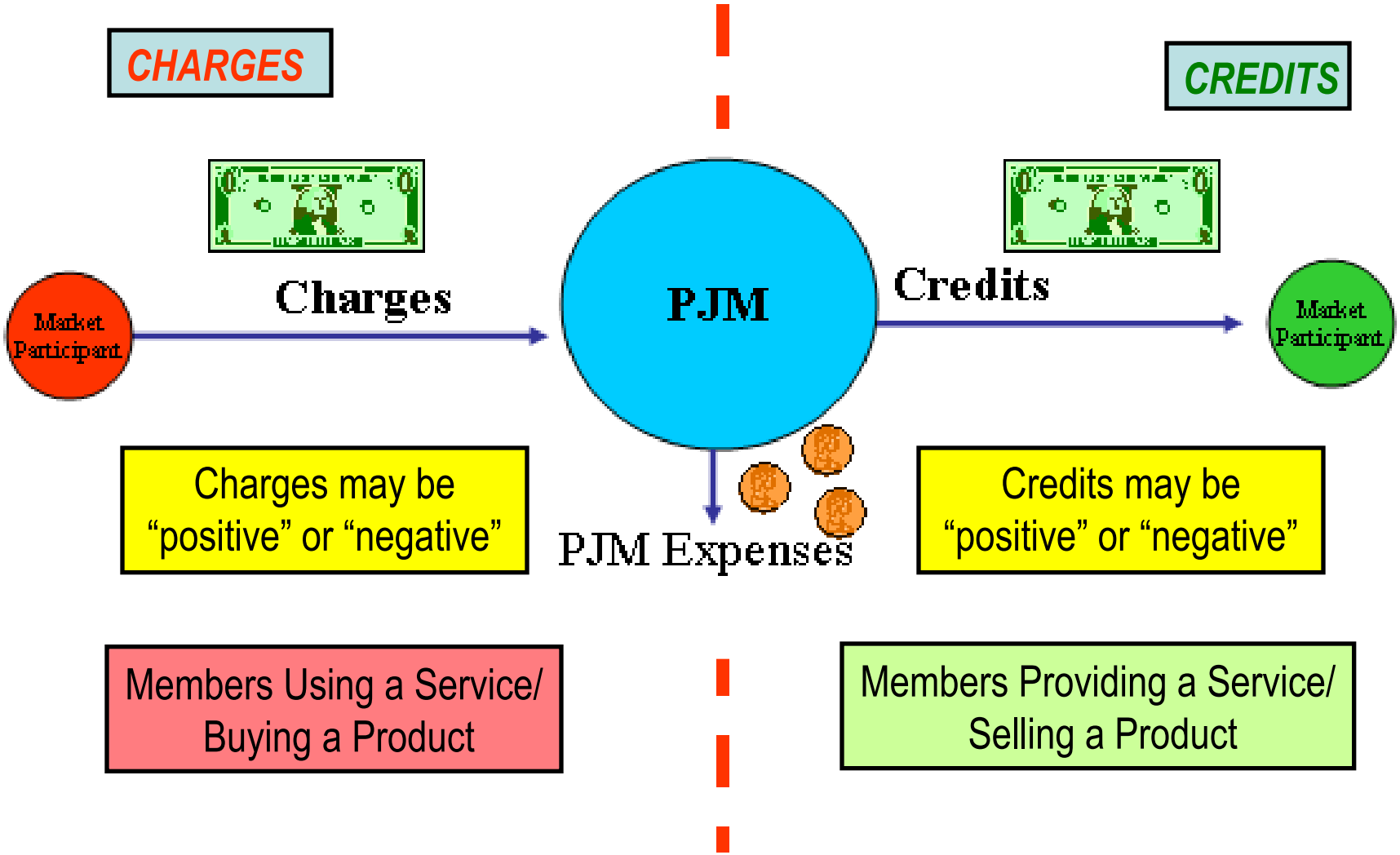
- **Charge**
  - Payments or obligations to PJM from the Market Participant
- **Credit**
  - Payments or obligations from PJM to the Market Participant



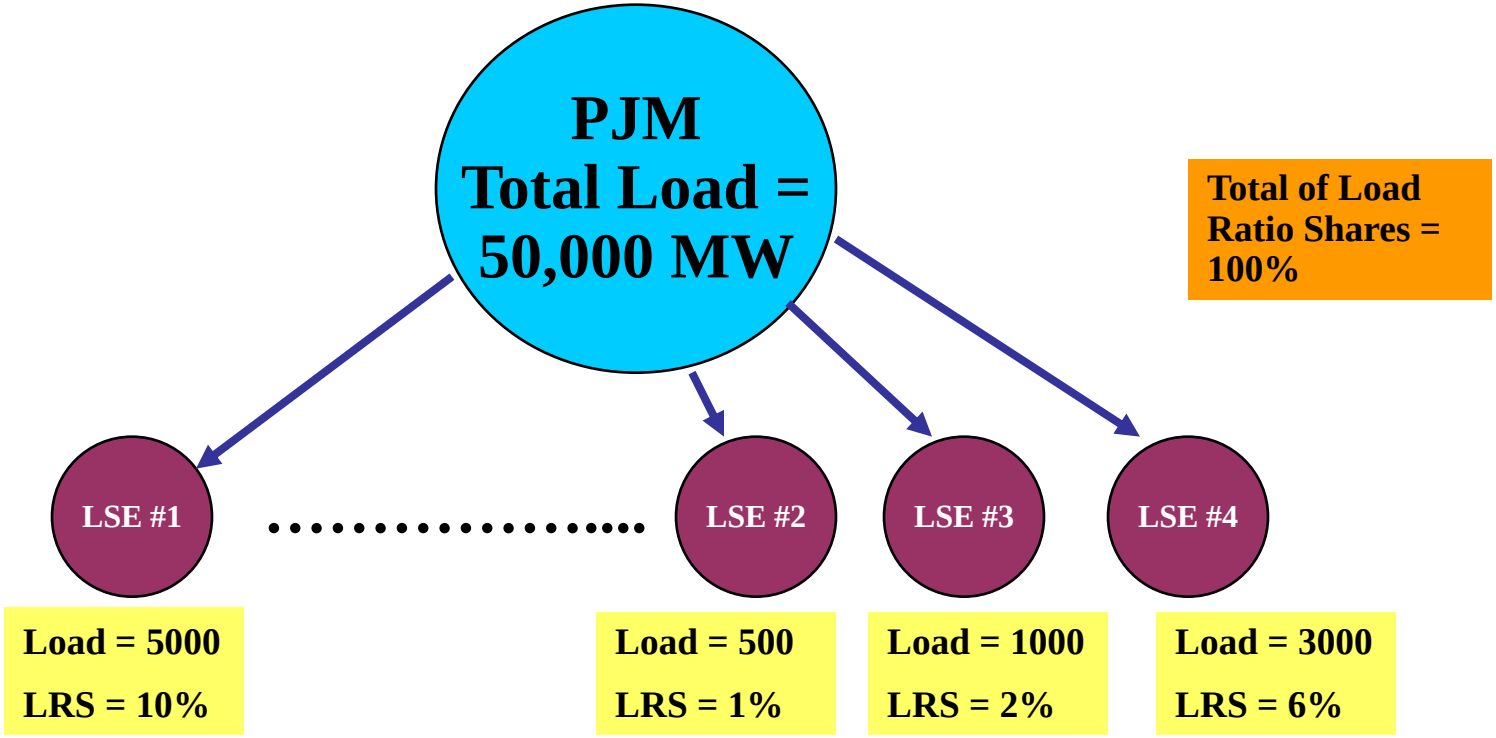
Zero-Sum

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

Summary of Charges and Credits



- **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
    - (LSE load) / (PJM Total Load)



- **"Average LMP"** vs. **"Load-weighted Average LMP"**

- Average LMP:

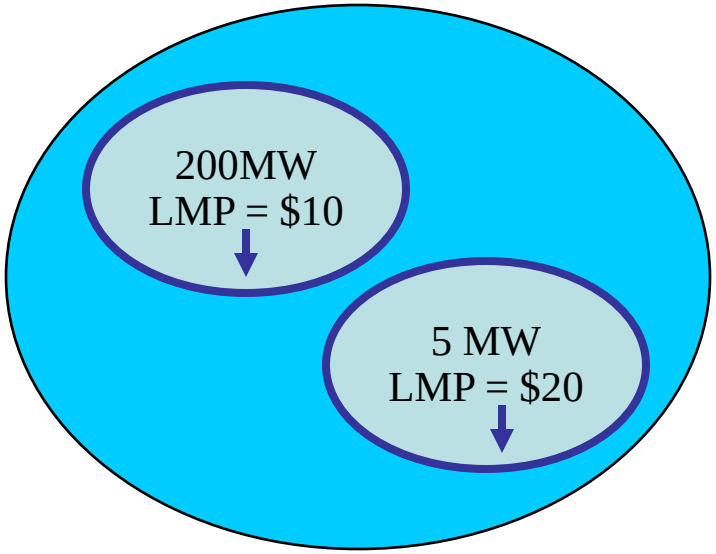
  ($10 + $20)/2 = $15

- 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**

Posted 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:
  - http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx

Day-Ahead LMP Components

DALMP = DASEP + DACP + 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

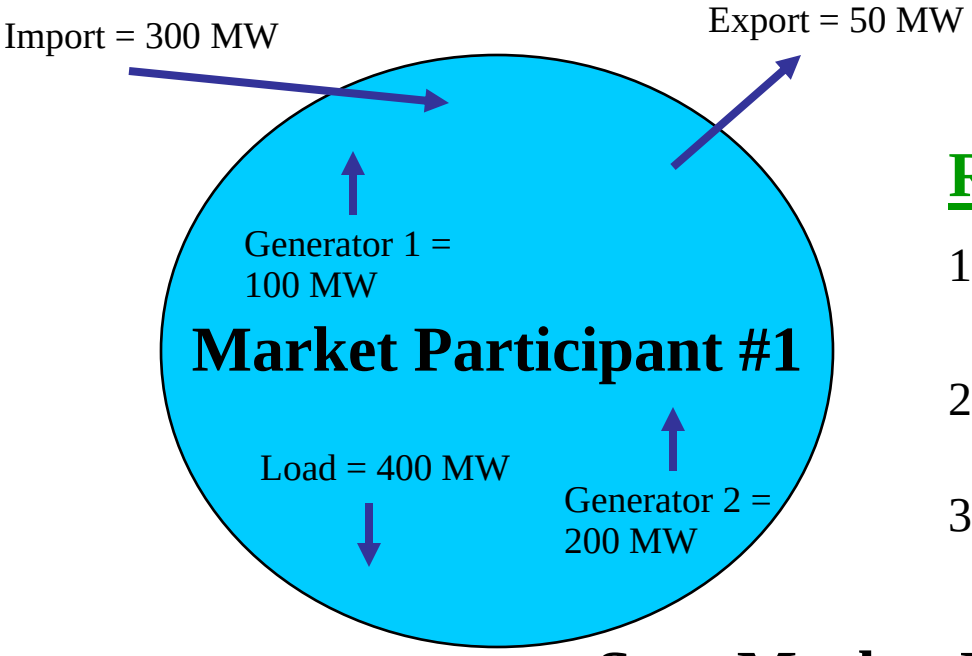
- Used to price Real-time Congestion based on deviation from Day-ahead values

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

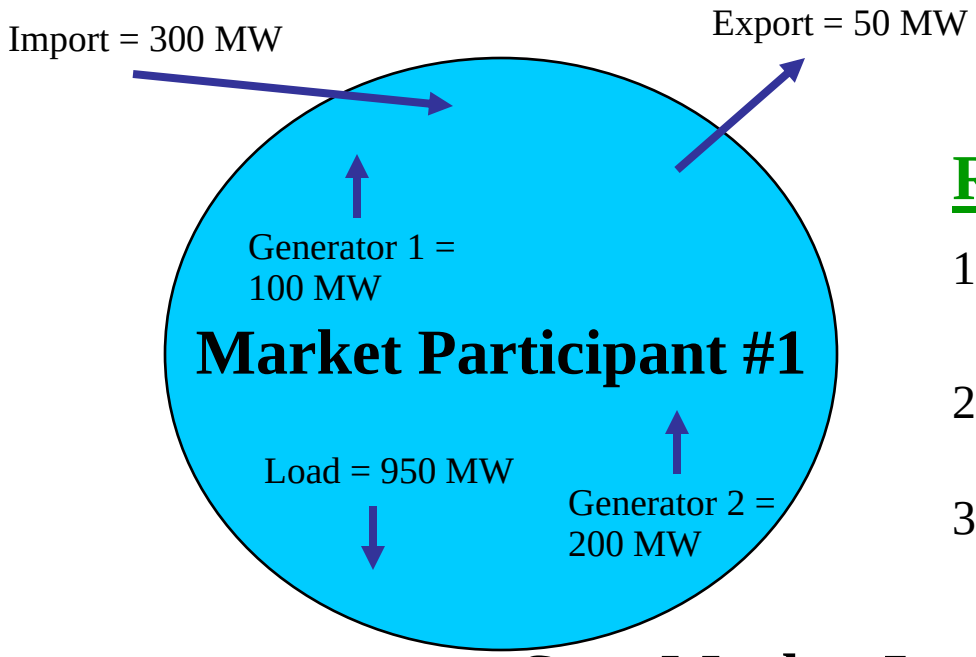


Resources	Load
100 MW (Gen 1)	400 MW (Load w/out losses)
200 MW (Gen 2)	50 MW (Export)
300 MW (Import)	

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

Positive Net Interchange = Buyer From Spot Market
Negative Net Interchange = Seller To Spot Market

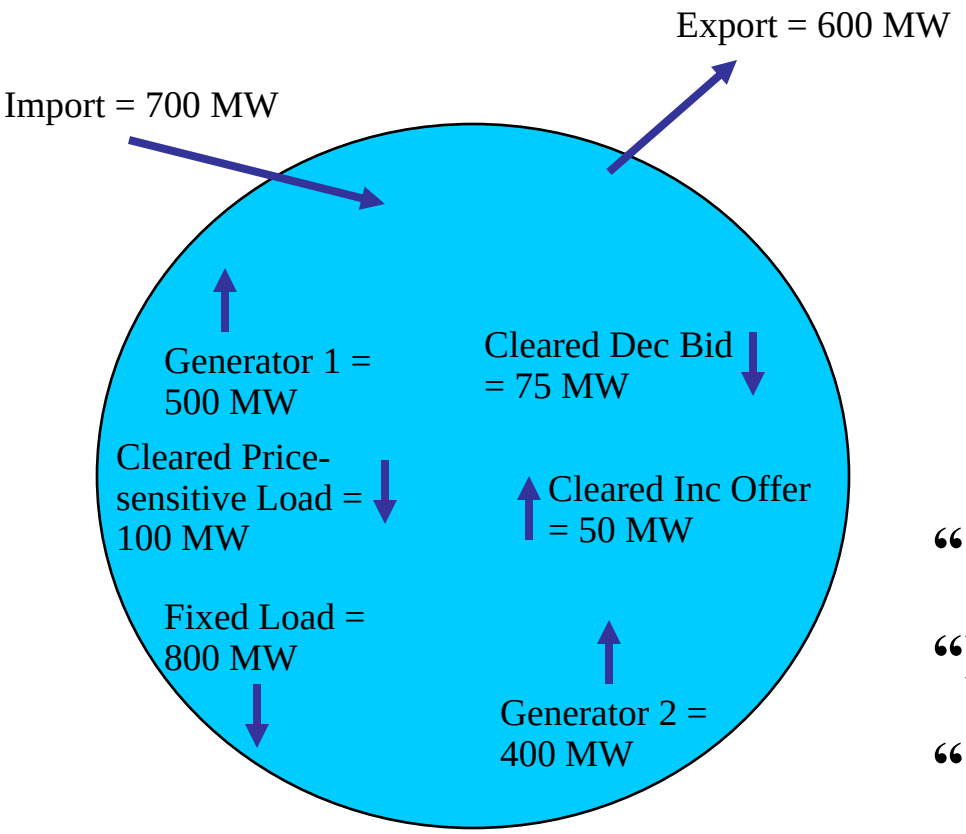


Resources	Load
100 MW (Gen 1)	950 MW (Load w/out losses)
200 MW (Gen 2)	50 MW (Export)
300 MW (Import)	

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:**



"Generation" = ?

"Load" = ?

"Spot Market Interchange" = ?

Agenda

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  - Congestion
  - Transmission Service
  - Ancillary Services
  - Miscellaneous
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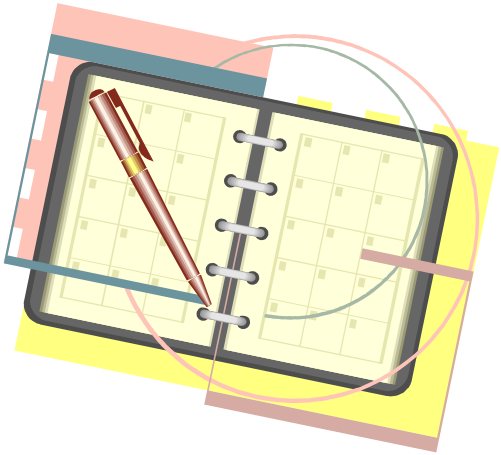


Customers receive monthly charges/credits for:

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

Quick Reference Guide To Market Settlements By Type of Business

February 2010

Important Note

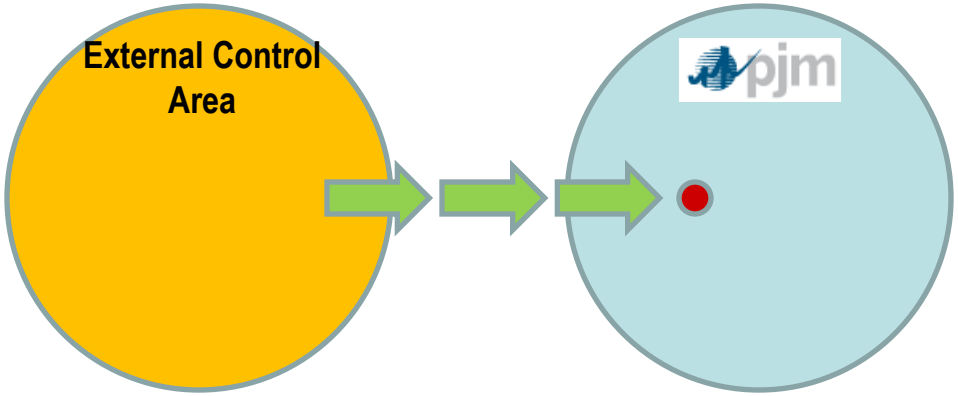
The purpose of this presentation is to provide a quick, consolidated reference of the potential charges and credits for which a participant typically may be responsible for conducting various types of PJM transactions.

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

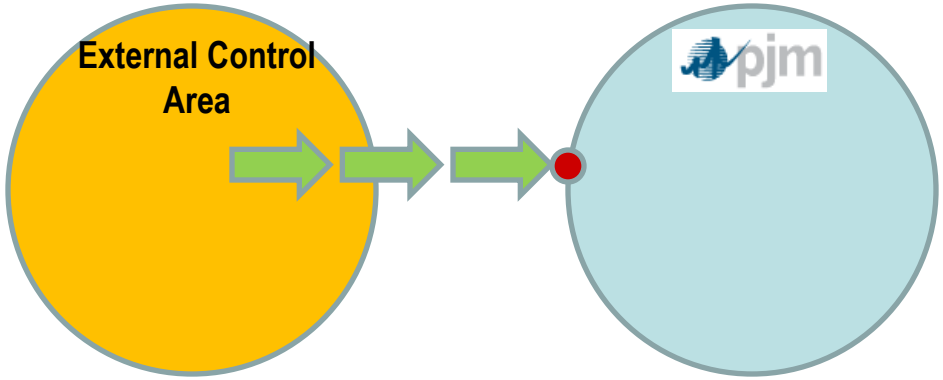
Emergency energy potentially applies to all types of transactions.

Imports – Point of Delivery Other Than External Interface



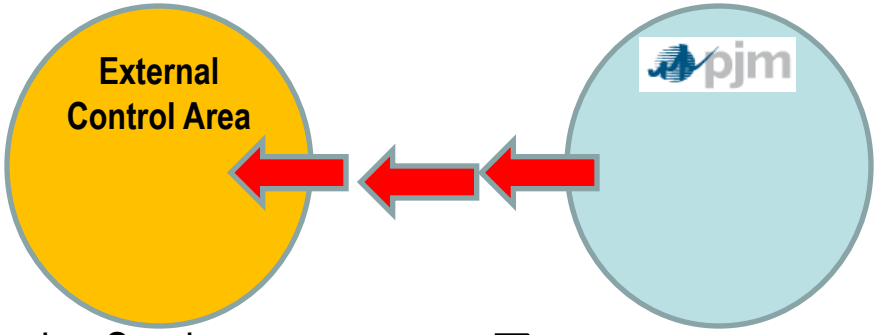
- ❑ Firm or Non-Firm Transmission Service
- ❑ Spot Market Energy
- ❑ Congestion (Relative to the interface)
- ❑ Losses (Relative to the interface)
- ❑ Operating Reserves (If scheduled real-time or deviation in real-time from day-ahead)
- ❑ Reactive (Schedule 2)
- ❑ Black-start (Schedule 6A)
- ❑ Control 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 AC^2 (Schedule 9-AC^2)
- ❑ Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)

Imports – "Spot In"



- ❑ **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 AC^2 (Schedule 9-AC^2)
- ❑ 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 AC^2 (Schedule 9-AC^2)
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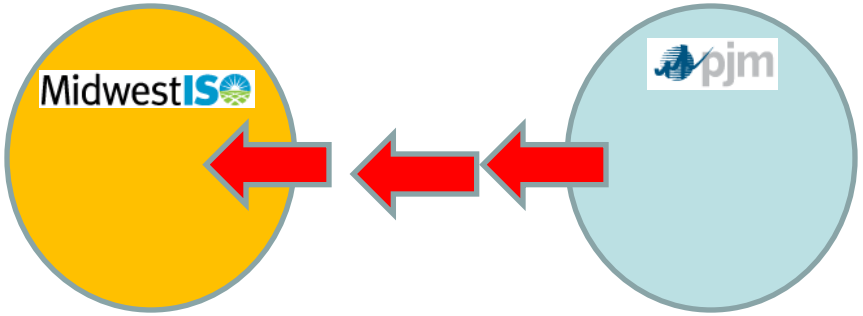
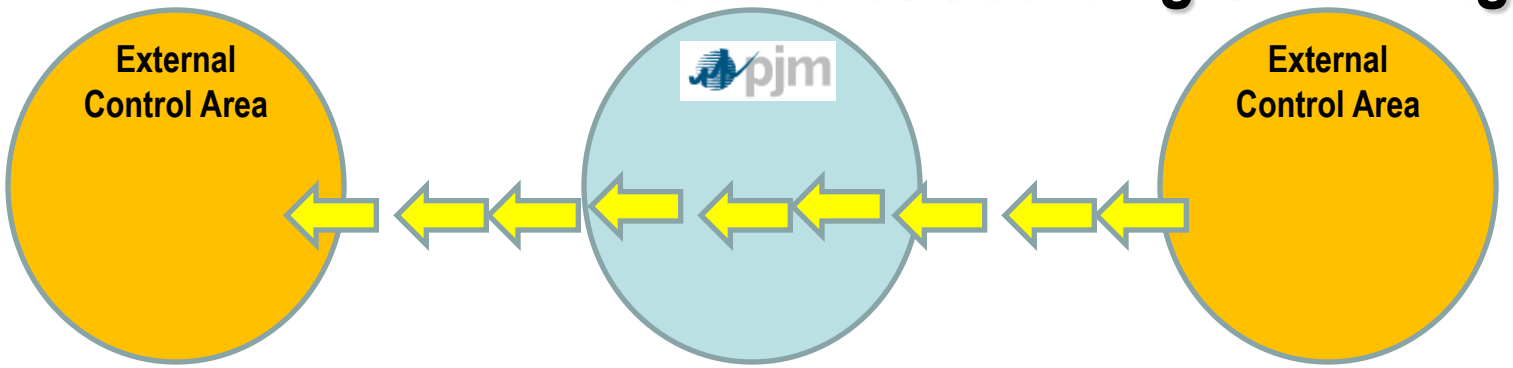
❑ Real-time exports loss surplus credit allocation (for those transactions paying for transmission service only)

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 AC^2 (Schedule 9-AC^2)
- ❑ Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)

Wheel – Not Sourcing or Sinking MISO



- ❑ Firm or Non-Firm Transmission Service
- ❑ Congestion
- ❑ Losses
- ❑ Reactive (Schedule 2)
- ❑ Black Start (Schedule 6A)
- ❑ Control Area Administration (Schedule 9-1)
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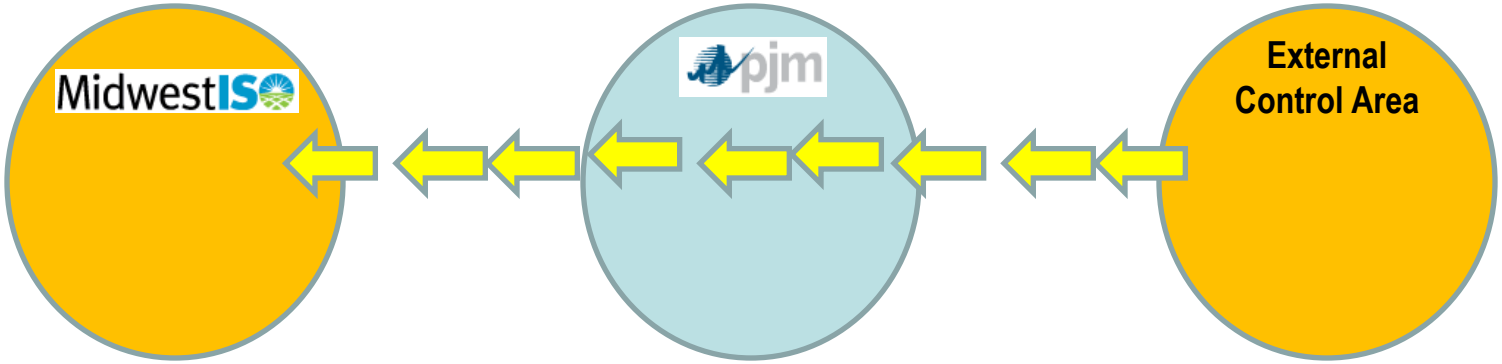
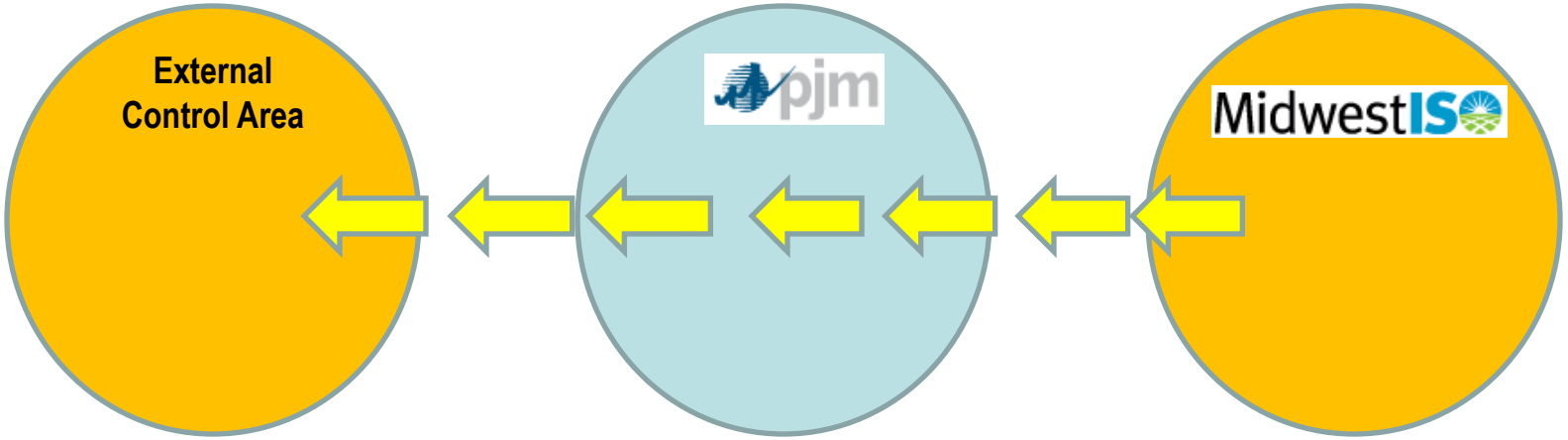
Wheel – Point of Delivery MISO



- ❑ 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 AC^2 (Schedule 9-AC^2)
- ❑ 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)
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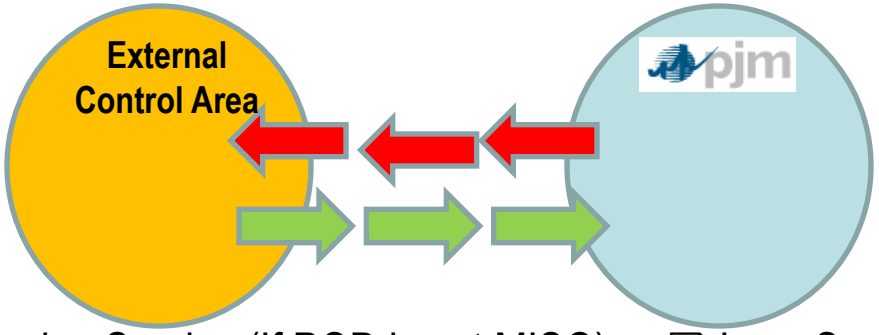
- ❑ Transmission Owner Scheduling, System Control and Dispatch Service (Schedule 1A)

Up-To-Congestion Transaction

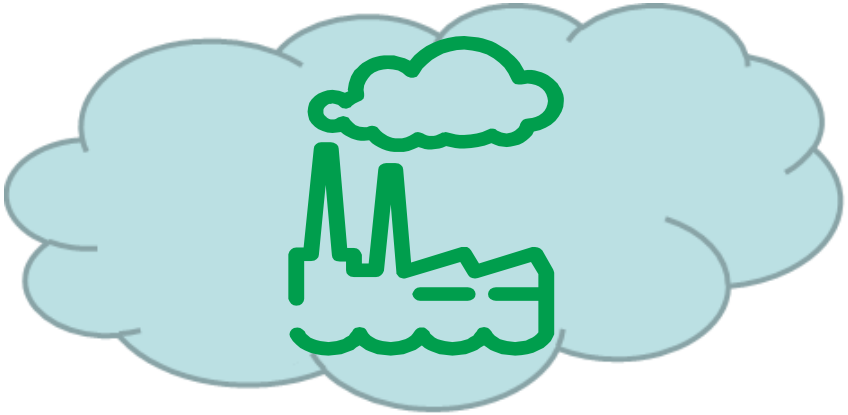


- ❑ Firm or Non-Firm Transmission Service (If POD is not MISO)
- ❑ Congestion (-$50.00 to $50.00/MWh Cap Applies)
- ❑ Losses
- ❑ Market Support (Schedule 9-3)
- ❑ MMU Funding (Schedule 9-MMU)
- ❑ Advanced Second Control Center AC^2 (Schedule 9-AC^2)
- ❑ Reactive (Schedule 2)
- ❑ Black Start (Schedule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

Increment Offer

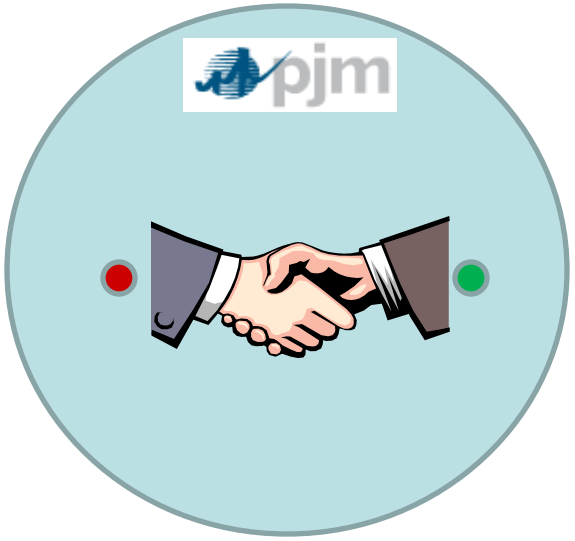


- ❑ Spot Market Energy
- ❑ Congestion
- ❑ Losses
- ❑ Balancing Operating Reserve Charges (Deviations)
- ❑ Market Support (Schedule 9-3)
- ❑ MMU Funding (Schedule 9-MMU)
- ❑ Advanced Second Control Center AC^2 (Schedule 9-AC^2)

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)

Internal Bilateral Transaction



- ❑ 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)

Load

- 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

Load

- ❑ 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 AC^2 (Schedule 9-AC^2)
- ❑ 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)

Load

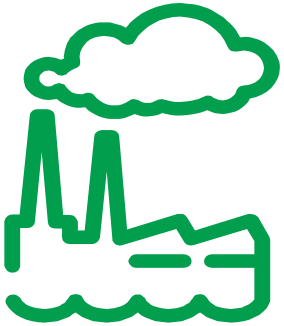
- ❑ RPM Auction (Resource make-whole payments allocated to LSE in applicable LDA)
- ❑ Locational Reliability Charge
- ❑ RTO Start-up Cost Recovery (ComEd and AEP Zones)
- ❑ Expansion Cost Recovery (except Dominion)
- ❑ Generation Deactivation (Affected Transmission Zones)
- ❑ Transmission Enhancement
- ❑ Load Response

Load

- ❑ 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*

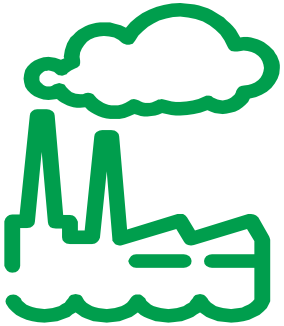
* Allocated to LSEs that paid a Locational Reliability Charge

Generation



- ❑ 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

Generation

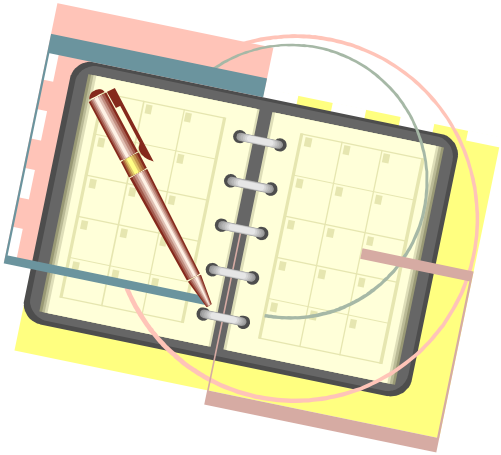


- ❑ Meter Error Correction
- ❑ Balancing Operating Reserve (Deviations Not Following Dispatch)
- ❑ Market Support (Schedule 9-3)
- ❑ Regulation and Frequency Response Administration (Schedule 9-4)
- ❑ Capacity Resource and Obligation Management (Schedule 9-5)
- ❑ Advanced Second Control Center AC^2 (Schedule 9-AC^2)
- ❑ 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

Agenda

- Market Settlements Terminology
- Line Items on a PJM Billing Statement
  - Spot Market Energy
  - Marginal Losses
  - Congestion
  - Transmission Service
  - Ancillary Services
  - Miscellaneous
  - Review

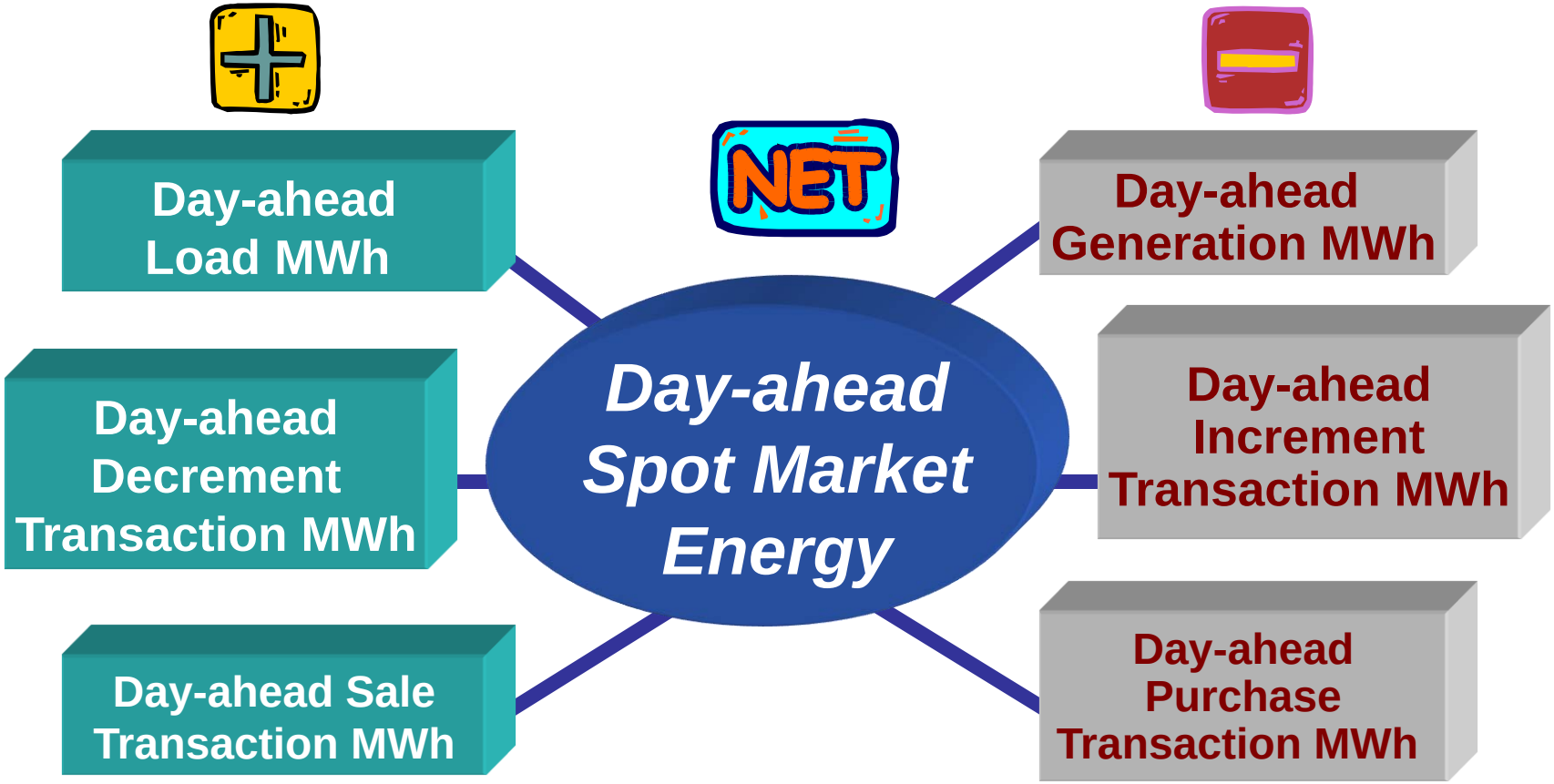


Spot Market Energy

- **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 Calculation



Day-ahead Spot Market Energy

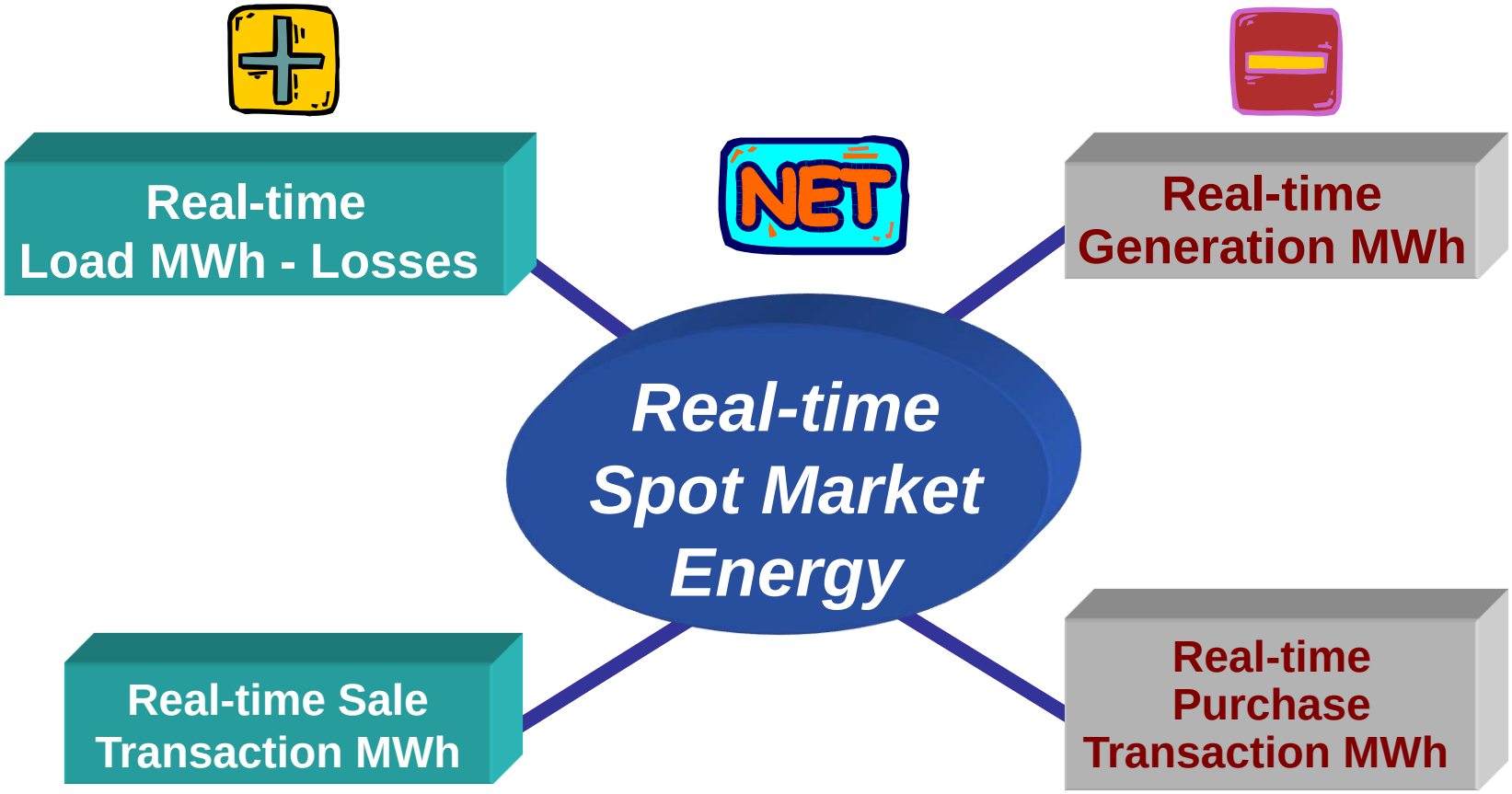
1200	Day-ahead Spot Market Energy

- **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*



** Net metered interchange (minus SE losses) used from eMTR*

Balancing Spot Market Energy

1205	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

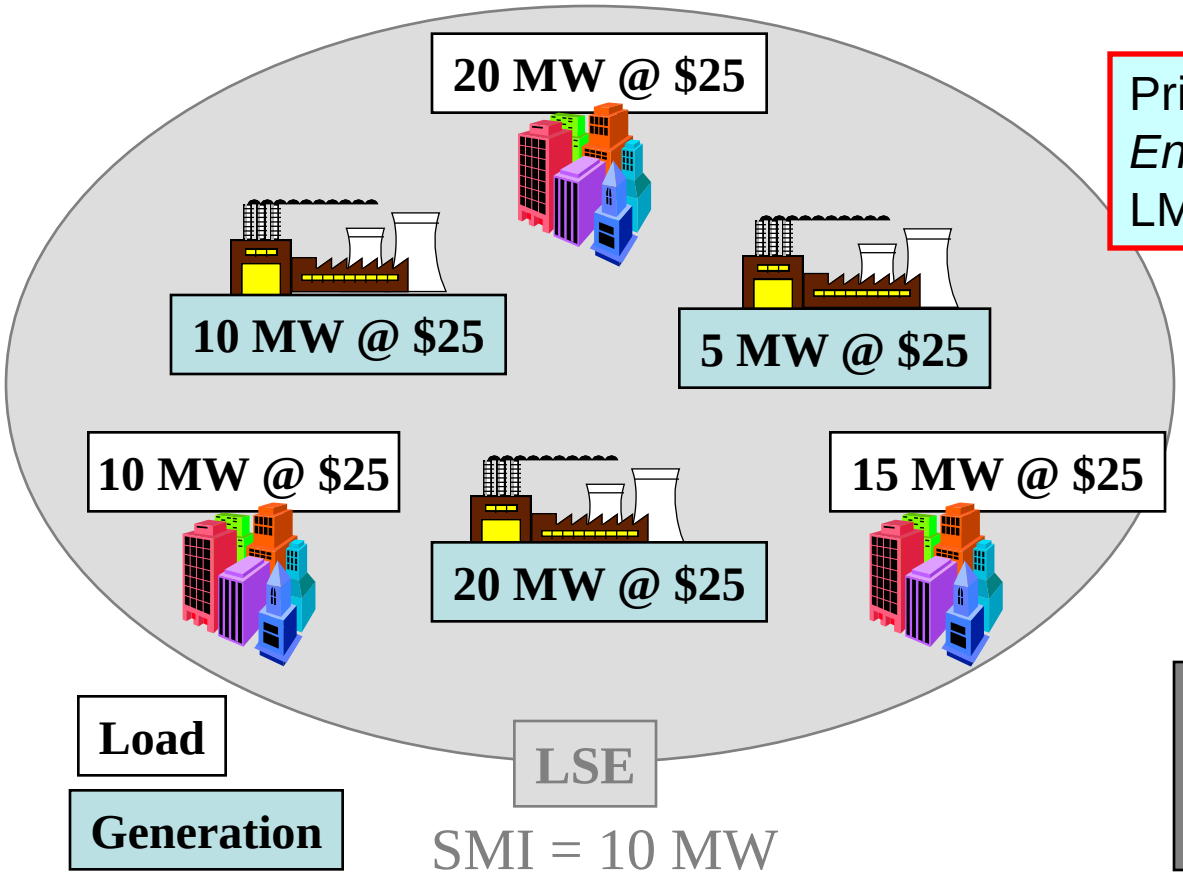
System Energy Price will be the same for all participants at all buses!

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

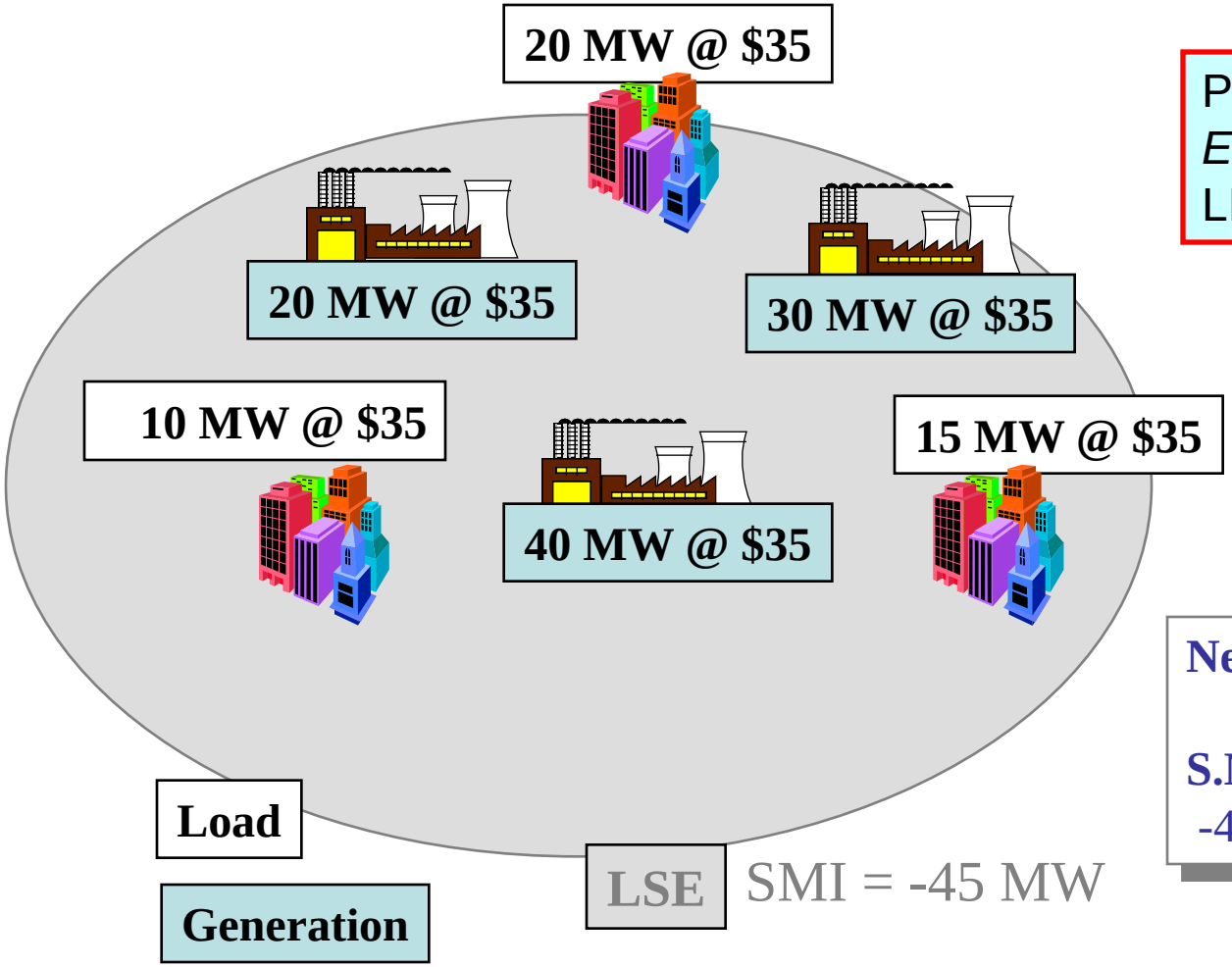


Prices shown are *System Energy Price* component of LMP

LSE Net Buyer of 10 MW

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

Spot Market Interchange Review - Net Seller

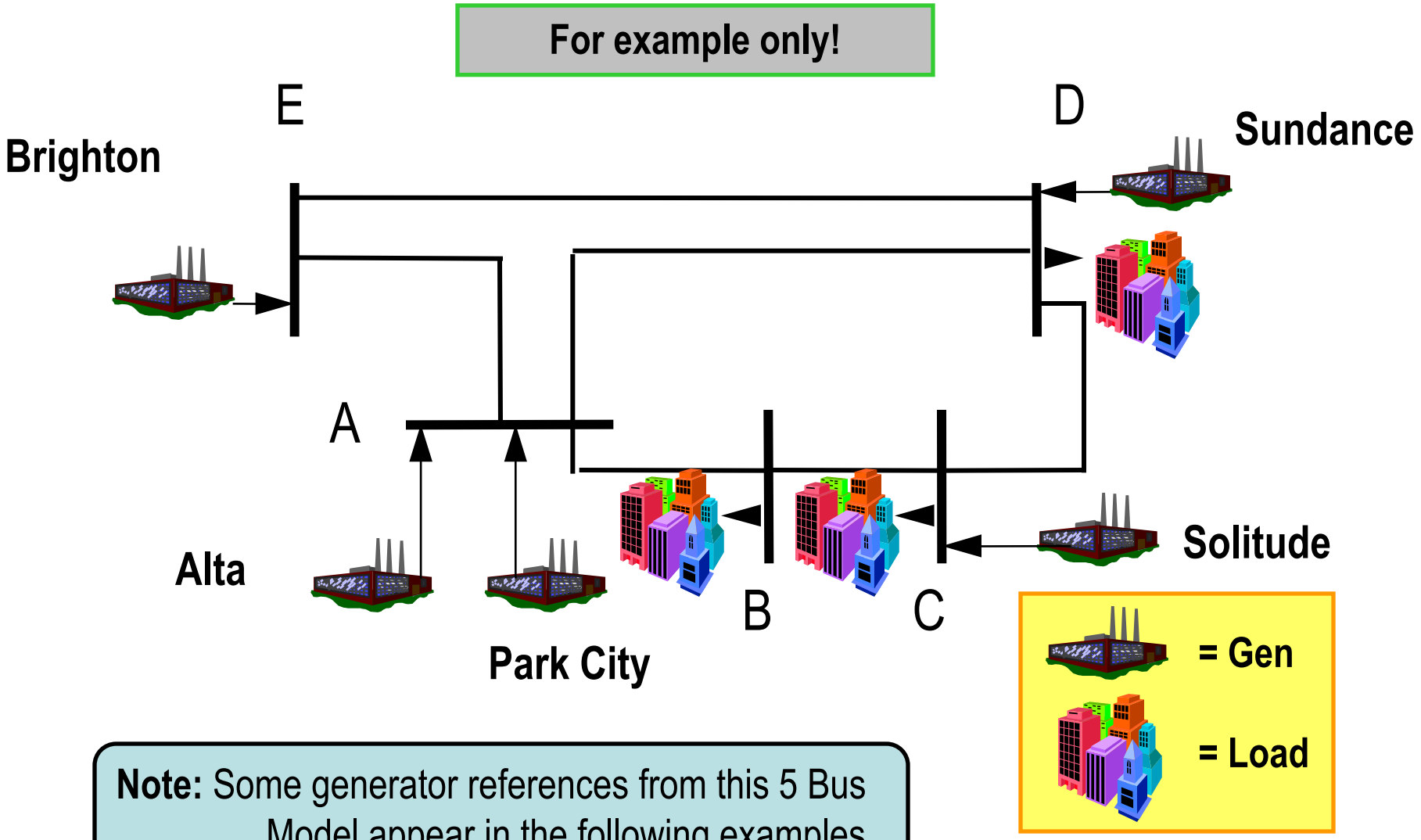


Prices shown are *System Energy Price* component of LMP

Net Seller of 45 MW

S.M. Energy Charge =
-45MW ($35) = **-$1575**

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

Energy Market Withdrawals	Energy Market Injections
200 MW (DA Demand)	100 MW (eSchedule purchase)
10 MW (Decrement Bid)	110 MW (Alta day-ahead schedule)
	10 MW (Increment Offer)
	0 MW (Solitude day-ahead schedule)
210 MW	220 MW

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

Real-Time Energy Withdrawals	Real-Time Energy Injections
220 MW (RT Load excluding losses)	100 MW (eSchedule purchase)
	110 MW (Alta actual generation)
	37 MW (Solitude actual generation)
220 MW	247 MW

220 MW – 247 MW = -27 MW

Real-Time Net Interchange

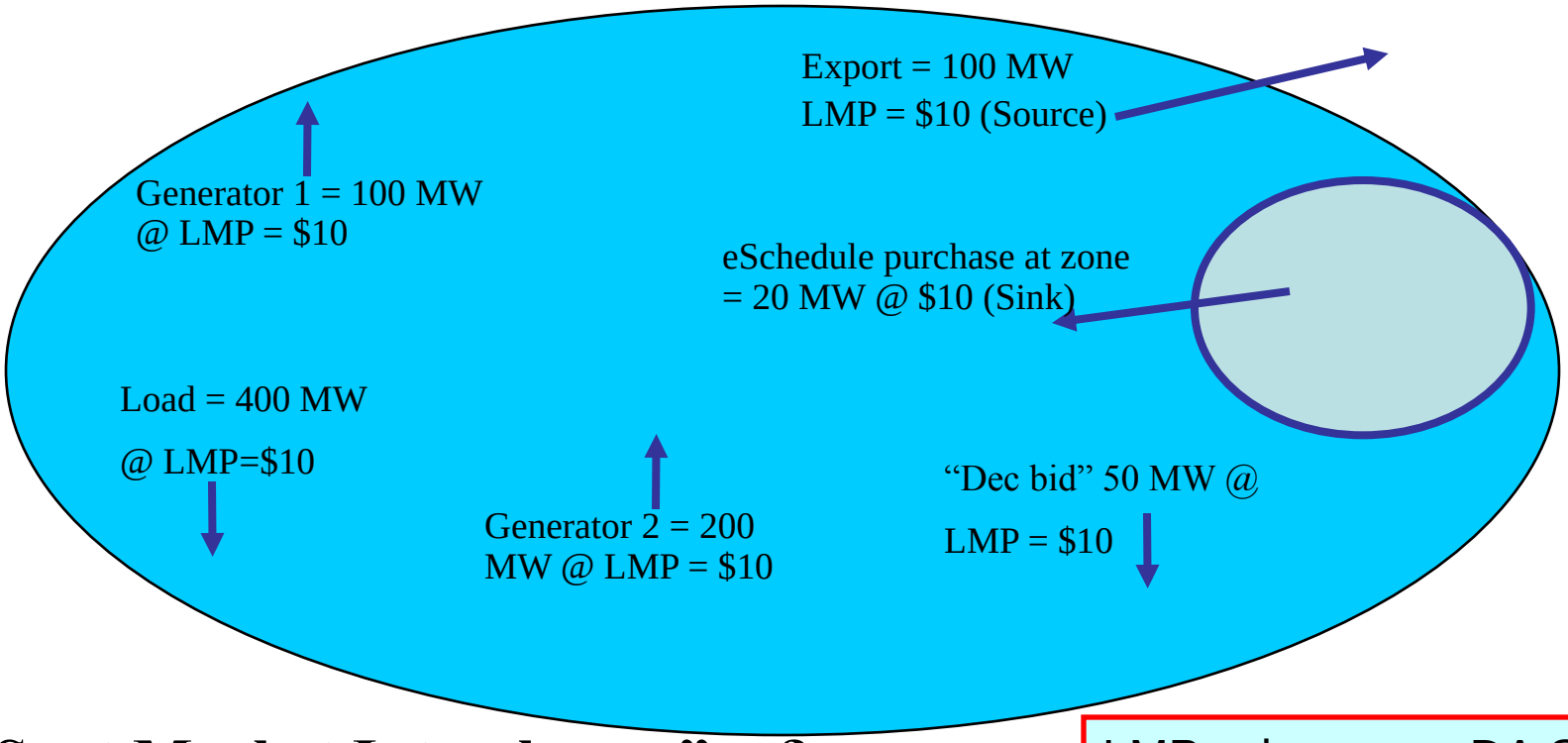
-27 MW – (-10 MW) = -17 MW ($11.75) = -$199.75 charge

(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:**



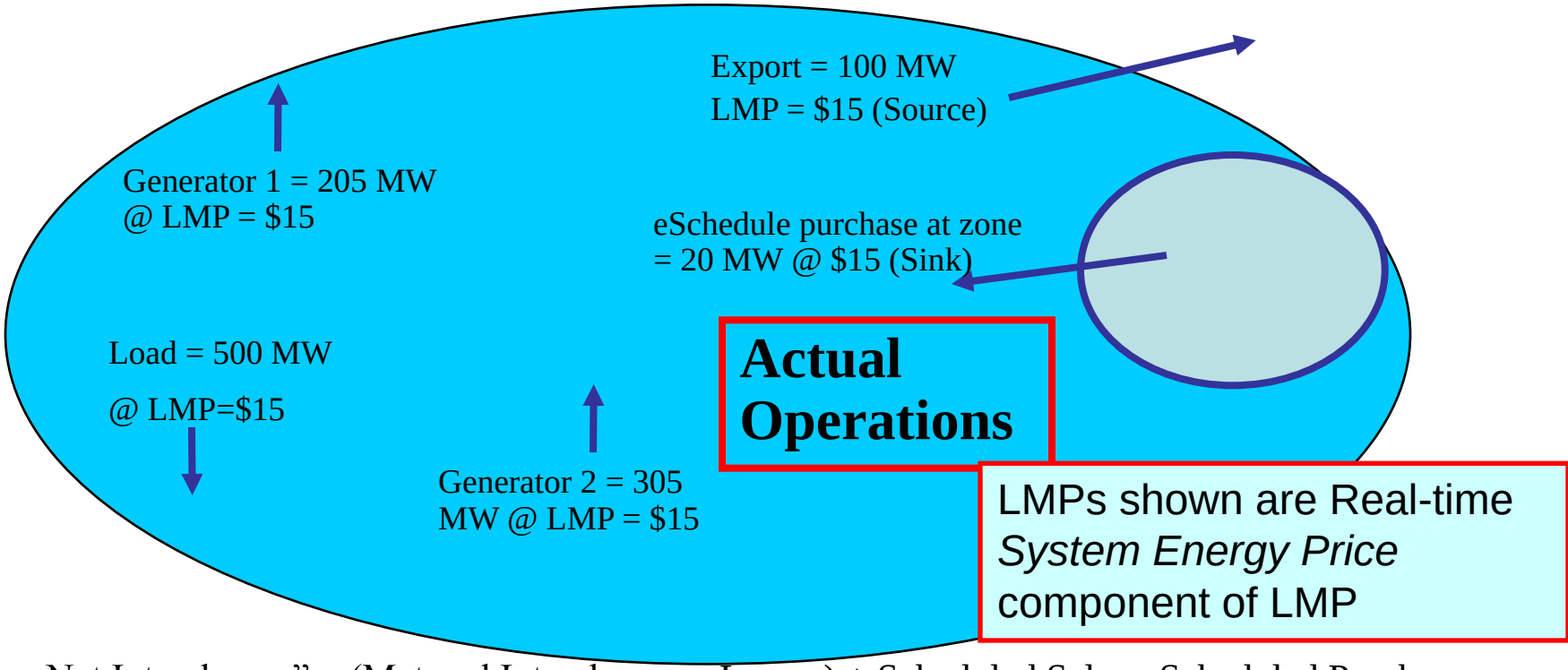
"Net Spot Market Interchange" = ?

"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:**



"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

MSRS - Spot Market Energy Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L
1	Spot Market Energy Charge Summary											
2	Customer	PJM Interc	Report Creatio	############								
3	Start Date	1/20/2008	End Date:	1/20/2008								
4	4000.01	4000.02	4000.05	4000.06	3000.28	3000.01	1200.01	3000.29	3000.3	3000.02	1205.01	4000.07
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	DA Net Interchange (MWh)	DA PJM Energy Price ($/MWh)	DA Spot Market Energy Charge ($)	RT Net Interchange (MWh)	Bal Net Interchange (MWh)	RT PJM Energy Price ($/MWh)	Bal Spot Market Energy Charge ($)	Version
6	1234	PALCO	01/20/2008 01	01/20/2008 06	-847.23	55.46	-46987.38	-768.686	78.544	34.67	2723.12	20080101
7	1234	PALCO	01/20/2008 02	01/20/2008 07	-916.93	53.18	-48762.34	-778.46	138.47	46.52	6441.62	20080101
8	1234	PALCO	01/20/2008 03	01/20/2008 08	-906.03	53.5	-48472.61	-1113.502	-207.472	61.73	-12807.25	20080101
9	1234	PALCO	01/20/2008 04	01/20/2008 09	-905.83	53.79	-48724.6	-889.659	16.171	47.77	772.49	20080101
10	1234	PALCO	01/20/2008 05	01/20/2008 10	-762.23	59.51	-45360.31	-610.721	151.509	37.42	5669.47	20080101

Data Granularity: Hourly

Frequency: Updated Daily

Supporting Calculations

DA Spot Market Energy Charge (1200.01) = DA Net Interchange (3000.28) * DA PJM Energy Price (3000.01)

Bal Net Interchange (3000.30) = RT Net Interchange (3000.29) - DA Net Interchange (3000.28)

Bal Spot Market Energy Charge (1205.01) = Bal Net Interchange (3000.30) * RT PJM Energy Price (3000.02)

MSRS – Day-Ahead Daily Energy Transactions

	A	B	C	D	E	F	G	H	I	J	K
1	Day-Ahead Daily Energy Transactions										
2	Customer .	PJM Interc	Report Cre	6/30/2008 17:05							
3	Start Date:	1/31/2008	End Date:	1/31/2008							
4	4000.01	4000.02	4000.04	4000.11	4000.09	4000.71	4000.1	3005	3005	3005.2	3005.26
5	Customer ID	Customer Code	Date	Transaction Type	Transaction ID	Up to Congestion	OASIS ID	EPT HE 01	EPT HE 02	EPT HE 24	Total MWh
6	1234	PALCO	1/31/2008	Demand	66666			100	100	100	2400
7	1234	PALCO	1/31/2008	Decrement	77777			200	200	200	4800
8	1234	PALCO	1/31/2008	Generation				0	0	0	0
9	1234	PALCO	1/31/2008	Generation				-150	-150	-150	-3600
10	1234	PALCO	1/31/2008	Increment	88888			-75	-75	-75	-3200
11	1234	PALCO	1/31/2008	Internal Bilateral	44444			0	160	0	160
12	1234	PALCO	1/31/2008	Import	T123456	Y	456789	-50	0	0	-50
13	1234	PALCO	1/31/2008	Export	T654321		345678	0	150	0	150
14	1234	PALCO	1/31/2008	Wheel In	T123123-In		234567	-50	-50	-50	-200
15	1234	PALCO	1/31/2008	Wheel Out	T123123-Out			50	50	50	200
16	1234	PALCO	1/31/2008	Total DA Net Interchange				75	385	75	710
17	End of Report										

Hours 3 through 23 Hidden Due to Space Considerations.

Possible Transaction Type values: Demand, Decrement, Load Response, Generation, Increment, Internal Bilateral, Import, Export, Wheel In, Wheel Out, Total DA Net Interchange

Supporting Calculations

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

Data Granularity: Hourly

Frequency: Updated Daily

	L	M	N	O	P	Q	R
1							
2							
3							
4	4000.23	4000.24	4000.21	4000.22	4000.18	4000.17	4000.07
5	Source PNODE Name	Source PNODE ID	Sink PNODE Name	Sink PNODE ID	Seller	Buyer	Version
6	PALCO	55555	PALCO	55555			20080101
7	WESTERN HUB	51288	WESTERN HU	51288			20080101
8	GROSS24 KV U	33333	GROSS24 KV	33333			20080101
9	GROSS24 KV U	44444	GROSS24 KV	44444			20080101
10	WESTERN HUB	51288	WESTERN HU	51288			20080101
11	APS	8394954	APS	8394954	PALCO	JCARL	20080101
12	SOUTHEAST	34509951	PALCO	55555	ALTWCA	PALCO	20080101
13	PALCO	55555	SOUTHEAST	34509951	PALCO	STENP	20080101
14	MICHFE	34509943	MISO	40523629	PALCO	PJM	20080101
15					PJM	PALCO	20080101
16							20080101

MSRS – Real-Time Daily Energy Transactions

	A	B	C	D	E	F	G	H	I	J	K
1	Real-Time Daily Energy Transactions										
2	Customer	PJM Interc	Report Cre	7/1/2008 13:49							
3	Start Date	#########	End Date:	1/31/2008							
4	4000.01	4000.02	4000.04	4000.11	4000.09	4000.13	4000.14	3006.01	3006.02	3006.24	3006.26
5	Customer ID	Customer Code	Date	Transaction Type	Transaction ID	NERC Tag	OASIS ID	EPT HE 01	EPT HE 02	EPT HE 24	Total MWh
6	1234	PALCO	1/31/2008	Internal Bilateral	3456			25	25	25	600
7	1234	PALCO	1/31/2008	Retail Load Responsibility	98765			35.77527	34.66013	39.76995	1021.648
8	1234	PALCO	1/31/2008	Wholesale Load Responsibility	56789			291.7672	291.6006	291.4261	7037.764
9	1234	PALCO	1/31/2008	Generation Responsibility	54321			-80.5	-80.5	-80.5	-1897.6
10	1234	PALCO	1/31/2008	Import	NIPS12345	MISO_PALCO10054321_PJM	123456	0	0	0	-50
11	1234	PALCO	1/31/2008	Export	MECS34567	PJM_PALCO10012345_MISO	654321	48	48	0	1104
12	1234	PALCO	1/31/2008	Adjusted Net Metered Interchange				-1100	-1102	-1103	-146374
13	1234	PALCO	1/31/2008	Default Supplier Load				0	0	0	0
14	1234	PALCO	1/31/2008	RT Net Interchange				-779.958	-783.239	-827.304	-138559
15	End of Report										

*

Supporting Calculations

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

	L	M	N	O	P	Q	R
1							
2							
3							
4	4000.23	4000.24	4000.21	4000.22	4000.18	4000.17	4000.07
5	Source PNODE Name	Source PNODE ID	Sink PNODE Name	Sink PNODE ID	Seller	Buyer	Version
6	WESTERN HUB	51288	WESTERN HUE	51288	PALCO	ANIPAT	20080101
7	AECO	51291	AECO	51291	PALCO	AE	20080101
8	AECO	51291	PPL	51299	PALCO	PPL	20080101
9	SITARCHYK NU	989898	SITARCHYK NU	989898	PPL	PALCO	20080101
10	MISO	40523629	PALCO	51299	NIPSCA	PALCO	20080101
11	PALCO	51299	MISO	40523629	PALCO	MECSCA	20080101
12							20080101
13					PALCO	AE	20080101
14							20080101

* Hours 3 through 23 Hidden Due to Space Considerations.

Data Granularity: Hourly

Frequency: Updated Daily

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.

	A	B	C	D	E	F	G	H	I	J	K
1	Real-Time Daily Energy Transactions										
2	Customer	PJM Interc	Report Cre	7/1/2008 13:49							
3	Start Date	#########	End Date:	1/31/2008							
4	4000.01	4000.02	4000.04	4000.11	4000.09	4000.13	4000.14	3006.01	3006.02	3006.24	3006.26
5	Customer ID	Customer Code	Date	Transaction Type	Transaction ID	NERC Tag	OASIS ID	EPT HE 01	EPT HE 02	EPT HE 24	Total MWh
6	1234	PALCO	1/31/2008	Internal Bilateral	3456			25	25	25	600
7	1234	PALCO	1/31/2008	Retail Load Responsibility	98765			35.77527	34.66013	39.76995	1021.648
8	1234	PALCO	1/31/2008	Wholesale Load Responsibility	56789			291.7672	291.6006	291.4261	7037.764
9	1234	PALCO	1/31/2008	Generation Responsibility	54321			-80.5	-80.5	-80.5	-1897.6
10	1234	PALCO	1/31/2008	Import	NIPS12345	MISO_PALCO10054321_PJM	123456	0	0	0	-50
11	1234	PALCO	1/31/2008	Export	MECS34567	PJM_PALCO10012345_MISO	654321	48	48	0	1104
12	1234	PALCO	1/31/2008	Adjusted Net Metered Interchange				-1100	-1102	-1103	-146374
13	1234	PALCO	1/31/2008	Default Supplier Load				0	0	0	0
14	1234	PALCO	1/31/2008	RT Net Interchange				-779.958	-783.239	-827.304	-138559
15	End of Report										

MSRS – Load eSchedules With and Without Losses

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

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Load eSchedules With and Without Losses												
2	Customer Acc	PJM Interconnec	Report Cre	###########									
3	Start Date:	3/1/2009	End Date:	3/31/2009									
4	4000.01	4000.02	4000.04	4000.1	4000.11	4000.16	4000.18	4000.17	3010.01	3010.02 *	3010.24	3010.26	4000.07
5	Customer ID	Customer Code	Date	eSchedules ID	Transaction Type	Status	Seller	Buyer	EPT HE 01	EPT HE 02	EPT HE 24	Total MWh	Version
6	1234	PALCO	3/1/2009	23456	Retail Load Responsibility	Load with Losses	SELLC	PALCO	6.874	2.673	2.522	85.414	20090301
7	1234	PALCO	3/1/2009	23456	Retail Load Responsibility	Load without Losses	SELLC	PALCO	6.548604	2.556752	2.416774	81.55726	20090301
8	1234	PALCO	3/1/2009	34567	Wholesale Load Responsibility	Load with Losses	KATEPL	PALCO	62.245	55.69	53.54	1358.807	20090301
9	1234	PALCO	3/1/2009	34567	Wholesale Load Responsibility	Load without Losses	KATEPL	PALCO	59.298491	53.268057	51.306132	1299.598181	20090301
10	1234	PALCO	3/1/2009	45678	Wholesale Load Responsibility	Load with Losses	MIKEPL	PALCO	41.2	35.02	31.93	841.51	20090301
11	1234	PALCO	3/1/2009	45678	Wholesale Load Responsibility	Load without Losses	MIKEPL	PALCO	39.249704	33.49699	30.597773	804.740636	20090301

* Hours 3 through 23 Hidden Due to Space Considerations.

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

Possible Status values: Load with Losses, Load without Losses

Agenda

- Market Settlements Terminology
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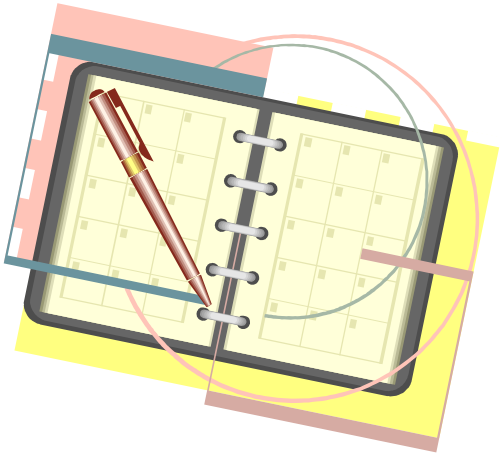
  - Review

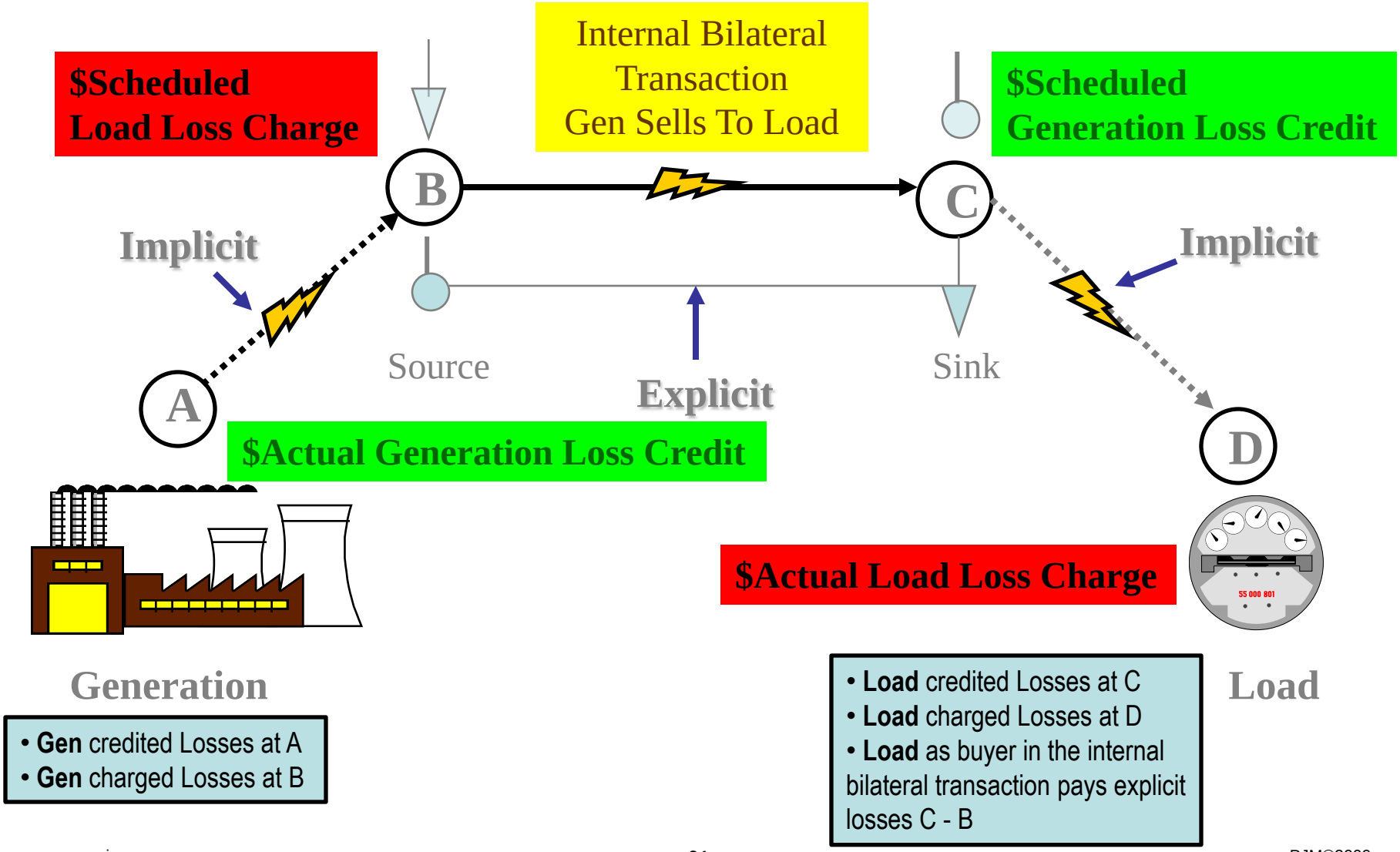


Losses Billing

- 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 participants 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

1220	Day-ahead Transmission Losses
1225	Balancing Transmission Losses

Implicit vs Explicit Loss Calculations



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

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

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 <u>external</u> transactions
- Buyer pays losses for <u>internal</u> 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 <u>external</u> transactions
- Buyer pays losses for <u>internal</u> transactions (network customer)
- Explicit loss charges are not included in the net loss bill calculations.

MSRS-Transmission Loss Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Transmission Loss Charge Summary												
2	Customer	PJM Intercor	Report Creation	6/26/2008 15:13									
3	Start Date	12/31/2008	End Date:	12/31/2008									
4	4000.01	4000.02	4000.05	4000.06	1220.11	1220.12	1220.01	1220.02	1225.11	1225.12	1225.01	1225.02	4000.07
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	DA Loss Withdrawal Charge ($)	DA Loss Injection Credit ($)	DA Implicit Loss Charge ($)	DA Explicit Loss Charge ($)	Bal Loss Withdrawal Charge ($)	Bal Loss Injection Credit ($)	Bal Implicit Loss Charge ($)	Bal Explicit Loss Charge ($)	Version
6	1234	PALCO	12/31/2008 01	12/31/2008 06	12072.83	-3158.97	15231.8	0	39.95	212.63	-172.68	-125.82	20081201
7	1234	PALCO	12/31/2008 02	12/31/2008 07	10915.28	-3312.05	14227.33	0	39.3	407.34	-368.04	-154.78	20081201
8	1234	PALCO	12/31/2008 03	12/31/2008 08	10219.15	-4014.7	14233.85	0	37.11	15.77	21.34	-184.73	20081201
9	1234	PALCO	12/31/2008 04	12/31/2008 09	9098.6	-5193.55	14292.15	0	50.81	170.82	-120.01	-164.37	20081201
10	1234	PALCO	12/31/2008 05	12/31/2008 10	8482.18	-7544.4	16026.58	0	35.04	342.32	-307.28	-109.53	20081201

Data Granularity: Hourly

Frequency: Updated Daily

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)

MSRS-Implicit Congestion and Loss Charge Details

	A	B	C	D	E	F	G	H	I	J
1	Implicit Congestion and Loss Charge Details									
2	Customer A	PJM Interc	Report Creation	############						
3	Start Date:	1/31/2008	End Date:	1/31/2008						
4	4000.01	4000.02	4000.05	4000.06	4000.19	4000.2	3000.06	1210.14	1210.15	3000.15
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	PNODE Name	PNODE ID	PNODE DA Congestion Price ($/MWh)	DA Congestion Withdrawal Energy (MWh)	DA Congestion Injection Energy (MWh)	PNODE DA Loss Price ($/MWh)
1736	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 3	49382	0	0	0	0
1737	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 4	49383	0	0	0	0
1738	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 7	49384	0	0	0	0
1739	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 8	49385	0	0	0	0
1740	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 9	49386	0	0	0	0
1741	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK11	1047952	0	0	0	0

	K	L	M	N	O	P	Q	R	S	T
1	1220.14	1220.15	3000.09	1215.14	1215.16	1215.15	1215.17	3000.18	1225.14	1225.15
2	DA Loss Withdrawal Energy (MWh)	DA Loss Injection Energy (MWh)	PNODE RT Congestion Price ($/MWh)	RT Congestion Withdrawal Energy (MWh)	Bal Congestion Withdrawal Energy Deviation (MWh)	RT Congestion Injection Energy (MWh)	Bal Congestion Injection Energy Deviation (MWh)	PNODE RT Loss Price ($/MWh)	RT Loss Withdrawal Energy (MWh)	Bal Loss Withdrawal Energy Deviation (MWh)
1736	0	0	0	0.819145867	-0.053825043	0	0	1.88	0.8191459	-0.053825043
1737	0	0	0	2.926078781	-0.140505285	0	0	1.88	2.9260788	-0.140505285
1738	0	0	0	1.631457367	-0.051177405	0	0	1.88	1.6314574	-0.051177405
1739	0	0	0	-0.019800709	-0.016494595	0	0	3.09	-0.0198007	-0.016494595
1740	0	0	0	-0.019800709	-0.016494595	0	0	3.09	-0.0198007	-0.016494595
1741	0	0	0	0.74408916	-0.054851568	0	0	3.09	0.7440892	-0.054851568

	U	V	W
1	1225.16	1225.17	4000.07
2	RT Loss Injection Energy (MWh)	Bal Loss Injection Energy Deviation (MWh)	Version
1736	0	0	20080101
1737	0	0	20080101
1738	0	0	20080101
1739	0	0	20080101
1740	0	0	20080101
1741	0	0	20080101

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

Data Granularity: Hourly

Frequency: Updated Daily

Supporting Calculations

DA Congestion Withdrawal Charge (from Congestion Charge Summary) = SUM (PNODE DA Congestion Price * DA Congestion Withdrawal Energy) for all PNODEs

DA Congestion Injection Credit (from Congestion Charge Summary) = SUM (PNODE DA Congestion Price * DA Congestion Injection Energy) for all PNODEs

DA Loss Withdrawal Charge (from Loss Charge Summary) = SUM (PNODE DA Loss Price * DA Loss Withdrawal Energy) for all PNODEs

DA Loss Injection Credit (from Loss Charge Summary) = SUM (PNODE DA Loss Price * DA Loss Injection Energy) for all PNODEs

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

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

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

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

Bal Congestion Withdrawal Charge (from Congestion Charge Summary) = SUM (PNODE RT Congestion Price * Bal Congestion Withdrawal Energy Deviation) for all PNODEs

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

Bal Loss Withdrawal Charge (from Loss Charge Summary) = SUM (PNODE RT Loss Price * Bal Loss Withdrawal Energy Deviation) for all PNODEs

Bal Loss Injection Credit (from Loss Charge Summary) = SUM(PNODE RT Loss Price ($/MWh) * Bal Loss Injection Energy Deviation (MWh)) for all PNODEs

MSRS-Explicit Loss Charges

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Explicit Loss Charges												
2	Customer	PJM Interc	Report Creatior	############									
3	Start Date	1/31/2008	End Date:	1/31/2008									
4	4000.01	4000.02	4000.05	4000.06	4000.09	4000.13	4000.1	4000.17	4000.18	4000.2	4000.22	4000.2	4000.24
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Transaction ID	NERC Tag	OASIS ID	Buyer	Seller	Sink PNODE Name	Sink PNODE ID	Source PNODE Name	Source PNODE ID
6	1234	PALCO	01/31/2008 01	01/31/2008 06	MECS56814	PJM_PALCO12345678_MISO	123456	MECSCA	PALCO	MISO	40523629	PPL	51299
7	1234	PALCO	01/31/2008 01	01/31/2008 06	NYIS246152	NYIS_PALCO87654321_PJM	654321	PALCO	NYISO	PECO	51297	NYIS	5413134

	M	N	O	P	Q	R	S	T	U	V	W
1											
2											
3											
4	4000.24	3000.72	3000.16	3000.17	1220.13	3000.73	3000.74	3000.19	3000.2	1225.13	4000.07
5	Source PNODE ID	DA Transaction MWh	DA Sink Loss Price ($/MWh)	DA Source Loss Price ($/MWh)	DA Explicit Loss Charge ($)	RT Transaction MWh	Transaction Deviation (MWh)	RT Sink Loss Price ($/MWh)	RT Source Loss Price ($/MWh)	Bal Explicit Loss Charge ($)	Version
6	51299	0			0	48	48	-1.6	0.739207	-112.28	20080101
7	5413134	40	0.8	0.75	2	50	10	1.01	0.739207	2.70793	20080101

Data Granularity: Hourly

Frequency: Updated Daily

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)

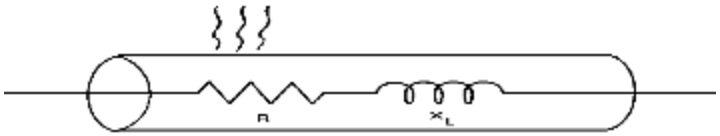
Bal Explicit Loss Charge (1225.13) = Bal Transaction Deviation (3000.74) * (RT Sink Loss Price (3000.19) - RT Source Loss Price (3000.20))

Loss Credit Allocation

Loss Surplus

- 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



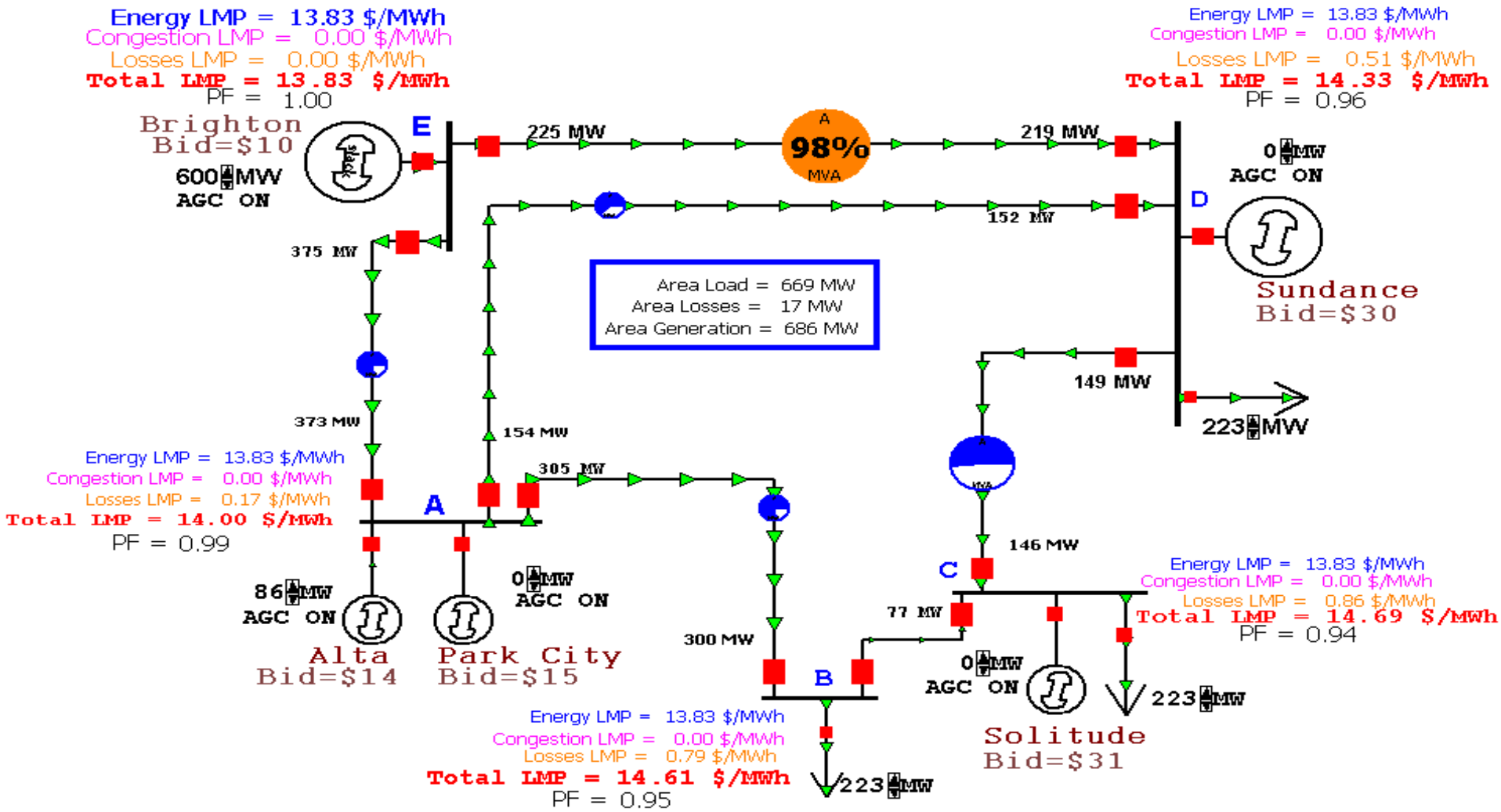
Loss Surplus Allocation

- 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)

Loss Credit = Total Loss Surplus ($) * (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)

2220	Transmission Losses

Loss Surplus - Example



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
			$9729.49

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

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

Generator	Bus	MWh	Loss Price + System Energy Price	Generator Payments
Brighton	E	600	$13.83	$8298
Alta	A	86	$14.00	$1204
Park City	A	0	$14.00	$0
Solitude	C	0	$14.69	$0
Sundance	D	0	$14.33	$0
				$9502

Surplus of **$227.49** is the Loss Revenues

Loss Surplus Allocation

WhereTheMoneyGoes

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		
	669		$227.49

$$\text{Loss Credit} = \text{Total Loss Surplus (\$)} * \left(\frac{\text{Customer total MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service}}{\text{Total PJM MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service}} \right)$$

MSRS - Transmission Loss Credit Summary

	A	B	C	D	E	F	G	H	I	J	K	L
1	Transmission Loss Credit Summary											
2	Customer A	PJM Interconn	Report Creation Ti	11/23/2009 11:41								
3	Start Date:	8/1/2009	End Date:	8/30/2009								
4	4000.01	4000.02	4000.05	4000.06	2220.11	3000.38	3000.48	2220.12	3000.49	2220.01	4000.07	
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Total PJM Loss Revenues ($)	RT Load (MWh)	RT Exports (MWh)	Up-To Congestion Transactions (MWh)	Total PJM RT Load plus Exports plus Up-To Congestion Transactions (MWh)	Transmission Loss Credit ($)	Version	
249	1234	PALCO	08/11/2009 11	08/11/2009 15	35150.16	265.597	0		75579.862	123.52	20091001	
250	1234	PALCO	08/11/2009 12	08/11/2009 16	37605.48	265.763	0		74823.913	133.57	20091001	

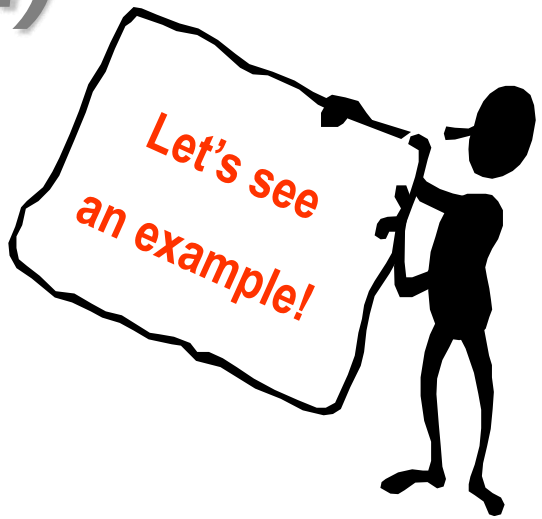
Supporting Calculations

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

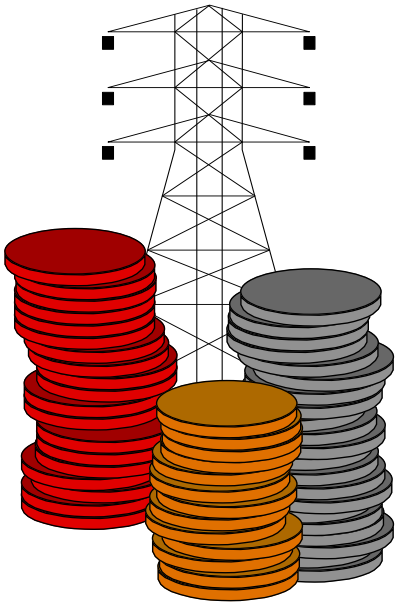
Frequency: Updated Daily

Example Case (Unconstrained)



Example - Day-ahead and Spot Market Energy

- **Case 1**
  - Unconstrained Day-ahead Market
  - Unconstrained Balancing Market



Example -Market Participants

Participant	Role
EDC 1	*Metered entity that owns generation & serves load in PJM*
LSE 2	*Retail load aggregator that serves portion of LSE 1's metered load*
EDC 3	*Metered entity that owns generation & serves load in PJM*
EDC 4	*Metered entity that owns generation & serves load in PJM*
Park City	*Merchant generation plant that sells to PJM Spot Market*
Alta	*Merchant generation plant that sells to PJM Spot Market & enters bilateral contracts with other PJM Members*

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

Bus	Generator	MWh Available	Owner	Offer Price	MWh Scheduled
E	Brighton	600	33.3 % EDC 3 66.7 % EDC 1	$10/MWh	600
A	Alta	110	Merchant Generator Company X	$14/MWh	86
A	Park City	100	Merchant Generator Company Y	$15/MWh	0
C	Solitude	20	15% EDC 1 42.5% EDC 3 42.5% EDC 4	$30/MWh	0
D	Sundance	200	100% EDC 4	$30/MWh	0

Example - Day-Ahead Market Transaction Schedules

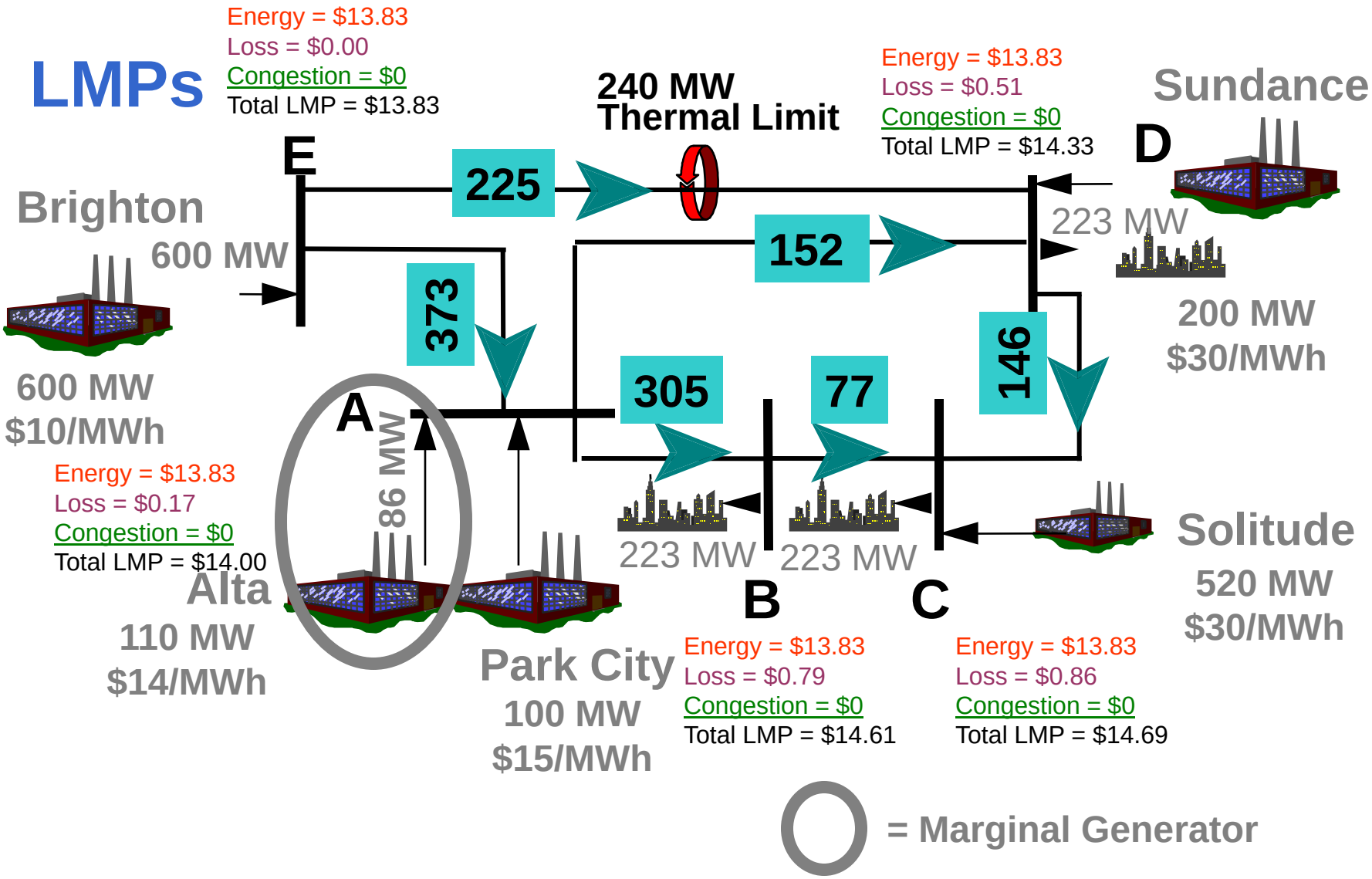
Alta schedules internal bilateral transaction in eSchedules for 5 MW on path A to D

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



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)	for EDC 1
23 = 23 (Dec bid @ B) - 0	for LSE 2
23 = 223 (P.S. Demand bid @ C) - 200 (33.3% of Brighton@E)	for EDC 3
218 = 223 (load @D) - 5 (purchase @D)	for EDC 4
0 = 0 - 0	for Park City
-81 = 5 (sale @D) - 86 (Alta generation @A)	for Alta

-17 (losses)

Example - Day-Ahead Spot Market Charges

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

Total Spot Market Negative Charges = **Negative Net Interchange (MWh)** * ***System Energy Price* Component of DA LMP ($/MWh)**

Example – Day Ahead Spot Market Charges

($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)		

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

Market Participant	Day-ahead Load	Bus	Loss Price ($/MWh)	DA Load Loss Charge ($)
EDC 1	200	B	0.79	158.00
LSE 2	23	B	0.79	18.17
EDC 3	223	C	0.86	191.78
EDC 4	223	D	0.51	113.73
Alta	5	A	0.17	0.85
				482.53

↑ * ↑ = ↑

Example – Day Ahead Implicit Loss Charges - Generation

Market Participant	Day-ahead Generation	Bus	Loss Price ($/MWh)	DA Generation Loss Credit ($)
EDC 1	400	E	0	0
LSE 2	0	-	-	-
EDC 3	200	E	0	0
EDC 4	5	D	0.51	2.55
Alta	86	A	0.17	14.62
				17.17

↑ * ↑ = ↑

Example – Day Ahead Implicit Loss Charge

Market Participant	DA Loss Charge ($)	DA Loss Credit ($)	DA Implicit Loss Charge
EDC 1	158.00	0	158.00
LSE 2	18.17	0	18.17
EDC 3	191.78	0	191.78
EDC 4	113.73	2.55	111.18
Alta	.85	14.62	(13.77)
			465.36

↑ - ↑ = ↑

Example – Day-Ahead Explicit Loss Charge

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

EDC 4: 5 * (0.51 - 0.17) = $1.70

Example - Transmission Congestion Charges

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

BUS	Generator	MWh Available	Owner	Offer Price	MWh Dispatched
E	Brighton	600	33.3 % EDC 3 66.7% EDC 1	$10/MWh	600
A	Alta	0	Merchant Gen – Company X	$14/MWh	
A	Park City	100	Merchant Gen – Company Y	$15/MWh	100
C	Solitude	520	15% EDC 1 42.5% EDC 3 42.5% EDC 4	$30/MWh	
D	Sundance	200	100% EDC 4	$30/MWh	

Example - Actual Operation: Transaction Schedules

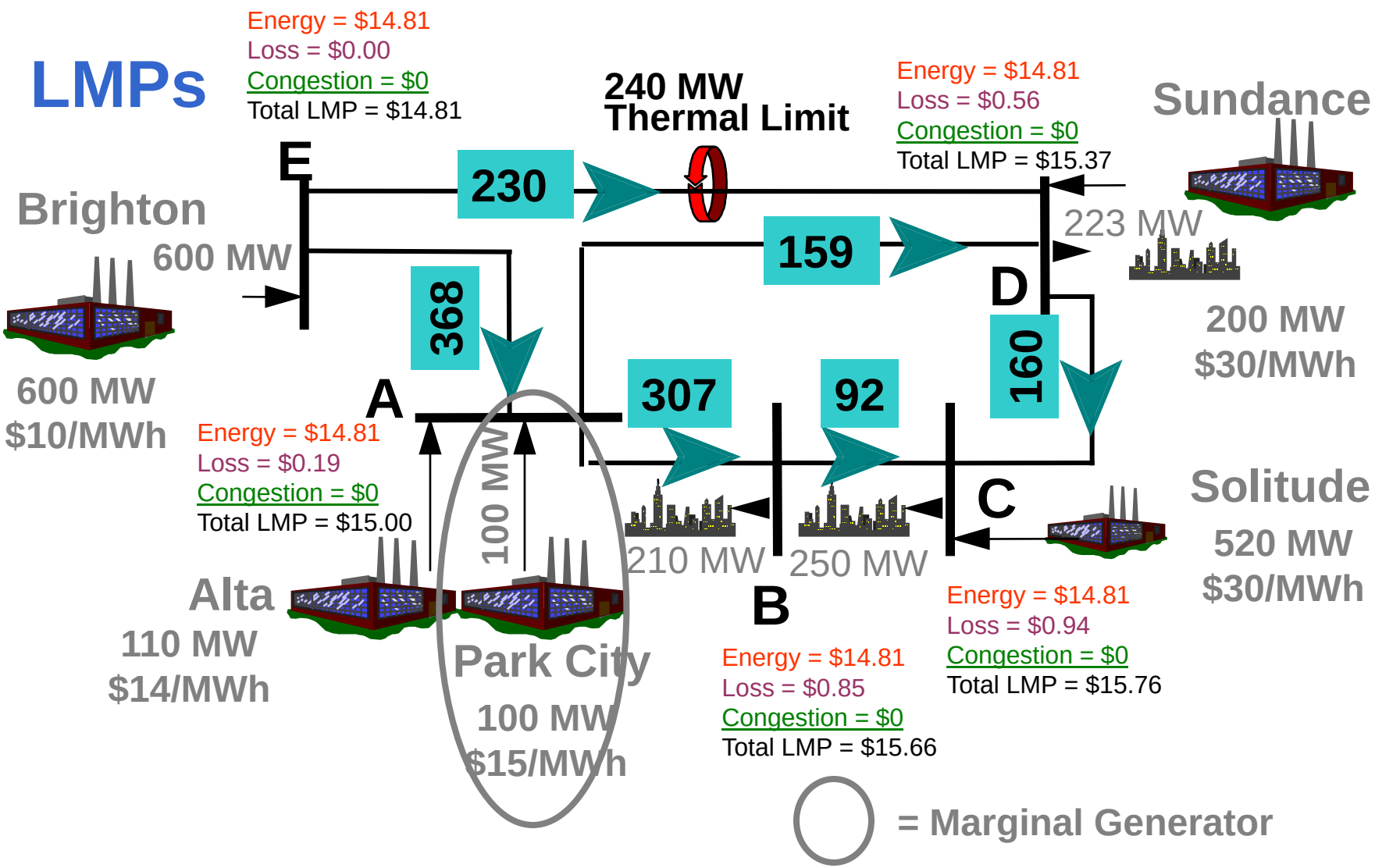
Since Alta scheduled internal bilateral transaction in eSchedules for 5 MW on path A to D in day-ahead market, schedule also applies to balancing market

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 - Actual Operations



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) ***for EDC 1***

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

50 = 50 (-200 Brighton gen @E + 250 load @C) ***+ 0 - 0*** ***for EDC 3***

218 = 223(223 load @D) ***+ 0 - 5*** (esched purchase from Alta @D) ***for EDC 4***

- 100 = -100 (100 gen @A) ***+ 0 - 0*** ***for Park City***

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

Balancing Net Interchange

Day-ahead Net Interchange

System Energy Price Component of Real-time LMP

($148.1) = (-210 - (-200 MWh))* $14.81/MWh for EDC 1

($44.43) = (20 - 23 MWh) * $14.81/MWh for LSE 2

$399.87 = (50 - 23 MWh) * $14.81/MWh for EDC 3

$0 = (218 - 218 MWh) * $14.81/MWh for EDC 4

($1481) = (-100 - 0) MWh * $14.81/MWh for Park City

$1273.66 = (5 - -81) MWh * $14.81/MWh for Alta

0

Example - Summary of Day-Ahead & Balancing Settlements

Market Participant	Day Ahead Spot Market Payments	Balancing Spot Market Payments	Total Spot Market Payments
EDC 1	($2766)	($148.1)	($2914.10)
LSE 2	$318	($44.43)	$273.57
EDC 3	$318	$399.87	$717.87
EDC 4	$3015	$0	$3015
Park City	$0	($1481.00)	($1481.00)
Alta	($1120.23)	$1273.66	$153.43
		Total	($235.23)

Example - Summary of Day-Ahead & Balancing Settlements

Market Participant	Day Ahead Spot Market Payments	Balancing Spot Market Payment	Total Spot Market Payments
EDC 1			(014.10)
LSE 2			$273.57
EDC 3	$318	$399.87	$717.87
EDC 4		$0	$3015
Park City		1.00)	($1481.00)
Alta	($1120.23)	.66	$153.43
		Total	($235.23)

Where is this residual credit supplied from?

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

Example – Balancing Implicit Losses – Load Loss Charges

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

↑ - ↑ * = ↑

Example – Balancing Implicit Losses – Generation Loss Credits

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

↑ - ↑ * = ↑

Example - Implicit Losses Charge

Market Participant	Balancing Loss Charge ($)	Balancing Loss Credit ($)	Balancing Implicit Loss Charge
EDC 1	(8.50)	0	(8.50)
LSE 2	(2.55)	0	(2.55)
EDC 3	25.38	0	25.38
EDC 4	0	0	0
Alta	0	(16.34)	16.34
Park City	0	19.00	(19.00)
			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

Market	Implicit Loss Charge ($)	Explicit Loss Charge ($)
Day Ahead	**465.36**	**1.70**
Balancing	11.67	0

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

Market Participant	Real-time Load
EDC 1	190mw@Bus B
LSE 2	20mw@Bus B
EDC 3	250mw@Bus C
EDC 4	223mw@Bus D
Park City	0
Alta	0

Total Real-time Load = 683mw

Example – Total Loss Surplus Distribution

$$\text{Loss Credit} = \text{Total Loss Surplus (\$)} * \left(\frac{\text{Customer total MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service}}{\text{Total PJM MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service}} \right)$$

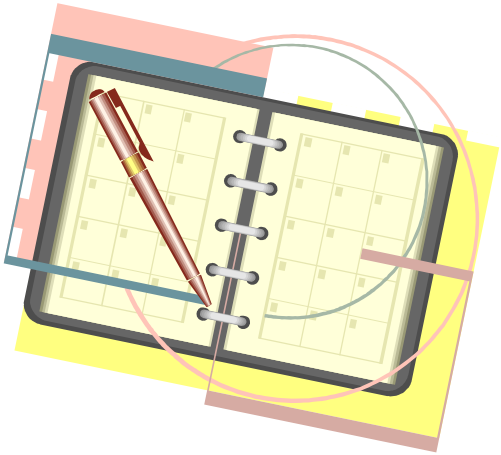
EDC 1	$67.74	=	$243.50	*	190 / 683
LSE 2	$ 7.13	=	$243.50	*	20 / 683
EDC 3	$89.13	=	$243.50	*	250 / 683
EDC 4	$79.50	=	$243.50	*	223 / 683

Example - Transmission Congestion Charges

No **Congestion Charges from Actual Operations**

Agenda

- 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

1210	Day-ahead Transmission Congestion
1215	Balancing Transmission Congestion

•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"

Locational Net Congestion Bill (Implicit Congestion Charge):

Load Congestion Charges - Generation Congestion Credits

Load Congestion Charges*:

Load: Load Bus MWh x *Congestion Price Component* of Load Bus LMP

Energy Sales: Sale MWh x *Congestion Price Component* of Source LMP

Decrement Bids: Dec Bid MWh x *Congestion Price Component* of Bus LMP

Generation Congestion Credits*:

Generation: Gen Bus MWh x *Congestion Price Component* of Gen Bus LMP

Energy Purchases: Purchase MWh x *Congestion Price Component* of Sink LMP

Increment Offers: Offer Bid MWh x *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

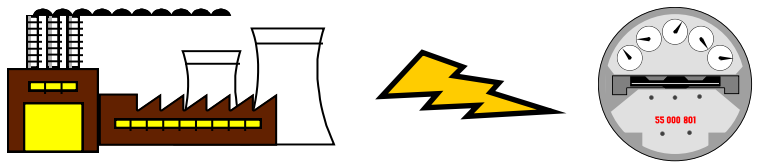
- all congestion implicit in delivering their resources to their loads

Interchange Charge = $500 = (50 MW * $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



50 MW **100 MW**

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)

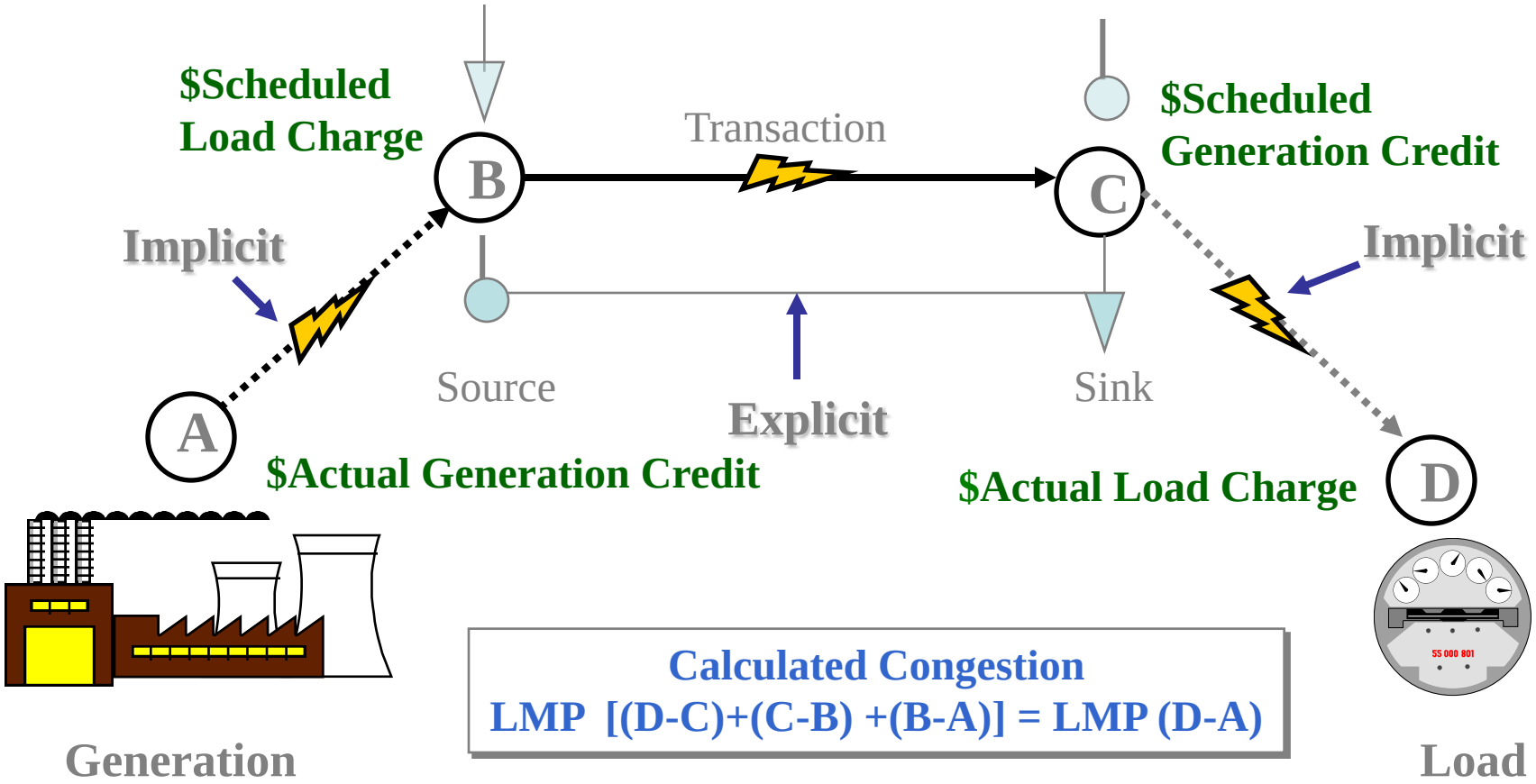
- Transmission customer pays congestion for external transactions
- Buyer pays congestion for internal transactions (network customer)

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)

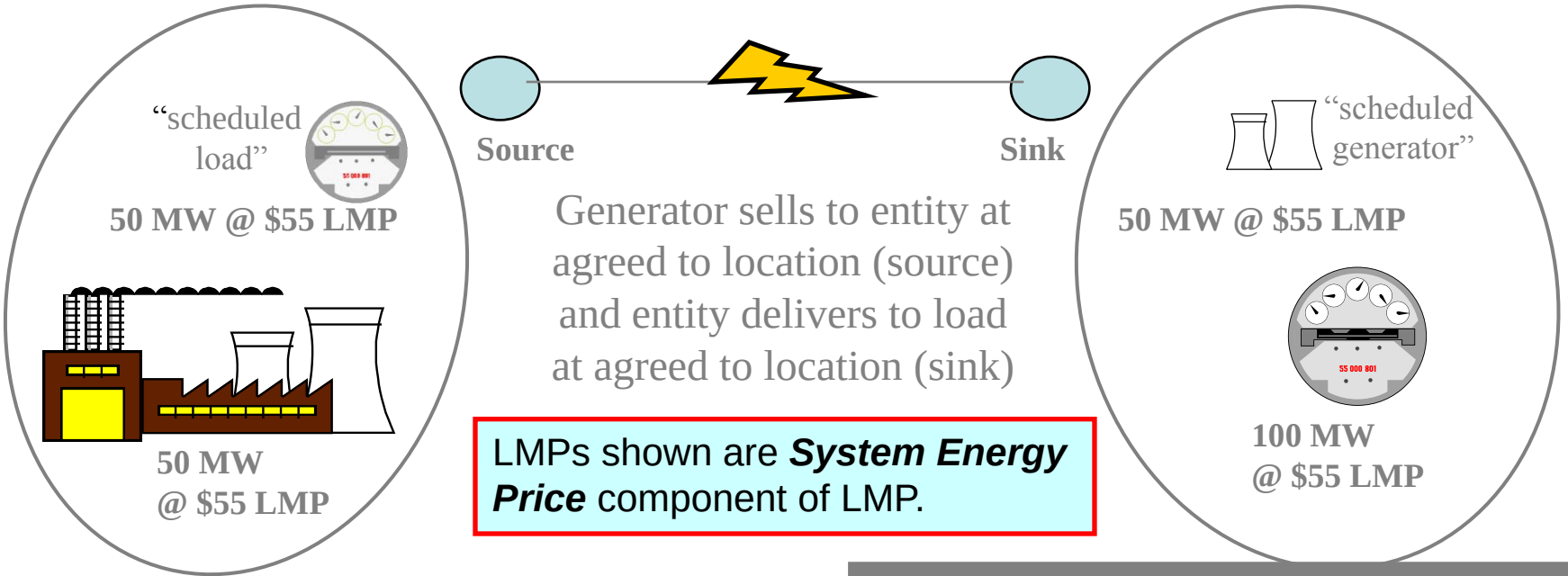
Congestion Calculations



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.

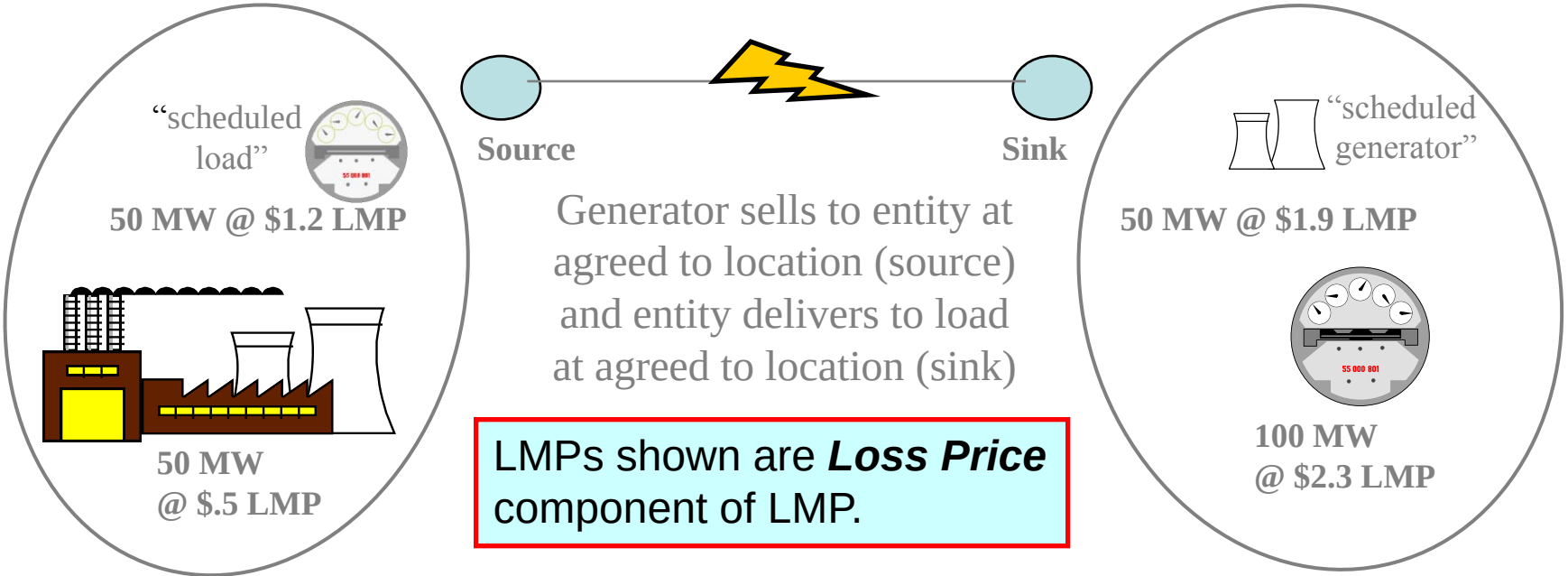
Spot Market Interchange = 0 MW
50 MW Generation
50 MW "Load" (Sale)

Generator Spot Market Interchange

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

LSE Spot Market Interchange

Example - Loss Calculation w/ Bilateral



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

Implicit Losses = $50
50 MW ($1.2) -50 MW($.5)

Generator Implicit Loss Charge

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

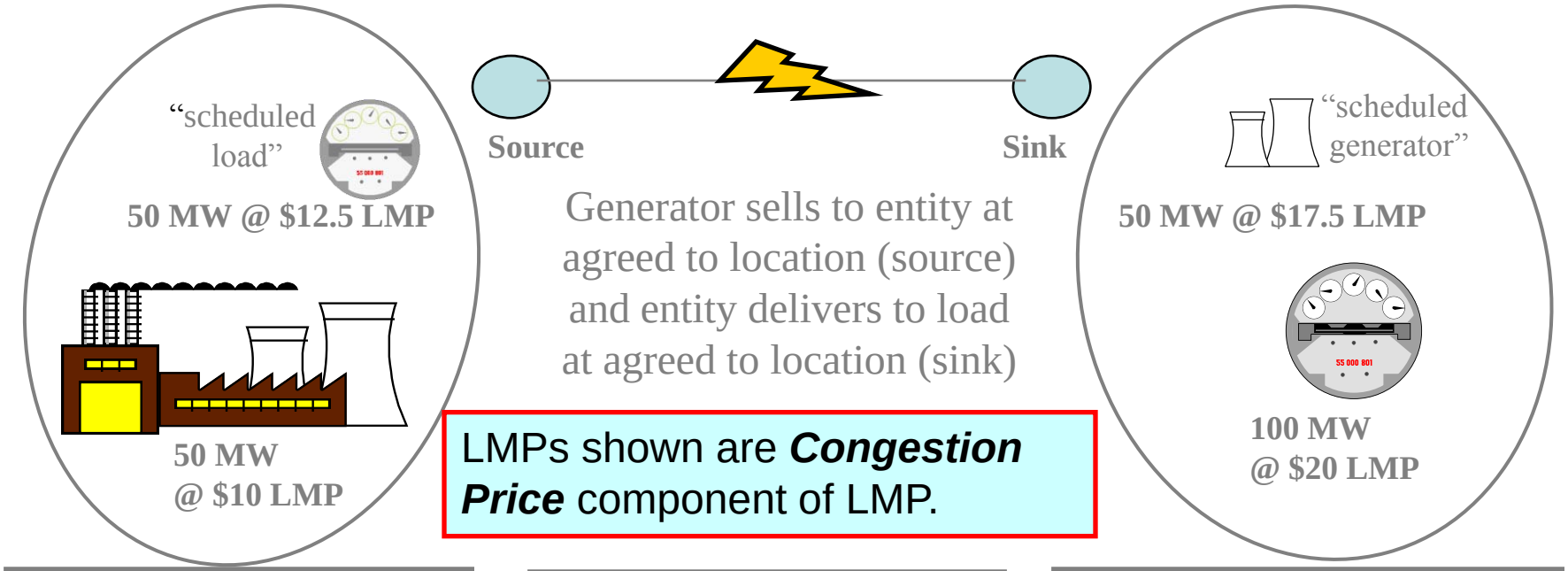
"Explicit Losses"

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



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

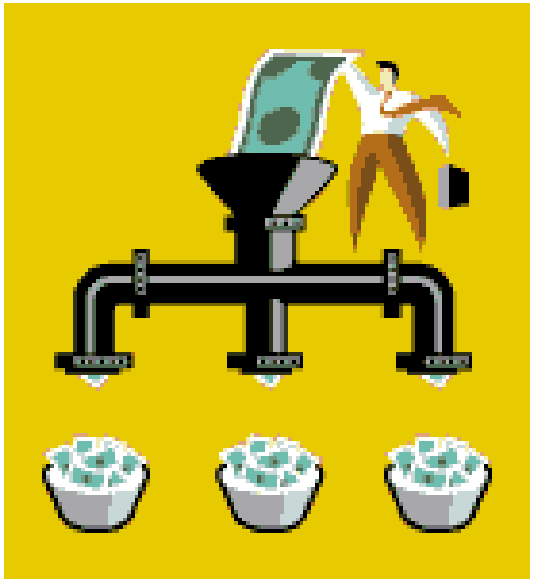
Congestion Calculation Steps

❶ Calculate congestion charges
- day-ahead market
- balancing market

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

❸ Allocate congestion charges based on target allocations

❹ Distribute excess



MSRS – Transmission Congestion Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Transmission Congestion Charge Summary												
2	Customer .	PJM Interc	Report Creatior	7/3/2008 13:27									
3	Start Date:	1/31/2008	End Date:	1/31/2008									
4	4000.01	4000.02	4000.05	4000.06	1210.11	1210.12	1210.01	1210.02	1215.11	1215.12	1215.01	1215.02	4000.07
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	DA Congestion Withdrawal Charge ($)	DA Congestion Injection Credit ($)	DA Implicit Congestion Charge ($)	DA Explicit Congestion Charge ($)	Bal Congestion Withdrawal Charge ($)	Bal Congestion Injection Credit ($)	Bal Implicit Congestion Charge ($)	Bal Explicit Congestion Charge ($)	Version
6	1234	PALCO	01/31/2008 01	01/31/2008 06	39653.71	33258.81	6394.9	0	0	0	0	0	20080101
7	1234	PALCO	01/31/2008 02	01/31/2008 07	90365.25	48335.19	42030.06	0	-264.69	-3820.45	3555.76	-532.13	20080101
8	1234	PALCO	01/31/2008 03	02/01/2008 08	42814.79	30066.48	12748.31	0	-1.05	-41.48	40.43	-2.27	20080101

Data Granularity: Hourly

Frequency: Updated Daily

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

	A	B	C	D	E	F	G	H	I	J	K
1	Explicit Congestion Charges										
2	Customer	PJM Interc	Report Creatior	############							
3	Start Date	1/31/2008	End Date:	1/31/2008							
4	4000.01	4000.02	4000.05	4000.06	4000.09	4000.13	4000.14	4000.17	4000.2	4000.21	4000.22
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Transaction ID	NERC Tag	OASIS ID	Buyer	Seller	Sink PNODE Name	Sink PNODE ID
6	1234	PALCO	01/31/2008 01	01/31/2008 06	NYIS123456	NYIS_PALCO10012345_PJM	876543	PALCO	NYISO	WESTERN HUB	51288
7	1234	PALCO	01/31/2008 02	01/31/2008 07	MECS654321	PJM_PALCO10054321_MISO	876542	MECSCA	PALCO	MISO	40523629
8	End of Report										

	L	M	N	O	P	Q	R	S	T	U	V	W
1												
2												
3												
4	4000.23	4000.24	3000.72	3000.07	3000.08	1210.13	3000.73	3000.74	3000.1	3000.11	1215.13	4000.07
5	Source PNODE Name	Source PNODE ID	DA Transaction MWh	DA Sink Congestion Price ($/MWh)	DA Source Congestion Price ($/MWh)	DA Explicit Congestion Charge ($)	RT Transaction MWh	Bal Transaction Deviation (MWh)	RT Sink Congestion Price ($/MWh)	RT Source Congestion Price ($/MWh)	Bal Explicit Congestion Charge ($)	Version
6	NYIS	5413134	0			0	100	100	0.181345	-1.84	202.13	20080101
7	EASTERN HUB	51217	0			0	50	50	-2.37	0.276431	-132.32	20080101
8												

MSRS – Explicit Congestion Charges

Data Granularity: Hourly

Frequency: Updated Daily

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

	A	B	C	D	E	F	G	H	I	J
1	Implicit Congestion and Loss Charge Details									
2	Customer A	PJM Interc	Report Creation	############						
3	Start Date:	1/31/2008	End Date:	1/31/2008						
4	4000.01	4000.02	4000.05	4000.06	4000.19	4000.2	3000.06	1210.14	1210.15	3000.15
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	PNODE Name	PNODE ID	PNODE DA Congestion Price ($/MWh)	DA Congestion Withdrawal Energy (MWh)	DA Congestion Injection Energy (MWh)	PNODE DA Loss Price ($/MWh)
1736	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 3	49382	0	0	0	0
1737	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 4	49383	0	0	0	0
1738	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 7	49384	0	0	0	0
1739	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 8	49385	0	0	0	0
1740	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK 9	49386	0	0	0	0
1741	1234	PALCO	01/31/2008 02	01/31/2008 07	LARRABEE230 KV BK11	1047952	0	0	0	0

	K	L	M	N	O	P	Q	R	S	T
1	1220.14	1220.15	3000.09	1215.14	1215.16	1215.15	1215.17	3000.18	1225.14	1225.15
2	DA Loss Withdrawal Energy (MWh)	DA Loss Injection Energy (MWh)	PNODE RT Congestion Price ($/MWh)	RT Congestion Withdrawal Energy (MWh)	Bal Congestion Withdrawal Energy Deviation (MWh)	RT Congestion Injection Energy (MWh)	Bal Congestion Injection Energy Deviation (MWh)	PNODE RT Loss Price ($/MWh)	RT Loss Withdrawal Energy (MWh)	Bal Loss Withdrawal Energy Deviation (MWh)
1736	0	0	0	0.819145867	-0.053825043	0	0	1.88	0.8191459	-0.053825043
1737	0	0	0	2.926078781	-0.140505285	0	0	1.88	2.9260788	-0.140505285
1738	0	0	0	1.631457367	-0.051177405	0	0	1.88	1.6314574	-0.051177405
1739	0	0	0	-0.019800709	-0.016494595	0	0	3.09	-0.0198007	-0.016494595
1740	0	0	0	-0.019800709	-0.016494595	0	0	3.09	-0.0198007	-0.016494595
1741	0	0	0	0.74408916	-0.054851568	0	0	3.09	0.7440892	-0.054851568

	U	V	W
1	1225.16	1225.17	4000.07
2	RT Loss Injection Energy (MWh)	Bal Loss Injection Energy Deviation (MWh)	Version
1736	0	0	20080101
1737	0	0	20080101
1738	0	0	20080101
1739	0	0	20080101
1740	0	0	20080101
1741	0	0	20080101

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

Data Granularity: Hourly

Frequency: Updated Daily

Supporting Calculations

DA Congestion Withdrawal Charge (from Congestion Charge Summary) = SUM (PNODE DA Congestion Price * DA Congestion Withdrawal Energy) for all PNODEs

DA Congestion Injection Credit (from Congestion Charge Summary) = SUM (PNODE DA Congestion Price * DA Congestion Injection Energy) for all PNODEs

DA Loss Withdrawal Charge (from Loss Charge Summary) = SUM (PNODE DA Loss Price * DA Loss Withdrawal Energy) for all PNODEs

DA Loss Injection Credit (from Loss Charge Summary) = SUM (PNODE DA Loss Price * DA Loss Injection Energy) for all PNODEs

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

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

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

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

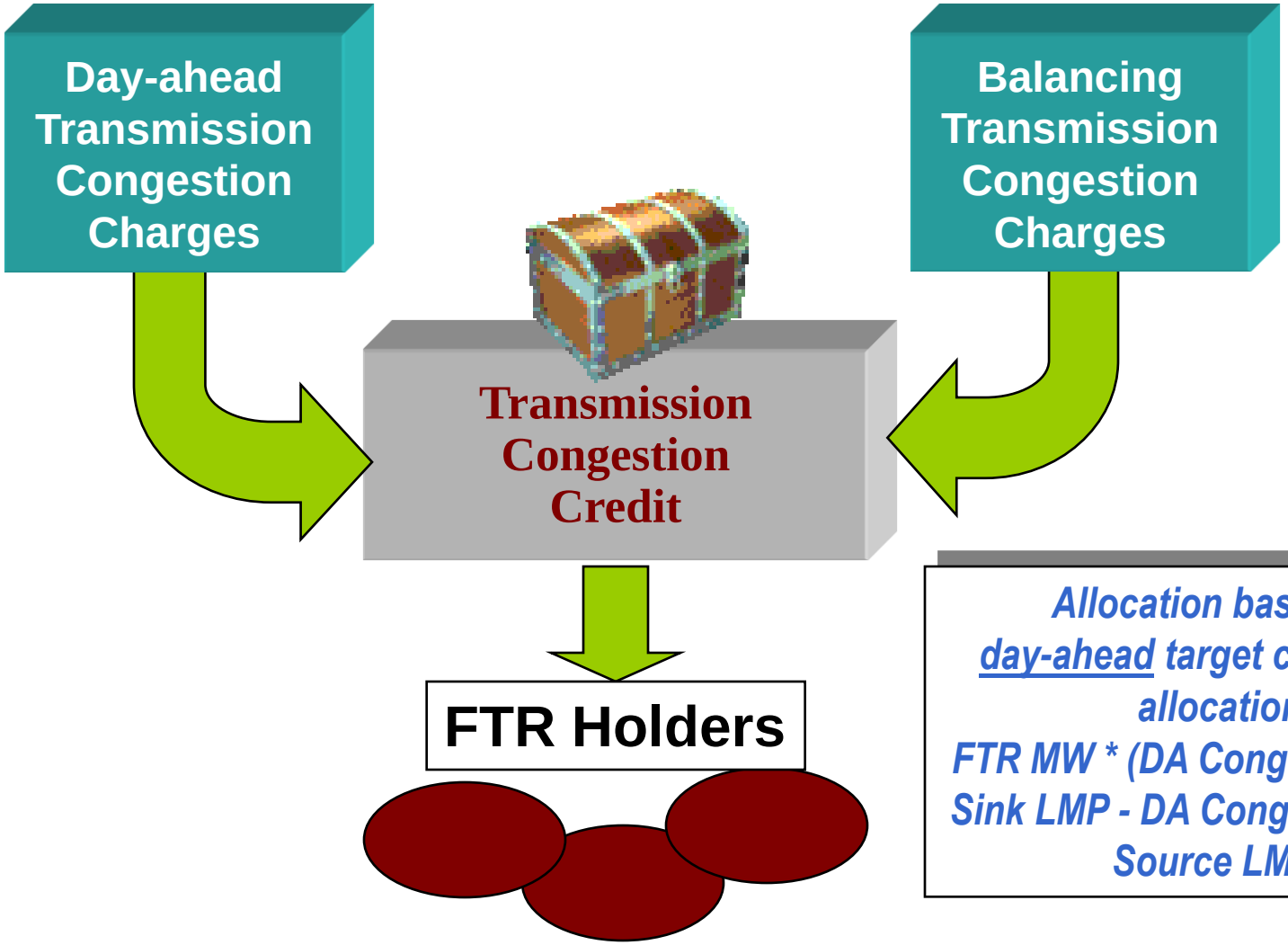
Bal Congestion Withdrawal Charge (from Congestion Charge Summary) = SUM (PNODE RT Congestion Price * Bal Congestion Withdrawal Energy Deviation) for all PNODEs

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

Bal Loss Withdrawal Charge (from Loss Charge Summary) = SUM (PNODE RT Loss Price * Bal Loss Withdrawal Energy Deviation) for all PNODEs

Bal Loss Injection Credit (from Loss Charge Summary) = SUM(PNODE RT Loss Price ($/MWh) * Bal Loss Injection Energy Deviation (MWh)) for all PNODEs

Day-ahead Congestion Credit



Allocation based on day-ahead target congestion allocation
*FTR MW * (DA Congestion Price Sink LMP - DA Congestion Price Source LMP)*

2210	Transmission Congestion

Congestion Credit Allocation

If total Day-ahead & Balancing Transmission Congestion Charges are …	*Then …*	*And the hourly congestion credit for the participants is …*
Greater than or equal to Day-ahead Target Allocations	**All allocations are satisfied,**	**The participant's target allocation**
Less than the Total Day-ahead Target Allocations,	**Target Allocations cannot be satisfied,**	**Reduced proportionately.**

- 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.

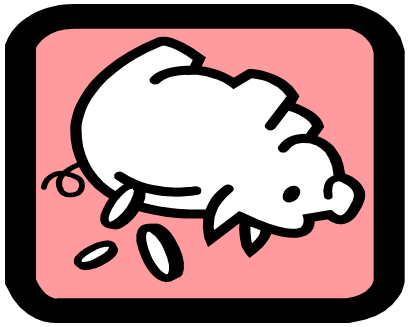
Stage Two – Any remaining excess after the stage one distribution will be used to satisfy any FTR deficiency from previous months within the Planning Period (June 1 to May 31) on a pro-rata basis up to the full FTR Target Allocation value.

Distributing Excess Transmission Congestion Charges

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.



FTR Target Allocation - Example

Table 8-7 - Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Load without Losses

Congestion Revenue

Pricing Node	Day-Ahead Congestion Price LMPs	Load	Load Payments	Generation	Generation Credits	Transmission Congestion Charges
A	$10	0	$0	100	$1,000	
B	$15	50	$750	0	$0	
C	$20	50	$1,000	100	$2,000	
D	$25	50	$1,250	0	$0	
E	$30	50	$1,500	0	$0	
Total		200	$4,500	200	$3,000	$1,500

FTR Target Allocations

Path	Day-Ahead Path Price	FTR MW	FTR Target Allocations	Positive FTR Target Allocations	Negative FTR Target Allocations
A-C	$10	50	$500	$500	$0
A-D	$15	50	$750	$750	$0
D-B	($10)	25	($250)	$0	($250)
B-E	$15	50	$750	$750	$0
Total				$2,000	($250)

Congestion Accounting	
Transmission Congestion Charges	$1,500
+Negative FTR Target Allocations	$250
=Total Congestion Charges	$1,750
Positive FTR Target Allocations	$2,000
-FTR Congestion Credits	$1,750
=Congestion Credit Deficiency	$250
FTR Payout Ratio	0.875

MSRS - Hourly Transmission Congestion Credits

	A	B	C	D	E	F	G	H	I	J
1	Hourly Transmission Congestion Credits									
2	Customer .	PJM Interc	Report Creatior	############						
3	Start Date:	1/31/2008	End Date:	1/31/2008						
4	4000.01	4000.02	4000.05	4000.06	2210.11	2210.12	2210.13	2210.01	2210.02	4000.07
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Total PJM FTR Target Credits ($)	Total PJM FTR Revenues ($)	Hourly FTR Target Credit ($)	Hourly FTR Credit ($)	End-of-Month FTR Credit ($)	Version
6	1234	PALCO	01/31/2008 01	01/31/2008 06	138670.55	201475.94	613.9	613.9		20080101
7	1234	PALCO	01/31/2008 02	01/31/2008 07	155378.73	147038.86	8654.43	8189.91		20080101
8	End of Report									

Data Granularity: Hourly

Frequency: Daily

Supporting Calculations

If Hourly FTR Target Credit < 0,
Hourly FTR Credit(2210.01) = Hourly FTR Target Credit (2210.13)

Else (Hourly FTR Target Credit >= 0),
Hourly FTR Credit(2210.01) = Hourly FTR Target Credit (2210.13) / Total PJM FTR Target Credits (2210.11) * Total PJM FTR Revenues (2210.12)

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.

MSRS – FTR Target Credits

	A	B	C	D	E	F	G	H	I	J	K
1	FTR Target Credits										
2	Customer	PJM Interc	Report Cre	#########							
3	Start Date	1/31/2008	End Date:	1/31/2008							
4	4000.01	4000.02	4000.04	4000.57	3001	4000.21	4000.22	4000.23	4000.24	4000.6	3000.81
5	Customer ID	Customer Code	Date	FTR ID	FTR MW	Sink PNODE Name	Sink PNODE ID	Source PNODE Name	Source PNODE ID	Hedge Type	FTR Ownership Share
6	1234	PALCO	1/31/2008	33333333	20	1 MIKE24 KV A-2	12345678	KATE18 KV KC2	87654321	OBLIGATION	1
7	1234	PALCO	1/31/2008	33333333	20	1 MIKE24 KV A-2	12345678	KATE18 KV KC2	87654321	OBLIGATION	1
8	1234	PALCO	1/31/2008	33333333	20	1 MIKE24 KV A-2	12345678	KATE18 KV KC2	87654321	OBLIGATION	1

	L	M	AK	AL	AM
1					
2		*			
3					
4	2210.14	3011.01	3011.24	3011.26	4000.07
5	Data Label	EPT HE 01	EPT HE 24	Total MWh	Version
6	Sink DA Congestion Price ($/MWh)	-8.77	-18.74		20080301
7	Source DA Congestion Price ($/MW	-9.81	-21.8		20080301
8	Target Credit ($)	20.8	61.2	1419	20080301

Data Granularity: Hourly

Frequency: Updated Daily

* HE 02 through HE 23
hidden due to space considerations

Supporting Calculations

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

MSRS – Congestion Credit Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Monthly Congestion Credit Summary												
2	Customer .	PJM Interc	Report C	7/9/2008 10:36									
3	Start Mont	March, 200	End Mon	March, 2008									
4	4000.01	4000.02	4000.03	2217.11	2217.12	2217.13	2217.01	2218	2217.14	2217.15	2217.16	2217.02	2218.02
5	Customer ID	Customer Code	Month	Monthly FTR Target Credit ($)	Monthly FTR Credit ($)	FTR Deficiency ($)	FTR Holder Excess Congestion Credit ($)	FTR Uplift Credit ($)	Monthly ARR Target Credit ($)	Monthly ARR Credit ($)	ARR Deficiency ($)	ARR Holder Excess Congestio n Credit ($)	ARR Uplift Credit ($)
6	End of Report												

	N	O
1		
2		
3		
4	2217.03	4000.07
5	Transmission Customer Excess Congestion Credit ($)	Version
6		

Data Granularity: Monthly

Frequency: Updated monthly

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)

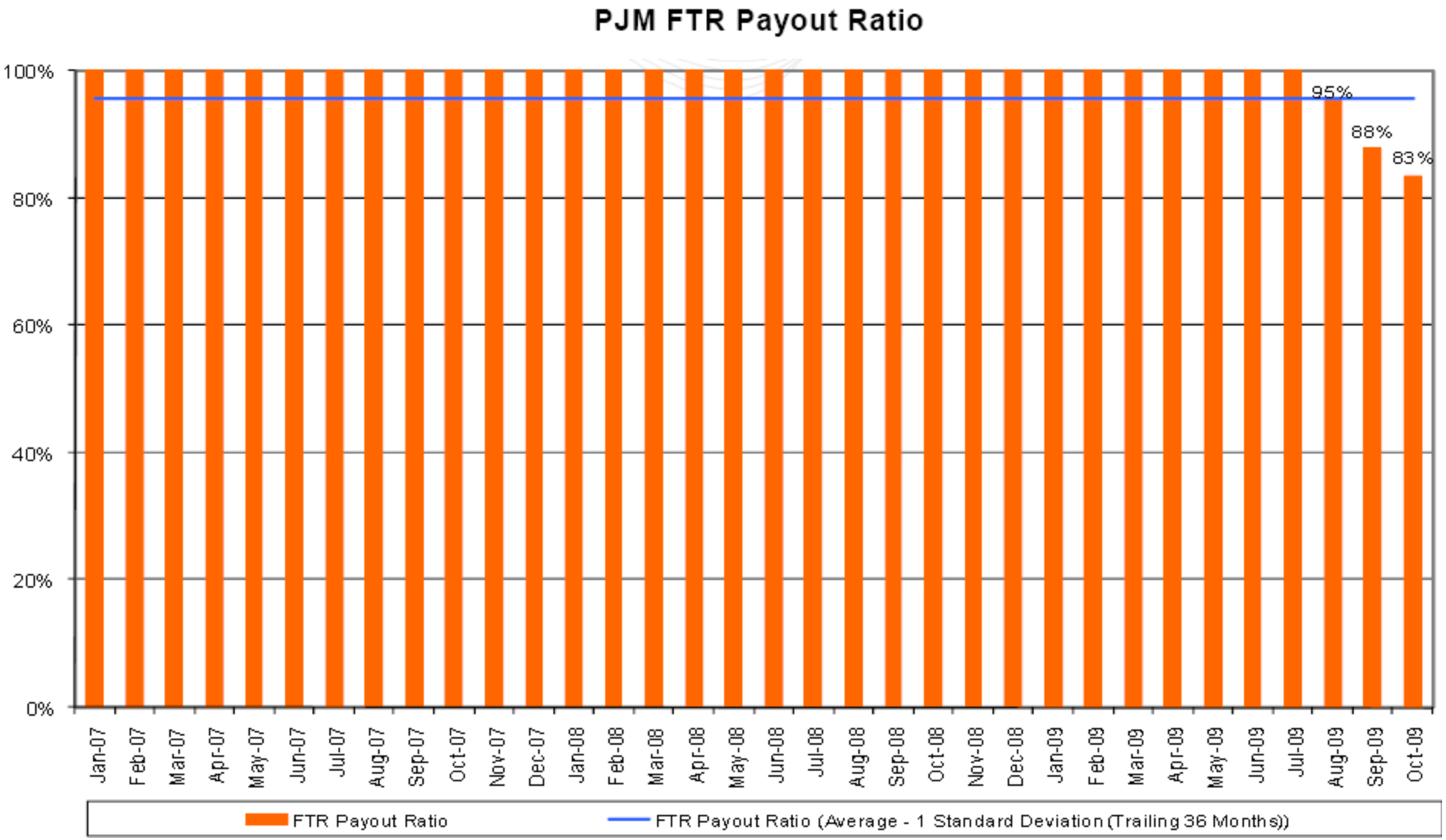
ARR Deficiency (2217.16) = Monthly ARR Target Credit (2217.14) – Monthly ARR Credit (2217.15)

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)

FTR Revenue Adequacy



Example Case (Constrained)

Example - Case 2

Unconstrained Day-ahead Schedule

- Total day-ahead demand of 669 MW

Constrained Actual Operations

- Total actual demand of 900 MW

Example -Market Participants

Participant	Role
EDC 1	***Metered entity that owns generation & serves load in PJM***
LSE 2	***Retail load aggregator that serves portion of LSE 1's metered load***
EDC 3	***Metered entity that owns generation & serves load in PJM***
EDC 4	***Metered entity that owns generation & serves load in PJM***
Park City	***Merchant generation plant that sells to PJM Spot Market***
Alta	***Merchant generation plant that sells to PJM Spot Market & enters bilateral contracts with other PJM Members***

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

Bus	Generator	MWh Available	Owner	Offer Price	MWh Scheduled
E	Brighton	600	33.3 % EDC 3 66.7 % EDC 1	$10/MWh	600
A	Alta	110	Merchant Generator Company X	$14/MWh	86
A	Park City	100	Merchant Generator Company Y	$15/MWh	0
C	Solitude	20	15% EDC 1 42.5% EDC 3 42.5% EDC 4	$30/MWh	0
D	Sundance	200	100% EDC 4	$30/MWh	0

Example - Day-Ahead Market Results: Transaction Schedules

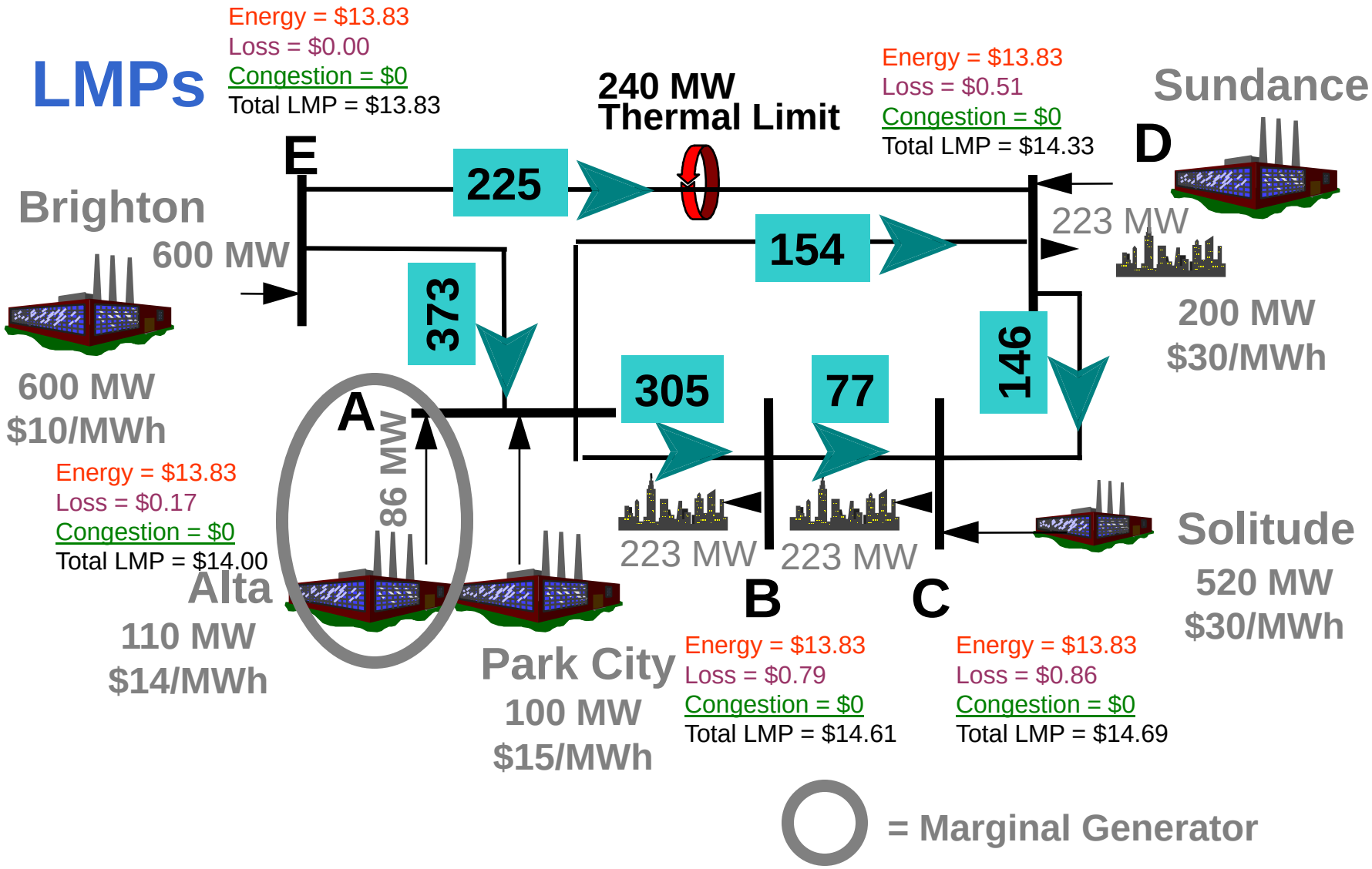
Alta schedules internal bilateral transaction in eSchedules for 5 MW on path A to D

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



Example - Day Ahead Settlements

Net Spot MWh = **DA Load + Energy Sale Transactions + Decrement Transactions** − **Generator + Energy Purchase Transactions + Increment Transactions**

-200 = 200 (load @B) - 400 (66.7% of Brighton @E)	for EDC 1
23 = 23 (Dec bid @ B) - 0	for LSE 2
23 = 223 (P.S. Demand bid @ C) - 200 (33.3% of Brighton@E)	for EDC 3
218 = 223 (load @D) - 5 (purchase @D)	for EDC 4
0 = 0 - 0	for Park City
-81 = 5 (sale @D) - 86 (Alta generation @A)	for Alta

-17 (losses)

Example - Day-Ahead Spot Market Charges & Credits

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

Total Negative Spot Market Charges = **Negative Net Interchange (MWh)** * ***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

Market Participant	Day-ahead Load	Bus	Loss Price ($/MWh)	Loss Charge ($)
EDC 1	200	B	0.79	158.00
LSE 2	23	B	0.79	18.17
EDC 3	223	C	0.86	191.78
EDC 4	223	D	0.51	113.73
Alta	5	A	0.17	0.85
				482.53

↑ * ↑ = ↑

Example – Day Ahead Implicit Losses – Generator Loss Credits

Market Participant	Day-ahead Generation	Bus	Loss Price ($/MWh)	DA Generation Loss Credit ($)
EDC 1	400	E	0	0
LSE 2	0	-	-	-
EDC 3	200	E	0	0
EDC 4	5	D	0.51	2.55
Alta	86	A	0.17	14.62
				17.17

↑ * ↑ = ↑

Example – Day Ahead Implicit Losses Charge

Market Participant	DA Loss Charge ($)	DA Loss Credit ($)	DA Implicit Loss Charge
EDC 1	158.00	0	158.00
LSE 2	18.17	0	18.17
EDC 3	191.78	0	191.78
EDC 4	113.73	2.55	111.18
Alta	.85	14.62	(13.77)
			465.36

↑ - ↑ = ↑

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**

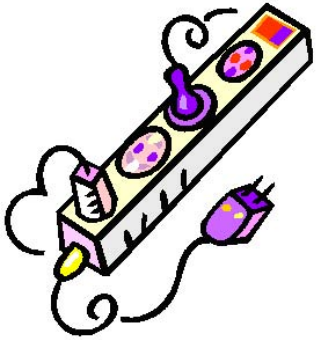
EDC 4: 5 * (0.51 - 0.17) = $1.70

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

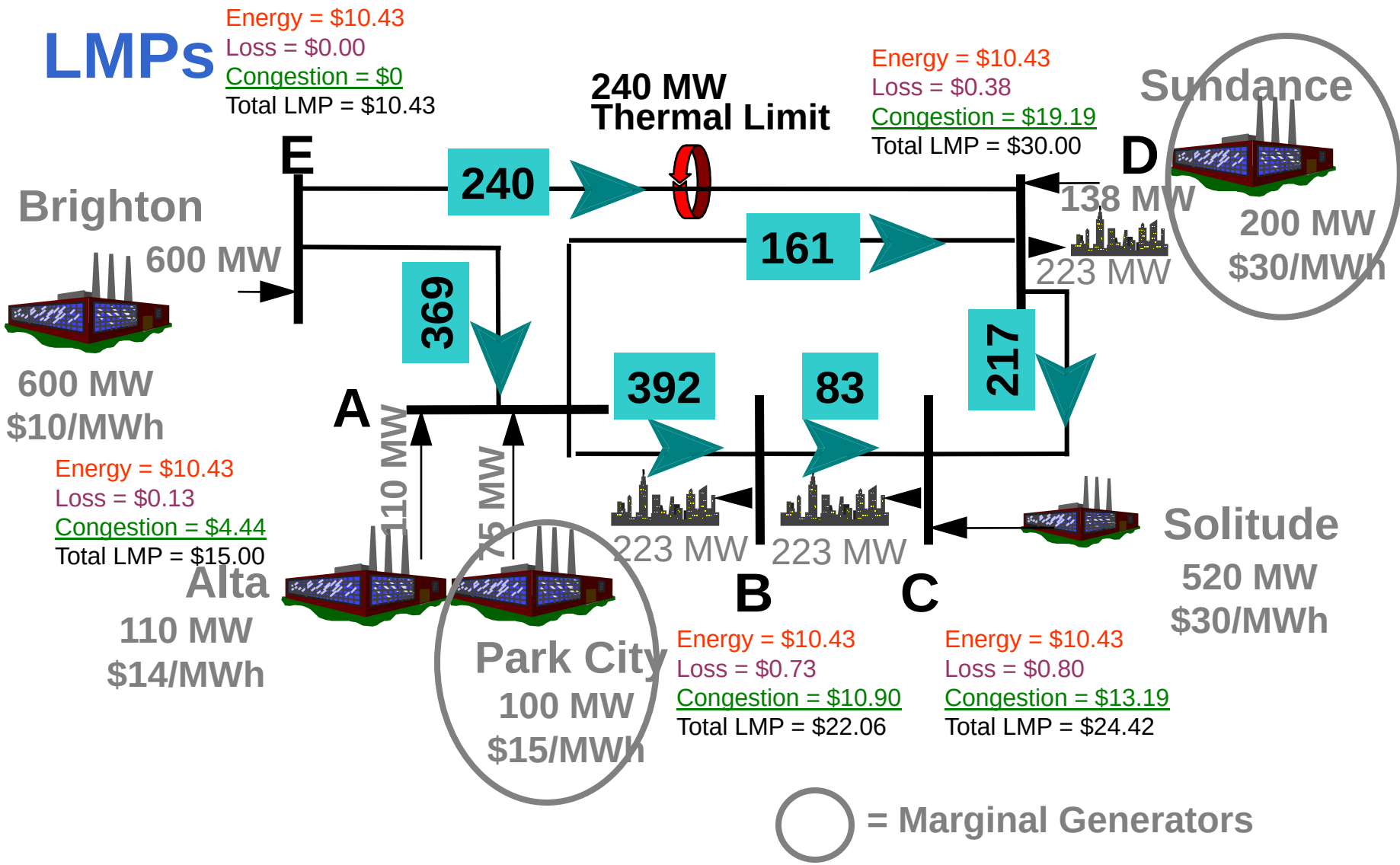
BUS	Generator	MWh Available	Owner	Offer Price	MWh Dispatched
E	Brighton	600	33.3 % EDC 3 66.7% EDC 1	$10/MWh	600
A	Alta	110	Merchant Gen – Company X	$14/MWh	110
A	Park City	100	Merchant Gen – Company Y	$15/MWh	75
C	Solitude	520	15% EDC 1 42.5% EDC 3 42.5% EDC 4	$30/MWh	0
D	Sundance	200	100% EDC 4	$30/MWh	138

Example - Actual Operations Transaction Schedules

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



Example - Balancing Settlements

Net Interchange MWh = **Metered Interchange – State Estimator Losses** + **Scheduled Load + Energy Sale Transactions** - **Scheduled Generation + Energy Purchase Transactions**

-130 = -100(-400 Brighton gen @E + 300 load @B) ***+ 0 -30*** (esched retail load transfer to LSE 2) ***for EDC 1***

30 = 0 + 30 (esched retail load transfer from EDC1) ***- 0*** ***for LSE 2***

100 = 100 (-200 Brighton gen @E + 300 load @C) ***+ 0 - 0*** ***for EDC 3***

157 = 162(-138 Sundance gen @D + 300 load @D) ***+ 0 - 5*** (esched purchase from Alta @D) ***for EDC 4***

- 75 = -75 (75 gen @A) ***+ 0 – 0*** ***for Park City***

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

-23 (losses)

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

Day-ahead Net Interchange

System Energy Price Component of Real-time LMP

$730.1 = (-130 - (-200 MWh))* $10.43/MWh	for EDC 1
$73.01 = (30 - 23 MWh) * $10.43/MWh	for LSE 2
$803.11 = (100 - 23 MWh) * $10.43/MWh	for EDC 3
($636.23) = (157 - 218 MWh) * $10.43/MWh	for EDC 4
($782.25) = (-75 - 0) MWh * $10.43/MWh	for Park City
($250.32)= (-105 – (-81)) MWh * $10.43/MWh	for Alta
(62.58)	

Example - Summary of Day Ahead & Balancing Settlements

Market Participant	Day Ahead Spot Market Payments	Balancing Spot Market Payments	Total Spot Market Payments
EDC 1	($2766)	730.1	($2035.9)
LSE 2	$318	73.01	$391.01
EDC 3	$318	$803.11	$1121.11
EDC 4	$3015	($636.23)	$2378.77
Park City	$0	($782.25)	($782.25)
Alta	($1120.23)	($250.32)	($1370.55)
		Total	($297.81)

Example – Balancing Implicit Losses – Load Loss Charges

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

↑ - ↑ * = ↑

Example – Balancing Implicit Losses – Generation Loss Credits

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

↑ - ↑ * = ↑

Example - Implicit Losses Charge

Market Participant	Balancing Loss Charge ($)	Balancing Loss Credit ($)	Balancing Implicit Loss Charge
EDC 1	51.10	0	51.10
LSE 2	5.11	0	5.11
EDC 3	61.60	0	61.60
EDC 4	29.26	52.44	(23.18)
Alta	0	3.12	(3.12)
Park City	0	9.75	(9.75)
			81.76

↑ - ↑ = ↑

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 * (0.38 - 0.13) = $0

Example – Total Loss Surplus

Market	Implicit Loss Charge ($)	Explicit Loss Charge ($)
Day Ahead	**465.36**	**1.70**
Balancing	81.76	0

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

Market Participant	Real-time Load
EDC 1	270mw@Bus B
LSE 2	30mw@Bus B
EDC 3	300mw@Bus C
EDC 4	300mw@Bus D
Park City	0
Alta	0

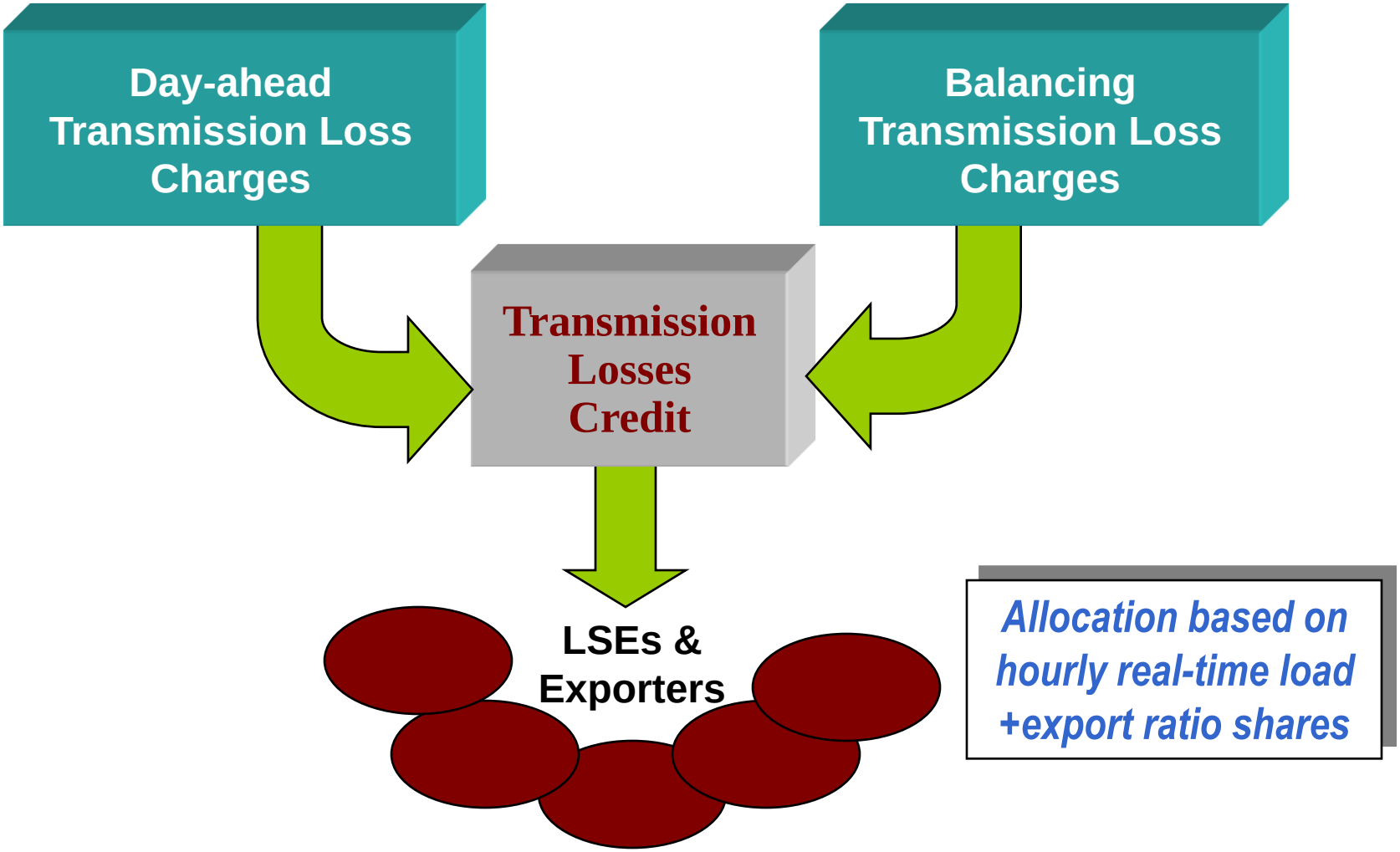
Total Real-time Load = 900mw

Example – Total Loss Surplus Distribution

$$\text{Loss Credit} = \text{Total Loss Surplus (\$)} * \left(\frac{\text{Customer total MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service}}{\text{Total PJM MWh of energy delivered to load + exports paying for transmission service + up-to-congestion transactions paying for transmission service}} \right)$$

EDC 1	$75.30	=	$251.01	*	270 / 900
LSE 2	$ 8.37	=	$251.01	*	30 / 900
EDC 3	$83.67	=	$251.01	*	300 / 900
EDC 4	$83.67	=	$251.01	*	300 / 900

Transmission Losses Credit



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

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

↑ - ↑ * = ↑

Example – Balancing Implicit Congestion – Generation Congestion Credits

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

↑ - ↑ * = ↑

Example - Implicit Congestion Charge

Market Participant	Balancing Congestion Charge ($)	Balancing Congestion Credit ($)	Balancing Implicit Congestion Charge
EDC 1	763.00	0	763.00
LSE 2	76.30	0	76.30
EDC 3	1015.63	0	1015.63
EDC 4	1477.63	2648.22	(1170.59)
Alta	0	106.56	(106.56)
Park City	0	333.00	(333.00)
			244.78

↑ - ↑ = ↑

Example – Balancing Explicit Congestion Charge

Balancing Explicit Congestion Charges = **Transaction Deviation (RT – DA) MWh** * (**Real Time Sink *Congestion Price*** - **Real Time Source *Congestion Price***)

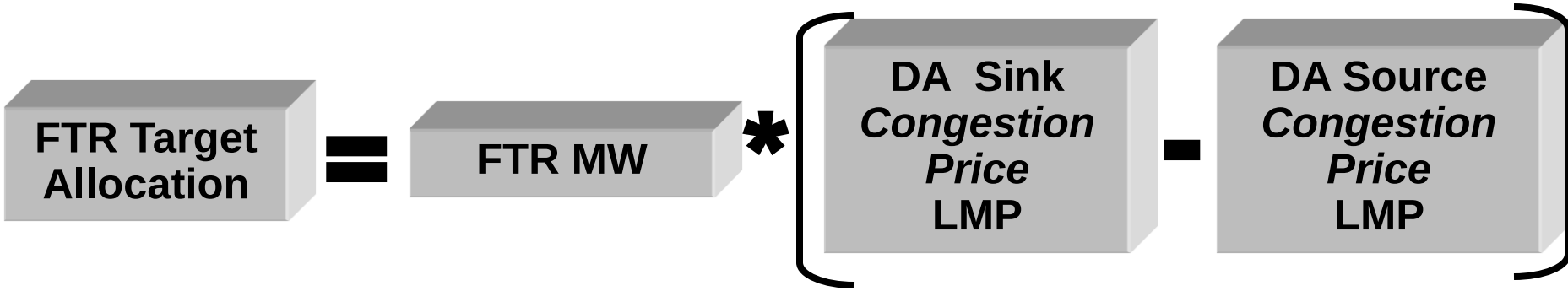
EDC 4: 0 * (19.19 – 4.44) = $0

Example – Total Congestion Charges

Market	Implicit Congestion Charge ($)	Explicit Congestion Charge ($)
Day Ahead	0	0
Balancing	244.78	0

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

MSRS – LMP Charges Report

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	Generator LMP Charges																
2	Customer	PJM Inte	Report Creation	###########													
3	Start Date	#######	End Date:	11/30/2009													
4	4000.01		4000.05	4000.06	4000.63	4000.64	3000.8	4000.19	4000.2	3000.32	3000.01	1200.11	3000.06	1210.18	3000.15	1220.18	3000.33
5	Customer ID	CUSTOMER_CODE	EPT Hour Ending	GMT Hour Ending	Unit ID	Unit Name	Unit Ownership Share	PNODE Name	PNODE ID	DA Scheduled MWh	DA PJM Energy Price ($/MWh)	DA Spot Market Energy Charge ($)	PNODE DA Congestion Price ($/MWh)	DA Transmission Congestion Charge ($)	PNODE DA Loss Price ($/MWh)	DA Transmission Loss Charge ($)	
12293	1234	PALCO	10/01/2009 03	10/01/2009 08	12345678	MICHAEL 1	1	MICHAEL	12345	667.9	23.41	15635.54	0.42	280.52	-0.22	-146.94	

Q	R	S	T	U	V	W	X	Y
3000.33	3000.91	3000.02	1205.11	3000.09	1215.2	3000.18	1225.2	4000.07
RT Generation (MWh)	Bal Generation (MWh)	RT PJM Energy Price ($/MWh)	Bal Spot Market Energy Charge ($)	PNODE RT Congestion Price ($/MWh)	Bal Transmission Congestion Charge ($)	PNODE RT Loss Price ($/MWh)	Bal Transmission Loss Charge ($)	Version
701.193	33.29	25.08	834.99	0.12	4	-0.68	-22.64	20091101

- 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)

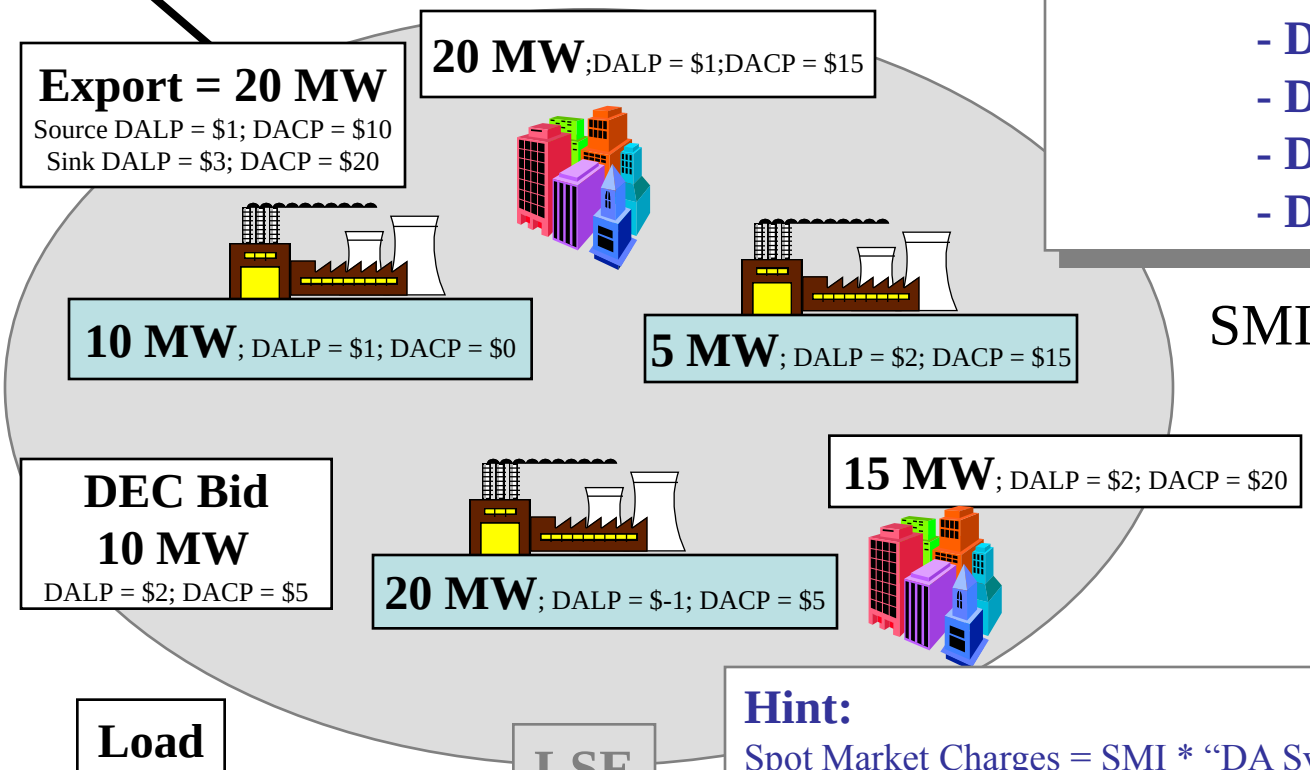
Bal Transmission Congestion Charge (1215.20) =
Bal Generation (3000.91) * PNODE RT Congestion Price (3000.09)

Bal Transmission Loss Charge (1225.20) =
Bal Generation (3000.91) * PNODE RT Loss Price (3000.18)

Exercise 4

Day - ahead Market
DA System Energy Price = $10

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



SMI = 30 MW (Net buyer)

Load

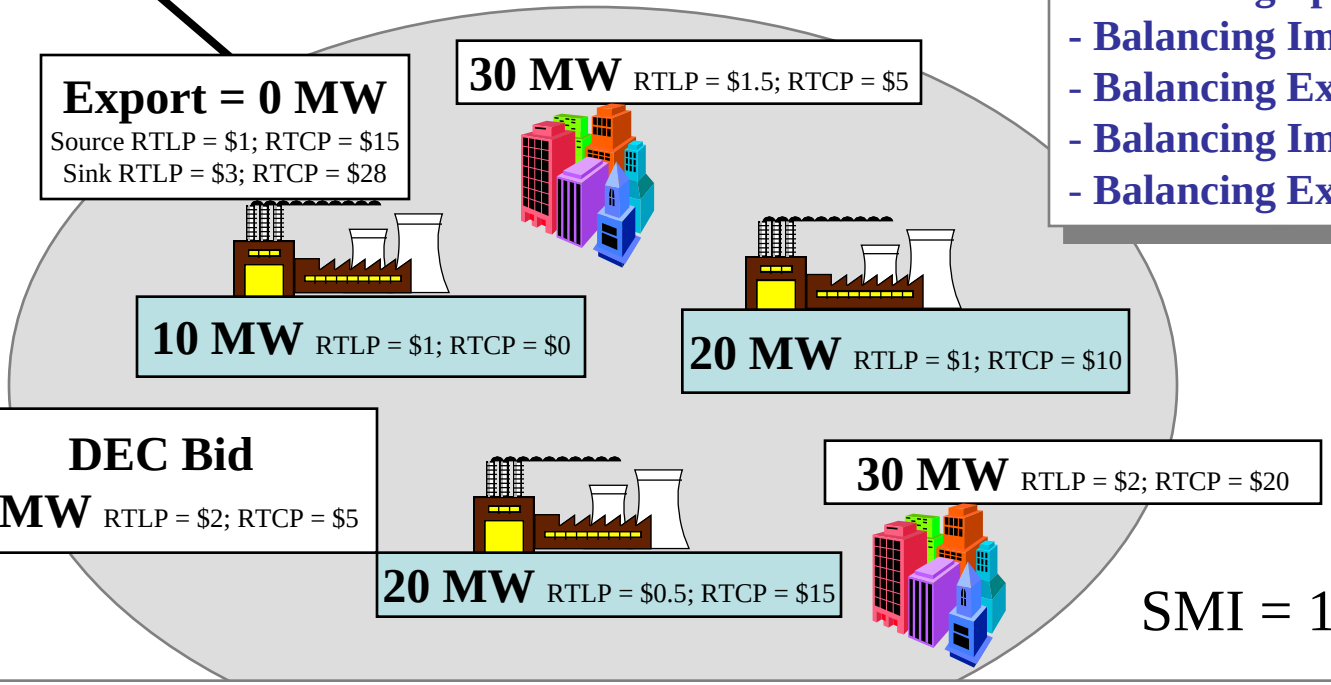
Generation

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)

Exercise 5

Balancing Market
RT System Energy Price = $20

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



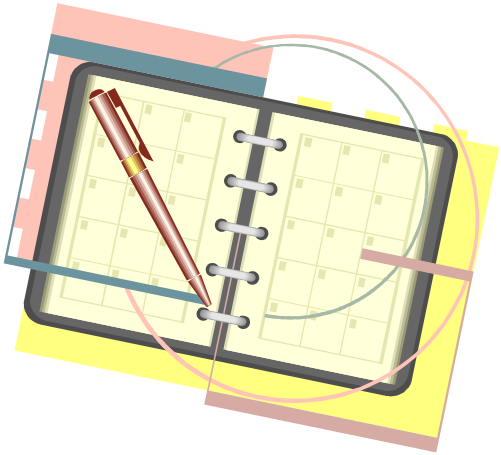
SMI = 10 MW (Net buyer)

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)

Agenda

- 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 = **Network Customer Daily Peak Load Contribution** * **1/365** * **Applicable Zonal rate**

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

Calculated for Network Customer for each zone where load is served.

- **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

1100	Network Integration Transmission Service
2100	Network Integration Transmission Service

Network Transmission Service Peak Loads

PJM Network Transmission Service Peak Loads for 2010

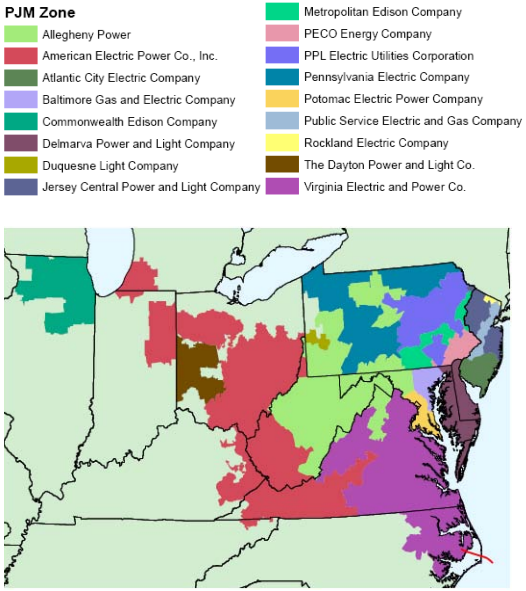
(Metered Demand Coincident with Zonal Peak Load Hour for Period 11/1/08-10/31/09)

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

Network Integration Transmission Service

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

Effective: January 1, 2010



- 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

Firm Point-to-Point Transmission Service

- **Charges**

1130	Firm Point-to-Point Transmission Service

Monthly Demand Charge = **Reserved Transmission Capacity** * **Applicable Tariff rate**

Yearly Charge ($/kW)	Monthly Charge ($/kW)	Weekly Charge ($/kW)	Weekday Charge ($/kW)	Weekend/NERC Holiday($/kW)
18.888	1.574	0.3632	0.0726	0.0519

- **Credits**

2130	Firm Point-to-Point Transmission Service

  - 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**

Hourly Non-firm Demand Charge = (**Reserved Transmission Capacity (MW Reserved – MW Curtailed)** * **Discounted Rate**) – **Hourly congestion charge if congestion > 0**

•Currently $0.67/MWh

Rebates for transaction MWh curtailed by PJM

- **Credits**
  - 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

1140	Non-Firm Point-to-Point Transmission Service
2140	Non-Firm Point-to-Point Transmission Service

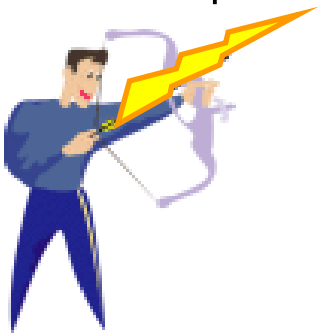
Non-Firm Point-to-Point Transmission Service

- 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)

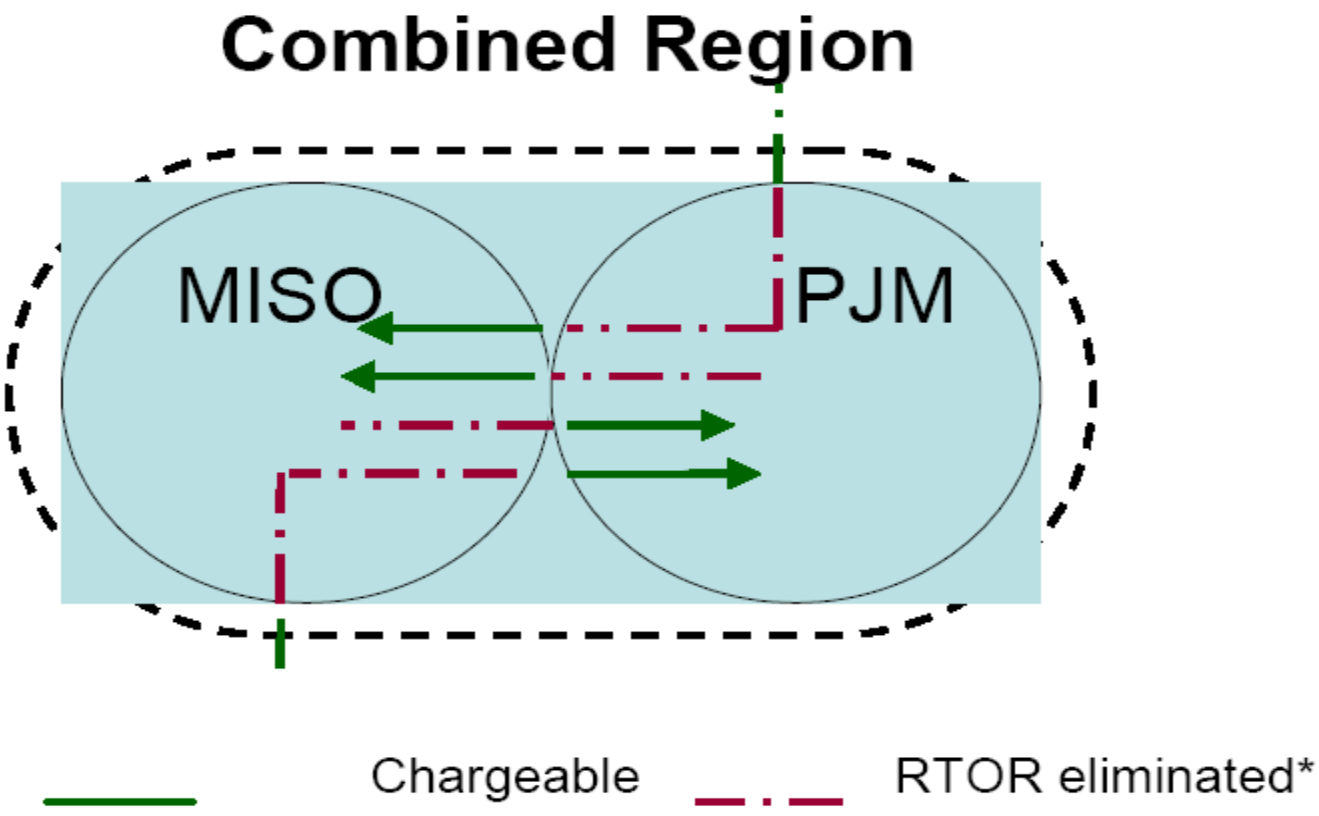
  - Purchase of Non-firm Service cannot result in a credit.

Regional Through and Out Rate (RTOR) Elimination

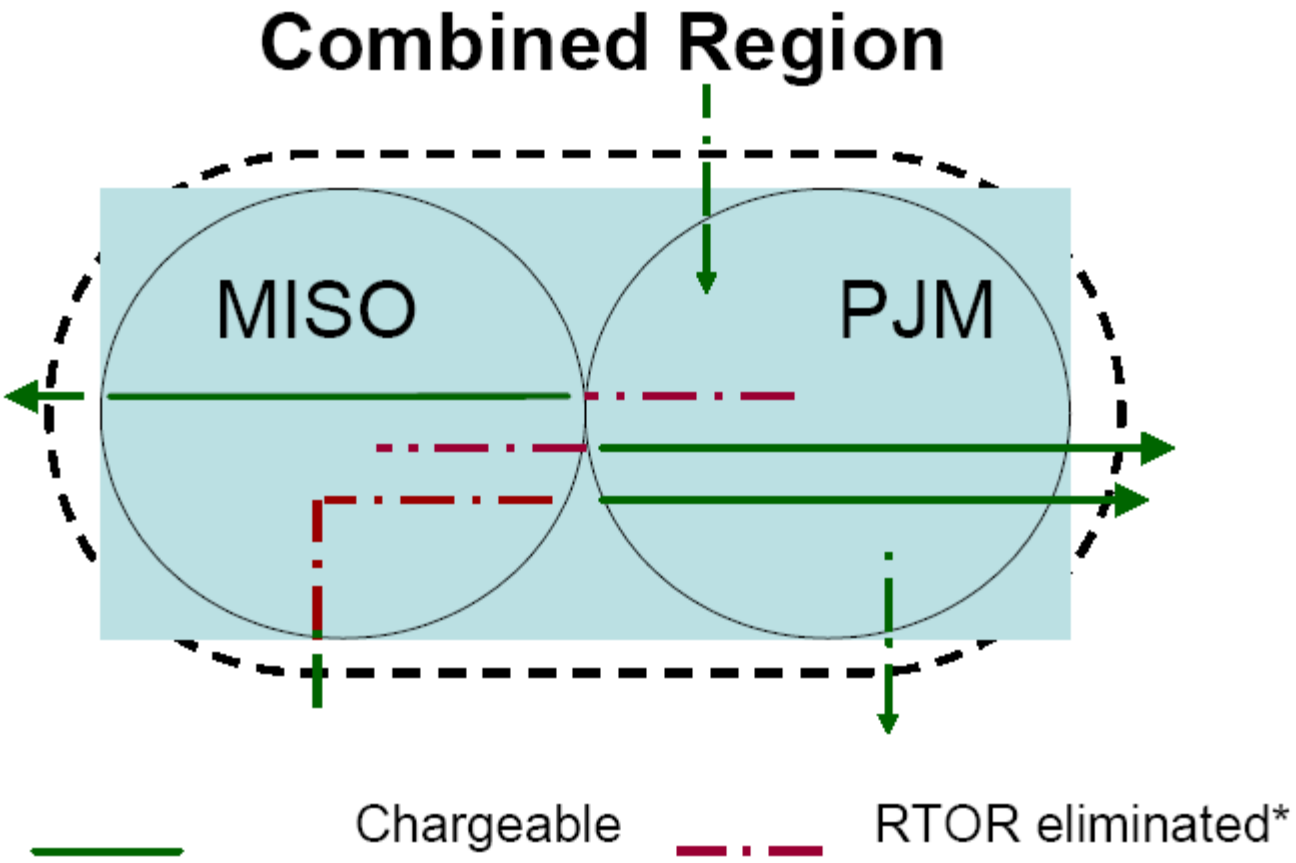
- PJM will not charge for a transmission reservation with a Point of Delivery in MISO requested on or after November 17, 2003
- PJM will charge for a transmission reservation with a Point of Delivery not in MISO (including PJM imports)
- PJM will charge for firm transmission reservations redirected from 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



Regional Through and Out Rate (RTOR) Elimination



MSRS – Network Integrated Transmission Service Charge Summary

	A	B	C	D	E	F	G	H	I
1	Network Integration Transmission Service Charge Summary								
2	Customer Ac	PJM Interc	Report Cre	#########					
3	Start Date:	1/31/2008	End Date:	1/31/2008					
4	4000.01	4000.02	4000.04	4000.32	3000.47	1100.11	1102.01	1100.01	4000.07
5	Customer ID	Customer Code	Date	Zone	Daily Peak Load (MW)	Network Rate ($/MW per day)	Network Service Exempt Charge ($)	Network Service Charge ($)	Version
6	1234	PALCO	1/31/2008	AECO	50	54.631148	0	2731.56	20080101
7	1234	PALCO	1/31/2008	JCPL	71	41.289617	0	2931.56	20080101
8	End of Report								

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

	A	B	C	D	E	F	G	H	I
1	Network Integration Transmission Service Credit Summary								
2	Customer Ac	PJM Interconne	Report Cre	#########					
3	Start Date:	1/31/2008	End Date:	1/31/2008					
4	4000.01	4000.02	4000.04	4000.32	2100.11	2100.12	2102.01	2100.01	4000.07
5	Customer ID	Customer Code	Date	Zone	Total Zone Network Service Charge ($)	Zone Revenue Requirement Share ($/MW per day)	Network Service Exempt Credit ($)	Network Service Credit ($)	Version
6	End of Report								

Data Granularity: Daily

Frequency: Updated Daily

Supporting Calculations

Network Service Credit (2100.01) = Total Zone Charge (2100.11) * Zone Revenue Requirement Share (2100.12)

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)

MSRS – Firm Point-to-Point Transmission Service Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Firm Point-to-Point Transmission Service Charges												
2	Customer .	PJM Interc	Report Cre	#########									
3	Start Date:	1/31/2008	End Date:	1/31/2008									
4	4000.01	4000.02	4000.04	4000.14	4000.51	4000.44	4000.45	4000.52	4000.53	1130.11	3000.52	1130.01	4000.07
5	Customer ID	Customer Code	Date	OASIS ID	Time Block	Begin Date	End Date	Point of Receipt	Point of Delivery	Firm PTP Rate ($/MW)	Reservati on Capacity (MW)	Firm PTP Transmis sion Service Daily Charge ($/MW per day)	Version
6	1432	PALCO	1/31/2008	824269	month	1/1/2008	1/31/2008	PJM	WEC	50.77419	100	0	20080101
7	End of Report												

Data Granularity: Daily

Frequency: Updated Daily

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

	A	B	C	D	E	F	G	H	I	J	K	L
1	Firm Point-to-Point Transmission Service Credit Summary											
2	Customer .	PJM Interc	Report Cre	#########								
3	Start Mont	January, 2	End Month	January, 2008								
4	4000.01	4000.02	4000.03	2130.11	3000.85	4000.32	3000.88	3000.89	2130.01	2132.11	2132.01	4000.07
5	Customer ID	Customer Code	Month	Total PJM Firm Charges ($)	Transmission Revenue Requirement Share	Zone	Zone Peak Load (MW-days)	Total Zone Peak Load (MW-days)	Firm Credit ($)	Total Zone PTP Load Firm Charge ($)	PTP Load Firm Credit ($)	Version
6	End of Report											

Data Granularity: Monthly

Frequency: Updated monthly

Supporting Calculations

Firm Credit (2130.01) = Total PJM Firm Charge (2130.11) * Transmission Revenue Requirement Share (3000.85) unless further allocation

If further allocation:
Firm Credit (2130.01) = Total PJM Firm Charge (2130.11) * Transmission Revenue Requirement Share (3000.85) * (Zone Peak Load (3000.88) / Total Zone Peak Load (3000.89))

PTP Load Firm Credit (2132.01) = Total Zone PTP Load Firm Charge (2132.11) unless further allocation

If further allocation:
PTP Load Firm Credit (2132.01) = Total Zone PTP Load Firm Charge (2132.11) * (Zone Peak Load (3000.88) / Total Zone Peak Load (3000.89))

MSRS – Non-Firm Point-to-Point Transmission Service Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L
1	Non-Firm Point-to-Point Transmission Service Charges											
2	Customer	PJM Interc	Report Cre	#######								
3	Start Date:	1/31/2008	End Date:	#######								
4	4000.01	4000.02	4000.04	4000.1	4000.15	4001	4000.5	4000.53	1140.11	3013.01	3013.24	4000.07
5	Customer ID	Customer Code	Date	OASIS ID	Reservation Type	Time Block	Point of Receipt	Point of Delivery	Data Label	EPT HE 01	EPT HE 24	Version
6	1234	PALCO	1/31/2008	123456	NON_FIRM_OFF_PEAK	month	PJM	NYIS	Hourly Non-Firm PTP Rate ($/MW per hour)	0.67	0.67	20080101
7	1234	PALCO	1/31/2008	123456	NON_FIRM_OFF_PEAK	month	PJM	NYIS	Reservation Capacity (MW)	100	100	20080101
8	1234	PALCO	1/31/2008	123456	NON_FIRM_OFF_PEAK	month	PJM	NYIS	Billable Capacity (MW)	100	100	20080101
9	1234	PALCO	1/31/2008	123456	NON_FIRM_OFF_PEAK	month	PJM	NYIS	Congestion Adjustment ($)	0	0	20080101
10	1234	PALCO	1/31/2008	123456	NON_FIRM_OFF_PEAK	month	PJM	NYIS	Non-Firm PTP Transmission Service Charge	67	67	20080101

Data Granularity: Hourly

Frequency: Updated Daily

Supporting Calculations

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

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

	A	B	C	D	E	F	G	H
1	Non-Firm Point-to-Point Transmission Service Credit Summary							
2	Customer Ac	PJM Interconr	Report Creation	#########				
3	Start Month:	January, 2008	End Month:	January, 2008				
4	4000.01	4000.02	4000.03	2140.11	2140.12	2140.13	2140.01	4000.07
5	Customer ID	Customer Code	Month	Total PJM Non-Firm Charges ($)	Network and Firm Demand Charge ($)	Total PJM Network and Firm Demand Charge ($)	Non-Firm Credit ($)	Version
6	End of Report							

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

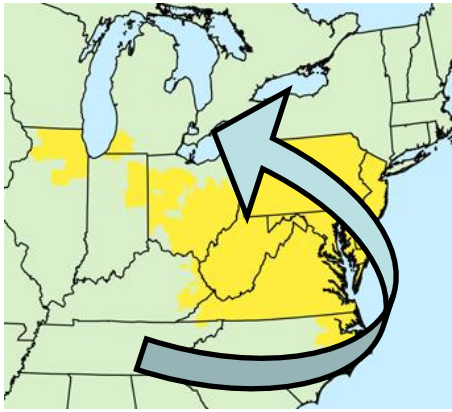
Non-Firm Credit (2140.01) = Total PJM Non-Firm Charges (2140.11) * (Network and Firm Demand Charge (2140.12) / Total PJM Network and Firm Demand Charge (2140.13))

Inadvertent Interchange

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

Inadvertent interchange posted on the PJM website at:

http://www.pjm.com/markets-and-operations/ops-analysis.aspx

	A	B	D	E	F	G	H	I	J	BG	BH	BI	BJ	BK	BL	BM
1																
2				ALTE			ALTW			TVA			WEC			Inadv.
3	Ending GMT	Beginning EPT		Actual	Sched	Inadv.	Actual	Sched	Inadv.	Actual	Sched	Inadv.	Actual	Sched	Inadv.	
724	1/31/2009 05:00	1/30/2009 23:00		-694	129	823	-240	0	240	499	88	-411	902	-50	-952	-12

By interface

Some interfaces removed due to space considerations

RTO Total inadvertent

MSRS - Inadvertent Interchange Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	Inadvertent Interchange Charge Summary													
2	Customer .	PJM Interc	Report Creatio	##############										
3	Start Date:	1/31/2008	End Date:	1/31/2008										
4	4000.01	4000.02	4000.05	4000.06	3000.5	3000.02	3000.12	3000.21	3000.38	3000.41	1230.01	1230.02	1230.03	4000.07
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Total PJM Inadvertent Interchange (MWh)	RT PJM Energy Price ($/MWh)	RT PJM Congestion Price ($/MWh)	RT PJM Loss Price ($/MWh)	RT Load (MWh)	Total PJM RT Load (MWh)	Inadvertent Energy Charge ($)	Inadvertent Congestion Charge ($)	Inadvertent Loss Charge ($)	Version
6	1234	PALCO	01/31/2008 01	01/31/2008 06	-193.462	34.67	0	0.023971	705.287	81119.04	-58.32	0	-0.04	20080101
7	1234	PALCO	01/31/2008 02	01/31/2008 07	-180.869	46.52	0	0.037474	689.531	79450.18	-73.02	0	-0.06	20080101

Data Granularity: Hourly

Frequency: Updated Daily

Supporting Calculations

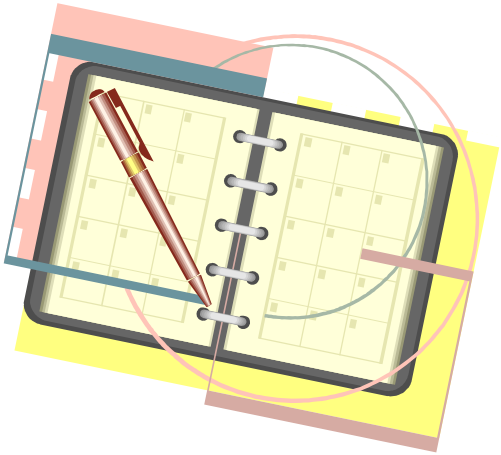
Inadvertent Energy Charge (1230.01) = (Total PJM Inadvertent Interchange (3000.5) * (RT Load (3000.38) / Total PJM RT Load (3000.41))) * RT PJM Energy Price (3000.02)

Inadvertent Congestion Charge (1230.02) = (Total PJM Inadvertent Interchange (3000.5) * (RT Load (3000.38) / Total PJM RT Load (3000.41))) * RT PJM Congestion Price (3000.12)

Inadvertent Loss Charge (1230.03) = (Total PJM Inadvertent Interchange (3000.5) * (RT Load (3000.38) / Total PJM RT Load (3000.41))) * RT PJM Loss Price (3000.21)

Agenda

- 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 Synchronzed Reserve Markets
  - Operating Reserves
- Capacity Credit Markets (and deficiency charges and allocations)
- Miscellaneous Categories

"Load" for Market Settlements Billing Items – Summary

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

Schedule 1-A Transmission Owner Scheduling, System Control and Dispatch Service

- **Charges for operation of Transmission Owner control centers**
  - **Pt-Pt customers**

Monthly Charge = **Energy Deliveries (MWh)** * **$0.1019/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**

Monthly Charge = **Real-time MWh monthly load** * **Schedule 1A zonal rates**

Including Losses

Zone	Rate ($/MWh)
Atlantic City Electric Company	0.0781
Baltimore Gas and Electric Company	0.0430
Delmarva Power & Light Company	0.0743
PECO Energy Company	0.1189
PP&L, Inc. Group	0.0618
Potomac Electric Power Company	0.0186
Public Service Electric and Gas Company	0.1030
Jersey Central Power & Light Company	0.0796
Metropolitan Edison Company	0.0796
Pennsylvania Electric Company	0.0796
Rockland Electric Company	0.2475
Commonwealth Edison Company	0.2223
AEP East Operating Companies	Rate updated annually Per Attachment H-14
The Dayton Power and Light Company	0.0797
Duquesne Light Company[1]	0.0520

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:

Transmission Owner	Share (%)
Atlantic City Electric Company	0.50
Baltimore Gas and Electric Company	0.80
Delmarva Power & Light Company	0.77
PECO Energy Company	2.68
PP&L, Inc. Group	1.36
Potomac Electric Power Company	0.33
Public Service Electric and Gas Company	2.64
Jersey Central Power & Light Company	1.30
Metropolitan Edison Company	0.43
Pennsylvania Electric Company	0.66
Rockland Electric Company	0.20
Commonwealth Edison Company	37.62
AEP East Operating Companies	47.90
The Dayton Power and Light Company	2.36
Duquesne Light Company	0.45

PJM Tariff Reference – Schedule 1A

Schedule 9 PJM Scheduling, System Control and Dispatch Service

- How PJM pays it's 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

1301	Control Area Administration
1308	Control Area Administration Refund

Schedule 9 PJM Scheduling, System Control and Dispatch Service

- 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

1302	FTR Administration

1309	FTR Administration Refund

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

1303	Market Support

1310	Market Support Refund

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

Schedule 9 PJM Scheduling, System Control and Dispatch Service

- Market Support Service
- (Schedule 9-3)

2) Defined as the number of bid/offer segments submitted by the market participant

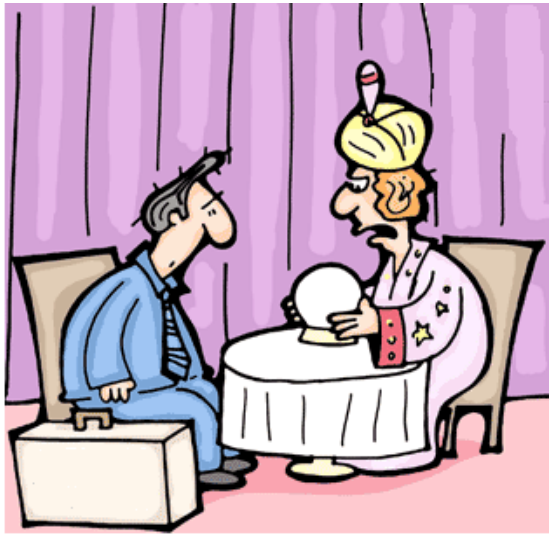
- A bid/offer segment equals each price/quantity pair submitted into the day-ahead energy market and is computed hourly for each Network Transmission Customer's fixed or price sensitive demand bid, each Market Seller's Increment Offer and each Market Buyer's Decrement Bid and computed daily for each 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



Schedule 9 PJM Scheduling, System Control and Dispatch Service

- 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

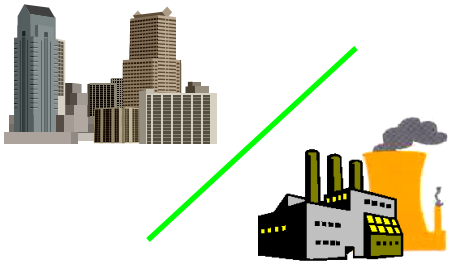
1304	Regulation Market Administration

1311	Regulation Market Administration Refund

Schedule 9 PJM Scheduling, System Control and Dispatch Service

- 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.



Schedule 9 PJM Scheduling, System Control and Dispatch Service

- Advanced Second PJM Control Center Cost (Schedule 9-6)
  - Recovery of the actual monthly costs of owning, leasing and operating AC^2
    - PJM's parallel control or second control center
  - Monthly accrued actual costs related to AC^2
  - 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%

1306	Advanced Second Control Center

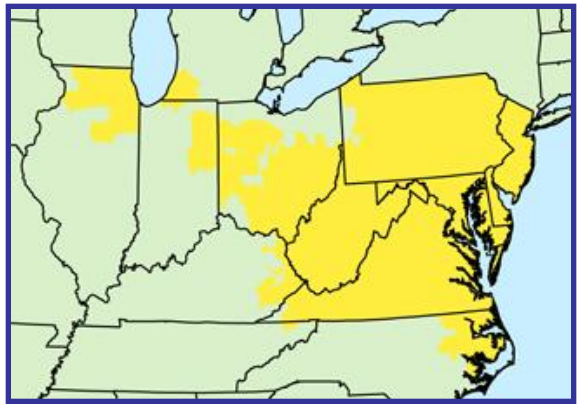
Schedule 9 PJM Scheduling, System Control and Dispatch Service

Effective Date	Schedule						
	9-1 Control Area Administration Service (per MWh)	9-2 Financial Transmission Rights (FTR) Administration Service		9-3 Market Support (MS) Service		9-4 Regulation & Frequency Response Administration Service (per MWh)	9-5 Capacity Resource & Obligation Management Service (per MWh)
		9-2 FTR Service Rate Component 1 (per FTR)	9-2 FTR Service Rate Component 2 (per bid/ offer)	9-3 MS Service Rate Component 1 (per MWh)	9-3 MS Service Rate Component 2 (per bid/ offer)		
June 1, 2006	0.1903	0.0029	0.0020	0.0432	0.0593	0.2599	0.0992
January 1, 2007	0.1852	0.0028	0.0020	0.0417	0.0583	0.2520	0.0958
January 1, 2008	0.1809	0.0027	0.0019	0.0399	0.0577	0.2442	0.0922
January 1, 2011	0.1750	0.0026	0.0018	0.0386	0.0577	0.2349	0.0894

- 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

1315	FERC Annual Charge Recovery

- 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



OPSI = Organization of PJM States, Inc.

1316	Organization of PJM States Inc. Funding

- 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

1314	Market Monitoring Unit (MMU) Funding

Schedule 10 North American Electric Reliability Corp. Charge

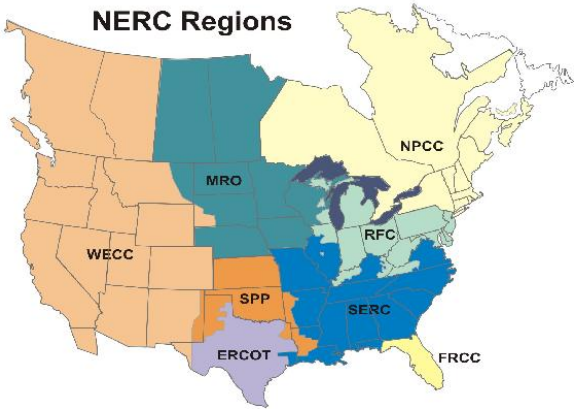
- North American Electric Reliability Corporation (NERC)
- (Schedule 10-NERC)
  - NERC is the Electric Reliability Organization certified by FERC
  - Purpose is to ensure the reliability of the interconnected bulk power system
  - Recovers a share of NERC's cost of operations
  - Based on energy delivered to load (excluding load in Dominion and Duquesne zones)
  - $0.0068/MWh for 2009
  - Over and under collections trued up in December billing cycle

1317	North American Electric Reliability Corp.

Schedule 10 Reliability First Corp. Charge

- 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

	A	B	C	D	E	F	G	H	I	J	K
1	Schedule 9 and 10 Charge Details										
2	Customer .	PJM Interconn	Report Cre	1/1/2008 16:31							
3	Start Date:	1/1/2008	End Date:	1/1/2008							
4	4000.01	4000.02	4000.04	4000.74	4000.75	3012.27	3012.28	3012.26	3012.01	3012.02	4000.07
5	Customer	Customer Cod	Date	Schedule	Determinant	Rate	Refund Rate	Daily Use	EPT HE 01	EPT HE 02	Version
6	1234	PALCO	1/1/2008	9-1: Control Area Administration	RT Load with Losses (MWh)	0.1809	-0.0265	9486.572	401.037	391.597	20080201
7	1234	PALCO	1/1/2008	9-1: Control Area Administration	RT PTP Transmission Use (MWh)	0.1809	-0.0265	75	0	0	20080201
8	1234	PALCO	1/1/2008	9-2: Financial Transmission Rights	Financial Transmission Rights (MW)	0.0027	-0.0003	290124	12088.5	12088.5	20080201
9	1234	PALCO	1/1/2008	9-2: Financial Transmission Rights	FTR Bid Obligations	0.0019	-0.0003	11208			20080201
10	1234	PALCO	1/1/2008	9-2: Financial Transmission Rights	FTR Bid Options X5	0.0019	-0.0003	0			20080201
11	1234	PALCO	1/1/2008	9-3: Market Support	DA Cleared Increment Offers (MWh)	0.0399	-0.0063	9620	405	405	20080201
12	1234	PALCO	1/1/2008	9-3: Market Support	DA Cleared Decrement Bids (MWh)	0.0399	-0.0063	7685	345	318	20080201
13	1234	PALCO	1/1/2008	9-3: Market Support	DA Cleared Up To Congestion Energy (MWh)	0.0399	-0.0063	0	0	0	20080201
14	1234	PALCO	1/1/2008	9-3: Market Support	RT Generation (MWh)	0.0399	-0.0063	121127.4	5116.267	4858.654	20080201
15	1234	PALCO	1/1/2008	9-3: Market Support	RT Load with Losses (MWh)	0.0399	-0.0063	9486.572	401.037	391.597	20080201
16	1234	PALCO	1/1/2008	9-3: Market Support	RT Network Import Use (MWh)	0.0399	-0.0063	75	0	0	20080201
17	1234	PALCO	1/1/2008	9-3: Market Support	RT Spot Import Use (MWh)	0.0399	-0.0063	0	0	0	20080201
18	1234	PALCO	1/1/2008	9-3: Market Support	RT PTP Transmission Use Excluding Wheel-Throughs (MWh)	0.0399	-0.0063	75	0	0	20080201
19	1234	PALCO	1/1/2008	9-3: Market Support	Generation Offer Segments	0.0577	-0.0061	269.4917			20080201
20	1234	PALCO	1/1/2008	9-3: Market Support	DA Market Bid/Offer Segments	0.0577	-0.0061	262			20080201
21	1234	PALCO	1/1/2008	9-4: Regulation and Frequency Response	Regulation Assigned (MWh)	0.2442	-0.0414	2125.771	113.997	78	20080201
22	1234	PALCO	1/1/2008	9-4: Regulation and Frequency Response	Regulation Obligation (MWh)	0.2442	-0.0414	104.9666	4.406	4.713	20080201
23	1234	PALCO	1/1/2008	9-5: Capacity Resource and Obligation Management	Unforced Capacity including FRR (MW)	0.0922	-0.0125	8611			20080201
24	1234	PALCO	1/1/2008	9-5: Capacity Resource and Obligation Management	UCAP Obligation (MW)	0.0922	-0.0125	646.14			20080201
25	1234	PALCO	1/1/2008	9-MMU: Market Monitoring Unit (MMU) Funding	9-3 Energy (MWh)	0.0053		148069	6267.304	5973.251	20080201
26	1234	PALCO	1/1/2008	9-MMU: Market Monitoring Unit (MMU) Funding	9-3 Bid/Offer Segments	0.0054		531.4917			20080201
27	1234	PALCO	1/1/2008	9-FERC: FERC Annual Charge Recovery	RT Load with Losses (MWh)	0.0558		9486.572	401.037	391.597	20080201
28	1234	PALCO	1/1/2008	9-FERC: FERC Annual Charge Recovery	RT PTP Transmission Use (MWh)	0.0558		75	0	0	20080201
29	1234	PALCO	1/1/2008	9-OPSI: Organization of PJM States, Inc Funding	RT Load with Losses (MWh)	0.00063		9486.572	401.037	391.597	20080201
30	1234	PALCO	1/1/2008	9-OPSI: Organization of PJM States, Inc Funding	RT PTP Transmission Use (MWh)	0.00063		75	0	0	20080201
31	1234	PALCO	1/1/2008	10-NERC: North American Electric Reliability Corporation Charge	RT RFC Load with Losses (MWh)	0.0068		9486.572	401.037	391.597	20080201
32	1234	PALCO	1/1/2008	10-RFC: Reliability First Corporation Charge	RT RFC Load with Losses (MWh)	0.0087		9486.572	401.037	391.597	20080201
33	End of Report										

Data Granularity: Daily

Frequency: Updated Daily

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

HE 02 through 23 hidden due to space

Advanced Second Control Center Charge Detail Report

	A	B	C	D	E	F	G	H	I
1	Advanced Second Control Center Charge Details								
2	Customer Ac	PJM Interconnection	Report Creation Timestamp (EPT):	2/28/2009 16:15					
3	Start Month:	November, 2008	End Month:	November, 2008					
4	4000.01	4000.02	4000.03	1306.11	1306.12	1306.13	1306.14	1306.01	4000.07
5	Customer ID	Customer Code	Month	Data Label	Total PJM AC2 Charge ($)	Total Usage	Total PJM Usage	AC2 Charge ($)	Version
6	1234	PALCO	November, 2008	AC2 Schedule 9-1	157916.74	282132.956	58198536.11	765.54	20090201
7	1234	PALCO	November, 2008	AC2 Schedule 9-2a	3554.4	8123472	145901296	197.9	20090201
8	1234	PALCO	November, 2008	AC2 Schedule 9-2b	2284.97	313824	228818496	3.13	20090201
9	1234	PALCO	November, 2008	AC2 Schedule 9-3a	83528.31	4809818.278	141623507.2	2836.79	20090201
10	1234	PALCO	November, 2008	AC2 Schedule 9-3b	1015.54	16462.7676	2067874	8.08	20090201
11	1234	PALCO	November, 2008	AC2 Schedule 9-4	3808.28	60088.27578	1212223.165	188.77	20090201
12	1234	PALCO	November, 2008	AC2 Schedule 9-5	1777.2	259194.06	8728858.88	52.77	20090201
13	End of Report								

- 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)**

1330	Reactive Supply and Voltage Control from Generation and Other Sources Service
2330	Reactive Supply and Voltage Control from Generation and Other Sources Service

Schedule 2 Reactive Supply and Voltage Control from Generation Sources Service

Zone	Generator or Other Source	Annual Reactive Revenue Requirement
AE	Conectiv Energy Supply, Inc.	$ 2,227,336.94
	Pedricktown Plant Holdings, LLC	$ 263,515.20
	RC Cape May Holdings, LLC	$ 2,625,947.86
AEP	AEP East Operating Companies (including Buckeye Power)	$ 32,917,432.81
	Indiana Municipal Power Agency	$ 489,001.00
	Allegheny Energy Supply Company, LLC	$ 257,814.00
	Rolling Hills Generating, LLC	$ 1,100,000.00
	Riverside Generating, LLC	$ 1,702,765.00
	Wolf Hills Energy, LLC	$ 442,023.00
	Big Sandy Peaker Plant, LLC	$ 525,904.00
	Duke Energy Shared Services, Inc. (Hanging Rock/Washington)	$ 4,999,161.22
	DPL Energy, LLC	$ 266,984.64
AP	Allegheny Energy Supply Company, LLC	$ 13,058,598.00
	Armstrong Energy Limited Partnership, LLC	$ 1,435,113.00
	Borough of Chambersburg	$ 137,769.96
	Pleasants Energy, LLC	$ 722,906.00
	Duke Energy Shared Services, Inc. (Fayette)	$ 2,312,572.00
	Monongahela Power Company	$ 3,597,453.00
	Potomac Edison Company	$ 716,596.00
BGE	Constellation Energy Commodities Group, Inc.	$ 8,344,846.00
COMED	Constellation Energy Commodities Group, Inc.	$ 1,200,000.00
	PPL EnergyPlus, LLC (University Park)	$ 1,175,000.00
	Edison Mission Marketing and Trading, Inc. (Midwest Generation)	$ 2,295,784.00
	Exelon Generation Company, LLC	$ 11,727,259.00
	Reliant Energy Electric Solutions, LLC (Aurora)	$ 1,490,000.00
	University Park Energy, LLC	$ 543,304.00
	Calumet Energy Team, LLC	$ 300,000.00
	Dynegy Kendall Energy, LLC	$ 1,600,000.00
	Duke Energy Shared Services, Inc. (Lee)	$ 1,500,000.00
	State Line Energy, LLC (Dominion Energy Marketing, Inc.)	$ 1,625,886.00
	Ameren Energy Generating Company (Elgin Energy Center)	$ 940,448.00
DAYTON	The Dayton Power & Light Company	$ 6,692,774.40
	DPL Energy, LLC	$ 963,596.12
	AEP East Operating Companies	$ 1,238,809.00
DELMARVA	NRG Power Marketing LLC	$ 2,642,338.00
	Conectiv Energy Supply, Inc. (Commonwealth Chesapeake)	$ 1,270,890.00
	Conectiv Energy Supply, Inc.	$ 3,756,981.00
	Delaware Municipal Electric Corporation	$ 356,186.00
	Easton Utilities Commission	$ 585,166.81
	City of Dover, DE	***$ 353,611.00***
DOM	Dominion Virginia Power	$ 27,500,000.00
	Shell Energy North America (US), LP	$ 1,385,697.27
	FPL Energy Power Marketing, Inc.	$ 268,439.38
	Old Dominion Electric Cooperative	$ 2,665,003.00
	Northern Virginia Electric Cooperative	$ 1,247,348.00
JCPL	Jersey Central Power & Light Company	$ 177,909.00
	BE Red Oak, LLC	$ 2,546,801.00
	Exelon Generation Company, LLC	$ 1,662,126.00
	FPL Energy Power Marketing, Inc.	$ 515,328.63
	ConEdison Energy, Inc. (Ocean Peaking Power)	$ 952,555.00
	Reliant Energy Electric Solutions, LLC	$ 864,715.45
METED	***Olympus Power, LLC (York Haven)***	$ 20,522.04
	Exelon Generation Company, LLC	$ 794,349.96
	York Generation Company, LLC	$ 313,367.38
	Reliant Energy Electric Solutions, LLC (Hunterstown)	$ 2,027,682.72
	Reliant Energy Electric Solutions, LLC	$ 1,223,751.00
	Ontelaunee Power Operating Company, LLC (Calpine)	$ 1,176,051.61
	PPL EnergyPlus, LLC	$ 2,476,042.00
PECO	Old Dominion Electric Cooperative	$ 654,639.00
	Exelon Generation Company, LLC	$ 8,695,200.00
	FPL Energy Power Marketing, Inc.	$ 393,182.49
	ConEdison Energy, Inc. (Rock Springs)	$ 766,570.00
	Fairless Energy, LLC (Dominion Energy Marketing, Inc.)	$ 3,146,913.73
	Merrill Lynch Commodities, Inc. (Liberty)	$ 2,222,472.57
	FPL Energy Marcus Hook, L.P.	$ 1,500,000.00
PENELEC	Allegheny Electric Cooperative, Inc.	$ 21,416.00
	Exelon Generation Company, LLC	$ 316,128.00
	Constellation Energy Commodities Group, Inc. (Handsome Lake)	$ 370,304.00
	FirstEnergy Solutions Corp.	$ 47,432.00
	Edison Mission Marketing and Trading, Inc.	$ 1,159,211.00
	Reliant Energy Electric Solutions, LLC (Seward)	$ 1,142,355.58
	Reliant Energy Electric Solutions, LLC	$ 266,844.36
	Brookfield Power Piney & Deep Creek LLC	$ 152,531.31
PEPCO	Mirant Energy Trading, LLC (Potomac River)	$ 4,733,477.04
	Pepco Energy Services, Inc. (Potomac Power Resources)	$ 721,722.96
	Sempra Energy Trading, LLC (Panda-Brandywine)	$ 912,068.73
PPL	Allegheny Electric Cooperative, Inc.	$ 898,115.00
	Allegheny Energy Supply Company, LLC	$ 178,214.00
	PPL EnergyPlus, LLC	$ 10,126,303.32
	UGI Development Company	$ 166,724.00
	WPS Westwood Generation, LLC	$ 103,950.00
	Safe Harbor Water Power Corporation	$ 2,149,747.00
	Conectiv Bethlehem, LLC	$ 2,699,389.00
	Corona Power, LLC (Sunbury)	$ 450,000.00
PSEG	PSEG Energy Resources and Trade LLC	$ 26,626,787.00
	Sunoco Power Marketing, LLC (Eagle Point)	$ 480,743.18
	Newmarket Power Company, LLC (Newark Bay)	$ 681,527.35
	Newmarket Power Company, LLC (Camden)	$ 414,545.40
	Newmarket Power Company, LLC (Bayonne)	$ 682,210.14
	York Generation Company LLC (Marcal)	***$ 393,159.00***

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

1378	Reactive Services	2378	Reactive Services

Reactive Services Charge Summary

	A	B	C	D	E	F	G	H	I
1	Reactive Services Charge Summary								
2	Customer Account:	PJM Interconnection	Report Creatio	########					
3	Start Date:	2/1/2009	End Date:	2/1/2009					
4	4000.01	4000.02	4000.04	4000.32	1378.11	3000.46	3000.42	1378.01	4000.07
5	Customer ID	Customer Code	Date	Zone	Total Zone Reactive Services Credit ($)	RT Zone Load (MWh)	Total RT Zone Load (MWh)	Reactive Services Charge ($)	Version
6									
7	End of Report								

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

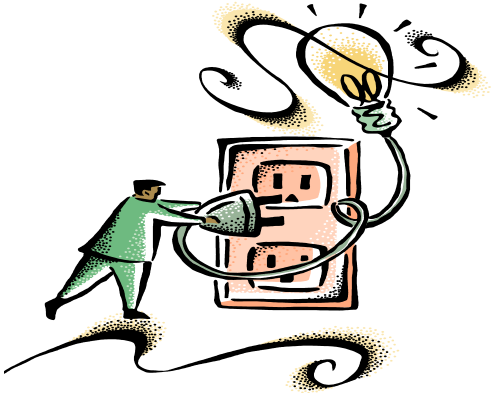
Schedule 6A Black Start Service

- **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

{(Fixed Blackstart Costs) + (Variable Blackstart Costs) + (Training Costs) + (Fuel Storage & Carrying Costs)} * (1 + Incentive Factor)

2380	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

Transmission Zone	Annual Black Start Revenue Requirement
AECO	$430,610.62
AEP	$852,966.20
APS	$157,775.75
BGE	$558,959.41
COMED	$4,292,847.62
DAYTON	$169,569.12
DPL	$452,729.32
DLCO	$30,939.08
JCPL	$506,348.46
METED	$470,786.51
PECO	$842,077.12
PENELEC	$392,336.60
PEPCO	$258,694.28
PPL	$179,589.26
PSEG	$1,098,525.08
PJM TOTAL	**$10,694,754.43**

Effective: January 1, 2010

Black Start Service Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Black Start Charge Summary												
2	Customer .	PJM Interco	Report Creati	#########									
3	Start Mont	January, 20	End Month:	January, 2008									
4	4000.01	4000.02	4000.03	4000.32	1380.11	4000.46	1380.12	1380.13	1380.14	1380.15	1380.16	1380.01	4000.07
5	Customer ID	Customer Code	Month	Zone	Zone Black Start Revenue Requirement ($)	Revenue Requirement Effective Date	Black Start Zone Peak Transmission Use (MW)	Black Start Non-Zone Peak Transmission Use (MW)	Black Start Total Zone Peak Transmission Use (MW)	Black Start Total PJM Zone Peak Transmission Use (MW)	Black Start Total PJM Non-Zone Peak Transmission Use (MW)	Black Start Charge ($)	Version
6	1234	PALCO	Jan-08	EDC ZONE	40635.34	August, 2007	9076.4		81790.4	3702054.1	723442.209	3772.21	20090501
7													
8	End of Report												

Supporting Calculations

- Zones:

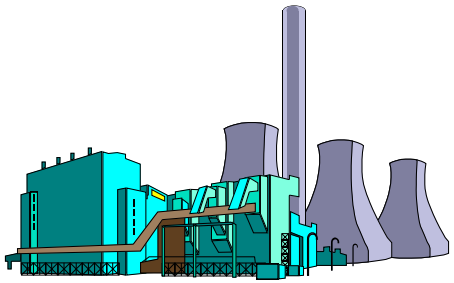
  Black Start Charge (1380.01) = Zone Black Start Revenue Requirement (1380.11) * (Black Start Zone Peak Transmission Use (1380.12) / Black Start Total Zone Peak Transmission Use (1380.14)) * (Black Start Total PJM Zone Peak Transmission Use (1380.15) / (Black Start Total PJM Zone Peak Transmission Use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

- Non-Zones:

  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 Market

- 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.

Regulation Credits

- 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

(RMCP * Adjusted Obligation) +
Share of Opportunity Cost Above RMCP +
Share of Unrecovered Costs

- 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

1340	Regulation and Frequency Response Service

MSRS - Regulation Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Regulation Summary														
2	Customer	PJM Interc	Report Cre	#########											
3	Start Date:	1/31/2008	End Date:	1/31/2008											
4	4000.01	4000.02	4000.05	4000.06	1340.18	1340.19	1340.2	1340.11	1340.12	1340.13	1340.14	3000.57	1340.01	2340.13	2340.14
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Total Assigned Reg (MWh)	RT Load (MWh)	Total PJM RT Load (MWh)	Reg Obligation (MWh)	Bilateral Reg Sales (MWh)	Bilateral Reg Purchases (MWh)	Adjusted Reg Obligation (MWh)	RMCP ($/MWh)	RMCP Charge ($)	PJM-Assigned Reg (MWh)	Self-Scheduled Reg (MWh)
6	End of Report														

	P	Q	R	S	T	U	V
1							
2							
3							
4	1340.15	1340.16	1340.17	1340.02	2340.15	2340.16	4000.07
5	Reg Purchases (MWh)	Total PJM Reg Purchase (MWh)	Total PJM Reg Lost Opportunity Credit ($)	Reg Lost Opportunity Cost Charge ($)	RMCP Credit ($)	Reg Lost Opportunity Cost Credit ($)	Version

Data Granularity: Hourly

Frequency: Updated daily

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)

MSRS - Regulation Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	Regulation Credits													
2	Customer .	PJM Interc	Report Cre	#########										
3	Start Date:	1/31/2008	End Date:	1/31/2008										
4	4000.01	4000.02	4000.05	4000.06	4000.63	4000.64	3000.8	2340.17	2340.18	3000.57	2340.19	2340.2	3000.35	3000.25
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Unit ID	Unit Name	Unit Ownership Share	PJM-Assigned Reg (MWh)	Self-Scheduled Reg (MWh)	RMCP ($/MWh)	RMCP Credit ($)	Bias Factor	RT LMP Desired MWh	RT Generator LMP ($/MWh)
6	End of Report													

	O	P	Q	R	S	T
1						
2						
3						
4	4000.67	2340.21	2340.22	2340.23	2340.24	4000.07
5	Hydro Spill Indicator	Reg Offer Price ($/MWh)	Reg Offer Amount ($)	Regulation Lost Opportunity Cost ($)	Regulation Lost Opportunity Cost Credit ($)	Version

Data Granularity: Hourly

Frequency: Updated daily

Supporting Calculations

RMCP Credit (2340.19) = (PJM-Assigned Reg (2340.17) + Self-Scheduled Reg (2304.18)) * RMCP (3000.57)

Reg Offer Amount (2340.22) = PJM-Assigned Reg (2340.17) * Reg Offer Price (2340.21)

Regulation Lost Opportunity Cost Credit (2340.24) = MAX((Regulation Lost Opportunity Cost (2340.23) + Reg Offer Amount (2340.22) - (PJM-Assigned Reg (2340.17) * RMCP (3000.57)), 0)

Day-ahead Scheduling Reserve

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

1365	Day-ahead Scheduling Reserve

2365	Day-ahead Scheduling Reserve

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

MSRS Day-ahead Scheduling Reserve Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	Day-Ahead	Scheduling	Reserve Summary															
2	Customer	PJM Interc	Report Creation	###########														
3	Start Date:	7/1/2009	End Date:	7/31/2009														
4	4000.01	4000.02	4000.05	4000.06	1365.11	1365.12	1365.13	1365.14	1365.15	1365.16	1365.17	1365.18	1365.19	1365.01	2365.18	2365.19	2365.2	4000.07
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Total PJM Cleared DASR MWh	RT Load (MWh)	Total PJM RT Load (MWh)	DASR Obligation (MWh)	Bilateral DASR Sales (MWh)	Bilateral DASR Purchases (MWh)	Adjusted DASR Obligation (MWh)	Total PJM DASR Adjusted Obligation (MWh)	Total PJM DASR Credits ($)	DASR Charge ($)	DASRMCP ($/MWh)	Cleared DASR MWh	DASR Credit ($)	Version
249	1234	PALCO	07/01/2009 09	07/01/2009 13	6393.3	267.6089	87225.29	19.615			19.615	6393.3	255.77	0.78	0.04	0	0	20090701
250	1234	PALCO	07/01/2009 10	07/01/2009 14	6396.3	267.4179	85353.24	20.04			20.04	6396.3	255.87	0.8	0.04	0	0	20090701

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

DASR Obligation (1365.14) = Total PJM Cleared DASR MWh (1365.11) * [RT Load (1365.12) / Total PJM RT Load (1365.13)]

Adjusted DASR Obligation (1365.17) = MAX [DASR Obligation (1365.14) + Bilateral DASR Sales (1365.15) – Bilateral DASR Purchases (1365.16)), 0]

DASR Charge (1365.01) = Total PJM DASR Credits (1365.19) * [Adjusted DASR Obligation (1365.17) / Total PJM Adjusted DASR Obligation (1365.18)]

DASR Credit (2365.20) = DASRMCP (2365.18) * Cleared DASR MWh (2365.19)

MSRS Day-ahead Scheduling Reserve Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	Day-Ahead Scheduling Reserve Credits													
2	Customer .	PJM Interc	Report Creation	############										
3	Start Date:	7/1/2009	End Date:	7/31/2009										
4	4000.01	4000.02	4000.05	4000.06	4000.63	4000.64	3000.84	2365.12	2365.13	2365.14	2365.15	2365.16	2365.17	4000.07
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Unit ID	Unit Name	Unit Ownership Share	DASRMCP ($/MWh)	Cleared DASR MWh	DASR Credit ($)	DASR Offer Price ($/MWh)	DASR Opportunity Cost ($)	DASR Operating Reserve Offset ($)	Version
6	1234	PALCO	07/02/2009 07	07/02/2009 11	12345678	KAITLYN 1	0.1234	0	90	0	0	0	0	20090701
7	1234	PALCO	07/02/2009 08	07/02/2009 12	12345678	KAITLYN 1	0.1234	0	90	0	0	0	0	20090701

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

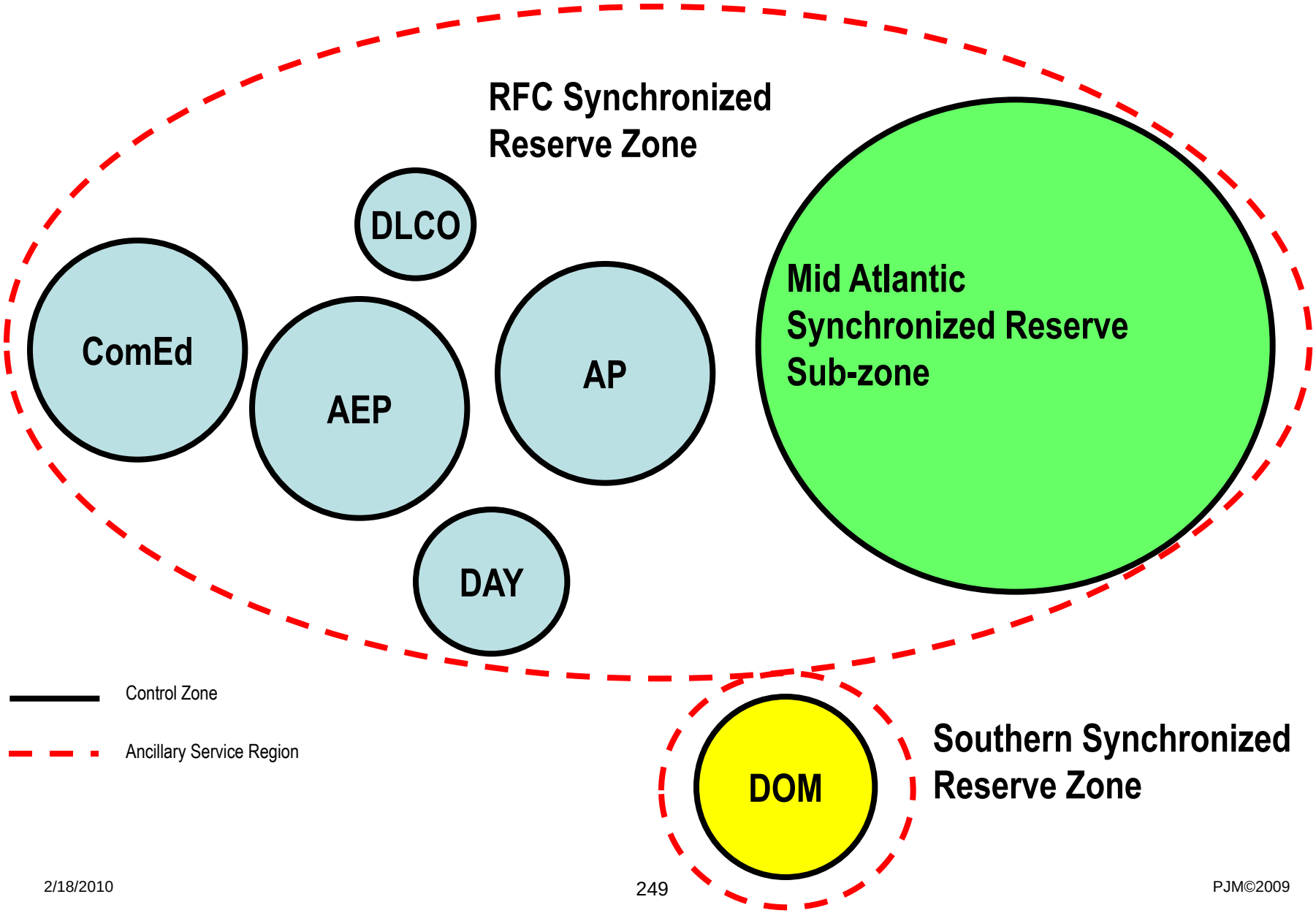
Schedule 5 Synchronized Reserve Service

- 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

Synchronized Reserve Tier 1 and Tier 2 Resources

Tier 1 – Economic	Marginal, partially loaded units - online, following economic dispatch and able to increase output in response to a Spinning event
Tier 2 – Non-economic	Condensers (CTs and hydro), steam reduced to provide spinning, CTs on at min – operating at a point that deviates from economic dispatch

Synchronized Reserve Market Areas



Tier 1 Compensation

- 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

Tier 1 Compensation Example

- **Hourly Integrated LMP = $30**
- **Synchronized Reserve Event LMP = $40**
- **Unit's Integrated MW Increase over the Synchronized Event = 20 MW**

MW Increase

Synchronized $ Adder

Synchronized Event Average LMP

Compensation for Spinning = (20 MW) [($50 + $40) - $30]

= (20 MW) ($60) = $1,200

Hourly LMP

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:
  - (SRMCP)*(Assigned Synchronized Capability)
  - (Synchronized offer)*(Assigned synchronized capability) + (Opportunity Cost in Real time) + (Energy use incurred in Real time) + 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

- 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

Tier 2 Charges

- 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

MSRS – Synchronized Reserve Obligation Details

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	Synchronized Reserve Obligation Details													
2	Customer .	PJM Interc	Report Creatio	############										
3	Start Date:	3/29/2008	End Date:	3/29/2008										
4	4000.01	4000.02	4000.05	4000.06	4000.33	4000.34	1360.21	1360.22	1360.23	1360.32	1360.24	1360.25	1360.26	1360.27
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Synch Reserve Zone	Subzone	Total Subzone Obligation (MWh)	Subzone Load (MWh)	Total Subzone Load (MWh)	Tier 2 Shortfall (MWh)	Synch Reserve Obligation (MWh)	Bilateral Synch Reserve Sales (MWh)	Bilateral Synch Reserve Purchases (MWh)	Adjusted Synch Reserve Obligation (MWh)
6	1234	PALCO	03/29/2008 01	03/29/2008 05	RFC	PJM Mid Atlantic	1512.277	670.5658	24674.84		41.09778			41.09778
7	1234	PALCO	03/29/2008 02	03/29/2008 06	RFC	PJM Mid Atlantic	1646.377	649.2318	23781.37		44.94611			44.94611

4	1360.28	1360.29	1360.33	1360.3	1360.31	1360.12	1360.14	3000.63	1360.15	4000.07
5	Tier 1 Estimate MWh	Remaining Bilateral Adjusted Obligation (MWh)	Total Subzone Remaining Bilateral Adjusted Obligation (MWh)	Total Subzone Tier 1 Excess (MWh)	Obligation Ratio Share of Excess Tier 1 (MWh)	Tier 1 Allocation to Obligation (MWh)	Above Obligation Tier 1 Adjustment (MWh)	Tier 2 Self-Scheduled MWh	Synch Reserve Purchases (MWh)	Version
6	12	29.097782	1436.586	256.4858	5.195073	17.19507	23.902709	143.993	0	20080301
7	12	32.946112	1566.2112	289.0111	6.079508	18.07951	26.866604	143.993	0	20080301

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

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Synchronized Reserve Tier 1 Charge Summary												
2	Customer .	PJM Interc	Report Cre	#########									
3	Start Date:	6/6/2008	End Date:	6/6/2008									
4	4000.01	4000.02	4000.05	4000.06	4000.33	4000.34	4000.36	4000.37	1360.11	1360.12	1360.13	1360.01	4000.07
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Synch Reserve Zone	Subzone	Synch Reserve Event Start Time (EPT)	Synch Reserve Event End Time (EPT)	Total Zone Tier 1 Credit ($)	Tier 1 Allocation to Obligation (MWh)	Total Zone Tier 1 Allocation to Obligation (MWh)	Tier 1 Charge ($)	Version
6	End of Report												

Data Granularity: Hourly

Frequency: Updated daily

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))

MSRS – Synchronized Reserve Tier 2 Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Synchronized Reserve Tier 2 Charge Summary												
2	Customer	PJM Interc	Report Creatio	############									
3	Start Date	3/29/2008	End Date:	3/29/2008									
4	4000.01	4000.02	4000.05	4000.06	4000.3	4000.34	1360.14	3000.61	1360.02	1360.15	1360.16	1360.17	1360.03
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Synch Reserve Zone	Subzone	Above Obligation Tier 1 Adjustment (MWh)	SRMCP ($/MWh)	SRMCP Charge ($)	Synch Reserve Purchases (MWh)	Total Zone Synch Reserve Purchases (MWh)	Total Zone Synch Reserve Lost Opportunity Cost Credit Cleared ($)	Synch Reserve Lost Opportunity Cost Charge Cleared ($)
6	1234	PALCO	03/29/2008 01	03/29/2008 05	RFC	PJM Mid Atlantic	33.7520675	28.88	974.76	0	1436.9392	0	0
7	1234	PALCO	03/29/2008 02	03/29/2008 06	RFC	PJM Mid Atlantic	25.6357516	14.22	364.54	0	1233.8564	724.62	0
8	End of Report												

	O	P	Q	R
1				
2				
3				
4	1360.19	1360.2	1360.04	4000.07
5	Tier 1 Lost (MWh)	Total Zone Tier 1 Lost (MWh)	Synch Reserve Lost Opportunity Cost Charge Added ($)	Version
6	18.367	225.228	0	20080301
7	15.315	159.849	0	20080301

Data Granularity: Hourly

Frequency: Updated daily

MSRS – Synchronized Reserve Tier 2 Charge Summary

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

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Synchronized Reserve Credit Summary												
2	Customer A	PJM Interc	Report Creatio	############									
3	Start Date:	3/29/2008	End Date:	3/29/2008									
4	4000.01	4000.02	4000.05	4000.06	4000.33	4000.34	3000.61	2360.14	2360.15	3000.63	2360.48	2360.16	2360.17
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Synch Reserve Zone	Subzone	SRMCP ($/MWh)	Tier 2 PJM-Scheduled MWh	Tier 2 PJM-Added MWh	Tier 2 Self-Scheduled MWh	Tier 2 Shortfall (MWh)	Tier 1 Credit ($)	SRMCP Credit ($)
6	1234	PALCO	03/29/2008 01	03/29/2008 05	RFC	PJM Mid Atlantic	6	11.999	0	23.998	0	0	215.98
7	1234	PALCO	03/29/2008 02	03/29/2008 06	RFC	PJM Mid Atlantic	6	11.999	0	23.998	0	0	215.98

	N	O	P
1			
2			
3			
4	2360.18	2360.19	4000.07
5	Synch Reserve Lost Opportunity Cost Credit Cleared ($)	Synch Reserve Lost Opportunity Cost Credit Added ($)	Version
6	0	0	20080301
7	0	0	20080301

Data Granularity: Hourly

Frequency: Updated daily

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))

MSRS – Synchronized Reserve Tier 1 Credits

	A	B	C	D	E	F	G	H	I	J	K
1	Synchronized Reserve Tier 1 Credits										
2	Customer .	PJM Interc	Report Creatio	############							
3	Start Date:	3/29/2008	End Date:	3/29/2008							
4	4000.01	4000.02	4000.05	4000.06	4000.63	4000.64	3000.8	4000.36	4000.37	2360.2	2360.21
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Unit ID	Unit Name	Unit Ownership Share	Synch Reserve Event Start Time (EPT)	Synch Reserve Event End Time (EPT)	Tier 1 Synch Reserve Response (MWh)	Synch Reserve Capability (MWh)
6	1234	PALCO	03/29/2008 21	03/30/2008 01	12345678	STEPHEN 01	1	3/29/2008 20:51	3/29/2008 20:59	0.023	0.994

Data Granularity: Hourly

Frequency: Updated daily

	L	M	N	O	P	Q
1						
2						
3						
4	2360.22	2360.23	3000.64	3000.25	2360.24	4000.07
5	Tier 1 Adjustment (MWh)	Tier 1 Credit MWh	Tier 1 Premium Price ($/MWh)	RT Generator LMP ($/MWh)	Tier 1 Credit ($)	Version
6	0	0.023	50	147.79	0	20080301

Supporting Calculations

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

MSRS – Synchronized Reserve Tier 2 Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	Synchronized Reserve Tier 2 Credits													
2	Customer	PJM Interc	Report Creatio	############										
3	Start Date	3/29/2008	End Date:	3/29/2008										
4	4000.01	4000.02	4000.05	4000.06	4000.63	4000.64	3000.8	3000.61	2360.25	2360.26	2360.27	2360.28	2360.29	3000.35
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Unit ID	Unit Name	Unit Ownership Share	SRMCP ($/MWh)	Tier 2 PJM-Scheduled MWh	Tier 2 PJM-Added MWh	Tier 2 Self-Scheduled MWh	Tier 2 Shortfall (MWh)	SRMCP Credit ($)	RT LMP Desired MWh
6	1234	PALCO	03/29/2008 01	03/29/2008 05	87654321	DAVIDC 02	0.3333	8.62	36	0	72	0	930.96	0

	O	P	Q	R	S	T	U	V	W	X
1										
2										
3										
4	3000.25	4000.67	2360.3	2360.31	2360.32	2360.33	2360.34	2360.35	2360.36	4000.07
5	RT Generator LMP ($/MWh)	Hydro Spill Indicator	Condenser Energy Use (MWh)	Condenser Energy Use Cost ($)	Synch Reserve Lost Opportunity Cost ($)	Synch Reserve Offer Amount ($)	Condenser Start Up Cost ($)	Synch Reserve Lost Opportunity Cost Credit Cleared ($)	Synch Reserve Lost Opportunity Cost Credit Added ($)	Version
6	47.91	N	0	0	0	216	0	0	0	20080301

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-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))))

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

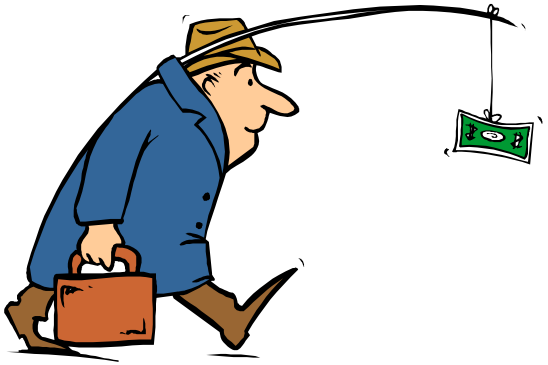
Operating Reserves

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:

  http://www.pjm.com/markets-and-operations/market-settlements/preliminary-billing-reports/ops-rates.aspx

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

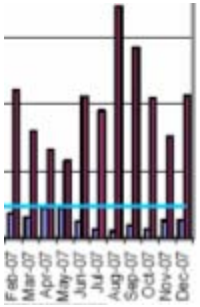
Total Cost:

- Total credit amount paid to generators to supply RT Operating Reserves
- Total "Bucket"

(8)

Rate:

- $ per MW charge that is derived from Total Cost
- Calculated daily
- http://www.pjm.com/markets-and-operations/market-settlements/preliminary-billing-reports/ops-rates.aspx



(6)

Charge:

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

Total Cost ÷ Charge = Rate

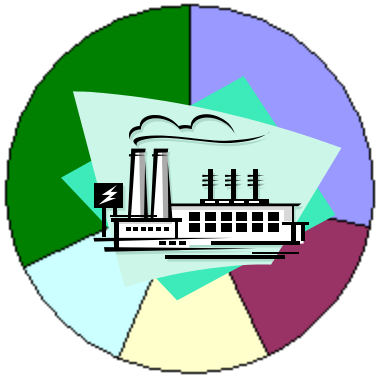
The "Package" of BOR Changes

Business Rule Change	Impact	Description
Segmented Make-Whole Payments	Generator Credits	Segment Make-Whole Payments as a function of the greater of the DA Schedule, or Min Run Time
Minimum Generator Operating Parameters – Parameter Limited Schedules	Generator Credits	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.
Use Ramp-Limited Desired MW to determine deviations	Generator Deviations	PJM will determine whether a generator is following dispatch and calculate the deviation based on a new calculation incorporating ramp limited desired MW
Supplier Netting at the Bus (Plant)	Generator Deviations	Generators that deviate from RT dispatch may offset deviations by another generator at the same bus.
Regional Balancing Operating Reserve Allocation	Charge Allocation	Allocate OR charges that were accrued for local constraints to the regions, creating "regional" rates for Balancing Operating Reserve charges.
Netting (by Zone, Interface, Hub)	Charge Allocation	Demand bucket should be netted locationally by zone, hub, or interface. Supply bucket should be netted locationally by zone, hub, or interface.
Balancing Operating Reserve Cost Allocation	Charge Allocation	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

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

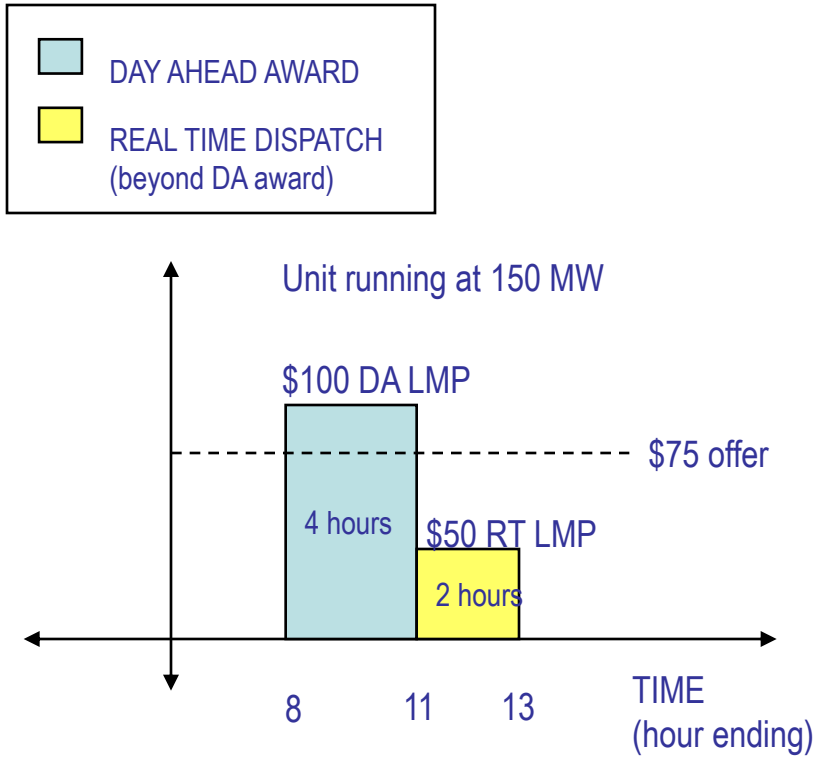
- Start-up costs (and applicable no-load costs) will be in the segment "greater of the DA Schedule or Min Run Time"

- Segmented Make-Whole Payments are an overall benefit to resources

Segmented Make-Whole Payments

Example 1 – Unit Y Extended Beyond DA Schedule

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 = (4hours * $75 * 150MW) = $45,000
- Day Ahead OR Credit: $0
- Balancing OR Credit: $0

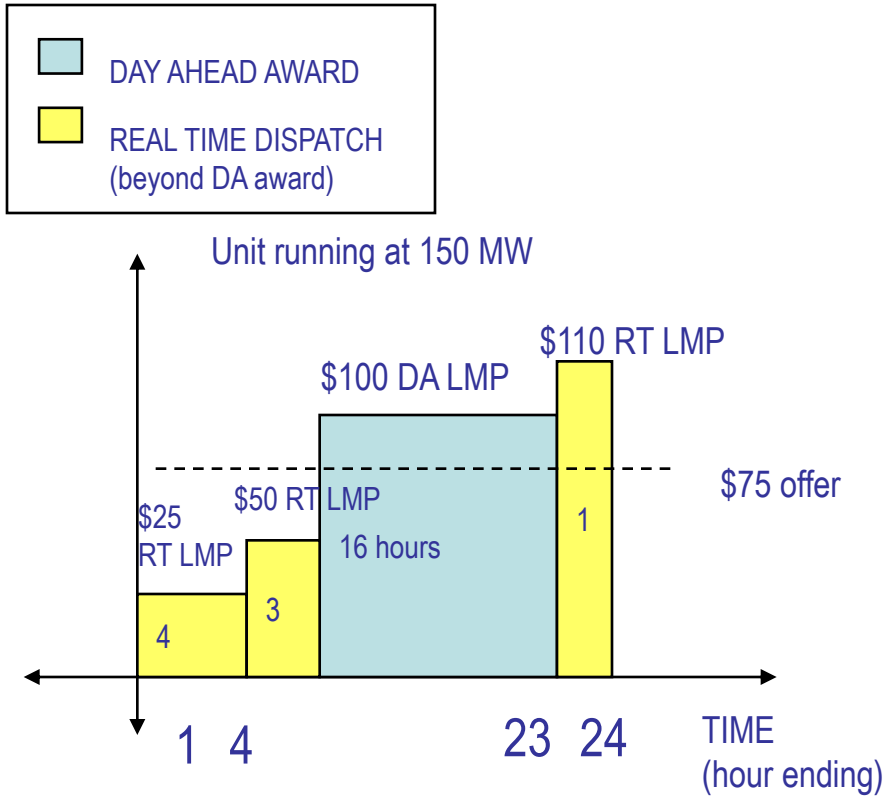
Segment 2: Extended Period

- RT Energy = (2 hours * $50 * 150MW) = $15,000
- RT Offer = (2 hours * $75 * 150MW) = $22,500
- Balancing OR Credit: $7,500

Segmented Make-Whole Payments

Example 2 – Unit Y Extended Before/ After DA Schedule

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 = (16hours * $75 * 150MW) = $180,000
- DA OR Credit: $0
- Balancing OR Credit: $0

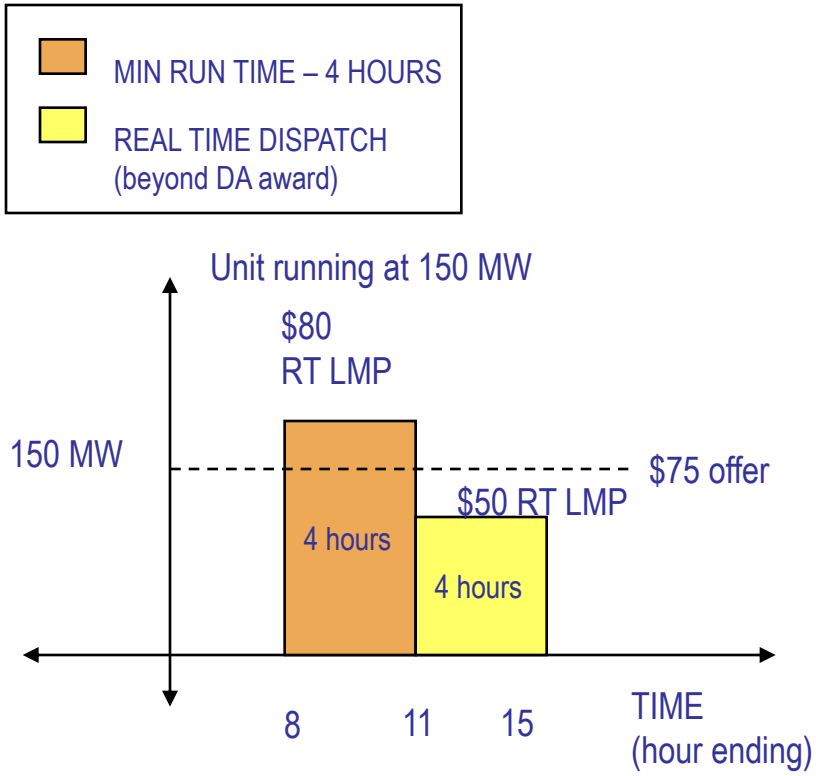
Segment 2: Extended Period

- RT Energy = (4 hours * $25 * 150MW) + (3hours * $50 * 150MW) + (1 hour * $110 * 150 MW) = $54,000
- RT Offer = (8 hours * $75 * 150MW) = $90,000
- Balancing OR Credit: $36,000

Segmented Make-Whole Payments

Example 3 – Unit Y Extended Beyond Min Run Time

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 = (4hours * $75 * 150MW) = 45,000
- Balancing OR Credit: $0

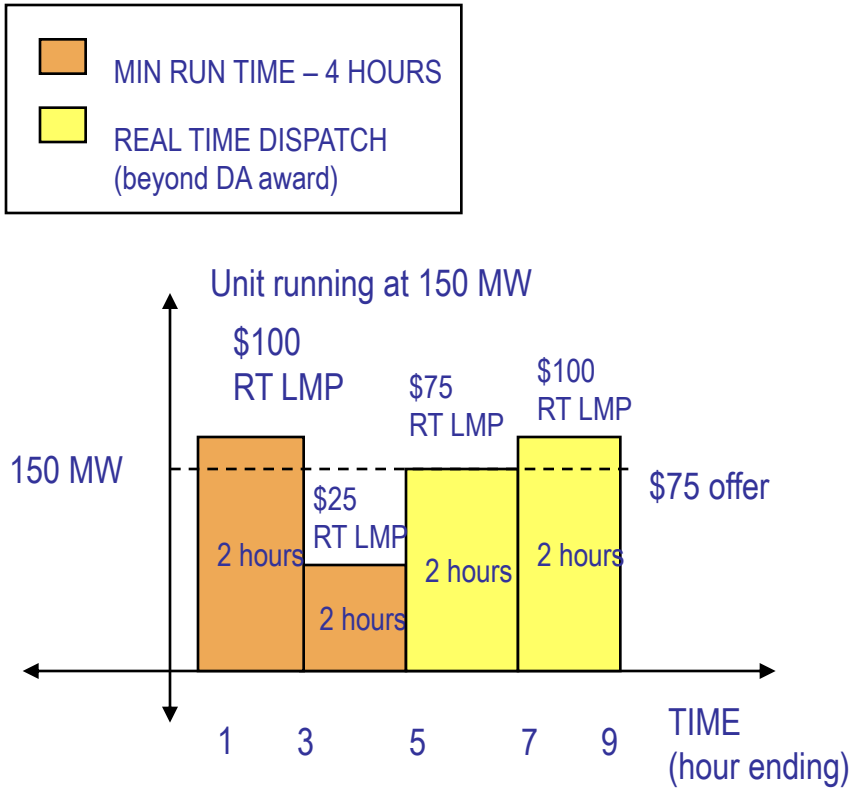
Segment 2: Extended Period

- RT Energy = (4 hours * $50 * 150MW) = $30,000
- RT Offer = (4 hours * $75 * 150MW) = $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 = (4hours * $75 *150MW) = $45,000
- Balancing OR Credit: $7,500

Segment 2: Extended Period

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

Parameter Limited Schedules

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

Potential Operational Scenarios

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.

Ramp Limited Desired MW Calculation for Deviations

- 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

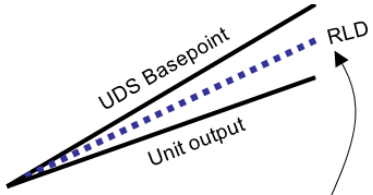
Ramp Limited Desired (RLD) – Getting Started

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



Dotted line represents Ramp-Limited Desired MW

Deviations based on this new line (see previous slide)

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

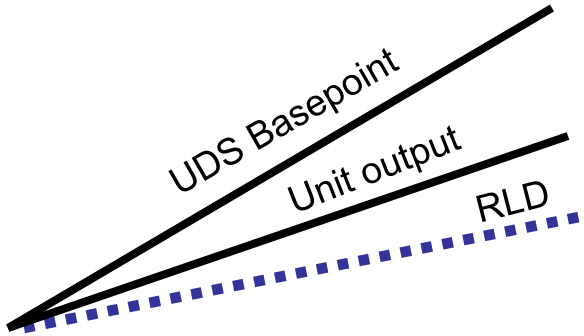
Operating Scenarios with RLD (Example 1)

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.

Unit considered following dispatch

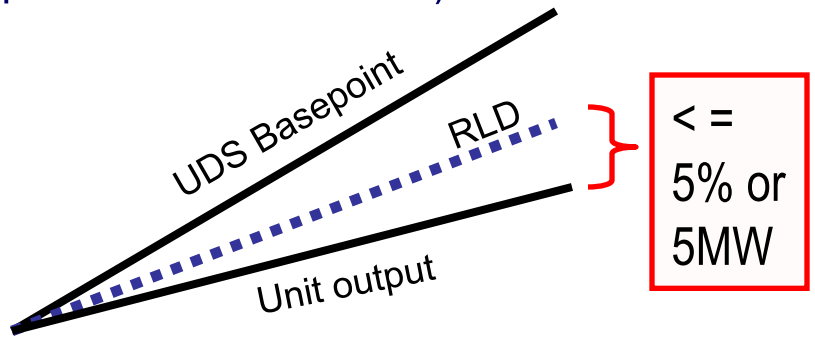
Unit considered following dispatch

(Dotted line represents Ramp-Limited Desired MW)



(or its % Off Dispatch is <= 10)

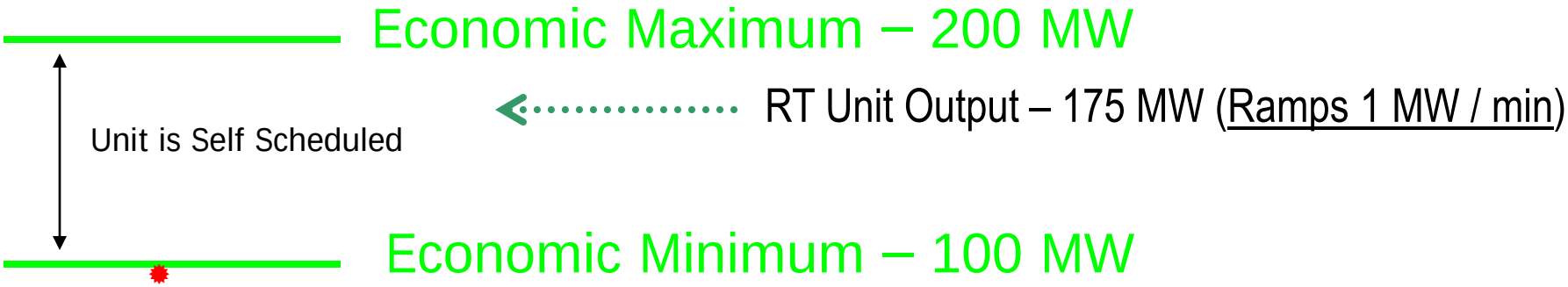
No Deviation Calculation



No Deviation Calculation

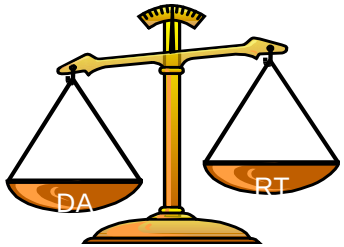
Operating Scenarios with RLD (Example 2)

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|



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

Deviation based on Hourly Integrated RT MWh – Day-Ahead MWh



Operating Scenarios with RLD (Example 3)

BR 41: A unit that is dispatchable Day-Ahead but is Fixed Gen in real-time will have deviations assessed using |hourly integrated Real-time MWh – UDS LMP Desired MW|

DA Economic Maximum – 200 MW

Unit is dispatchable in DA

Fixed Gen in RT

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

DA Economic Minimum – 100 MW

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

Deviation based on RT MWh - UDS LMP Desired

Operating Scenarios with RLD (Example 4)

BR 45 – 46: PJM will calculate a Ramp Limited Desired MW value for units where the economic minimum and economic maximum are at least as far apart in real-time as they are in Day-Ahead (around a 5% or 5 MW bandwidth)
If a unit's real-time economic minimum is greater than its Day Ahead economic minimum by 5% or 5MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5MW, whichever is lower, then deviations for the unit will be calculated as |hourly integrated Real time MWh – UDS LMP Desired MWh|

In Summary:

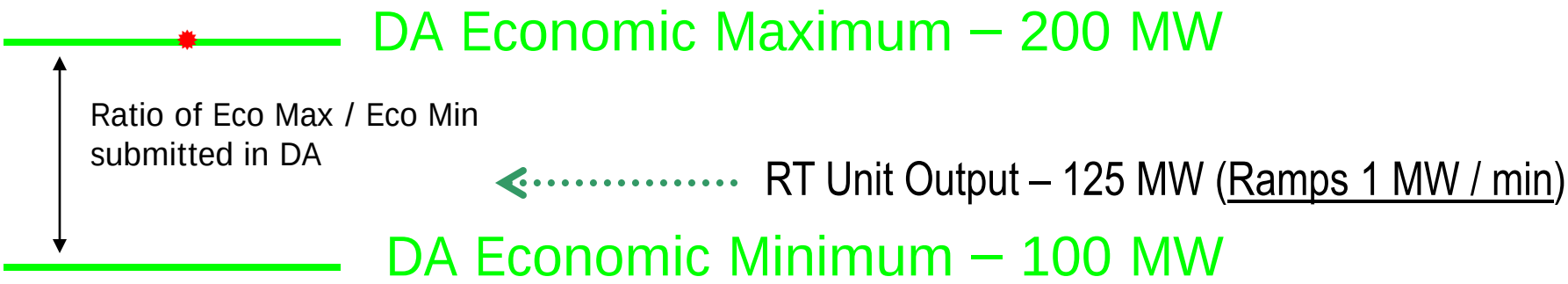
If the Real-Time ratio of Eco Min / Eco Max become more restrictive than what was submitted in the Day-Ahead, then the deviation is calculated as:

Real Time MWh – 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:

Real Time MWh – Ramp Limited Desired MWh

Operating Scenarios with RLD (Example 4 cont.)



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

Operating Scenarios with RLD (Example 5)

BR 48: If the unit is deemed "not following dispatch" and its % Off Dispatch is <= 20%, the deviation will be calculated as the |hourly integrated Real-time Mwh – hourly integrated Ramp Limited Des MW|.

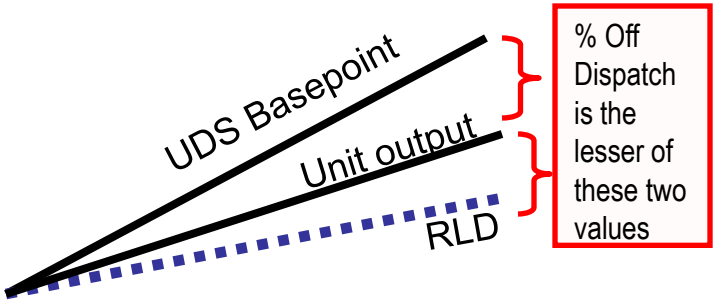
As mentioned earlier, If deviation value is within 5% or 5 MW (whichever is greater) of Ramp Limited Desired MW, no deviations will be calculated

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 |hourly integrated Real time MWh – UDS LMP Desired MWh|

Deviation based on RT MWh – UDS LMP Desired MWh

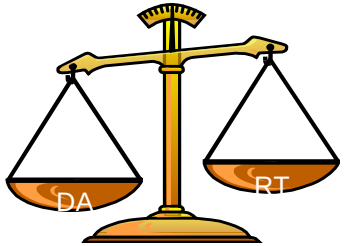
% Off Dispatch – percentage off dispatch using the lesser of the difference between the actual output and the UDS basepoint or the actual output and Ramp Limited Desired MW



Operating Scenarios with RLD (Example 6)

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

Supplier Netting at the Bus

Generators A and B are located at the same bus. Both generators are deemed to be "not following dispatch" for a given hour.

	Station A 138KV ST1	Station A 138KV ST2
RT Desired MW	100	200
RT Output (MW)	112	178
Deviation (MW)	12	-22

Nets to 10 MW

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

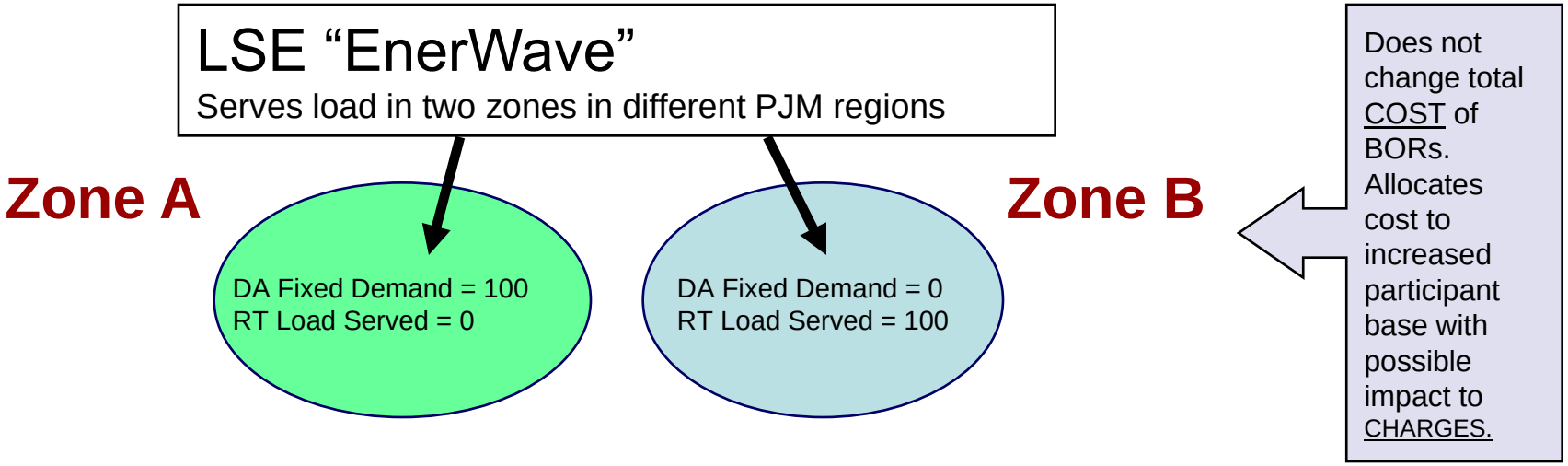
** Note: Ramp Limited Desired MW calculation could also be applicable

Deviation Calculation Buckets

Balancing Operating Reserve Charges Applied to:

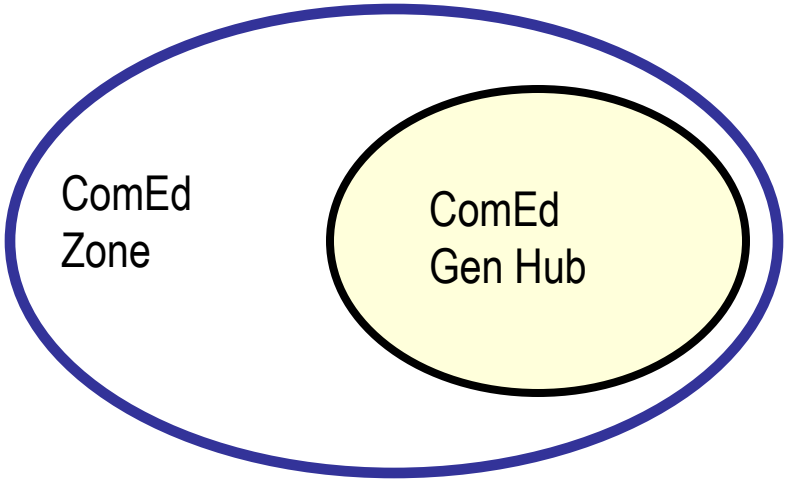
Day-Ahead		Real-Time
	"Bucket 1"	
Cleared Decrements, DA Load, Sales/Export By Zone, by Hub, by Interface	← Net Deviation of total →	RT Load, Sales/Export By Zone, by Hub, by Interface
	"Bucket 2"	
Cleared Increments, Purchases/Imports By Zone, by Hub, by Interface	← Net Deviation of total →	Purchases/Imports By Zone, by Hub, by Interface
	"Bucket 3"	
DA Scheduled Generation	← Individual deviation on each generator not following dispatch →	RT Generation

Netting Deviations - Example

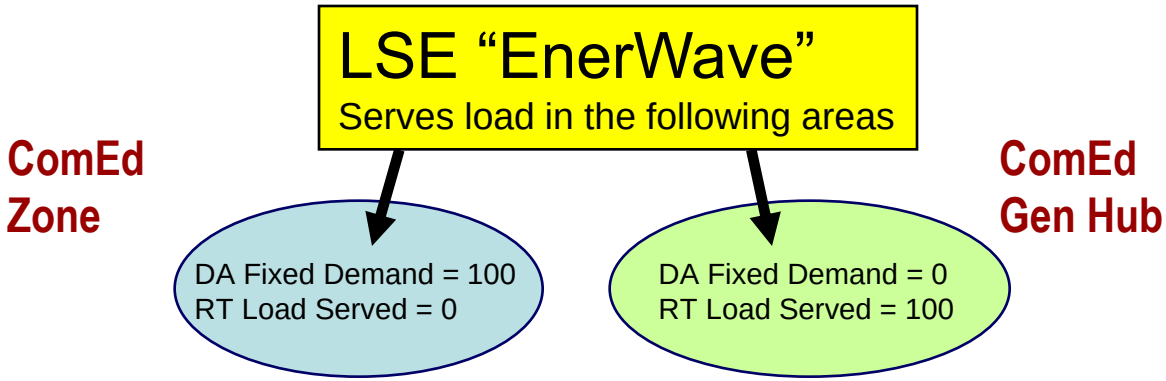


Deviation calculation = 100 (Zone A) + 100 (Zone B) = 200 MW Total Dev

Nested Hubs



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 will should be allocated to real-time load share plus exports.**

Balancing Operating Reserve Cost Allocation (BORCA)

Differentiating the reasons why operators are making decisions into the following categories:

a) Reliability
b) Managing Deviations from DA positions

	Reliability	Managing Deviations
Numerator	Collect system costs (BOR) due to reliability decisions	Collect system costs (BOR) due to changes (deviations) from DA schedules on a System–wide & Local basis
Denominator	RT Load and Exports	All Deviations (Including Incs & Decs)

Balancing Operating Reserve Cost Allocation (BORCA)

Reliability Analysis

1

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

Operating Day (0001 to 2400)

2

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

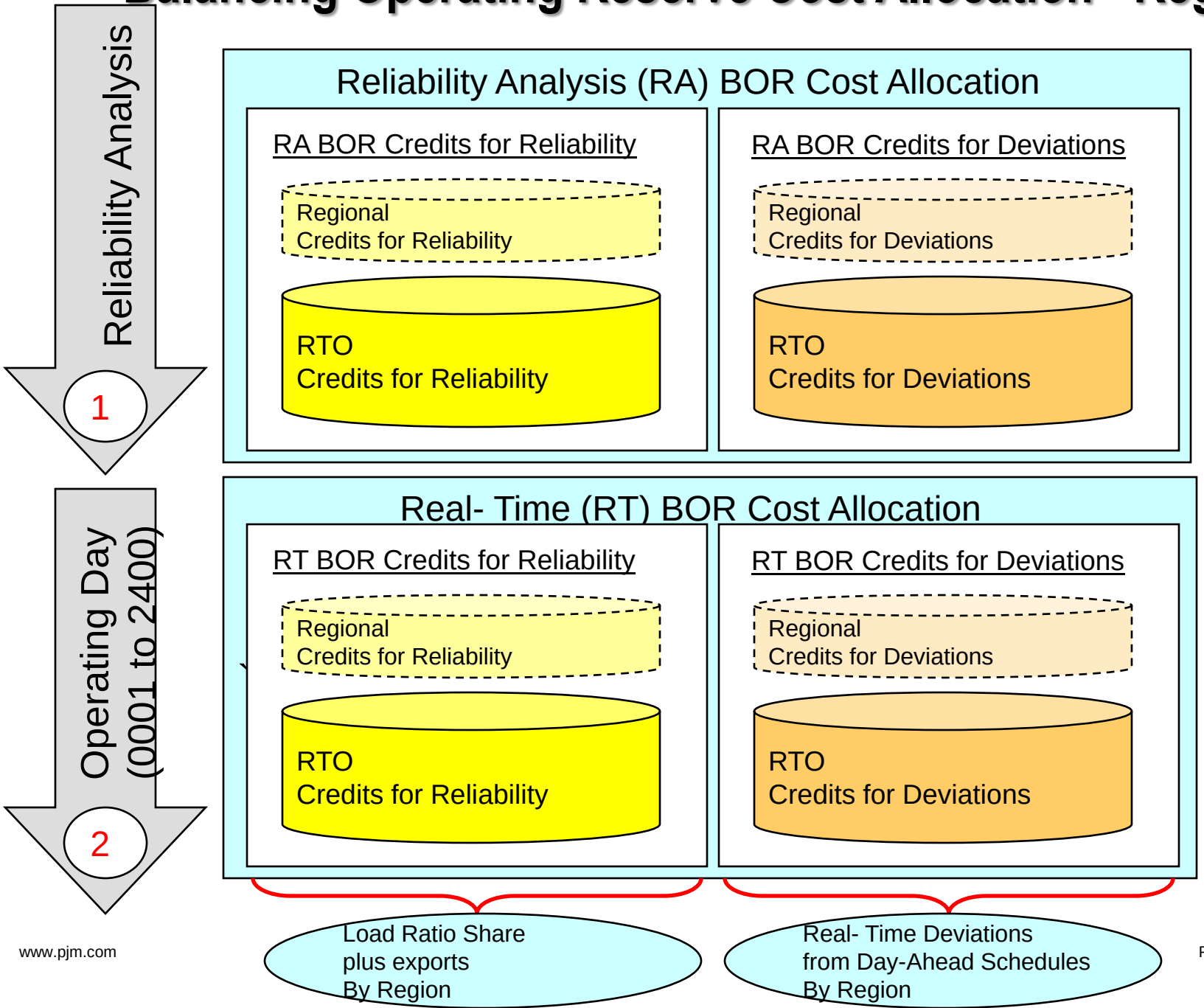
Balancing Operating Reserve Cost Allocation - Regional

- **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.

Balancing Operating Reserve Cost Allocation - Regional

- 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



Allocation for Reliability

BORs for Reliability are allocated by Load Ration Share plus Exports:

Participant's Reliability Allocation (by RTO or Region)

=

Total BORs for Reliability (by RTO or Region)

*

$$\left(\frac{\text{Customer total MWh of energy delivered to load + exports (by RTO or Region)}}{\text{Total PJM MWh of energy delivered to load + exports (by RTO or Region)}} \right)$$

Allocation for Deviations

BORs for Deviations are allocated by participants based on deviations from Day-Ahead scheduled quantities:

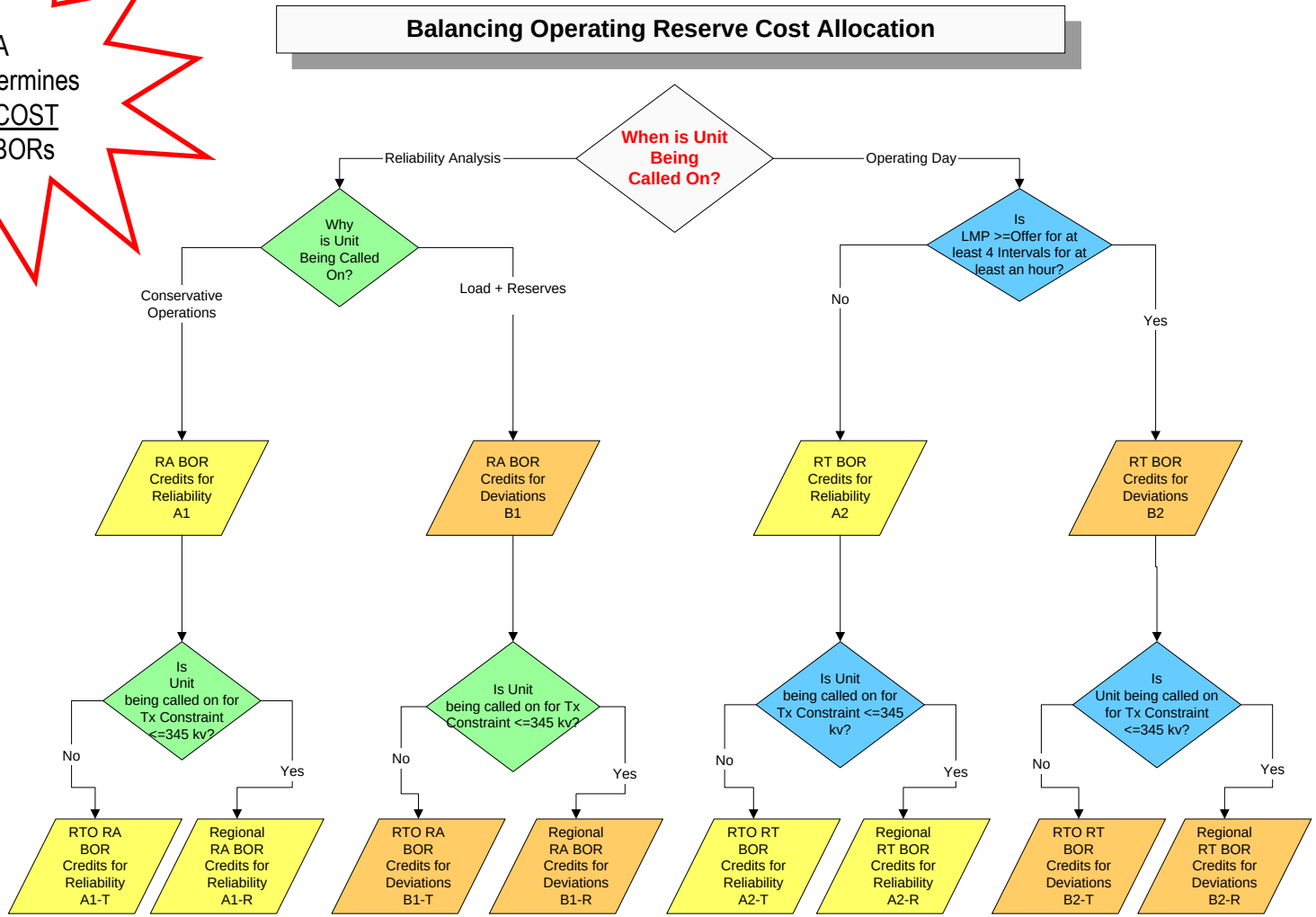
RTO Rate for BORs for Deviations = (Total $ Cost of BORs in RTO for Deviations / Total MW Deviations Across RTO (after netting by zone, hub, interface))

Participants Deviation Allocation = RTO Rate for BORs for Deviations * Total MW Deviations of Participant

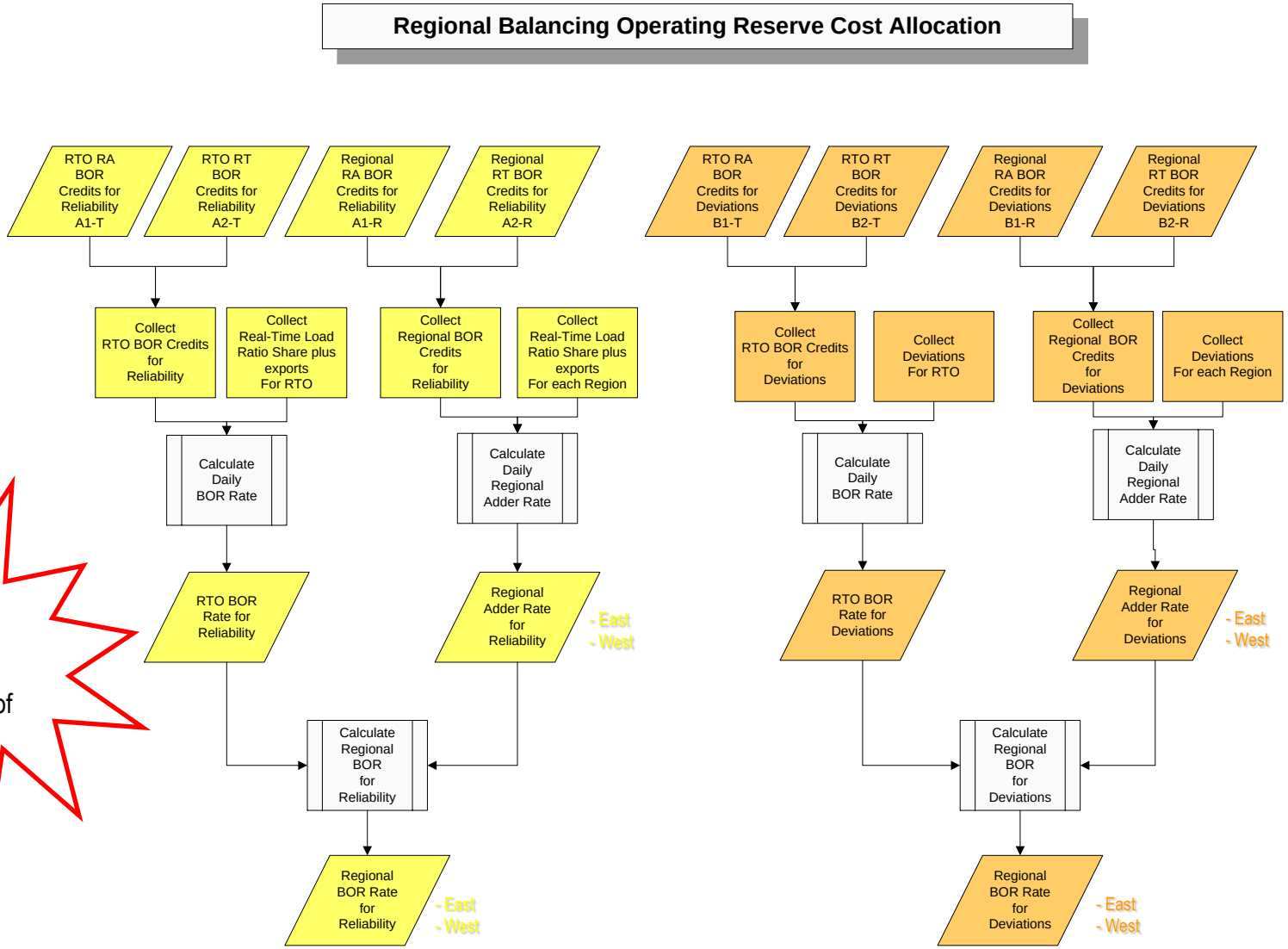
This example shows the calculation for deviations across RTO (not regional)

Balancing Operating Reserve Cost Allocation

This BORCA process determines the TOTAL COST (credits) of BORs

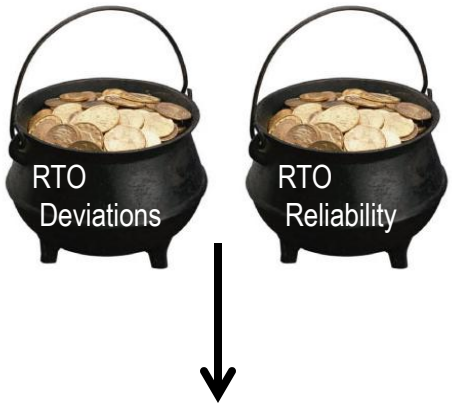


Balancing Operating Reserve Cost Allocation - Regional



This BORCA process determines the ALLOCATION of the total costs

Allocation Methodology



"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

"Reliability" Allocated to real-time load plus exports and "Deviations" allocated to deviations in region

The rate for this bucket will be in the form of an adder to the RTO rate

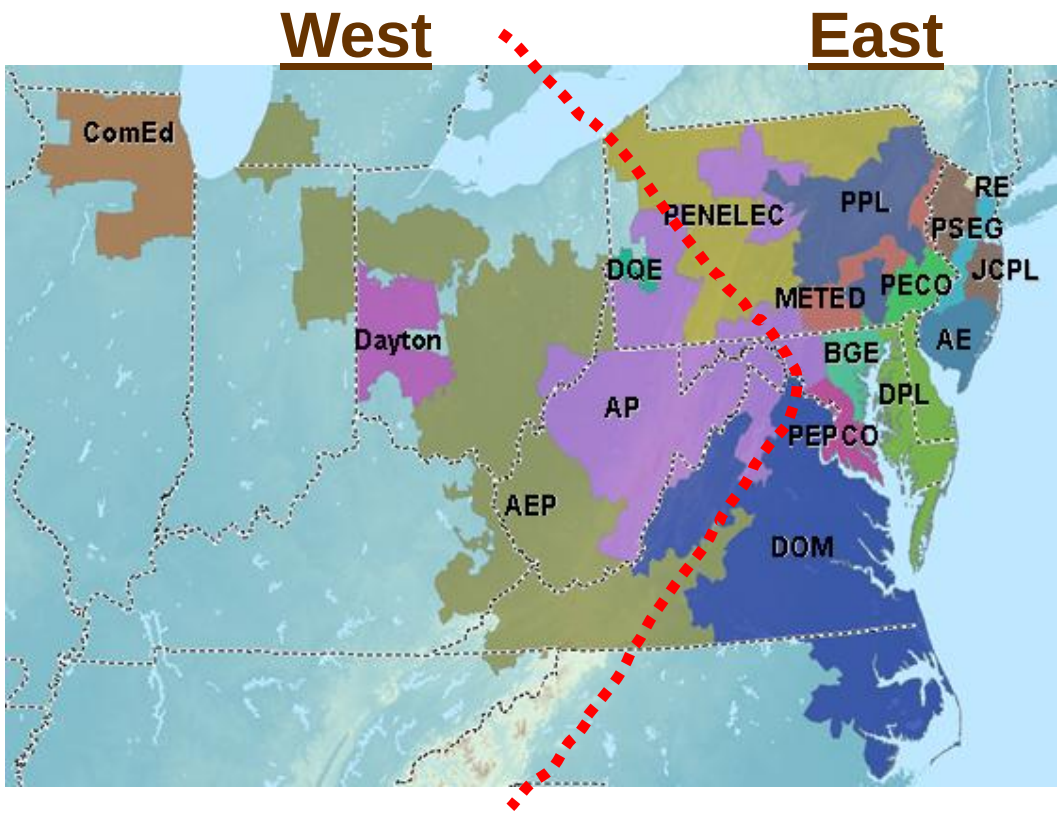
Regional costs allocated regionally

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

Balancing Operating Reserve Regions



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

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

Balancing Operating Reserve Quick Reference

Day-Ahead Operating Reserve Rates	RTO Balancing Operating Reserve Rates		East Balancing Operating Reserve Rates		West Balancing Operating Reserve Rates	
DA Operating Reserve Rate	RTO Bal Operating Reserve for Reliability Rate	RTO Bal Operating Reserve for Deviations Rate	East Bal Operating Reserve for Reliability Rate	East Bal Operating Reserve for Deviations Rate	West Bal Operating Reserve for Reliability Rate	West Bal Operating Reserve for Deviations Rate
$/MWh of cleared DA Demand, Decrements, Load Response, and Exports	$/MWh of RT Load plus Exports	$/MWh of RT Deviations	$/MWh of RT Load plus Exports	$/MWh of RT Deviations	$/MWh of RT Load plus Exports	$/MWh of RT Deviations

East Zones	East Interfaces	West Zones	West Interfaces
BC	CPLEEXP	AEP	IMO
DOM	CPLEIMP	APS	MICHFE
PN	DUKEXP	COMED	MISO
PEP	DUKIMP	DUQ	NIPSCO
ME	NCMPAEXP	DAY	NORTHWEST
PL	NCMPAIMP		
JC	NEPTUNE		
PE	NYIS		
DPL	OVEC		
PS	SOUTHEXP		
RECO	SOUTHIMP		
AE			

- 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

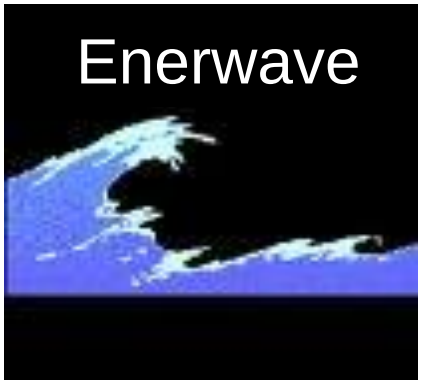
- The Load Ratio Share of Enerwave is:

ComEd – 30%	Western Region – 2%	RTO – 1%	3% Total RTO
BGE – 40%	Eastern Region – 4%	RTO – 2%	

- 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)

RTO Rate for Deviations

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?

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

RTO Rate for Deviations

In BGE:
150MW X $2 = $300 (Load dev)

Total BOR charges for Enerwave
$620 ***

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

Scenario #3 – BOR Cost Allocation (cont)

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

In ComEd:
$200,000 X .01 = $2,000

In BGE:
$200,000 X .02 = $4,000

Load Ratio Share by Zone (totals 3%)

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 X .01 = $1,000

In BGE:
$100,000 X .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 X .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)

Load Ratio Share for Western Region

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

RTO Rate for Reliability: $3 ← Charged for BORs across RTO
Regional Adder for Reliability (West): $1 ← Charged for BORs for CT in AEP
Enerwave's Total Rate for Reliability: $4 ← Enerwave's total charge for all BORs

MSRS Operating Reserve Reports

Operating Reserve

- Generator Credit Summary
- Generator Portfolio Credit Summary (Operating Reserve Credit Summary)
- Operating Reserve Deviation Summary
- Operating Reserve Deviation Summary (pre-12/1/2008)
- Operating Reserve Generator Deviations
- Operating Reserve Generator Deviations (pre-12/1/2008)
- Operating Reserve Generator Credit Details
- Operating Reserve Generator Credit Details (pre-12/1/2008)
- Operating Reserve Charge Summary
- Regional Balancing Operating Reserve Charge Summary
- Operating Reserve for Load Response Charge Summary
- Operating Reserve Lost Opportunity Cost Credits
- Operating Reserve Transaction Credits
- Reactive Services Charge Summary
- Reactive Services Credits
- Synchronous Condensing Charge Summary
- Synchronous Condensing Credits

MSRS Operating Reserve Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Operating Reserve Charge Summary												
2	Customer .	PJM Intercon	Report	6/5/2009 13:42									
3	Start Date:	########	End D:	2/5/2009									
4	4000.01	4000.02	4000	1370.11	3000.37	1370.12	1370.13	1370.01	1375.36	1375.37	1375.01	1375.02	4000.07
5	Customer ID	Customer Code	Date	Total PJM DA Operating Reserve Credit ($)	DA Load (MWh)	DA Operating Reserve Exports (MWh)	Total PJM DA Load Plus Exports (MWh)	DA Operating Reserve Charge ($)	Bal Operating Reserve for Reliability Charge ($)	Bal Operating Reserve for Deviations Charge ($)	Bal Operating Reserve Charge ($)	Bal Operating Reserve Local Constraint Charge ($)	Version
6													
7	End of Report												

Data Granularity: Daily

Frequency: Updated daily

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

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Generator Credit Summary															
2	Customer :	PJM Interc	Report Cre	########												
3	Start Date:	########	End Date:	########												
4	4000.01	4000.02	4000.04	4000.63	4000.64	3000.8	2370.11	2375.11	2375.12	2375.13	2377.11	2377.12	2378.11	2378.12	2378.13	2378.14
5	Customer ID	Customer Code	Date	Unit ID	Unit Name	Unit Ownership Share	DA Operating Reserve Generator Credit ($)	Bal Operating Reserve Generator Credit ($)	Bal Operating Reserve Startup Cancellation Credit ($)	Bal Operating Reserve Lost Opportunity Cost Credit ($)	Synchronous Condensing Credit ($)	Synchronous Condensing Lost Opportunity Cost Credit ($)	Reactive Services Generator Credit ($)	Reactive Services Lost Opportunity Cost Credit ($)	Reactive Services Condensing Credit ($)	Reactive Services Condensing Lost Opportunity Cost Credit ($)
6																
7	End of Report															

Q	R	S	T	U	V	W
2340.11	2340.12	2360.11	2360.12	2360.13	2365.11	4000.07
Reg RMCP Credit ($)	Reg Lost Opportunity Cost Credit ($)	Synch Reserve Tier 1 Credit ($)	Synch SRMCP Credit ($)	Synch Reserve Lost Opportunity Cost Credit ($)	DASR Credit ($)	Version

Data Granularity: Daily

Frequency: Updated daily

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 and Day-ahead Scheduling Reserve Credits.

MSRS Operating Reserve Deviation Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	Operating Reserve Deviation Summary																		
2	Customer .	PJM Interc	Report Cre	########															
3	Start Date:	6/5/2009	End Date:	6/5/2009															
4	4000.01	4000.02	4000.05	4000.06	4000.77	4000.78	4000.79	4000.8	1365.16	1365.17	1365.18	1365.19	1365.2	1375.21	1375.22	1375.23	1375.24	1375.25	1375.26
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Bal Operating Reserve Location Name	Bal Operating Reserve Location ID	Location Type	Bal Operating Reserve Region Name	DA Increment Offers (MWh)	DA Operating Reserve Imports (MWh)	DA Internal Bilateral Purchases (MWh)	DA Operating Reserve Injection (MWh)	RT Operating Reserve Imports (MWh)	RT Internal Bilateral Purchases (MWh)	RT Operating Reserve Injection (MWh)	Operating Reserve Injection Deviation (MWh)	DA Decrement Bids (MWh)	DA Demand Bids (MWh)	DA Load Response Bids (MWh)
6																			
7	End of Report																		

T	U	V	W	X	Y	Z	AA	AB	AC	AD
1375.27	1375.28	1375.29	3000.38	1375.3	1375.31	1375.32	1375.33	1375.34	1375.35	4000.07
DA Operating Reserve Exports (MWh)	DA Internal Bilateral Sales (MWh)	DA Operating Reserve Withdrawal (MWh)	RT Load (MWh)	RT Operating Reserve Exports (MWh)	RT Internal Bilateral Sales (MWh)	RT Operating Reserve Withdrawal (MWh)	Operating Reserve Withdrawal Deviation (MWh)	Operating Reserve Generator Deviation (MWh)	Locational Total Deviation	Version

Data Granularity: Hourly

Frequency: Updated daily

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.

MSRS Operating Reserve Deviation Summary

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

	A	B	C	D	E	F	G	H	I	J	K	L
1	Operating Reserve Generator Credit Details											
2	Customer .	PJM Interc	Report Cre	########								
3	Start Date:	######	End Date:	#######								
4	4000.01	4000.02	4000.04	4000.63	4000.64	3000.8	3014.26	3014.01	3014.02	3014.24	3014.27	4000.07
5	Customer ID	Customer Code	Date	Unit ID	Unit Name	Unit Ownership Share	Data Label	EPT HE 01	EPT HE 02	EPT HE 24	Total	Version
6												
7	End of Report											

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.

Data Granularity: Hourly

Frequency: Updated daily

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

MSRS Operating Reserve Lost Opportunity Cost Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	Operating Reserve Lost Opportunity Cost Credits																	
2	Customer .	PJM Interc	Report Cre	########														
3	Start Date:	####	End Date:	#####														
4	4000.01	4000.02	4000.05	4000.06	4000.63	4000.64	3000.8	4000.65	3000.32	3000.92	3000.24	3000.33	3000.93	3000.25	3000.34	3000.94	3000.95	3000.99
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Unit ID	Unit Name	Unit Ownership Share	Schedule ID	DA Scheduled MWh	Offer at DA MWh ($/MWh)	DA Generator LMP ($/MWh)	RT Generation (MWh)	Offer at RT MWh ($/MWh)	RT Generator LMP ($/MWh)	RT LMP Desired MWh	Reg MWh Adj	Synch Reserve MWh Adj	Offset for Reg High < LMP Desired (MWh)
6	End of Report																	

S	T	U
3000.96	2375.18	4000.07
MWh Reduced	Operating Reserve Lost Opportunity Cost Credit ($)	Version

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:

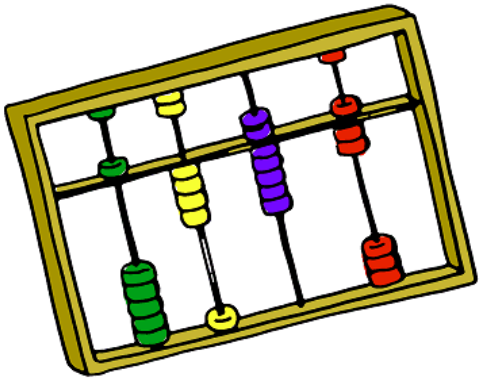
MWh Reduced (3000.96) = 0

Operating Reserve Lost Opportunity Cost Credit (2375.18) = MAX ((RT Generator LMP (3000.25) - DA Generator LMP (3000.24)) * DA Scheduled MWh (3000.32), (RT Generator LMP (3000.25) - Offer at DA MWh (3000.92)) * DA Scheduled MWh (3000.32)), 0)

Else:

MWh Reduced (3000.96) = RT LMP Desired MWh(3000.34) - RT Generation (3000.33) - Reg MWh Adj (3000.94) - Synch Reserve MWh Adj (3000.95) – Reg High < LMP Desired (3000.99)

Operating Reserve Lost Opportunity Cost Credit (2375.18) = MWh Reduced (3000.96) * (max(RT Generator LMP (3000.25) - Offer at RT MWh (3000.93)), 0)



MSRS Operating Reserve Transaction Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Operating Reserve Transaction Credits														
2	Customer .	PJM Interc	Report Cre	#########											
3	Start Date:	####	End Date:	####											
4	4000.01	4000.02	4000.04	4000.09	4000.21	4000.22	3000.75	2370.12	2370.13	2370.14	3000.76	2375.15	2375.16	2375.17	4000.07
5	Customer ID	Customer Code	Date	Transaction ID	Sink PNODE Name	Sink PNODE ID	DA Transaction MWh	DA Offer ($)	DA Revenue ($)	DA Operating Reserve Transaction Credit ($)	RT Transaction MWh	RT Offer ($)	Bal Revenue ($)	Bal Operating Reserve Transaction Credit ($)	Version
6	End of Report														

Data Granularity: Daily

Frequency: Updated daily

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 (2370.14) = MAX (DA Offer (2370.12) - DA Revenue (2370.13), 0)

Bal Operating Reserve Transaction Credit (2375.17) = MAX (RT Offer (2375.15) - Bal Revenue (2375.16) - DA Revenue (2370.13) - DA Operating Reserve Transaction Credit (2370.14), 0)

MSRS Regional Balancing Operating Reserve Charge Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	Regional Balancing Operating Reserve Charge Summary													
2	Customer .	PJM Interc	Report Cre	###########										
3	Start Date:	4/15/2009	End Date:	4/15/2009										
4	4000.01	4000.02	4000.04	1375.38	1375.39	1375.4	1375.41	1375.42	1375.43	1375.44	1375.45	1375.46	1375.47	1375.48
5	Customer ID	Customer Code	Date	Total RTO BalOpRes for Reliability Credit ($)	PJM RT Load plus Exports (MWh)	Total PJM RT Load plus Exports (MWh)	RTO Bal OpRes for Reliability Charge ($)	Total East Bal OpRes for Reliability Credit ($)	East RT Load plus Exports (MWh)	Total East RT Load plus Exports (MWh)	East Bal OpRes for Reliability Charge ($)	Total West Bal OpRes for Reliability Credit ($)	West RT Load plus Exports (MWh)	Total West RT Load plus Exports (MWh)
6	1234	PALCO	4/15/2009	0	12685.48	2191347	0	0	12260.48	1182494	0	0	425	1008853
7	End of Report													

O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
1375.49	1375.5	1375.51	1375.52	1375.53	1375.54	1375.55	1375.56	1375.57	1375.58	1375.59	1375.6	1375.61	4000.07
West Bal OpRes for Reliability Charge ($)	Total RTO Bal OpRes for Deviations Credit ($)	PJM Deviations (MWh)	Total PJM Deviations (MWh)	RTO Bal OpRes for Deviations Charge ($)	Total East Bal OpRes for Deviations Credit ($)	East Deviations (MWh)	Total East Deviations (MWh)	East Bal OpRes for Deviations Charges ($)	Total West Bal OpRes for Deviations Credit ($)	West Deviations (MWh)	Total West Deviations (MWh)	West Bal OpRes for Deviations Charge ($)	Version
0	578445.5	12241.43	515777.6	13728.79	14876.23	11536.43	281934.5	608.72	0	705	233200.1	0	20090401

This report displays the regional components of the customer account's daily balancing operating reserve for reliability charge and balancing operating reserve for deviations charge.

Data Granularity: Daily

Frequency: Updated daily

MSRS Regional Balancing Operating Reserve Charge Summary

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))

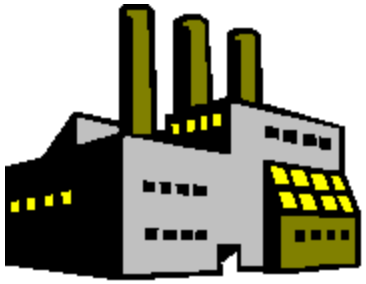
Synchronous Condensing

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

	A	B	C	D	E	F	G	H	I
1	Synchronous Condensing Charge Summary								
2	Customer Acc	PJM Intercor	Report Creati	###########					
3	Start Date:	4/1/2009	End Date:	4/1/2009					
4	4000.01	4000.02	4000.04	1377.11	3000.39	1377.12	1377.13	1377.01	4000.07
5	Customer ID	Customer Code	Date	Total PJM Synchronous Condensing Credit ($)	RT Load (MWh)	RT Operating Reserve Exports (MWh)	Total PJM RT Load plus Operating Reserve Exports (MWh)	Synchronous Condensing Charge ($)	Version
6	End of Report								

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)

MSRS Synchronous Condensing Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Synchronous Condensing Credits												
2	Customer	PJM Interc	Report Cre	########									
3	Start Date:	4/1/2009	End Date:	4/1/2009									
4	4000.01	4000.02	4000.05	4000.06	4000.63	4000.64	3000.8	4000.65	4000.66	2377.13	2377.14	2377.15	3000.25
5	Customer ID	Customer Code	EPT Hour Ending	GMT Hour Ending	Unit ID	Unit Name	Unit Ownership Share	Schedule ID	Reactive Services Indicator	Condensing Duration (Hours)	Condensing Offer ($/hr)	Energy Use (MWh)	RT Generator LMP ($/MWh)
6	End of Report												

N	O	P	Q	R	S	T	U	V	W
2377.16	2377.17	3000.98	3000.33	3000.61	2377.18	2377.19	2378.18	2378.19	4000.07
Offer at RT LMP Desired MWh ($/MWh)	Condensing Start Up Cost ($)	Economic Max (MWh)	RT Generation (MWh)	SRMCP ($/MWh)	Synchronous Condensing Credit ($)	Synchronous Condensing Lost Opportunity Cost Credit ($)	Reactive Services Condensing Credit ($)	Reactive Services Condensing Lost Opportunity Cost Credit ($)	Version

Data Granularity: Daily

Frequency: Updated daily

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.

MSRS Synchronous Condensing Credits

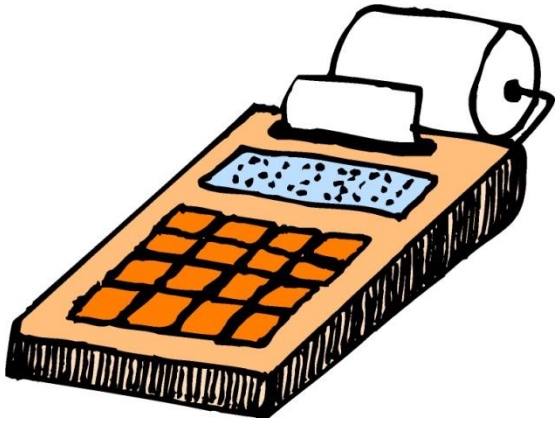
Supporting Calculations

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))

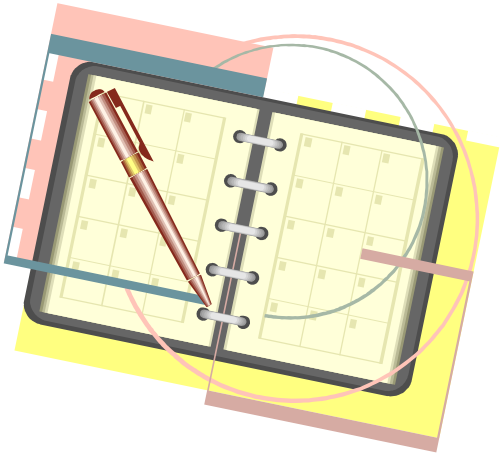
Synchronous Condensing Lost Opportunity Cost Credit (2377.19) = MAX(MAX(Economic Max (3000.98) - MAX(RT Generation MWh (3000.33), 0), 0)) * (MAX(RT Generator LMP (3000.25) - Offer at RT LMP Desired MWh (2377.16), 0)) - Synchronous Condensing Credit (2377.18), 0)

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)



Agenda

- 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?

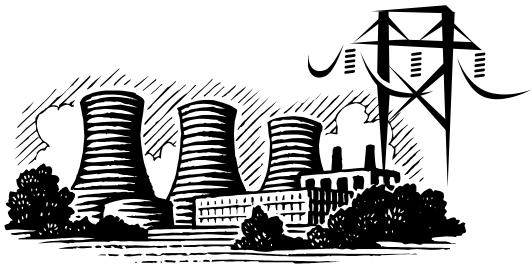
- Reliability Pricing Model (RPM) is PJM's resource adequacy construct
- The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP)
- RPM adds stability and a locational 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

Billing Line Items			Billing Line Items
ID #	CHARGES	ID#	Credits
1600	RPM Auction	2600	RPM Auction
1610	Locational Reliability		
		2620	Interruptible Load for Reliability
		2630	Capacity Transfer Rights
		2640	Incremental Capacity Transfer Rights
1650	Non-Unit Specific Capacity Transaction	2650	Non-Unit Specific Capacity Transaction
1660	Demand Resource and ILR Compliance Penalty	2660	Demand Resource and ILR Compliance Penalty
1661	Capacity Resource Deficiency	2661	Capacity Resource Deficiency
1662	Generation Resource Rating Test Failure	2662	Generation Resource Rating Test Failure
1663	Qualifying Transmission Upgrade Compliance Penalty	2663	Qualifying Transmission Upgrade Compliance Penalty
1664	Peak Season Maintenance Compliance Penalty	2664	Peak Season Maintenance Compliance Penalty
1665	Peak-Hour Period Availability	2665	Peak-Hour Period Availability

Locational Reliability Charges =

Daily Unforced Capacity Obligation in Zone * **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 **<u>for each zone</u>** where the participant has an unforced capacity obligation.

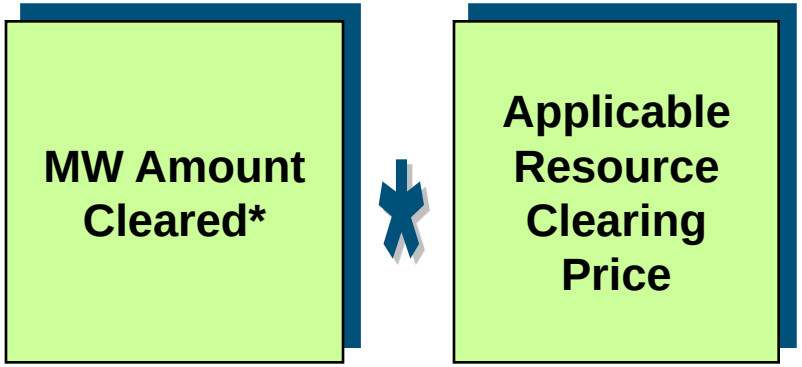
1610	Locational Reliability Charge

RPM Auction 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.

1600	RPM Auction Charge

RPM Auction Credit =



- 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

Capacity Resource Deficiency Charges

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.

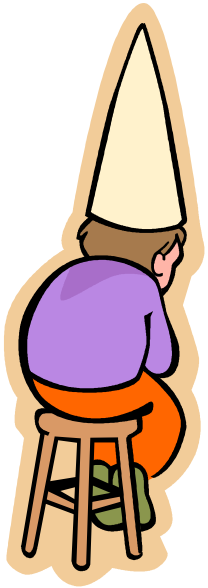
1661	Capacity Resource Deficiency

Allocation of Capacity Resource Deficiency Charges

- 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.

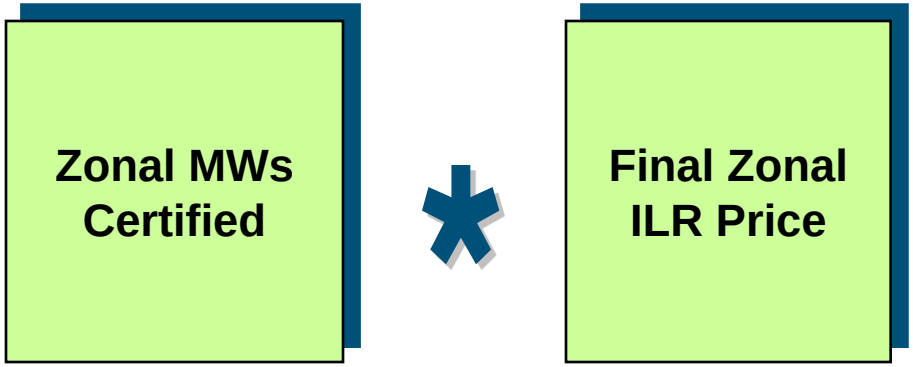
Capacity Resource Deficiency Credit =

$$\text{Total PJM Capacity Deficiency Charge} * \frac{\text{UCAP Obligation}}{\text{Total PJM UCAP Obligation}}$$



2661	Capacity Resource Deficiency

ILR Reliability Credit =



- 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 CapacityTransfer 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**

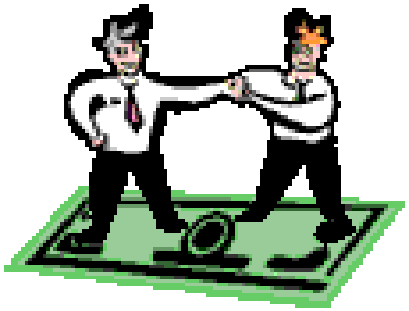
Each incremental CTR owner will receive a daily Incremental CTR Credit

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 =

Transaction Amount * **Price Applicable to Pricing Point**

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 =

Transaction Amount * **Price Applicable to Pricing Point**

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 =

Under-Compliance MW * **LM Compliance Penalty Rate**

- 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 ½ * 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

Load Management Compliance Penalty Credit

Total PJM DR and ILR Compliance Penalty Charge

Calculations are per event

Not to exceed 20% of resource annual revenue

Over Complying Resource

If there are excess dollars

Shared by all LSE's Based on average daily UC Obligation during the month of the event

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 =

Deficiency MW * (**Resource Clearing Price** + **The higher of (.2*RCP or $20)**)

1662	Generation Resource Rating Test Failure

Qualifying Transmission Upgrade Compliance Penalty Charge

- 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 =

Deficiency MW * (**Resource Clearing Price** + **The higher of (.2*RCP or $20)**)

1663	Qualifying Transmission Upgrade Compliance Penalty

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=

Deficiency MW * (**Resource Clearing Price** + **The higher of (.2*RCP or $20)**)

1664	Peak Season Maintenance Compliance Penalty

Generation Resource Rating Test Failure Credit

- 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 =

$$\text{Total PJM Gen Resource Rating Test Failure Charge} * \frac{\text{UCAP Obligation}}{\text{Total PJM UCAP Obligation}}$$

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 =

$$\text{Total PJM Qualifying Transmission Upgrade Charge} * \frac{\text{UCAP Obligation}}{\text{Total PJM UCAP Obligation}}$$

2663	Qualifying Transmission Upgrade Compliance Penalty

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 =

$$\text{Total PJM Peak Season Maintenance Compliance Penalty Charge} * \frac{\text{UCAP Obligation}}{\text{Total PJM UCAP Obligation}}$$

2664	Peak Season Maintenance Compliance Penalty

Deficiency & Penalty Charges

Charge = Rate * MW Amount

Charge	Rate	MW Amount	Assessed	Billed	Allocated
Peak-Hour Period Availability Charge	Daily Peak-Hour Period Availability Charge Rate = RCP + higher of (.2 X RCP or $20)	Net Peak Period Capacity Shortfall for RPM Resource Commitments in LDA	Daily	Retroactively for entire DY in September bill after conclusion of DY	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
	Daily Peak-Hour Period Availability Charge Rate = Weighted average RCP in a LDA	Net Peak Period Capacity Shortfall for FRR Capacity Plan Commitments in LDA			
Capacity Resource Deficiency Charge	Daily Deficiency Rate = RCP + higher of (.2 X RCP or $20)	MW Amount of Shortage	Daily	Monthly during DY	Pro-rata basis to those LSEs who were charged Daily Locational Reliability Charge based on their Daily UCAP Obligation
Qualifying Transmission Upgrade Delay Penalty	QTU Delay Penalty Rate = RCP + higher of (.2 X RCP or $20)	Cleared MW Amount of Incremental Import Capability Not Delivered	Daily	Monthly during DY	Pro-rata basis to those LSEs who were charged Daily Locational Reliability Charge based on their Daily UCAP Obligation

Deficiency & Penalty Charges

Charge = Rate * MW Amount

Charge	Rate	MW Amount	Assessed	Billed	Allocated
Generation Resource Rating Test Failure Charge	Daily Deficiency Rate = RCP + higher of (.2 X RCP or $20)	Daily ICAP Shortfall for RPM Resource Commitments * (1-Effective EFORd)	Daily	Retroactively for entire DY in June bill after conclusion of DY	Pro-rata basis to those LSEs who were charged Daily Locational Reliability Charge based on their Daily UCAP Obligation
	See Attachment A For FRR Calculation	Daily ICAP Shortfall for FRR Capacity Plan Commitments * (1-Effective EFORd)			
PSM Compliance Penalty Charge	Daily Deficiency Rate = RCP + higher of (.2 X RCP or $20)	Daily PSM Shortfall for RPM Resource Commitments * (1-Effective EFORd)	Daily	Retroactively for entire DY in June bill after conclusion of DY	Pro-rata basis to those LSEs who were charged Daily Locational Reliability Charge based on their Daily UCAP Obligation
	See Attachment A For FRR Calculation	Daily PSM Shortfall for FRR Capacity Plan Commitments * (1-Effective EFORd)			
Load Management (DR and ILR) Compliance Charge	LM Compliance Penalty Rate = higher of (1/ #events or ½ * Weighted Annual Revenue Rate)	Net Zonal Under-Compliance MW in a Category	LM Event basis	Third billing month after the LM event occurs	DR & 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.

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

RPM

- 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

MSRS Capacity Transfer Rights Credit Summary

	A	B	C	D	E	F	G	H	I	J	K
1	Capacity Transfer Rights Credit Summary										
2	Customer .	PJM Interc	Report Crea	########							
3	Start Date:	8/1/2009	End Date:	8/31/2009							
4	4000.01	4000.02	4000.04	4000.32	2630.11	3001.23	3001.31	2630.12	2630.13	2630.01	4000.07
5	Customer ID	Customer Code	Date	Zone	CTR MW	UCAP Obligation (MW)	Total Zone UCAP Obligation (MW)	Traded CTR MW	Zonal CTR Rate ($/CTR MW)	CTR Credit ($)	Version
6	1234	PALCO	6/1/2009	EDC	258.8	324.252	8377.505		89.272218	894.23	20091001
7	1234	PALCO	6/2/2009	EDC	258.8	324.252	8377.505		89.272218	894.23	20091001

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)

MSRS Deficiency Credit Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Deficiency Credit Summary															
2	Customer :	PJM Interc	Report Cre	########												
3	Start Date:	8/1/2009	End Date:	8/31/2009												
4	4000.01	4000.02	4000.04	1661.11	1662.11	1663.11	1664.11	2666.11	3001.29	3001.3	2661.01	2662.01	2663.01	2664.01	2666.01	4000.07
5	Customer ID	Customer Code	Date	Total PJM Capacity Resource Deficiency Charge ($)	Total PJM Gen Resource Rating Test Failure Charge ($)	Total PJM Qualifying Transmission Upgrade Compliance Penalty Charge ($)	Total PJM Peak Season Maintenance Compliance Penalty Charge ($)	Total PJM Load Management Test Failure Charge ($)	UCAP Obligation (MW)	Total PJM UCAP Obligation (MW)	Capacity Resource Deficiency Credit ($)	Gen Resource Rating Test Failure Credit ($)	Qualifying Transmission Upgrade Compliance Penalty Credit ($)	Peak Season Maintenance Compliance Penalty Credit ($)	Load Management Test Failure Credit ($)	Version
6	1234	PALCO	6/1/2009	91.83	0	0	0		324.252	133887	0.22	0	0			20091001

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.

MSRS Deficiency Credit Summary

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Deficiency Credit Summary															
2	Customer	PJM Interc	Report Cre	########												
3	Start Date:	8/1/2009	End Date:	8/31/2009												
4	4000.01	4000.02	4000.04	1661.11	1662.11	1663.11	1664.11	2666.11	3001.29	3001.3	2661.01	2662.01	2663.01	2664.01	2666.01	4000.07
5	Customer ID	Customer Code	Date	Total PJM Capacity Resource Deficiency Charge ($)	Total PJM Gen Resource Rating Test Failure Charge ($)	Total PJM Qualifying Transmission Upgrade Compliance Penalty Charge ($)	Total PJM Peak Season Maintenance Compliance Penalty Charge ($)	Total PJM Load Management Test Failure Charge ($)	UCAP Obligation (MW)	Total PJM UCAP Obligation (MW)	Capacity Resource Deficiency Credit ($)	Gen Resource Rating Test Failure Credit ($)	Qualifying Transmission Upgrade Compliance Penalty Credit ($)	Peak Season Maintenance Compliance Penalty Credit ($)	Load Management Test Failure Credit ($)	Version
6	1234	PALCO	6/1/2009	91.83	0	0	0		324.252	133887	0.22	0	0			20091001

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))

MSRS Demand Resource and ILR Compliance Penalty Charges and Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Demand Resource and ILR Compliance Penalty Charges and Credits														
2	Customer	PJM Interc	Report Cre	########											
3	Start Date:	8/1/2009	End Date:	8/31/2009											
4	4000.01	4000.02	4000.04	4001.21	4001.22	4000.32	1660.11	1660.12	1660.01	2660.11	2660.12	2660.13		2660.01	4000.07
5	Customer ID	Customer Code	Date	Resource ID	Resource Name	Zone	DR and ILR Compliance Penalty Rate ($/MW)	Under Compliance (MW)	DR and ILR Compliance Penalty Charge ($)	Total PJM DR and ILR Compliance Penalty Charge ($)	Over Compliance (MW)	Total PJM Over Compliance (MW)	DMD_ILR_EV_CR_RATE	DR and ILR Compliance Penalty Credit ($)	Version
6	End of Report														

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.

MSRS Demand Resource and ILR Compliance Penalty Charges and Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	Demand Resource and ILR Compliance Penalty Charges and Credits														
2	Customer	PJM Interc	Report Cre	########											
3	Start Date:	8/1/2009	End Date:	8/31/2009											
4	4000.01	4000.02	4000.04	4001.21	4001.22	4000.32	1660.11	1660.12	1660.01	2660.11	2660.12	2660.13		2660.01	4000.07
5	Customer ID	Customer Code	Date	Resource ID	Resource Name	Zone	DR and ILR Compliance Penalty Rate ($/MW)	Under Compliance (MW)	DR and ILR Compliance Penalty Charge ($)	Total PJM DR and ILR Compliance Penalty Charge ($)	Over Compliance (MW)	Total PJM Over Compliance (MW)	DMD_ILR_EV_CR_RATE	DR and ILR Compliance Penalty Credit ($)	Version
6	End of Report														

Supporting Calculations

DR and ILR Compliance Penalty Charge[1] (1660.01) = DR and ILR Compliance Charge Penalty Rate (1660.11) * Under Compliance (1660.12)

DR and ILR Compliance Penalty Credit (2660.01) =
MIN(
Total PJM DR and ILR Compliance Penalty Charge (2660.11) * (Over Compliance (2660.12) / Total PJM Over Compliance (2660.13)),
DR and ILR Compliance Credit Penalty Rate (2660.17) * Over Compliance (2660.12)
)

[1]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.

MSRS Interruptible Load for Reliability Credit Summary

	A	B	C	D	E	F	G	H
1	Interruptible Load for Reliability Credit Summary							
2	Customer .	PJM Interc	Report Cre	########				
3	Start Date:	8/1/2009	End Date:	8/31/2009				
4	4000.01	4000.02	4000.04	4000.32	3001.25	2620.11	2620.01	4000.07
5	Customer ID	Customer Code	Date	Zone	ILR MW	Final Zonal ILR Price ($/MW)	ILR Reliability Credit ($)	Version
6	End of Report							

This report displays the account's ILR Credit for each zone where the account's ILR MW is greater than 0 MW.

Supporting Calculations

ILR Reliability Credit (2620.01) = ILR MW (3001.25) * Final Zonal ILR Price (2620.11)

MSRS Locational Reliability Charge Summary

	A	B	C	D	E	F	G	H
1	Locational Reliability Charge Summary							
2	Customer .	PJM Interc	Report Cre	########				
3	Start Date:	8/1/2009	End Date:	8/31/2009				
4	4000.01	4000.02	4000.04	4000.32	3001.23	3001.24	1610.01	4000.07
5	Customer ID	Customer Code	Date	Zone	UCAP Obligation (MW)	Final Zonal Capacity Price ($/MW)	Locational Reliability Charge ($)	Version
6	1234	PALCO	6/1/2009	EDC	324.252	196.5264	63724.17	20091001

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)

MSRS Non-Compliance Charge Summary

	A	B	C	D	E	F	G	H	I	J	K
1	Non-Compliance Charge Summary										
2	Customer .	PJM Interc	Report Cre	########							
3	Start Date:	8/1/2009	End Date:	8/31/2009							
4	4000.01	4000.02	4000.04	4001.21	4001.22	4001.24	3001.26	3001.34	3001.35	3001.28	4000.07
5	Customer ID	Customer Code	Date	Resource ID	Resource Name	Deficiency Type	Deficiency MW	Wtd-Avg Resource Clearing Price ($/MW)	Deficiency Rate	Deficiency Charge ($)	Version
6	End of Report										

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

Deficiency Rate (3001.35) = Wtd-Avg Resource Clearing Price (3001.34) + MAX(0.2 * Wtd-Avg Resource Clearing Price, 20)

Deficiency Charge (3001.28) = Deficiency MW (3001.26) * Deficiency Rate (3001.35)

MSRS RPM Auction Charges and Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	RPM Auction Charges and Credits													
2	Customer .	PJM Interc	Report Cre	########										
3	Start Date:	8/1/2009	End Date:	8/31/2009										
4	4000.01	4000.02	4000.04	4001.25	4001.21	4001.22	4001.23	1600.11	3001.22	1600.01	2600.01	2600.11	2600.02	4000.07
5	Customer ID	Customer Code	Date	RPM Buy Bid ID	Resource ID	Resource Name	RPM Auction	Cleared Capacity (MW)	Capacity Price ($/MW)	RPM Auction Charge ($)	RPM Auction Credit ($)	Make-Whole MW	RPM Auction Make-Whole Credit ($)	Version
8	1234	PALCO	6/1/2009	5432			THIRD	335	86	28810				20091001
9	1234	PALCO	6/1/2009		12345678	KAITLYN 1	BASE	11.8	191.32		2257.58	0	0	20091001

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 that has cleared capacity greater than 0 MW.

Supporting Calculations

RPM Auction Charge (1600.01) = Cleared Capacity (1600.11) * Capacity Price (3001.22) when Buy Bid ID is populated

RPM Auction Charge (2600.01) = Cleared Capacity (1600.11) * Capacity Price (3001.22) when Resource ID is populated

MSRS Non-Unit Specific Capacity Transaction Charges and Credits

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Non-Unit Specific Capacity Transaction Charges and Credits												
2	Customer .	PJM Interc	Report Cre	########									
3	Start Date:	8/1/2009	End Date:	8/31/2009									
4	4000.01	4000.02	4000.04	4001.26	4000.17	4000.18	4001.27	1650.11	1650.12	1650.01	2650.01	4000.07	
5	Customer ID	Customer Code	Date	Non-Unit Specific Capacity Transaction ID	Buyer	Seller	Location	Transaction MW	Transaction Price ($/MW)	Non-Unit Specific Capacity Transaction Charge ($)	Non-Unit Specific Capacity Transaction Credit ($)	Version	
6	1234	PALCO	8/1/2009	1234567	PALCO	OTHER 1	EMAAC_LDA	110	191.32		21045.2	20091001	

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

FTR Auction

- **Charges**
  - Monthly on/off peak charges calculated as:
    - (FTR purchased) * (Applicable FTR Market Price)
- **Credits**
  - Monthly on/off peak credits calculated as:
    - (FTR sold) * (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

1500	Financial Transmission Rights Auction
2500	Financial Transmission Rights Auction

Auction Revenue Rights

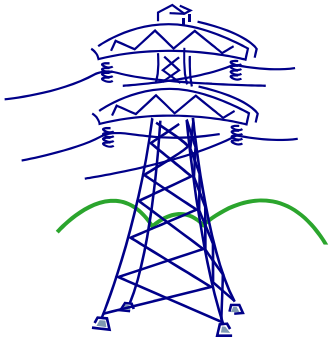
• Auction Revenue Rights (ARRs) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers

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

2510	Auction Revenue Rights



MSRS - ARR Target Credits

	A	B	C	D	E	F	G	H	I	J	K
1	ARR Target Credits										
2	Customer .	PJM Inter(	Report Creation Timestamp (EPT):	7/9/2008 10:40							
3	Start Date:	#########	End Date:	1/31/2008							
4	4000.01	4000.02	4000.04	4000.55	4000.56	4000.32	4000.21	4000.23	3001	2510.11	3000.82
5	Customer ID	Customer Code	Date	ARR ID	ARR Type	Zone	Sink PNODE Name	Source PNODE Name	ARR MW	ARR Rate ($/MW per day)	ARR Ownership Share
6	1234	PALCO	1/31/2008	12345678	Network	AECO	AECO_ZONE	STEPHEN230 KV	25.1	35.969016	1

	L	M	N
1			
2			
3			
4	2510.12	2510.01	4000.07
5	ARR Total Target Credit ($)	ARR Target Credit ($)	Version
6	902.822302	902.822302	20080101

Data Granularity: Daily

Frequency: Updated Daily

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

ARR Reassignment Example

Current ARR Reassignment Methodology

June 10th

ARR 1234 Zone A Customer A = 100% Ownership

Sink Locational Price	Source Locational Price	MW	Annual Value	Daily Value
$70.00	$50.00	20	$400.00	$1.10

ARR 5678 Zone A Customer A = 20% Ownership
Customer E = 80 % Ownership

Sink Locational Price	Source Locational Price	MW	Annual Value	Daily Value
$50.00	$40.00	20	$200.00	$0.55

	Load	Value Calculation NOT PROVIDED IN CURRENT SYSTEM	June 10th Portfolio Value
Customer A	100 MW	($1.10 * 100% + $0.55 * 20%)	$1.21
Customer E	100 MW	($0.55 * 80%)	$ 0.44

ARR Reassignment Example

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

	June 11th Value Calculation NOT PROVIDED IN CURRENT REPORTING SYSTEM	June 11th Portfolio Value
Customer A	80% * $1.21	$0.968
Customer C	25% * $1.21 * 20%	$0.0605
Customer D	75% * $1.21 * 20%	$0.1815
Customer E	100% * $0.44	$0.44

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

	June 10th Load	June 10th Ownership	June 11th Load	Ownership Shift	June 11th Ownership
Customer Account A	100	100%	80	-20%	80%
Customer Account B	100	0%	80	0%	0%
Customer Account C	100	0%	110	5%	5%
Customer Account D	100	0%	130	15%	15%
Customer Account E	100	0%	100	0%	0%
Total	500	100%	500	0%	100%

ARR 5678

	June 10th Load	June 10th Ownership	June 11th Load	Ownership Shift %	June 11th Ownership
Customer Account A	100	20%	80	-4%	16%
Customer Account B	100	0%	80	0%	0%
Customer Account C	100	0%	110	1%	1%
Customer Account D	100	0%	130	3%	3%
Customer Account E	100	80%	100	0%	80%
Total	500	100%	500	0%	100%

ARR Reassignment Example

New ARR Reassignment Methodology:

Portfolio Value Calculation = Ownership % * Daily Value of ARR

June 10th	ARR 1234	ARR 5678	Total June 10th Portfolio Value
Customer Account A	100% * $1.10 = $1.10	20% * $.55 = $0.11	$1.21
Customer Account B	No Ownership	No Ownership	$0.00
Customer Account C	No Ownership	No Ownership	$0.00
Customer Account D	No Ownership	No Ownership	$0.00
Customer Account E	No Ownership	80% * $0.55 = $0.44	$0.44

June 11th	ARR 1234	ARR 5678	Total June 11th Portfolio Value
Customer Account A	80% * $1.10 = $.88	16% * $0.55 = $0.088	$.968
Customer Account B	0% * $ 1.10 = $0.00	0% * $0.55 = $0.00	$0.00
Customer Account C	5% * $ 1.10 = $0.055	1% * $0.55 = $0.0055	$0.0605
Customer Account D	15% * $ 1.10 = $0.165	3% * $0.55 = $0.0165	$0.1815
Customer Account E	0 * $ 1.10 = $0.00	80% * $0.55 = $0.44	$0.44

Emergency Energy Accounting

- PJM may purchase energy from outside PJM as needed to alleviate or end 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.

1260	Emergency Energy

2260	Emergency Energy

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:

Emergency Energy Purchase (MWh) * (Emergency Energy Purchase Price – Real-time Interface LMP)

Emergency Energy Sales By PJM

- 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

    OR
  - 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:

Emergency Energy Sale (MWh) * (Emergency Energy Sale Price – 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:

Min Gen Emergency Energy Purchase (MWh) * (Emergency Energy Purchase Price – 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:

Min Gen Emergency Energy Sale (MWh) * (Emergency Energy Sale Price – 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

MSRS Load Response Summary

4	4000.03	4000.05	4000.06	4000.93	4000.94	4000.95	4000	3001.14	3000.24	1240.11	2240.01	1240.01	1241.11	1241.12	1241.13	3000.83	3001.15	3(
5	Billing Month	EPT Hour Ending	GMT Hour Ending	Registration ID	EDC Account Number	End Use Customer	Zone	DA Load Response MWh	DA LMP ($/MWh)	DA Retail Rate Used ($/MWh)	DA Load Response Credit ($)	DA Load Response Charge ($)	CBL (kWh)	Metered Load (kWh)	Load Response Loss Factor	EDC Loss De-ration Factor	RT Load Response MWh	RT
681	August, 2009	07/28/2009 17	07/28/2009 21	123456	1234567890	Michael Inc	EDC	0					5359.25	4390	1.0345	0.022427	0.98	

	3000.25	1241.14	2241.01	1241.01	4000.07
se MWh	RT LMP ($/MWh)	RT Retail Rate Used ($/MWh)	RT Load Response Credit ($)	RT Load Response Charge ($)	Version
	59.21	37.02	21.74		20090901

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.

MSRS Load Response Summary Calculations

Supporting Calculations

DA Load Response Charge (1240.01) = DA Load Response MWh (3001.14) * MAX (DA LMP (3000.24) - DA Retail Rate Used (1240.11), 0)

DA Load Response Credit (2240.01) = DA Load Response MWh (3001.14) * MAX(DA LMP (3000.24) - DA Retail Rate Used (1240.11), 0)

RT Load Response MWh (3001.15) = Load Response Loss Factor (1241.13) * (1 – EDC Loss De-ration Factor (3000.83)) * ((CBL (1241.11) - Metered Load (1241.12)) / 1000)

If RT Load Response MWh – DA Load Response MWh >= 0,
RT Load Response Charge (1241.01) = (RT Load Response MWh (3001.15) - DA Load Response MWh (3001.14)) * MAX(RT LMP (3000.25) - RT Retail Rate Used (1240.11), 0)

Else, RT Load Response Charge (1241.01) = (RT Load Response MWh (3001.15) - DA Load Response MWh (3001.14)) * (RT LMP (3000.25) - - DA LMP (3000.24)) + RT Load Response MWh (3001.15) * MAX (0, DA LMP (3000.24) – MIN (RT Retail Rate Used (1240.11) - RT LMP (3000.25), 0))

If RT Load Response MWh – DA Load Response MWh >= 0
RT Load Response Credit (2241.01) = (RT Load Response MWh (3001.15) - DA Load Response MWh (3001.14)) * MAX (RT LMP (3000.25) - RT Retail Rate Used (1240.11), 0)

Else,
If RT Load Response MWh – DA Load Response MWh < 0
RT Load Response Credit (2241.01) = (RT Load Response MWh (3001.15) - DA Load Response MWh (3001.14)) * MAX (0, DA LMP (3000.24) – MIN (RT Retail Rate Used (1240.11) - RT LMP (3000.25), 0))

Else, RT Load Response Credit (2241.01) = 0

MSRS Load Response Zonal Charge Allocations

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	Economic Load Response Zonal Charge Allocations															
2	Customer .	PJM Interc	Report Cre	########												
3	Start Mont	August, 20	End Month	August, 2009												
4	4000.01	4000.02	4000.03	4000.05	4000.06	4000.32	1240.12	3001.11	1240.13	1240.02	1241.15	3001.12	3001.13	1241.02	4000.07	
5	Customer ID	Customer Code	Billing Month	EPT Hour Ending	GMT Hour Ending	Zone	Total DA Load Response Zone Charge ($)	DA Demand (MWh)	Total Zone DA Demand (MWh)	DA Load Response Charge Allocation ($)	Total RT Load Response Zone Charge ($)	RT Load (MWh)	Total Zone RT Load (MWh)	RT Load Response Charge Allocation ($)	Version	
6	End of Report															

This report display's 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))

- **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**

1720	RTO Start-up Cost Recovery
2720	RTO Start-up Cost Recovery

- **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**

1720	RTO Start-up Cost Recovery
2720	RTO Start-up Cost Recovery

• 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

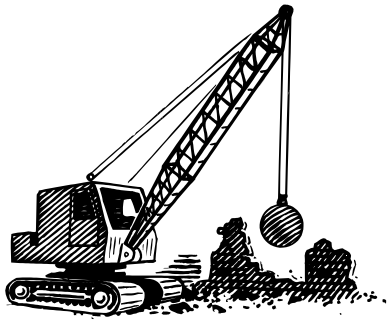
1730	Expansion Cost Recovery
2730	Expansion Cost Recovery

• 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

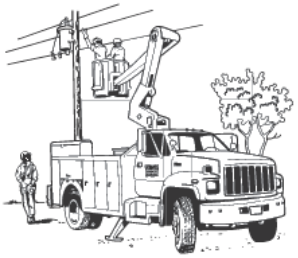
1930	Generation Deactivation
2930	Generation Deactivation



• 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

1108	Transmission Enhancement
2108	Transmission Enhancement



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.

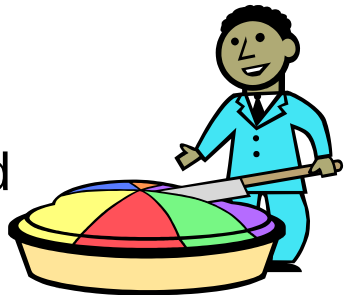
Billing Line Items related to Default Supplier Load MWh

- 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 <u>not</u> 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.

Default Supplier Allocations on RT Transactions Report

- 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																
Customer Account:	EDC A, LLC	Report Creation Timestamp (EPT):	02/05/2008	9:56:48 AM												
Start Date:	2/1/2008	End Date:	2/1/2008													
Customer ID	Customer Code	Date	Transaction Type	Transaction ID	NERC Tag	OASIS ID	EPT HE 01	EPT HE 02	EPT HE 02*	EPT HE 03	Source PNODE Name	Source PNODE ID	Sink PNODE Name	Sink PNODE ID	Seller	Buyer
101	EDCA	2/1/2008	Retail Load Responsibility	57149			-40	-40	0	-40	ZONEA	100	ZONEA	100	COMPB	EDCA
101	EDCA	2/1/2008	Retail Load Responsibility	65787			-50	-50	0	-50	ZONEA	100	ZONEA	100	COMPA	EDCA
101	EDCA	2/1/2008	Adjusted Net Metered Interchange				100.254	99.378	0	102.578						
101	EDCA	2/1/2008	eMTR Allocated EHV Losses				0.251	0.248	0	0.256						
101	EDCA	2/1/2008	Default Supplier Load				-7.353500	-6.738200	0	-8.983800					COMPA	EDCA
101	EDCA	2/1/2008	Default Supplier Load				-3.151500	-2.887800	0	-3.850200					COMPB	EDCA
101	EDCA	2/1/2008	Total RT Net Interchange				0	0	0	0						

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

Congestion Reconciliation Report Example

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

Real-Time Daily Energy Transactions																
Customer Account:	EDC A, LLC	Report Creation Timestamp (EPT):	02/05/2008	9:56:48 AM												
Start Date:	2/1/2008	End Date:	2/1/2008													
Customer ID	Customer Code	Date	Transaction Type	Transaction ID	NERC Tag	OASIS ID	EPT HE 01	EPT HE 02	EPT HE 02*	EPT HE 03	Source PNODE Name	Source PNODE ID	Sink PNODE Name	Sink PNODE ID	Seller	Buyer
101	EDCA	2/1/2008	Retail Load Responsibility	57149			-40	-40	0	-40	ZONEA	100	ZONEA	100	COMPB	EDCA
101	EDCA	2/1/2008	Retail Load Responsibility	65787			-50	-50	0	-50	ZONEA	100	ZONEA	100	COMPA	EDCA
101	EDCA	2/1/2008	Adjusted Net Metered Interchange				100.254	99.378	0	102.578						
101	EDCA	2/1/2008	eMTR Allocated EHV Losses				0.251	0.248	0	0.256						
101	EDCA	2/1/2008	Default Supplier Load				-7.353500	-6.738200	0	-8.983800					COMPA	EDCA
101	EDCA	2/1/2008	Default Supplier Load				-3.151500	-2.887800	0	-3.850200					COMPB	EDCA
101	EDCA	2/1/2008	Total RT Net Interchange				0	0	0	0						

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

Congestion and Loss Load Reconciliation Charges														
Customer Account:	Company A, LLC	Report Creation Timestamp (EPT):	5/5/2008 9:56:48											
Start Billing Month:	April, 2008	End Billing Month:	April, 2008											
4000.01	4000.02	4000.03	4000.05	4000.06	4000.10	4000.18	4000.17	3000.7	4000.19	4000.2	3000.09	1410.01	3000.18	1420.01
Customer ID	Customer Code	Billing Month	EPT Hour Ending	GMT Hour Ending	eSchedules ID	Seller	Buyer	Load Reconciliation Energy (MWh)	PNODE Name	PNODE ID	PNODE RT Congestion Price ($/MWh)	Congestion Load Reconciliation Charge ($)	PNODE RT Loss Price ($/MWh)	Loss Load Reconciliation Charge ($)
100	COMPA	4/1/2008	2/1/2008 01	2/1/2008 06	57149		EDCA	-3.5	ZONEA	100	5.067894	-17.737629	2.048462	-7.169617
100	COMPA	4/1/2008	2/1/2008 02	2/1/2008 07	57149		EDCA	-3.5	ZONEA	100	4.758746	-16.655611	4.583082	-16.040787
100	COMPA	4/1/2008	2/1/2008 03	2/1/2008 08	57149		EDCA	-3.5	ZONEA	100	7.235974	-25.325909	5.284278	-18.494973

Congestion Reconciliation Report Example

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

Congestion and Loss Load Reconciliation Charges														
Customer Account:	Company B, LLC	Report Creation Timestamp (EPT):	5/5/2008 9:56:48											
Start Billing Month:	April, 2008	End Billing Month:	April, 2008											
4000.01	4000.02	4000.03	4000.05	4000.06	4000.1	4000.18	4000.17	3000.7	4000.19	4000.2	3000.09	1410.01	3000.18	1420.01
Customer ID	Customer Code	Billing Month	EPT Hour Ending	GMT Hour Ending	eSchedules ID	Seller	Buyer	Load Reconciliation Energy (MWh)	PNODE Name	PNODE ID	PNODE RT Congestion Price ($/MWh)	Congestion Load Reconciliation Charge ($)	PNODE RT Loss Price ($/MWh)	Loss Load Reconciliation Charge ($)
102	COMPB	4/1/2008	2/1/2008 01	2/1/2008 06	57149	COMPB	EDCA	5	ZONEA	100	5.067894	25.33947	2.048462	10.24231
102	COMPB	4/1/2008	2/1/2008 01	2/1/2008 06	57149		EDCA	-1.5	ZONEA	100	5.067894	-7.601841	2.048462	-3.072693
102	COMPB	4/1/2008	2/1/2008 02	2/1/2008 07	57149	COMPB	EDCA	5	ZONEA	100	4.758746	23.79373	4.583082	22.91541
102	COMPB	4/1/2008	2/1/2008 02	2/1/2008 07	57149		EDCA	-1.5	ZONEA	100	4.758746	-7.138119	4.583082	-6.874623
102	COMPB	4/1/2008	2/1/2008 03	2/1/2008 08	57149	COMPB	EDCA	5	ZONEA	100	7.235974	36.17987	5.284278	26.42139
102	COMPB	4/1/2008	2/1/2008 03	2/1/2008 08	57149		EDCA	-1.5	ZONEA	100	7.235974	-10.853961	5.284278	-7.926417

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

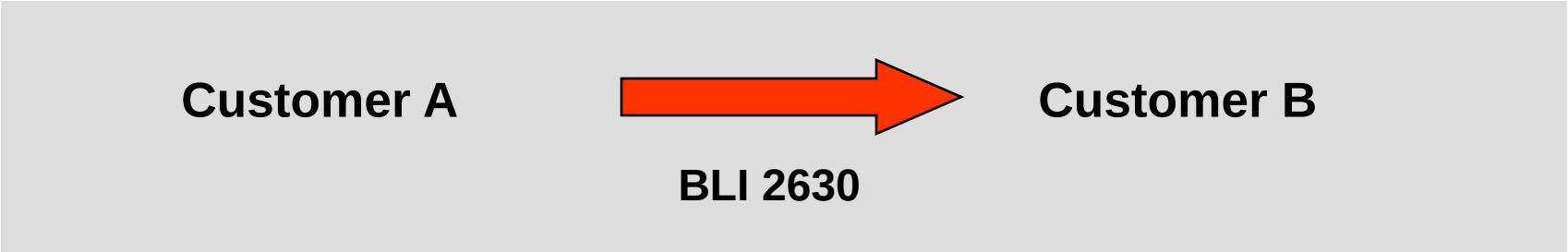
- In MSRS reports, the data supporting the transferred BLI will display on the applicable settlement report(s) of both the "Transfer From" and the "Transfer To" account

- 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 identifers 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



Billing Line Item Transfer - Example

Capacity Transfer Rights Credit Summary

Customer Account: Customer A

Report Creation Timestamp (EPT): 03/04/2008 10:58:26AM

Start Date: 09/01/2006

End Date: 09/30/2006

4000.01	4000.02	4000.04	4000.32	2630.11	3001.23	3001.31	2630.12
Customer ID	Customer Code	Date	Zone	CTR MW	UCAP Obligation (MW)	Total Zone UCAP Obligation (MW)	Traded CTR MW
123	Customer A	09/10/2006	AEP	12.0	1.000	6.500	5.0
123	Customer A	09/14/2006	PJM	15.0	1.000	6.500	5.0
Date Range Total							

Customer A is the Transfer From organization
The report will display Customer A's data only

Billing Line Item Transfer - Example

Capacity Transfer Rights Credit Summary

Customer Account: Customer B

Report Creation Timestamp (EPT): 03/04/2008 10:50:06AM

Start Date: 09/01/2006

End Date: 09/30/2006

4000.01	4000.02	4000.04	4000.32	2630.11	3001.23	3001.31	2630.12
Customer ID	**Customer Code**	**Date**	**Zone**	**CTR MW**	**UCAP Obligation (MW)**	**Total Zone UCAP Obligation (MW)**	**Traded CTR MW**
456	Customer B	09/01/2006	DOM	120.0	1.000	6.500	5.0
456	Customer B	09/05/2006	DOM	12.0	1.000	6.500	5.0
456	Customer B	09/20/2006	DOM	26.0	3.500	6.500	20.0
123	Customer A	09/10/2006	AEP	12.0	1.000	6.500	5.0
123	Customer A	09/14/2006	PJM	15.0	1.000	6.500	5.0
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

MSRS
Market Settlements Reporting System

pjm

MSRS Report Viewer

Customer Account: Power and Light Co. **Report:** Billing Line Item Transfer Summary

Start Date: 04/14/2008 **End Date:** 04/14/2008 **Version:** Latest **File Type:** Select file type.

Display | Download Now | Add to Cart | E-Mail PJM Market Settlements about this report.

1 / 1

pjm

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 End: 04/14/2008

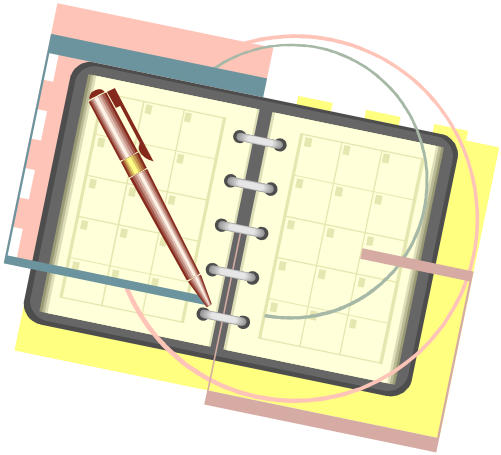
4001.03	4001.04	4001.05	4001.06	3000.07	4000.09
Billing Period Start Date	Source Billing Period Start Date	Billing Line Item ID	Billing Line Item Name	Transfer Amount ($)	Transferred From (Customer Account)

4000.00	4000.01	4000.02	4000.07
Transferred From (Customer Code)	Transferred To (Customer Account)	Transferred To (Customer Code)	Version

Review and Additional Resources

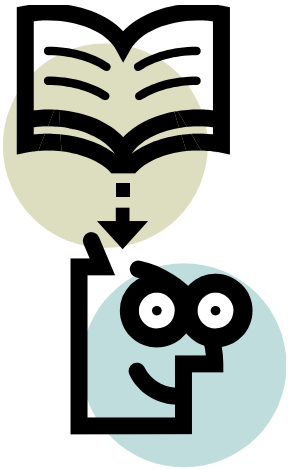
Agenda

- 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

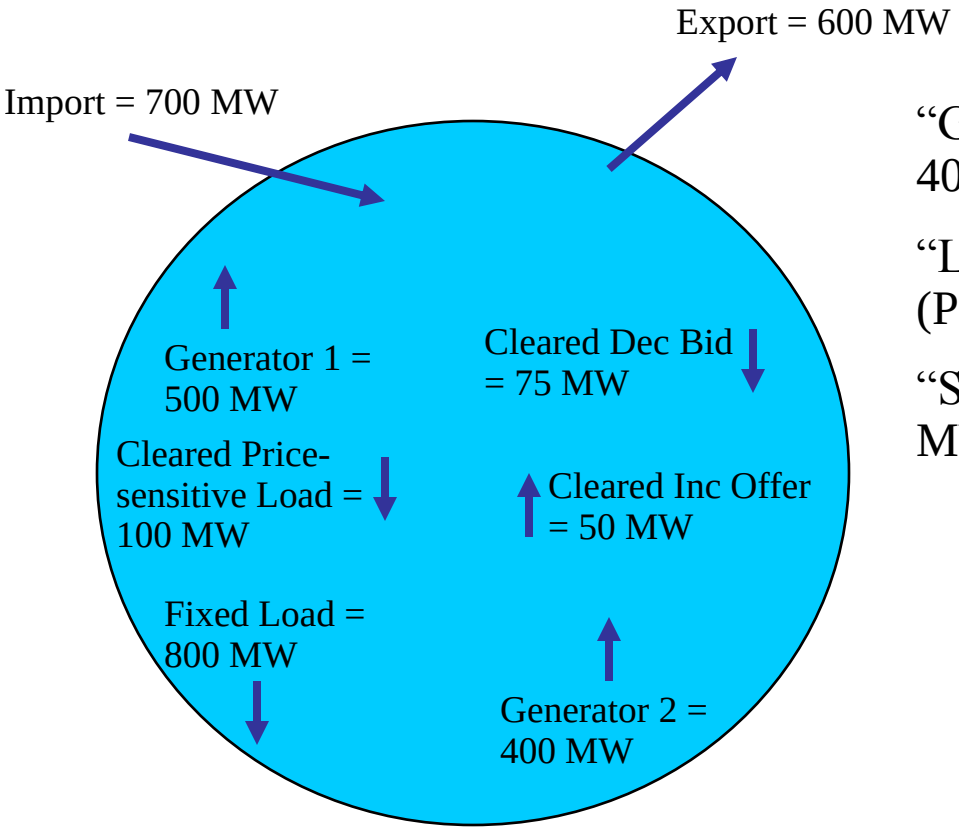


- Important Phone Numbers
  - Member Relations Hotline
    - General Questions
      - 610-666-8980
      - Toll free – 1-866-400-8980
      - http://www.pjm.com/about/contact/form-contact.html
  - Market Settlements Hotline
    - Specific questions about individual bill
      - 610-666-8825
      - mrkt_settlement_ops@pjm.com
  - Market Operations Hotline
    - Specific Markets-related questions
      - 610-666-8998

Appendix

Exercise 1 - Answer

- **Calculate the "Day-ahead Spot Market Interchange" for the Market Participant shown below:**



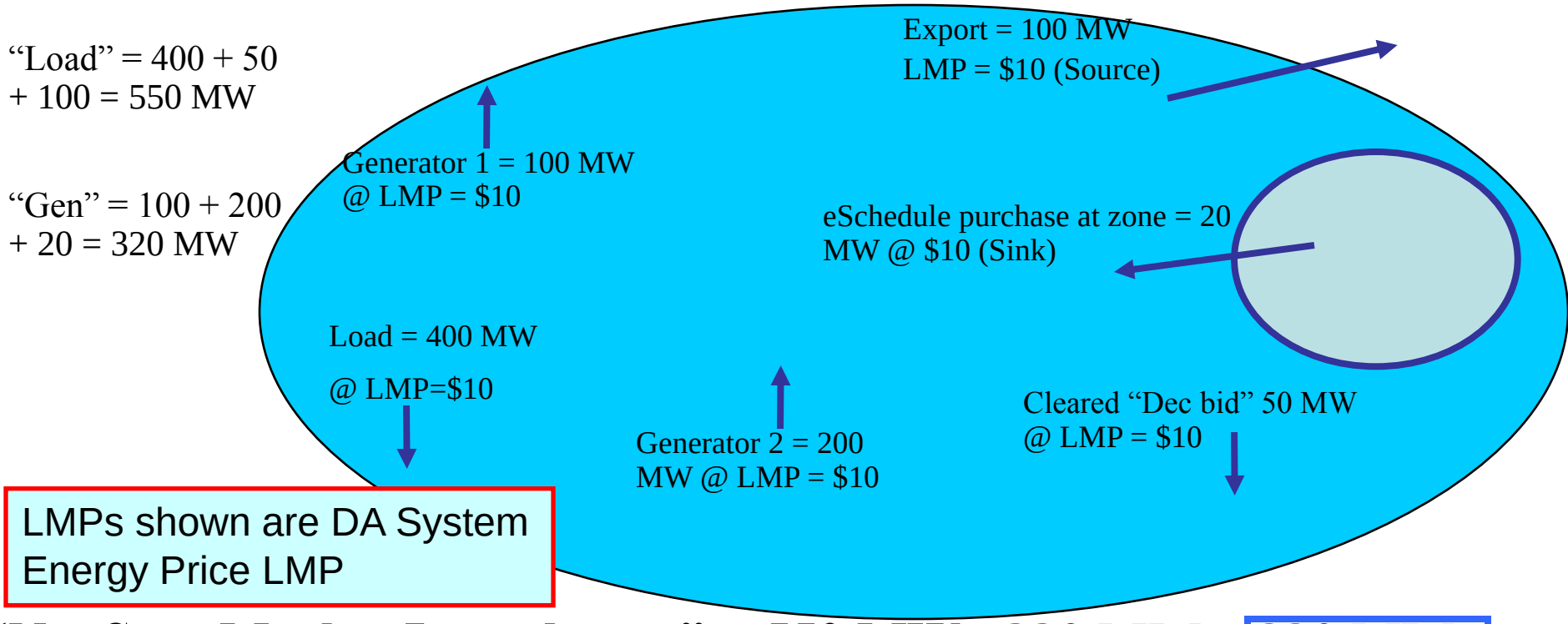
"Generation" = 700 (Import) + 500 (Gen 1) + 400 (Gen 2) + 50 (Inc offer) = 1650 MW

"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:**



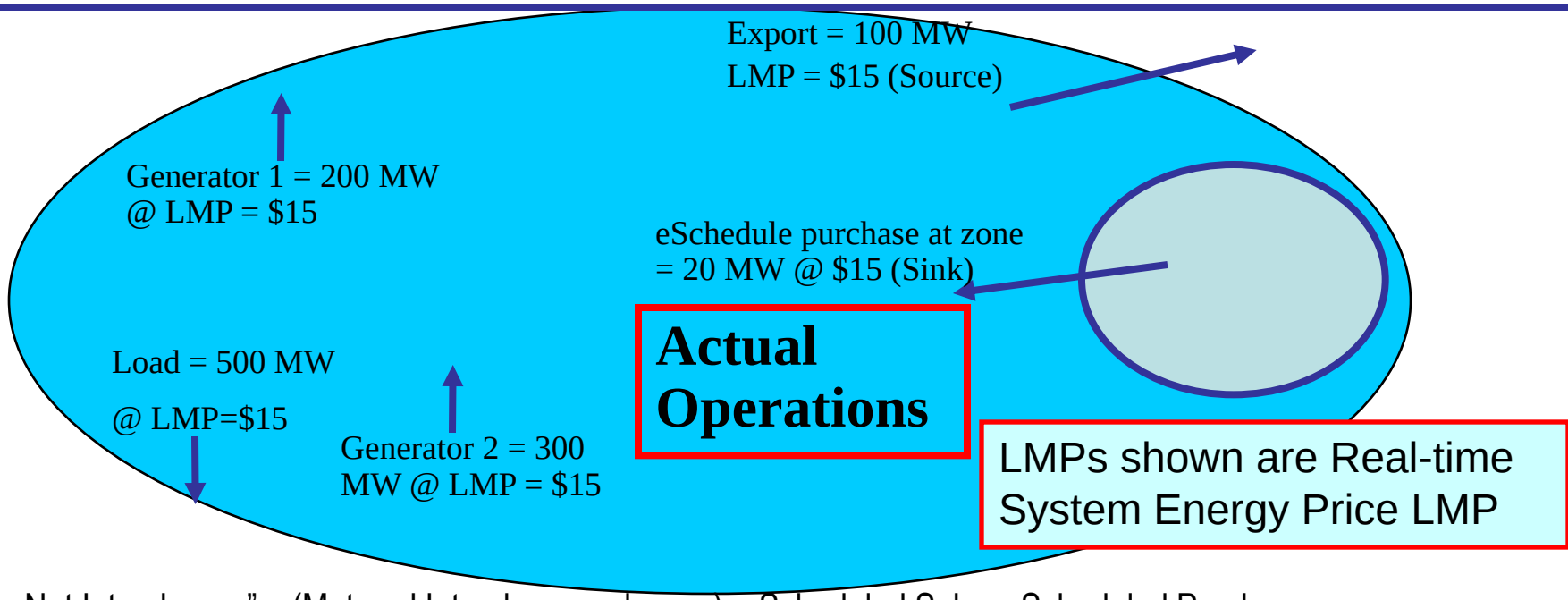
LMPs shown are DA System Energy Price LMP

"Net Spot Market Interchange" = 550 MW - 320 MW = 230 MW

"Day-ahead charges or credits" = (230 MW)($10) = $2300 charge

Exercise 3- Answer

- **Calculate the "Balancing Spot Market Energy" for the participant shown below:**



"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 credi

DA charge - Balancing Credit = 2300 - 2250 = $50 charge

Exercise 3- Answer

- **Calculated Individually**

	Day-ahead	Balancing	Net
Export	-1000	0	-1000
eSched	200	0	200
Dec Bid	-500	750	250
Gen 1	1000	1500	2500
Gen 2	2000	1500	3500
Load	-4000	-1500	-5500
Total	-2300	2250	-50

Exercise 4 - Answer

Day - ahead Market
DA System Energy Price = $10

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

20 MW;DALP = $1;DACP = $15

10 MW; DALP = $1; DACP = $0

5 MW; DALP = $2; DACP = $15

DEC Bid
10 MW
DALP = $2; DACP = $5

20 MW; DALP = $-1; DACP = $5

15 MW; DALP = $2; 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

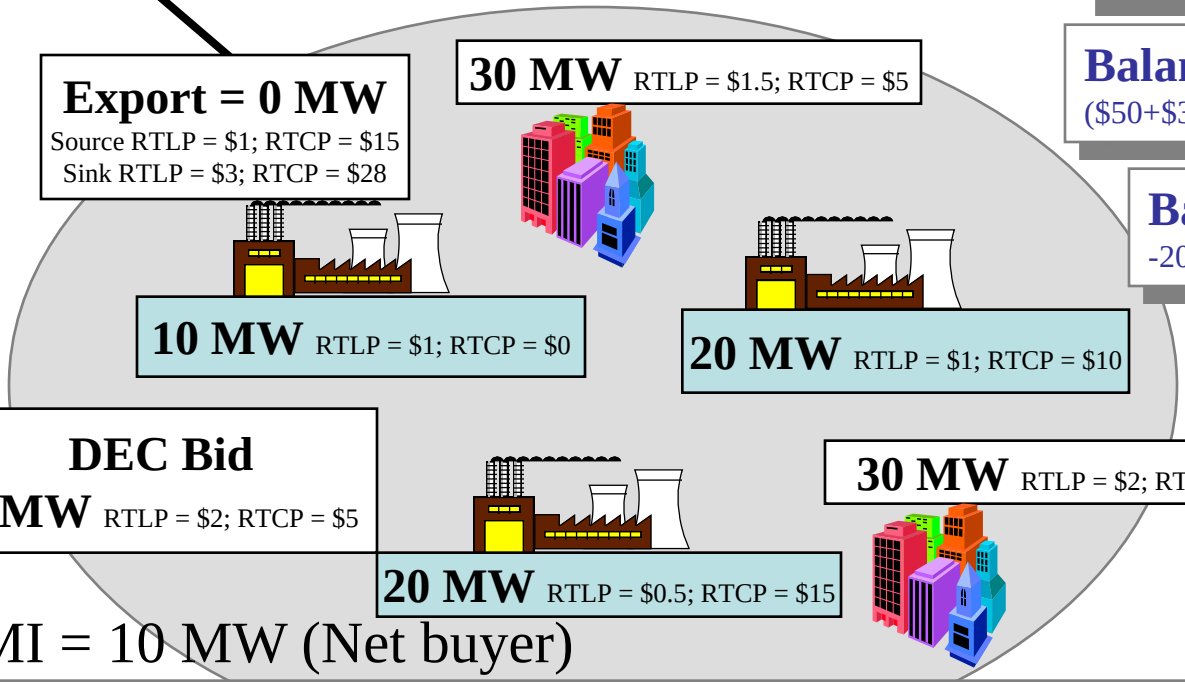
DA Explicit Losses:
20 ($3-$1) = $40

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)

Exercise 5

Balancing Market
RT System Energy Price = $20

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



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

SMI = 10 MW (Net buyer)

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

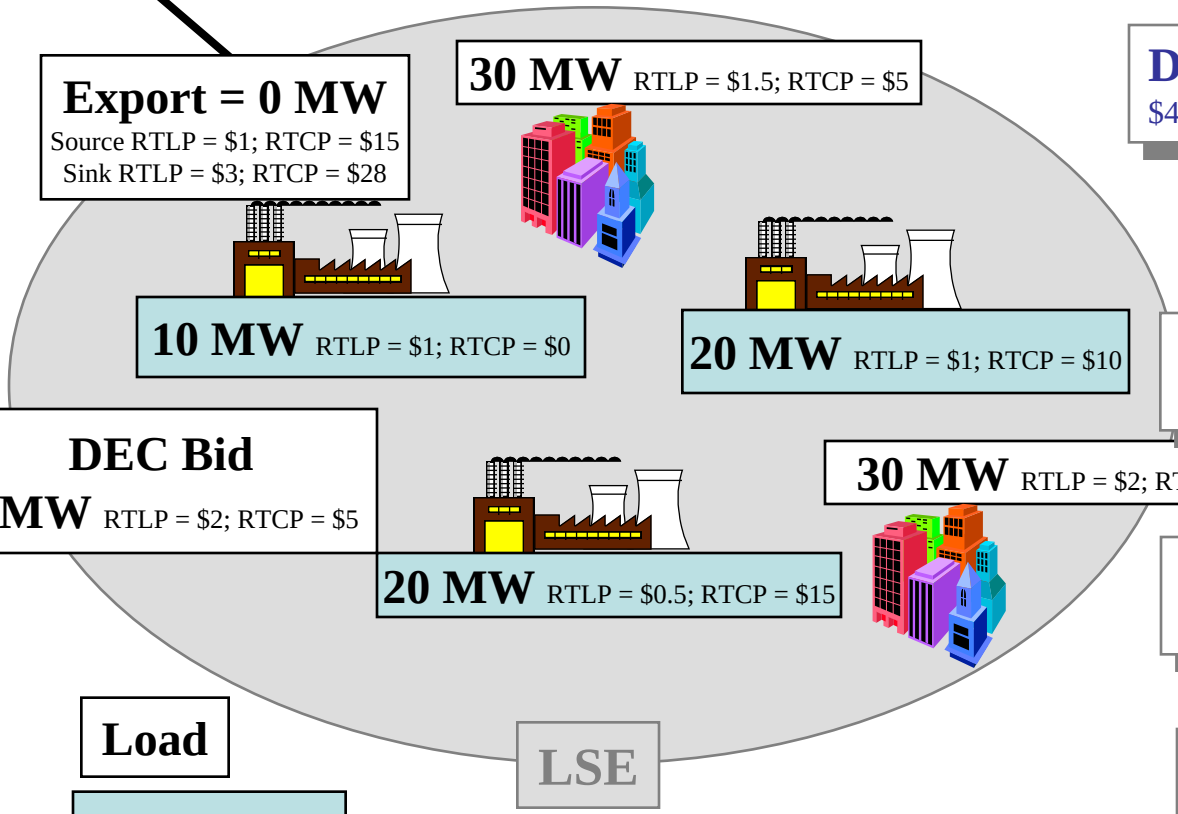
DA Explicit Losses:
-20 ($3-$1) = ($40)

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)

Exercise 5

Balancing Market
RT System Energy Price = $20

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



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

Load

Generation

DA Implicit Congestion:
$475

DA Explicit Congestion:
$200

Balancing Implicit Congestion:
$150

Balancing Explicit Congestion
($260)

Total Congestion
$565

Quick Review - Answer

Match the OATT Schedule to the Ancillary Service