



Changes to Operating Reserve Accounting Methodology Revised

PJM State & Member Training Dept.

- Define Operating Reserves and previous calculation methodologies
 - Summarize the changes and impacts of the new Balancing Operating Reserve (BOR) construct
 - Review new BOR calculation methodologies
 - Segmented Make-Whole Payments
 - Minimum Generator Operating Parameters
 - Ramp-Limited Desired MW to determine deviations
 - Supplier Netting at the Bus to offset deviations
 - Netting (deviations net by zone, hub or interface)
 - Balancing Operating Reserve Cost Allocation (BORCA)
 - Regional Balancing Operating Reserve Cost Allocation
- } Generator focused
- } Load Serving Entity focused

*Upon completion of this presentation,
participants will have the ability to:*

- Define Operating Reserves from an accounting standpoint
- Differentiate the current Balancing Operating Reserve (BOR) rules from the new BOR rules
- Summarize the various components of the new BOR Reserve calculation construct

	Preliminary Vote	Final Vote	
Modified Day-ahead Scheduling Reserve Methodology	MRC Nov 14, 2007 Endorsed	MRC Nov 14, 2007 Endorsed	Implemented 1/1/08
Day-ahead Scheduling Reserve Market	MRC Nov 14, 2007 Endorsed	MC Jan 15, 2007 Endorsed	Implemented 6/1/08
Revised Operating Reserve Accounting Methodology	MC Nov 15, 2007 Endorsed	MC Nov 15, 2007 Endorsed	Implementation Dec 1, 2008

- “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
 - Defined in Operating Agreement
 - Schedule 1-3.2.3 & 3.3.3
- Following slides refer to the **Accounting** Definition

- Separate Operating Reserves for Day-ahead and Balancing Markets
- Cleared offers for pool-scheduled generation in the day-ahead market are guaranteed to be made whole for the day
- Accepted offers for pool-scheduled generation operating in the real-time market as requested are also made whole
- Additional payments provided for generator cancellations, and generation reduced for reliability
- Charge allocations based on day-ahead load + exports, and real-time deviations from day-ahead market scheduled quantities (unless following dispatch)

- Generators, synchronous condensers, and transactions dispatched for PJM are eligible
- For each eligible resource, daily credit is the balancing offer amount in excess of
 - Balancing Market revenue
 - any Day-Ahead Market revenue
 - any Day-Ahead Operating Reserves credits
 - any Day-Ahead Scheduling Reserve credits (in excess of DASR offer + Opportunity Cost)
 - any Regulation revenue (in excess of Regulation offer + Opportunity Cost)
 - any Synchronized Reserve revenue (in excess of offer plus opportunity, energy usage and startup costs)



The fundamental objective of Balancing Operating Reserve (BOR) Credits does not change with the implementation of the new BOR construct

- Allocated proportionately to all deviations from day-ahead scheduled quantities, including:
 - “load” , internal sales, and export transactions
 - (not including dynamically scheduled transactions)
 - generation (for self-scheduled or PJM scheduled generation not following real-time dispatch instructions and signals)
 - Self-scheduled units not dispatched by PJM above their economic minimum limits (unless reducing for a Min Gen Event)
 - cleared inc offers, internal purchases, and import transactions



The fundamental objective of Balancing Operating Reserve (BOR) Charges does not change with the implementation of the new BOR construct



Generator Offer: \$100

- \$75

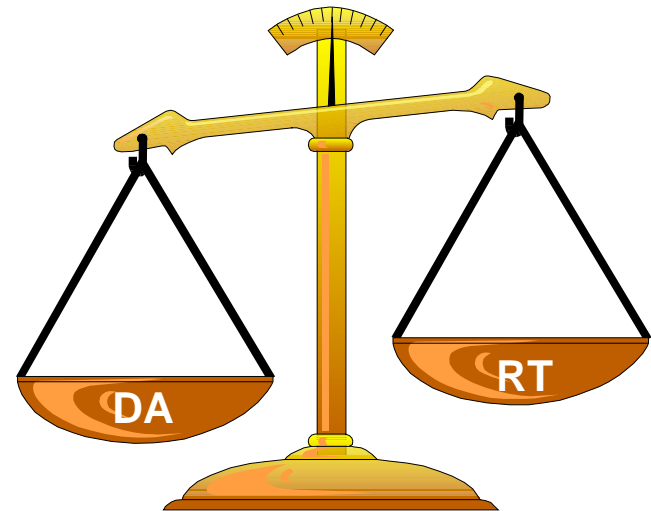
\$25

Total Revenue For Generator:

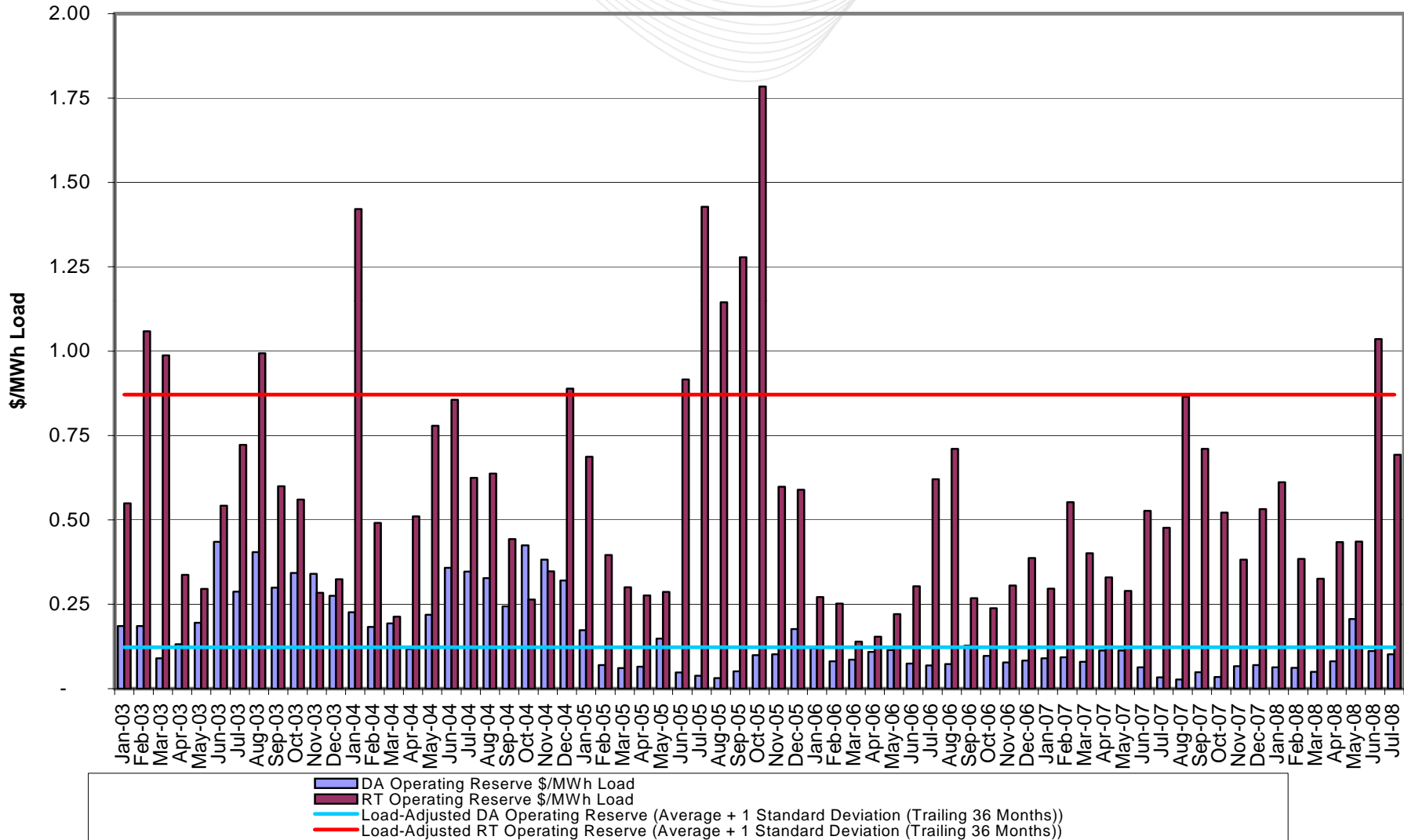
- Synch Reserve Revenue = \$10
- DASR Market Revenue = \$2
- DA Op Reserve Revenue = \$3
- Balancing Market Revenue = \$10
- Day Ahead Market Revenue = \$50

= \$75

Charged to participants that deviate from Day Ahead Market position:



PJM Operating Reserve Costs 2003-2008 (\$/MWh Load)



- The modified Operating Reserve Business Rules are designed to:
 - incent participants to bid their Day-ahead quantities as close as possible to what they expect in the Balancing Market, thereby leading to increased convergence between Day-Ahead and Real Time prices and increased market efficiency.
 - incent generators to follow PJM dispatch instructions and provide flexibility, thus increasing market efficiency and system reliability
 - appropriately allocate OR costs to transactions in areas that contribute to the additional costs

Total Cost:

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



(8)

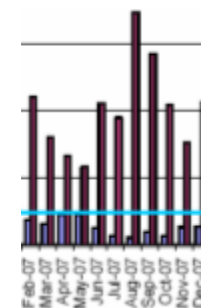
Charge:

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



Rate:

- \$ per MW charge that is derived from **Total Cost**
- Calculated daily
- <http://www.pjm.com/markets/jsp/ops-rate.jsp>



(6)

$$\text{Total Cost} \div \text{Charge} = \text{Rate}$$



The "Package" of Proposed BOR Changes

Proposed 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 <u>locationally</u> by zone, hub, or interface. Supply bucket should be netted <u>locationally</u> 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

The Members Committee voted on the BOR changes as a “Package.” This approach facilitated compromise between suppliers (generators, DSR) and those entities bearing the costs of BORs (LSEs, etc)

Segmented Make-Whole Payments	Will be an overall benefit to generators
Parameter Limited Schedules	Could be a liability to some generators
Ramp-Limited Desired MWs	Could be an overall benefit (or liability) to generators
Supplier Netting at the Bus	Will be an overall benefit to a few generators
Netting by Zone, Hub, Interface	Could be a liability to entities (other than generators) that deviate from DA schedules
Regional BORCA	Could be a benefit or liability to LSEs More closely allocates the BOR costs
BORCA	Could be a benefit or liability to LSEs More closely allocates the BOR costs



Due to the volatile nature and RT operational basis of Operating Reserves, it is difficult to accurately model the future financial impacts and the allocation (regional, RTO) of the charges



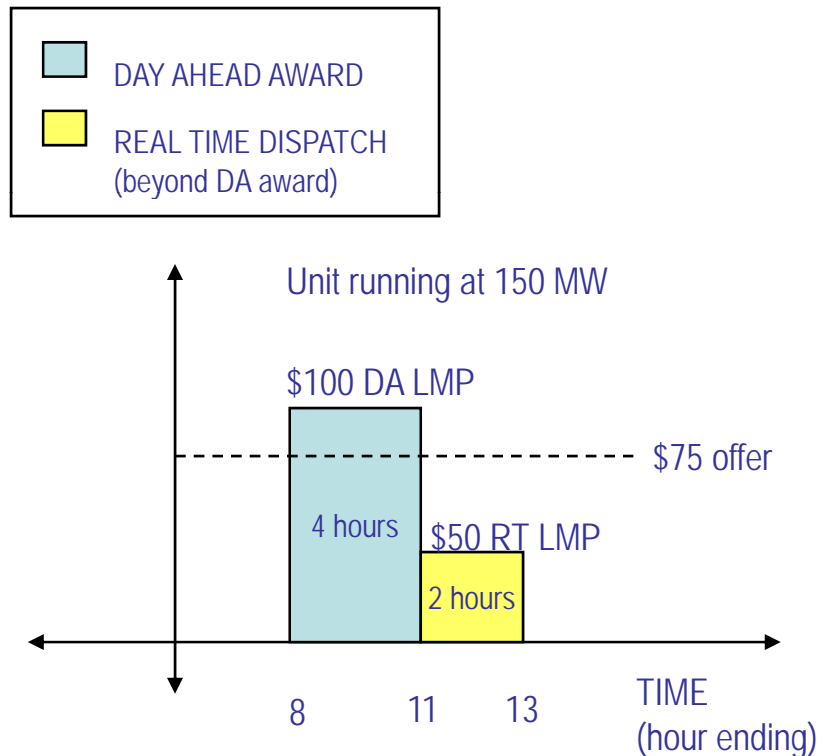
Rule changes applicable to Supply (generators)

- Current Rule
 - The total resource offer amount for generation, including startup and no-load costs as applicable, is compared to its total energy market value for an entire 24-hour period.
- Desired Outcome
 - Solidify incentive to follow PJM dispatch and continue operating when minimum run time has expired
- Proposed Change
 - Segment Make-Whole Payments as a function of the greater of the DA Schedule, or Min Run Time

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

Segment 2: Extended Period

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

Note: Under current rules, this unit receives a balancing payment of \$ 0

Balancing OR Credit = Offer Value (6 hours * \$75 * 150 MW) – (DA Energy + RT Energy) = \$67,500 – (\$60,000 + \$15,000) = - \$7,500 → 0

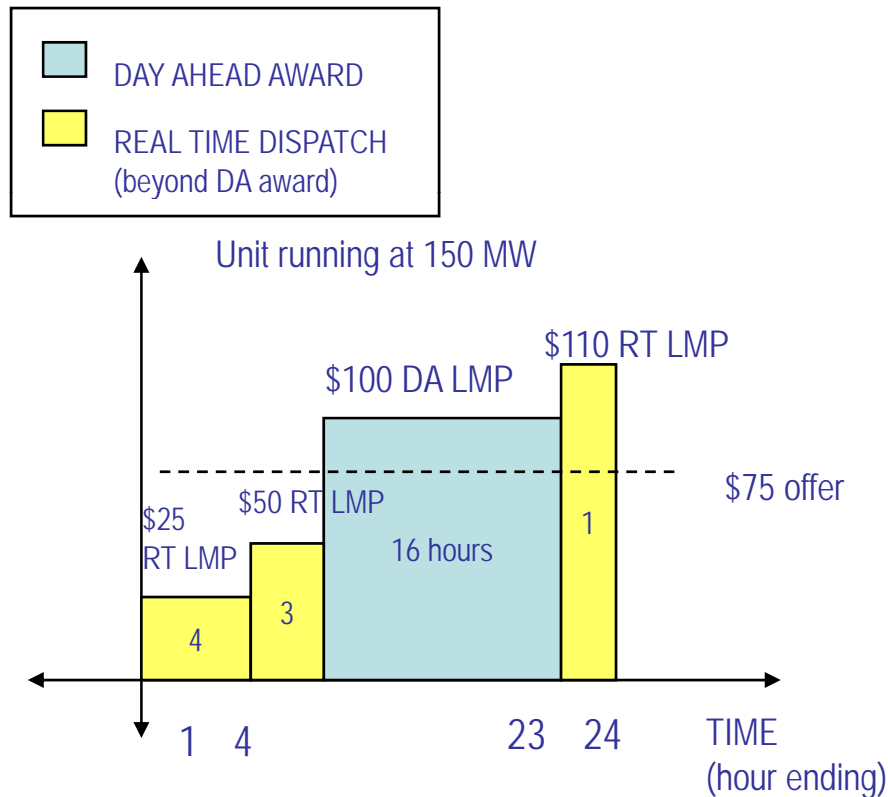
**DA operating reserve credits, regulation revenue, and spinning revenue are also applied against balancing OR credits.



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

Note: Under current rules, this unit receives a balancing payment of \$ 0

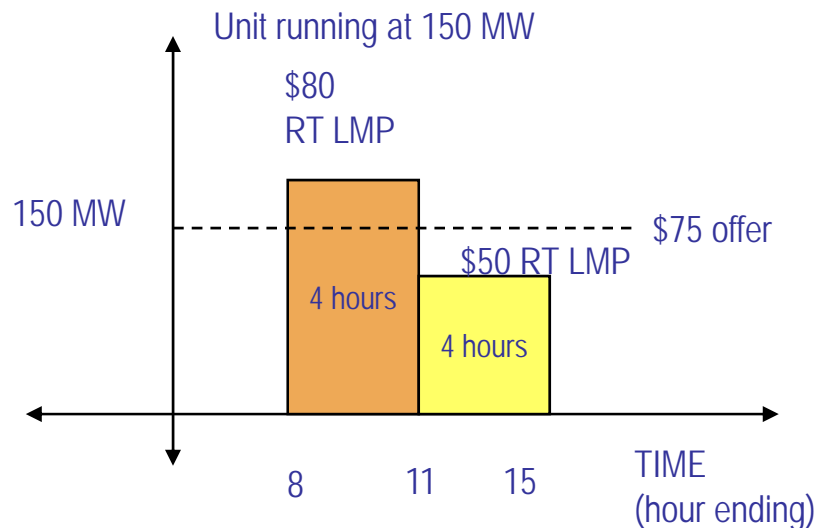
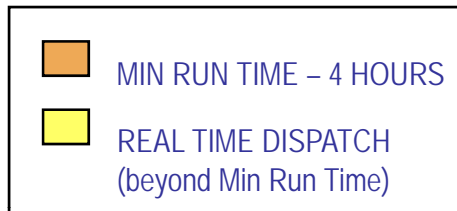
Balancing OR Credit = Offer Value (24 hours * \$75 * 150MW) – (DA Energy + RT Energy) = \$270,000 – (\$240,000 + \$54,000) = - \$34,000 → 0

**DA operating reserve credits, regulation revenue, and spinning revenue are also applied against balancing OR credits.

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

Note: Under current rules, this unit receives a balancing payment of \$12,000

Balancing OR Credit = Offer Value (8 hours * \$75 * 150MW) – (DA Energy + RT Energy) = \$90,000 – (\$0 + \$78,000) = \$12,000

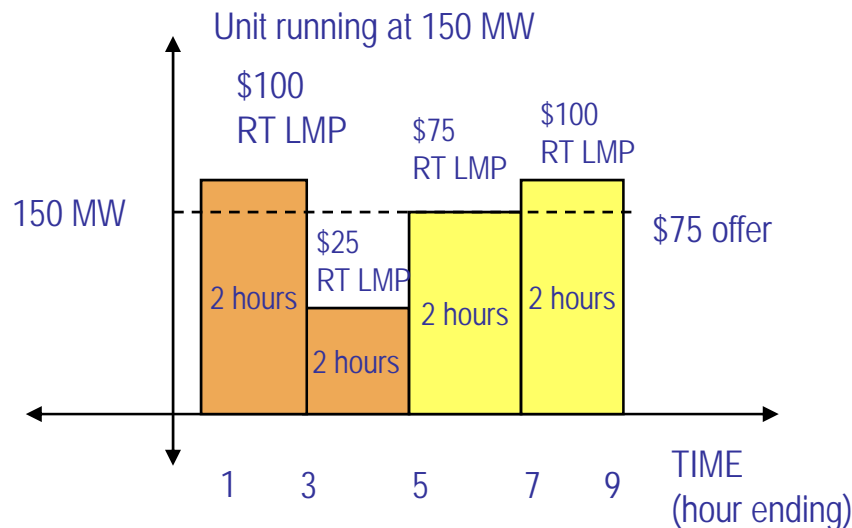
**Regulation revenue, and spinning revenue are also applied against balancing OR credits.



Segmented Make-Whole Payments

Example 4 – Unit Y Extended Beyond Min Run Time

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



Explanation:

Segment 1: Min Run Time

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

Segment 2: Extended Period




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

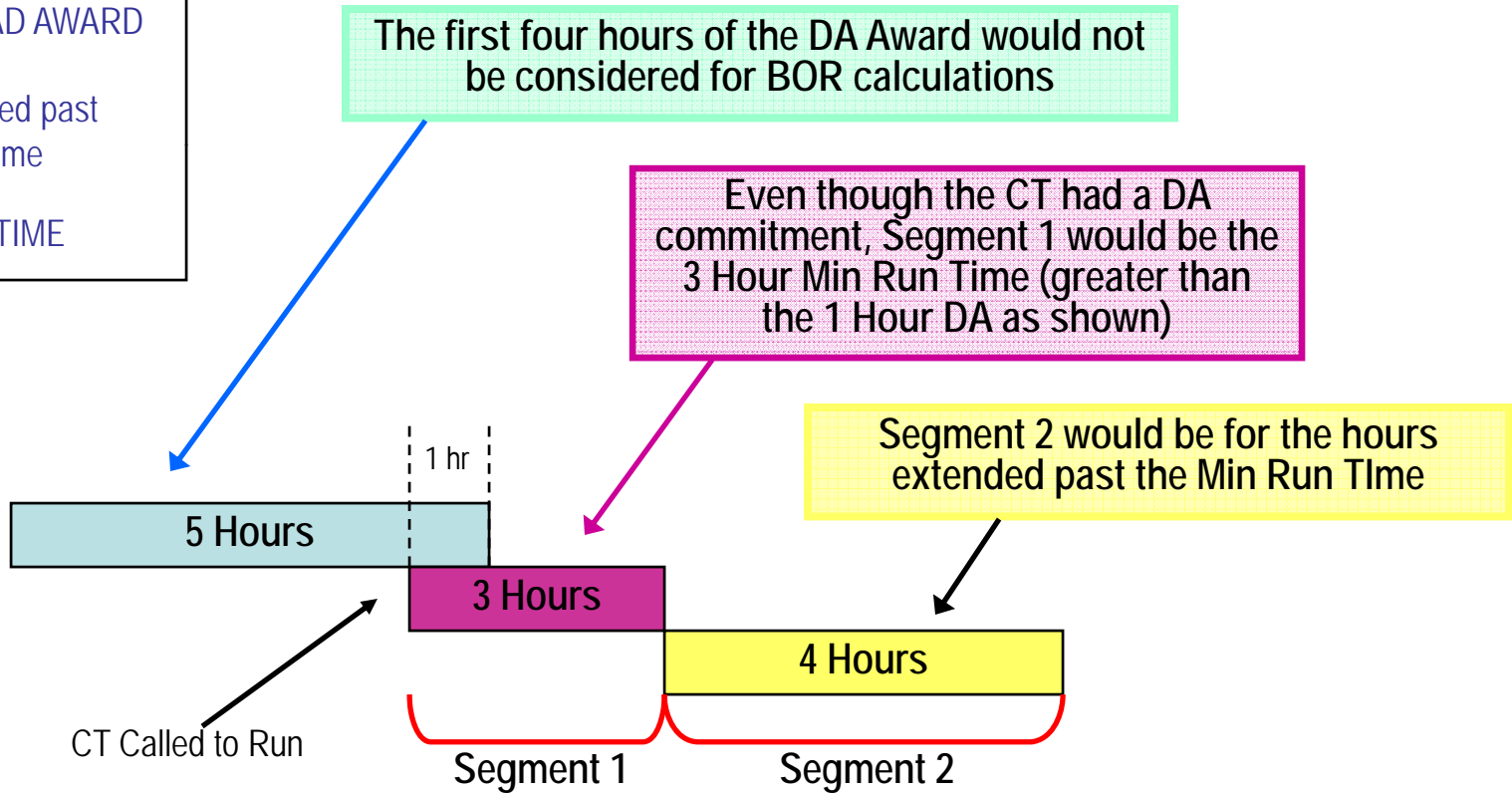
Note: Under current rules, this unit receives a balancing payment of \$ 0

$$\text{Balancing OR Credit} = \text{Offer Value (8 hours * \$75 * 150MW)} - (\text{DA Energy} + \text{RT Energy}) = \$90,000 - (\$0 + \$90,000) = \$0$$

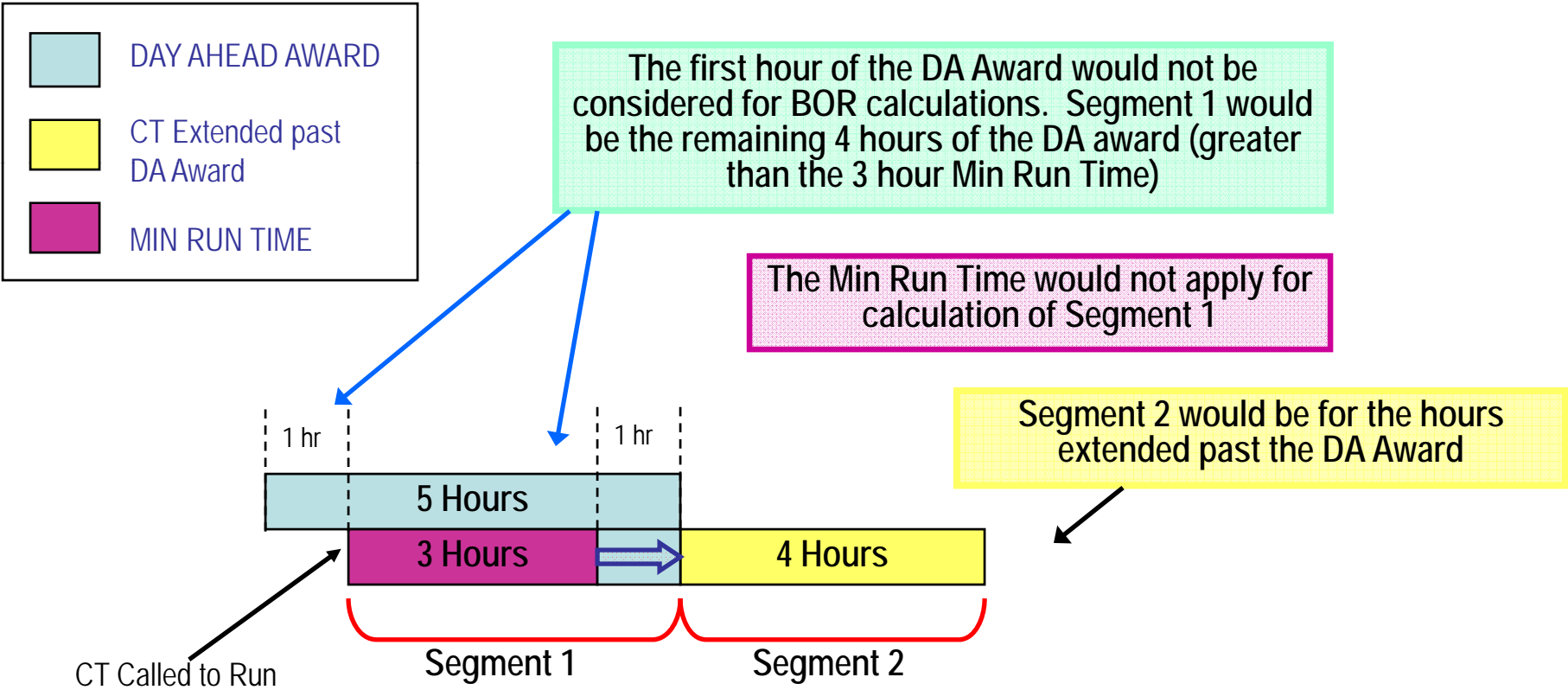
**Regulation revenue, and spinning revenue are also applied against balancing OR credits

Example 5: CT Unit had DA commitment and was called to run in RT. The DA commitment and the time when the unit was called to run do not align.

	DAY AHEAD AWARD
	CT Extended past Min Run Time
	MIN RUN TIME



Example 6: CT Unit had DA commitment and was called to run in RT. The DA commitment and the time when the unit was called to run do not align.



- 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 will be an overall benefit to resources

Current Rule

- Each generator may submit their operating parameters for individual units when participating in the Day-Ahead and Real-time Energy Markets.

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.

Proposed 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.

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

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

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

i.e.

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



When are Parameter-Limited Schedules used?

Units will be committed on Parameter-Limited Schedules when:

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

-- OR --

2) PJM:

- declares a Maximum Generation Emergency
- issues a Maximum Generation Emergency Alert
- schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert for all or any part of such Operating Day

Normal Operations



Generators continue on their Price Schedule and non-limited parameters

Generator fails the Three Pivotal Supplier Test (TPS)



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

Max Emergency Alert, loading, etc.



Generators continue on their price schedule but placed on their Parameter-Limited Schedules (note: Scarcity Pricing rules may apply)



Parameter Limited Schedules - PJM-defined unit parameters

PJM Unit Parameter Matrix Summary

Turn Down Ratio = Economic Maximum MW / Economic Minimum MW

Parameter	Minimum Down Time (Hrs)	Minimum Run Time (Hrs)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio
Small Frame CT and Aero CT Units - Up to 29 MW ICAP	2.0 or Less	2.0 or Less	2 or More	14 or More	1.0 or More
Medium Frame CT and Aero CT Units - 30 MW to 65 MW ICAP	2.0 or Less	3.0 or Less	2 or More	14 or More	1.0 or More
Medium-Large Frame CT Units - 65 MW to 125 MW ICAP	3.0 or Less	5.0 or Less	2 or More	14 or More	1.0 or More
Large Frame CT Units - 135 MW to 180 MW ICAP	4.0 or Less	5.0 or Less	2 or More	14 or More	1.0 or More
Combined Cycle Units	4.0 or Less	6.0 or Less	2 or More	11 or More	1.5 or More
Petroleum and Natural Gas Steam Units - Pre-1985	7.0 or Less	8.0 or Less	1 or More	7 or More	3.0 or More
Petroleum and Natural Gas Steam Units - Post-1985	3.5 or Less	5.5 or Less	2 or More	11 or More	2.0 or More
Sub-Critical Coal Units	9.0 or Less	15.0 or Less	1 or More	5 or More	2.0 or More
Super-Critical Coal Units	84.0	24.0 or Less	1 or More	2 or More	1.5 or More



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



Parameter-Limited Schedules – example for Min Down Time

Without Parameter-Limited Schedules in effect:

A Natural Gas Steam Unit (pre-1985) submits a 48-hour Minimum Down Time



This parameter could result in market power issues (takes away PJM's flexibility to cycle unit)

With Parameter-Limited Schedules in effect:

PJM implements the parameter-limited schedule based on history of the unit or on unit class (in this case, 7 hours or less)



Business Rule 14: 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.

See Appendix for complete list of PJM-defined values

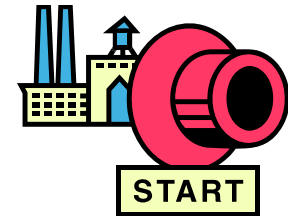


Parameter-Limited Schedules – example for Max Weekly Starts

Without Parameter-Limited Schedules in effect:

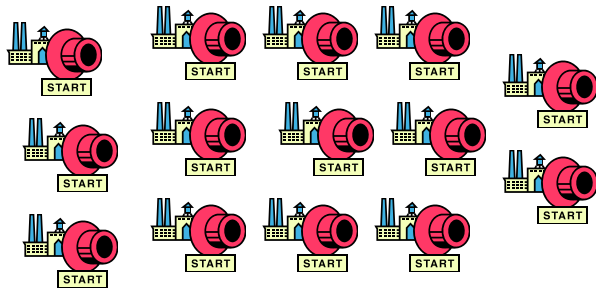
A Combustion Turbine (CT) with a 75MW ICAP submits Maximum Weekly Starts of 1

This parameter could result in market power issues (takes away PJM's flexibility to cycle unit)



With Parameter-Limited Schedules in effect:

PJM implements the parameter-limited schedule based on submitted value or unit class (in this case, 14 starts or more)



Business Rule 17 - 18: The initial Maximum Starts per Week for a unit will be based on the posted level for the PJM-defined unit class. If the Maximum Starts Per Week submitted for a unit is less than the PJM-defined unit class maximum starts per week, then the unit's Maximum Starts per Week will be set equal to the PJM-defined unit class posted Maximum Starts per Week.

See Appendix for complete list of PJM-defined values

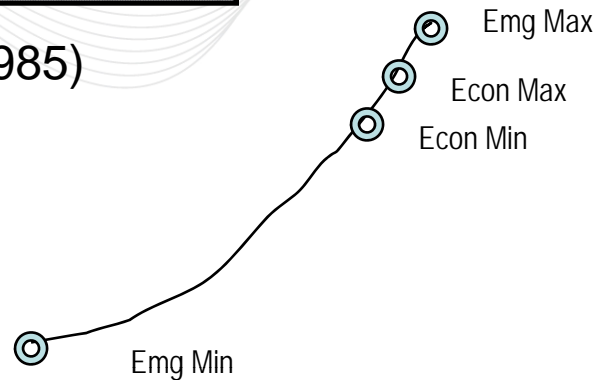


Parameter-Limited Schedules – example for Turn Down Ratio

Without Parameter-Limited Schedules in effect:

A Natural Gas Steam Unit (pre-1985) submits the following:

- Emg Max: 250**
- Econ Max: 240**
- Econ Min: 230**
- Emg Min: 50**



This parameter could result substantial BOR charges due to inflexibility of unit

With Parameter-Limited Schedules in effect:

PJM implements the parameter-limited schedule based on history of the unit or on unit class:

- Emg Max: 250**
- Econ Max: 240**
- Econ Min: 80**
- Emg Min: 50**

(example uses a Turn Down Ratio value of 3)

Business Rule 10 - 13: Turn Down Ratio is defined as the ratio of economic maximum MW to economic minimum MW. The minimum acceptable Turn Down Ratio applicable to an individual unit will be the greater of: a) the difference between the minimum of the economic minima and the maximum of the economic maxima submitted over the prior 24 months, or b) 90 percent of the PJM-defined unit class Turn Down Ratio. If the resulting unit Turn Down Ratio is less than 90 percent of the PJM-defined unit class Turn Down Ratio, then the unit's Turn Down Ratio will be set equal to 90 percent of PJM-defined unit class Turn Down Ratio. For CTs, the Turn Down Ratio will assumed to be 1.0.

See Appendix for complete list of PJM-defined values

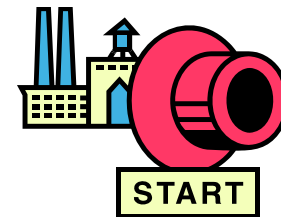


Parameter-Limited Schedules – example for Max Daily Starts

Without Parameter-Limited Schedules in effect:

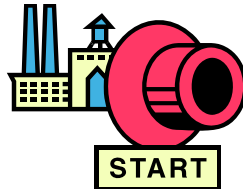
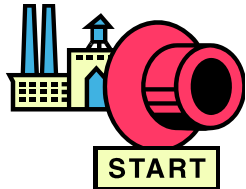
A Combined Cycle unit Maximum Daily Starts of 1

This parameter could result in market power issues (takes away PJM's flexibility to cycle unit)



With Parameter-Limited Schedules in effect:

PJM implements the parameter-limited schedule based on submitted value or unit class



Business Rule 19 - 20: The Maximum Starts Per day will be based on the PJM-defined unit class for non-CT units. For CT units, the minimum value of maximum starts per day will be 2. If the number of Maximum Daily Starts submitted by a unit is less than the PJM-defined unit class Starts per Day for a non-CT unit, or less than 2 for a CT, then the unit's Maximum Starts per Day will be set equal to the PJM-defined unit class Maximum Starts per Day for a non-CT unit and 2 for a CT.

See Appendix for complete list of PJM-defined values

**eMarket updates will be required
in the current parameter screens
to reflect new parameter limits**

- eMKT/XML functionality will be modified to validate the unit parameters within each schedule on a unit basis.
 - Current XML queries have been modified to accept this validation without changes to the XML code in the queries
- Units are assigned to unit classes (that mirror the matrix) or will be assigned to their own "class" if they are granted an exception.
 - Exceptions that are granted for the period will be including in eMKT.
- Participants will be able to view the limits on the screens, and will have a separate screen for all the limits assigned for all their units.
 - A new XML query has been created to report this information

- Schedules (both Price and Cost) will be identified as PLS
 - All Cost Based Schedules will need to be PLS
 - New Price Based Schedules that are PLS will need to be submitted with the schedule numbers 70-79
- Schedules that are PLS that do not pass validation:
 1. Cannot be submitted via XML or
 2. Cannot be made available.
- **Begin November 15th**, 2008 PJM will be verifying all current schedules in eMKT pass the PLS validation and will contact generation owners if schedules will need to be modified prior to go-live on December 1, 2008

http://localhost:8080/emkt/pjm_esuite_framework/eSuiteMaster.htm - Microsoft Internet Explorer

File Edit View Favorites Tools Help

Back Forward Stop Refresh Home Search Favorites

Google

Go

Bookmarks 391 blocked Check AutoLink AutoFill Send to

Settings

Links Linux Weblogic 8.1 Tools W2K Tomcat 5 W2K Weblogic 9

Address http://localhost:8080/emkt/pjm_esuite_framework/eSuiteMaster.htm Go

eSuite

Unit Schedules Dispatch Lambda Market Results Regulation Market Synchronized Reserve Market DA Scheduling Reserve Market Con Ed

Unit Hourly Updates Unit Detail Energy Ramp Rates SyncRes Ramp Rates Weather Forecast Parameter Limits

Unit Detail Search

Portfolio: [n] Uni: [] Date: 10/14/2008 (mm/dd/yyyy) [Change Date] [Get Report]

Unit Detail Result for []

Name	Value	Name	Value
Type Of Unit	Single Boiler	Plant Name	xyz
Unit Number	1	Unit Shortname	xyz
Node	xyz	Operating Company	AEPSCG
Capacity Resource	Yes	Regulation Resource	Yes
Default Status	Economic	Default Ramp Rate	5.0
Fixed Gen.	No	Emergency Min(MW)	270.0
Emergency Min(MW)	270.0	Emergency Max(MW)	820.0
Economic Min(MW)	550.0	Economic Max(MW)	800.0
Regulation Min(MW)	550.0	Regulation Max(MW)	800.0
		Spinning Max(MW)	820.0
Per. 1 Cost Based Startup	Yes	Per. 2 Cost Based Startup	Yes
Per. 1 Hot Startup Cost(\$)	0.00		
Per. 1 Inter Startup Cost(\$)	0.00		
Per. 1 Cold Startup Cost(\$)	0.00		
Per. 1 No Load Cost(\$)	2739.00		
Condense Available	No	Condense Startup Cost(\$)	0.00
Condense Energy Usage(MW)	0.0	Condense To Gen Cost(\$)	0.00
Condense Notification Time	0.0	Condense Hourly Cost(\$)	(null)
Parameter Limits Description	Combined Cycle Unit	Turndown Ratio Limit	(null)
Maximum Daily Starts Limit	2	Maximum Weekly Starts Limit	4
Minimum Runtime Limit	1.75	Minimum Downtime Limit	1.25

Public
Generator
Demand
Admin
AEPSCG
superuser

Copyright

Updated page to display parameter limits for resource.

Unit Schedules Dispatch Lambda Market Results Regulation Market Synchronized Reserve Market DA Scheduling Reserve Market Con Ed

Schedule Offers Schedule Detail Schedule Manager Schedule Selection

Schedule Detail Search Get Report

Portfolio: Unit: Date: 10/14/2008
(mm/dd/yyyy) Change Date

Schedule:

Schedule Detail Result for

Name	Value	Name	Value
Description	CostBased	Schedule Available	Yes
Market Type	Both	Fuel Type	(null)
Use Startup No Load	Yes	Max Runtime (Hour)	168.00
Hot Startup Cost(\$)	39904.53	Maximum Daily Starts Limit: 2	1
Inter Startup Cost(\$)	56612.64	Max Weekly Energy(MW)	137760.0
Cold Startup Cost(\$)	125494.79	Maximum Weekly Starts Limit: 4	1
No Load Cost(\$)	3432.84	Hot To Cold Time(Hour)	72.00
Emergency Max(MW) Default: 820	835.0	Hot To Inter Time(Hour)	8.00
Economic Max(MW) Default: 800	800.0	Hot Notification Time(Hour)	2.00
Economic Min(MW) Default: 550	550.0	Inter Notification Time(Hour)	2.00
Emergency Min(MW) Default: 270	270.0	Cold Notification Time(Hour)	2.00
Minimum Downtime(Hour) Limit: 1.25	72.00	Hot Startup Time(Hour)	9.00
Minimum Runtime(Hour) Limit: 1.75	24.00	Inter Startup Time(Hour)	14.00
		Cold Startup Time(Hour)	19.00

Public
Generator
Demand
Admin
AEP SOG
superuser

Updated page to display parameter limits for resource with corresponding schedule parameters.



NEW eMKT: Schedule Manager Screen

Updated page to display parameter limited attribute in the schedule type column.

http://localhost:8080/emkt/pjm_esuite_framework/eSuiteMaster.htm - Microsoft Internet Explorer

File Edit View Favorites Tools Help

Back Forward Stop Home Search Favorites

Google Go Bookmarks 391 blocked Check AutoLink AutoFill Send to Settings

Links Linux Weblogic 8.1 Tools W2K Tomcat 5 W2K Weblogic 9

Address http://localhost:8080/emkt/pjm_esuite_framework/eSuiteMaster.htm Go

eSuite

Unit Schedules Dispatch Lambda Market Results Regulation Market Synchronized Reserve Market DA Scheduling Reserve Market Con Ed

Schedule Offers Schedule Detail Schedule Manager Schedule Selection Get Report

Schedule Selection

Portfolio: Unit: Date: 10/14/2008
(mm/dd/yyyy) Change Date

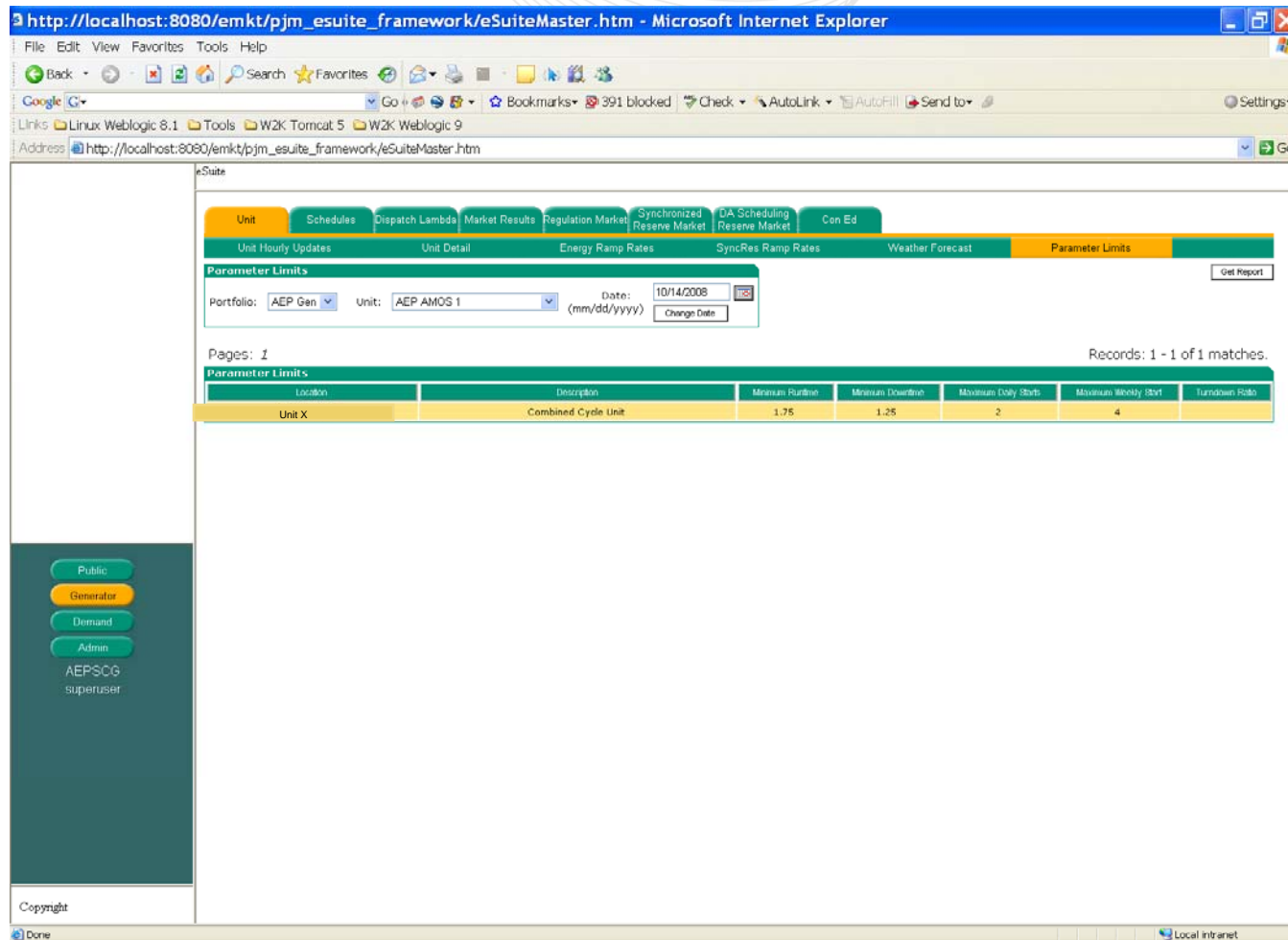
Pages: 1 Records: 1 - 2 of 2 matches.

Location Name	Type	Parameter Limited	Schedule Name	Market Type	Available	No Load Cost	Cold Start Cost	Int. Start Cost	Hot Start Cost
Unit X	Cost	Yes	CostBased	Both	Available	3432.84	150614.30	67657.62	46576.09
Unit Y	Price	No	PriceBased	Both	Available	3432.84	125494.79	56612.64	39904.53

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Generator
Demand
Admin
AEPSCG
superuser

Copyright

Updated page to display parameter limited attribute of schedule.



New private page displaying each resource's associated parameter limits. A XML report of same is available using the standard Get Report button.

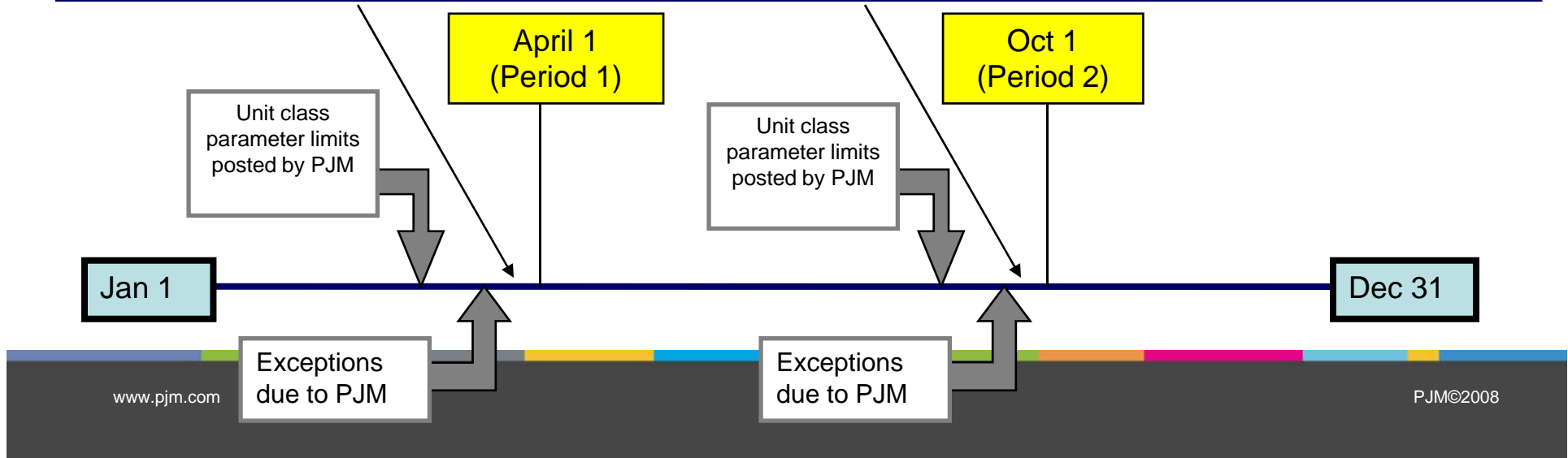
Parameter Limited Schedules - Timeline

- PJM posts unit class specific parameter limits 30 days prior to bi-annual enrollment period
- Generator Suppliers submitting schedules for units with physical operational limitations (exceptions) need to submit 20 days prior to bi-annual enrollment period
 - Operational limitations include
 - Restrictions due to age & long term degradation
 - Modifications due to life extension program
 - Environmental permit limitations (non-emergency conditions)

Note: PLS exceptions need to be submitted 20 days prior to December 1, 2008 implementation

Submit request for new exception to ParameterExceptions@pjm.com

All Parameter-Limited Schedules must be submitted in eMKT 7 days prior to the bi-annual enrollment period



- 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.
- Each generation supplier must supply the required unit operating data in support of the exception.
- 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.

NEW Daily Exception Process - Timeline

- **By 10 am prior to the close of DAM**
 - Initial Deadline to request a parameter exception that will begin the next operating day
 - PLS Schedules (both Price & Cost) will be revised in eMKT to change the parameter limit for the next operating day
 - Daily Exception Requests should be emailed to ParametersExceptions@pjm.com

- **By 4 pm prior to operating day (close of the DAM)**
 - PJM must receive a complete exception request that includes:
 - Unit Name
 - Parameter Limit Requested
 - Reason for Daily Exception Request
 - Justification for Daily Exception Request, including required unit operating data in support of the exception
 - Date on which the exception period will end. Exceptions granted may not continue past the beginning of the next period.

 - If PJM does not receive a complete exception request, and the unit did not clear in the DAM, the unit schedule will returned to its previous parameter limits.

- **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 Operating Agreement.
 - While under dispute, the generation supplier will be required to submit parameter-limited schedules for the period as determined during the exception process.

- 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.

- A resource could have its parameters changed under certain operational conditions. These conditions are:
 1. failing a Three Pivotal Supplier Test
 2. Max Generation Alert, loading, etc.
- Parameters that could be impacted are Turn Down Ratio, Min Down Time, Min Run Time, Min Daily Starts, Max Weekly Starts
- Exceptions, for the entire 6-month period or for a certain number of days within the period, may be submitted. Exceptions must abide by the timeline and other requirements per the business rules.

- Current Rule
 - PJM calculates all generator balancing operating reserve deviations as (Real time MWh – Day-Ahead MWh)
- Desired Outcome
 - Create greater incentive for generators to follow PJM dispatch instruction
- Proposed Changes
 - PJM will determine whether a generator is following dispatch and calculate the deviation based on a new calculation incorporating ramp limited desired MW

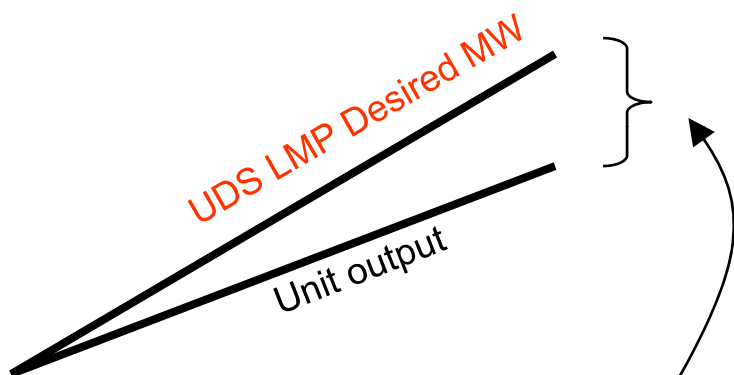
Definitions, Acronyms, and New Terms applicable to RLD

- 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

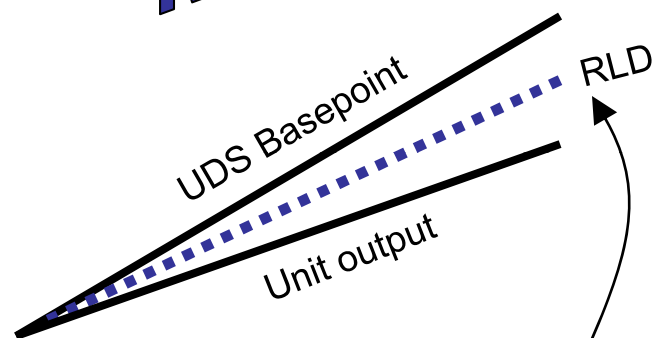
- Which units will this apply to?
 - DA Scheduled units
 - RA Run (2nd pass) Scheduled units
 - Must-Run units that are dispatchable and dispatched above Eco Min

Old Rules



If greater than 10%, unit could be considered deviating (10% of PJM desired, 5% or 5MW from DA schedule)

New Rules



Dotted line represents Ramp-Limited Desired MW

Deviations based on this new line (see previous slide)

$$\text{Ramp_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLAtime}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

- AOutput = Unit's output at case solution time
- UDSLAtime = UDS look ahead time
- Case_Eff_time = Time between base point changes
- RL_Desired = Ramp limited desired MW

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

No Deviation Calculation ?

Real Time MWh – Ramp Limited Desired MWh ?

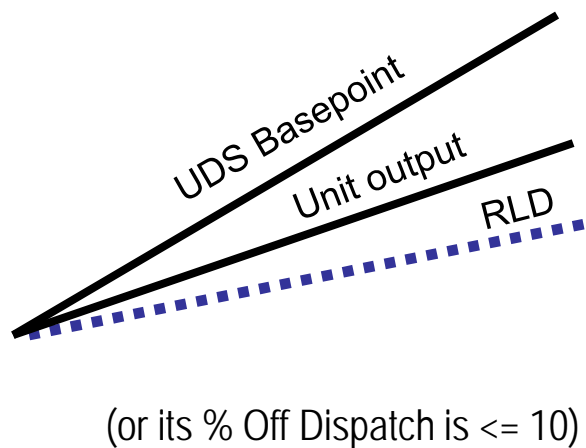
Real Time MWh – UDS LMP Desired MWh ?

Real Time MWh – Day-Ahead MWh ?

See Business Rules for more details

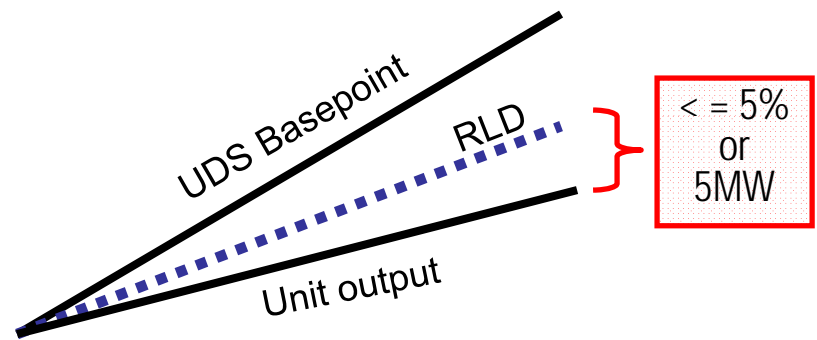
BR 39: A **pool-scheduled or dispatchable self-scheduled** generator is considered to be "following dispatch" if its actual output is between its Ramp Limited Desired MW and UDS Basepoint, (or its % off dispatch is ≤ 10) or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated Ramp Limited Desired MW. A self-scheduled generator must also be dispatched above economic minimum.

Unit considered following dispatch
(Dotted line represents Ramp-Limited Desired MW)



No Deviation Calculation

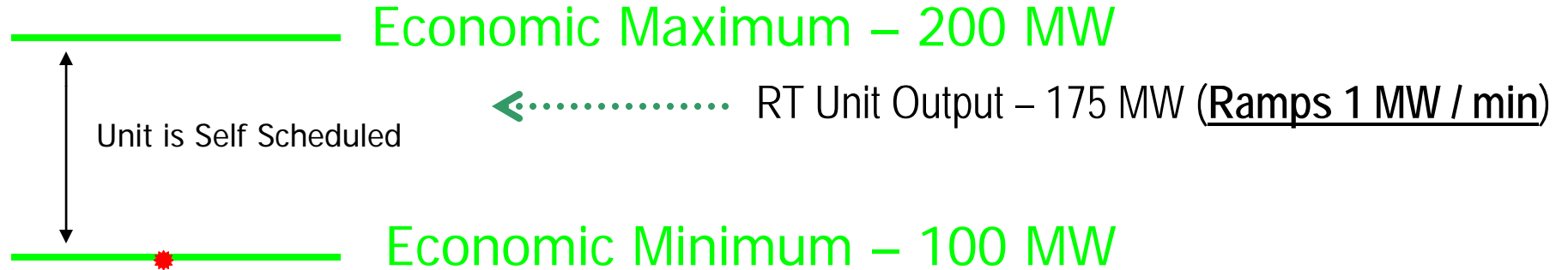
Unit considered following dispatch
(Dotted line represents Ramp-Limited Desired MW)



No Deviation Calculation

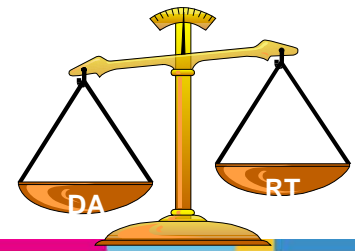
Operating Scenarios with RLD (Example 2)

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|



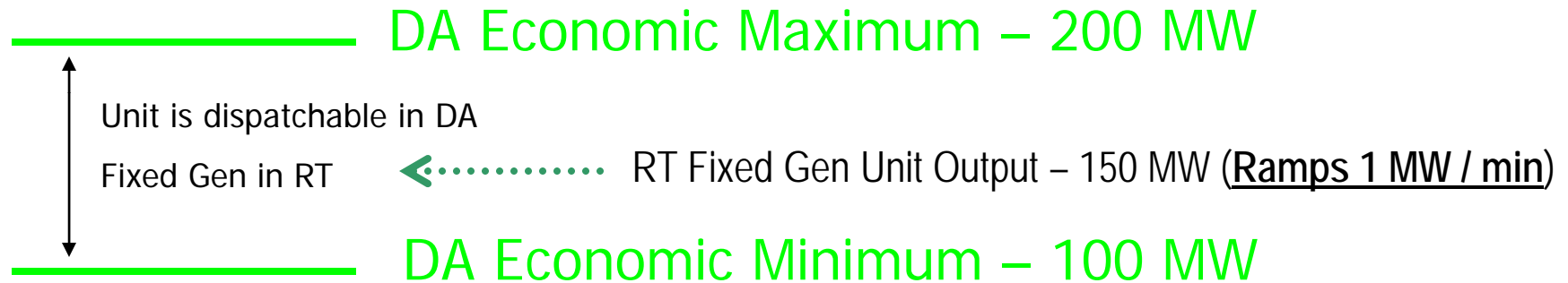
The RT dispatch lambda is \$50, which translates to 100 MW (Eco Min)

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 $|\text{hourly integrated Real-time MWh} - \text{UDS LMP Desired MW}|$



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

Deviation based on RT MWh - UDS LMP Desired

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
 $|\text{hourly integrated Real time MWh} - \text{UDS LMP Desired MWh}|$

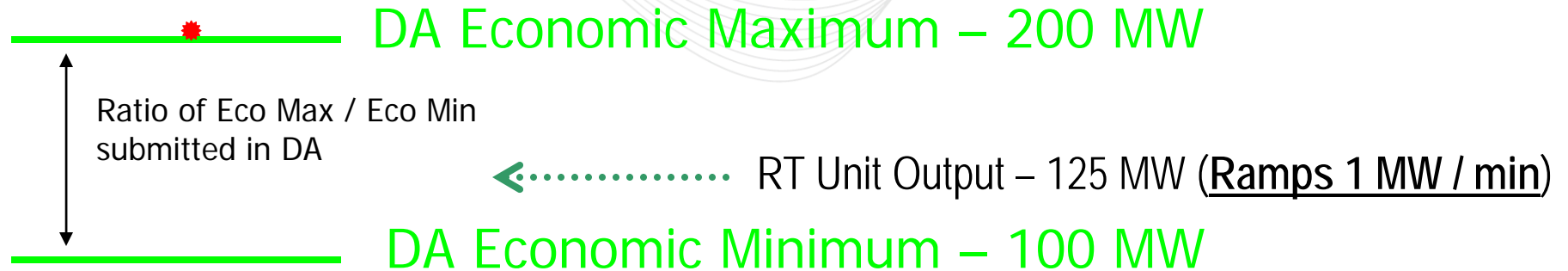
In Summary:

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:

$$\text{Real Time MWh} - \text{UDS LMP Desired MWh}$$

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

$$\text{Real Time MWh} - \text{Ramp Limited Desired MWh}$$



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

If RT Eco Max = 200 and RT Eco Min = 100
 then,

Deviation based on Ramp-Limited Desired (145 – 125) if unit does not respond to lambda increase
 (note: % off Dispatch is < 20%)

.....

If RT Eco Max = 200 and RT Eco Min = 125
 then,

Deviation based on UDS LMP Desired (200 – 125) if unit does not respond to lambda increase

BR 48: If the unit is deemed “not following dispatch” and its **% Off Dispatch is $\leq 20\%$** , the deviation will be calculated as the $|\text{hourly integrated Real-time MWh} - \text{hourly integrated Ramp Limited Des MW}|$.

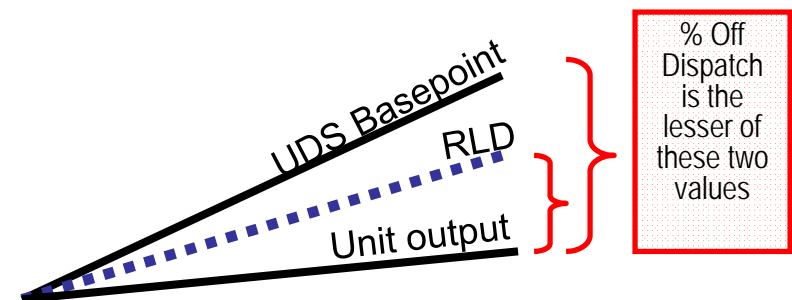
As mentioned earlier, If deviation value is within 5% or 5 MW (whichever is greater) of Ramp Limited Desired MW, no deviations will be calculated

Deviation based on RT MWh – Ramp-Limited Desired MW

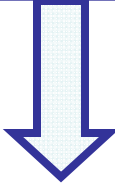
BR 49: If the unit is deemed to be “not following dispatch” and its **% off Dispatch is $> 20\%$** , the unit’s deviations will be calculated as $|\text{hourly integrated Real time MWh} - \text{UDS LMP Desired MWh}|$

Deviation based on RT MWh – UDS LMP Desired MWh

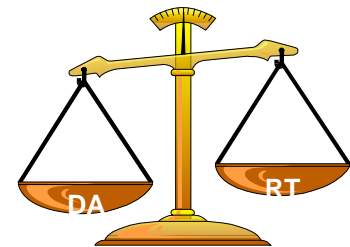
% Off Dispatch – percentage off dispatch using the lesser of the difference between the actual output and the UDS basepoint or the actual output and Ramp Limited Desired MW



BR 50: If a unit is deemed to be “not following dispatch” and **has tripped**, the deviation MW for the hour it tripped and the hours it remains offline throughout its DA Schedule will be calculated as |hourly integrated Real time MWh – Day-Ahead MWh|



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



- 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

- Current Rule
 - PJM calculates all generator deviations individually. Deviations by one generator cannot offset deviations by another generator.
- Desired Outcome
 - Recognize that generator injections at the same bus are electrically equivalent as far as their impact on the system.
- Proposed Changes
 - Generators that deviate from RT dispatch may offset deviations by another generator at the same 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

Old Rules

Unit 1: 12MW deviation
Unit 2: 22MW deviation

Total MWs subject to BOR charges: 34MW

New Rules

Deviation MW at the Bus:
 $12\text{MW} + (-22\text{MW}) = 10\text{MW}^{**}$
 (**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

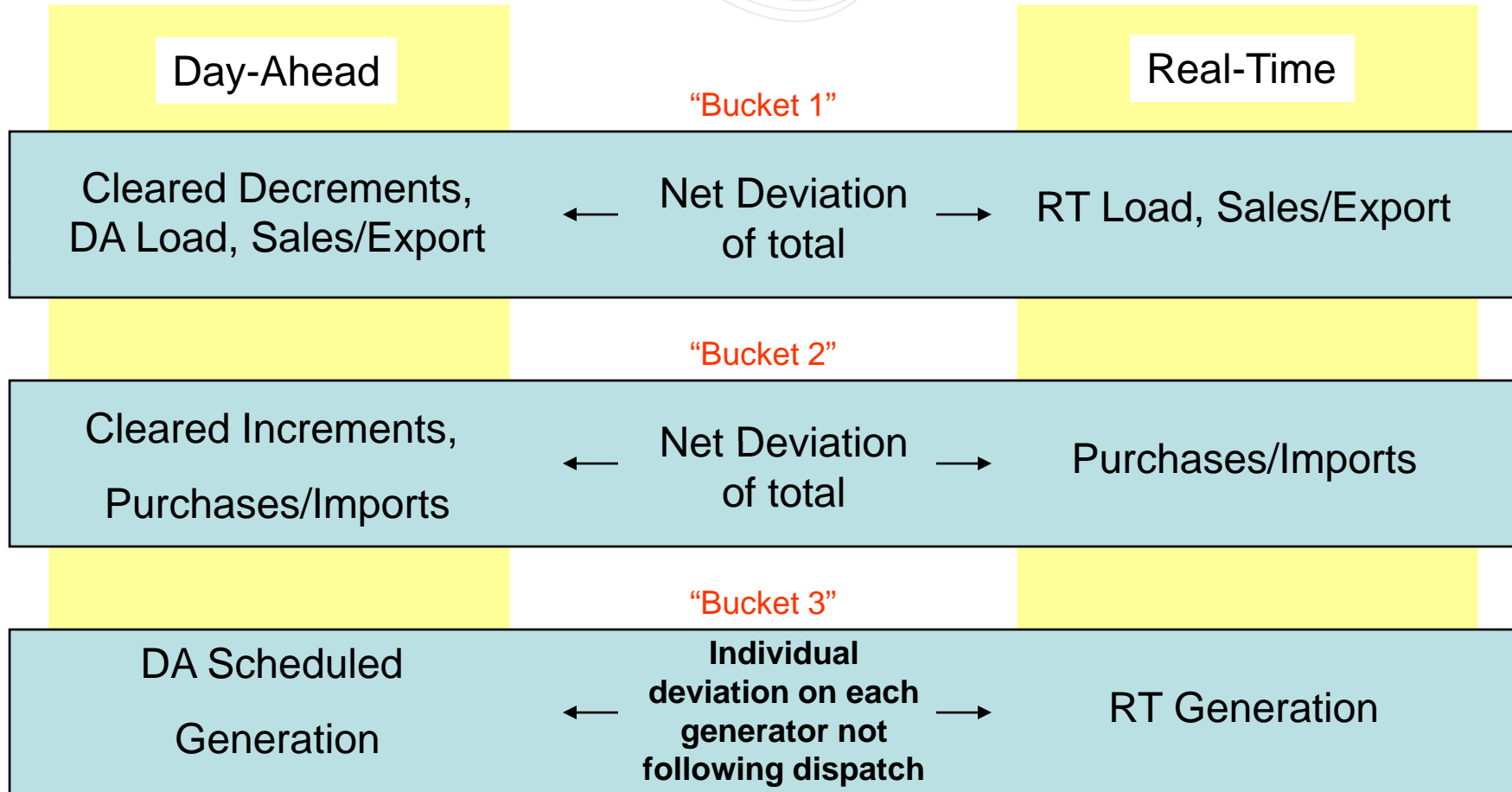
- Generators that deviate from RT dispatch may offset deviations by another generator at the same bus
- For deviations purposes, these two units will look like one unit
- This change should be an overall benefit to a handful of generators within PJM



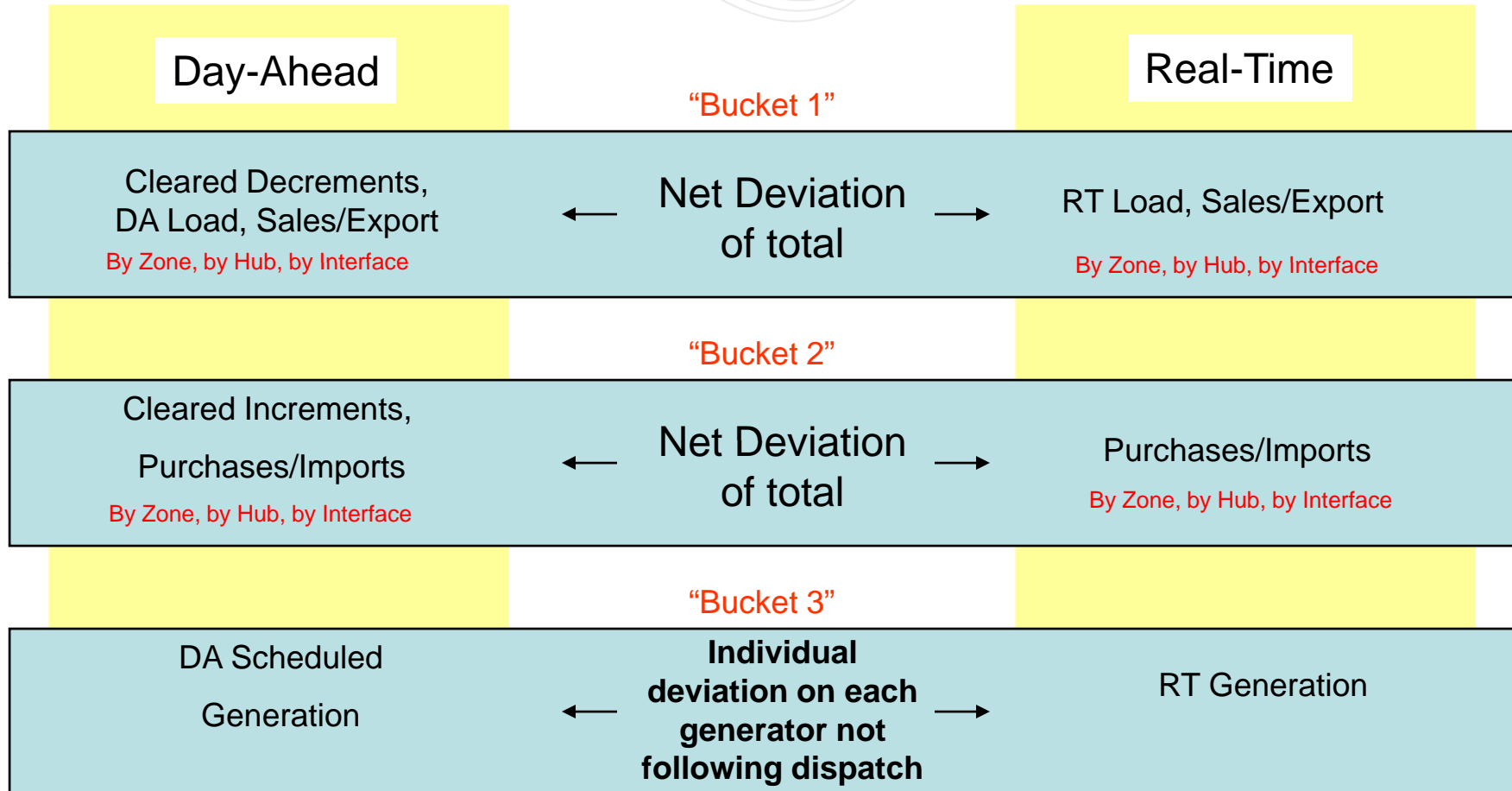
Rule changes applicable to Demand (Load Serving Entities)

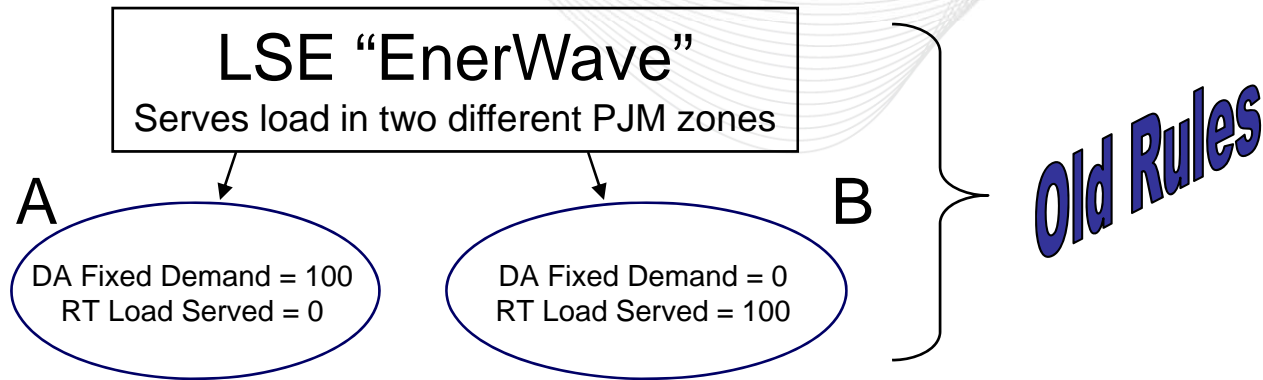
- Current Rule
 - Demand bucket is netted across the RTO, meaning that a negative deviation in one zone could be offset by a positive deviation another zone. Supply bucket is also netted across the RTO.
- Desired Outcome
 - Recognize that deviations at differing locations on the system can impact balancing operating reserve costs.
- Proposed Change
 - Demand bucket should be netted by zone, hub, or interface. Supply bucket should be netted by zone, hub, or interface.

Balancing Operating Reserve Charges Applied to:

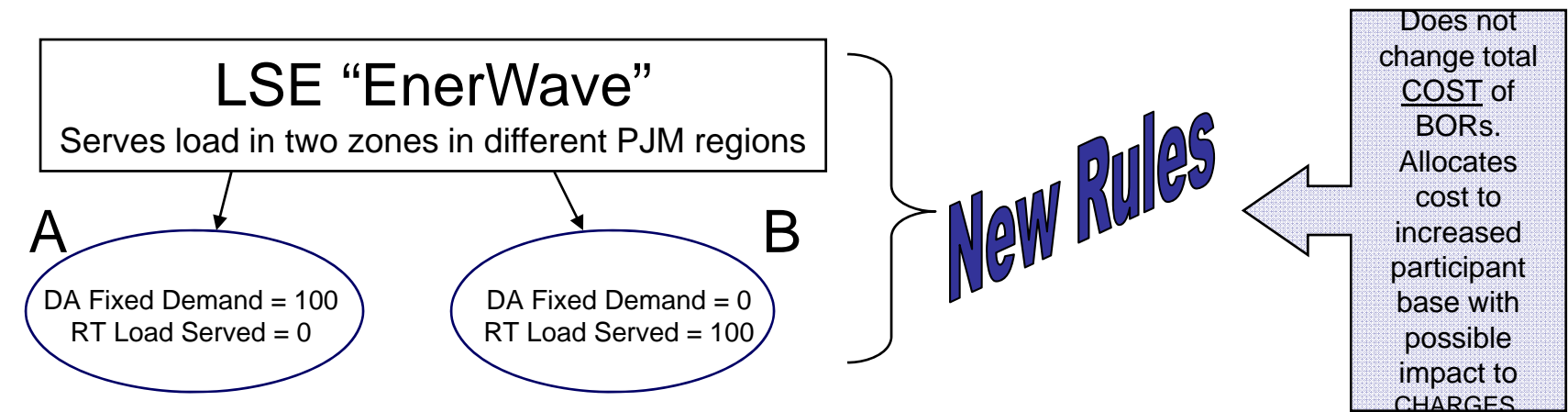


Balancing Operating Reserve Charges Applied to:

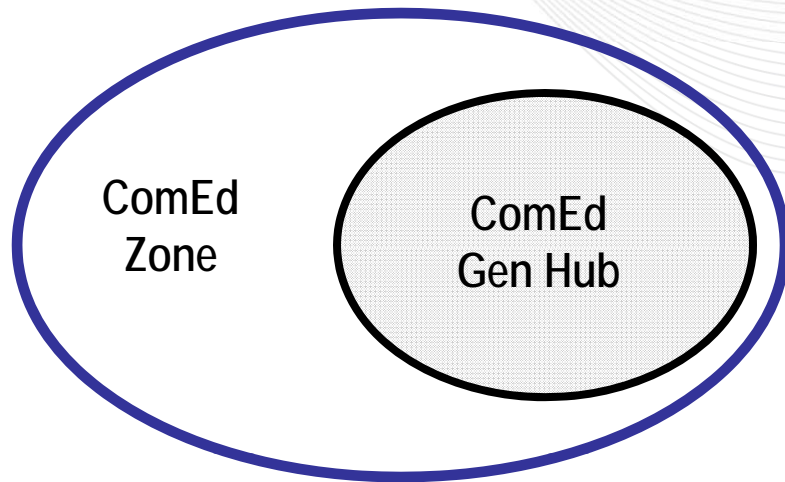




Deviation calculation = 0 MW Total Dev (DA position in Zone A offsets RT position in Zone B)

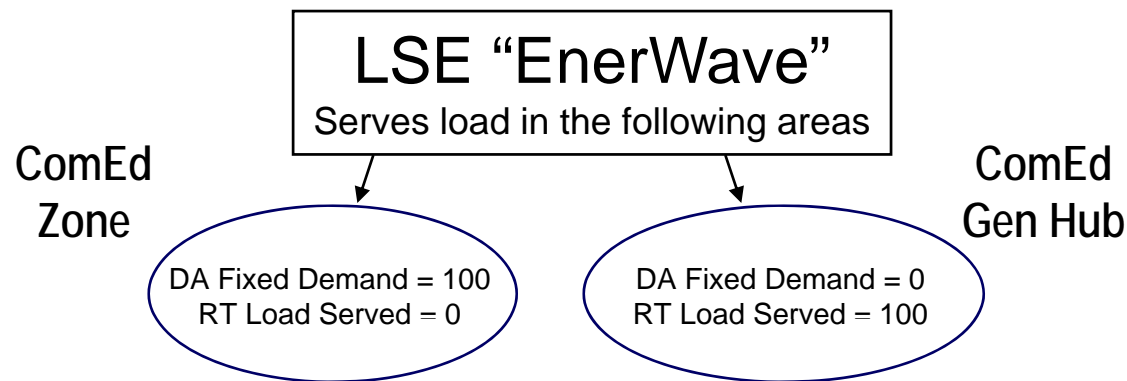


Deviation calculation = 100 (Zone A) + 100 (Zone B) = 200 MW Total Dev



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)

- For determination of BORs, Demand and Supply buckets will be netted by Zone, Hub, or Interface
- Deviations for Generators will continue to be calculated by individual unit (except for Supplier Netting at the Bus change as previously discussed)

Current Rule

- Under the current Operating Reserve methodology, all Balancing OR Costs are allocated to deviations.

Desired Outcome

- 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.

Proposed 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.**

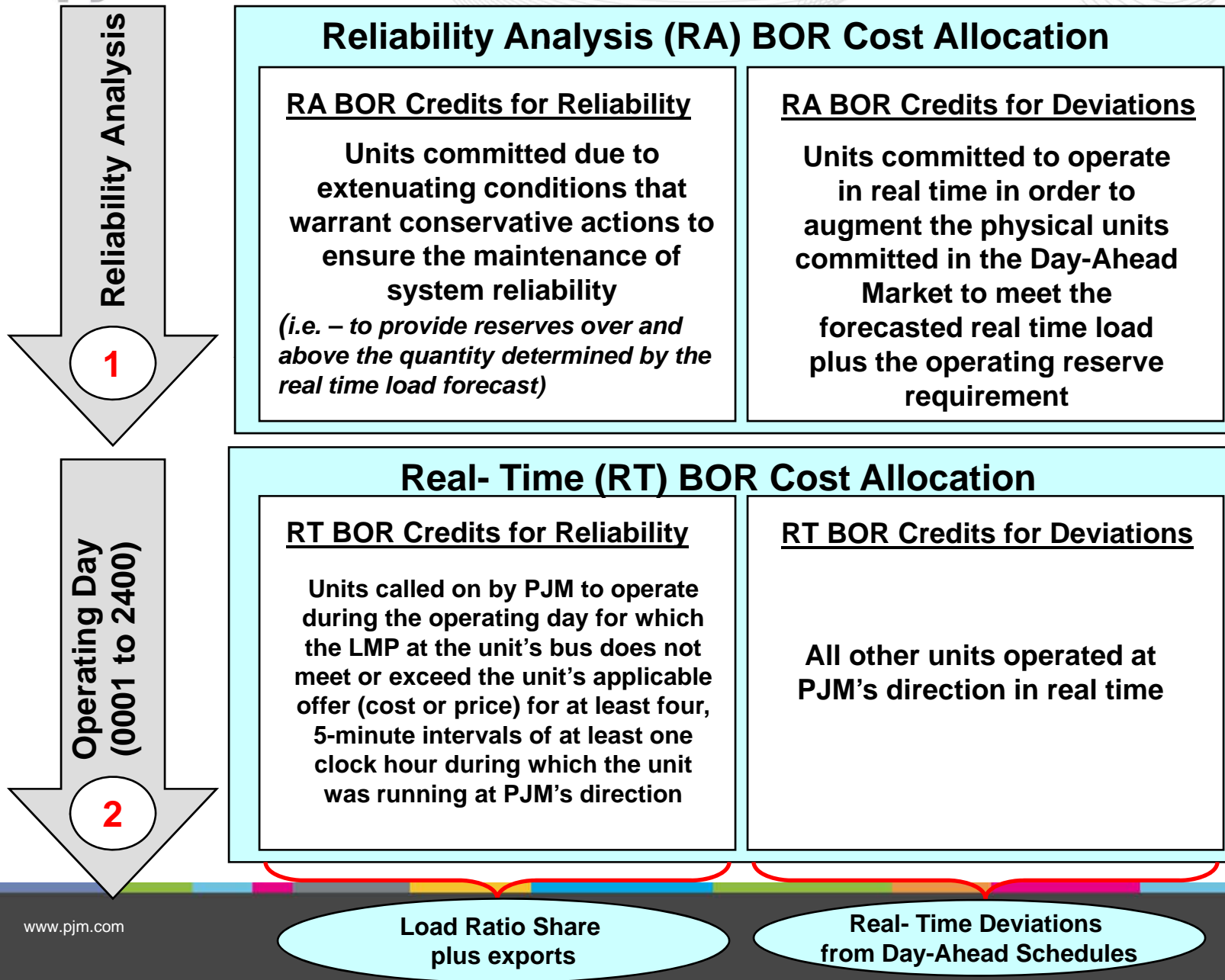
Differentiating the reasons why operators are making decisions into the following categories:

- 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	All Deviations (Including Incs & Decs)



Balancing Operating Reserve Cost Allocation (BORCA)

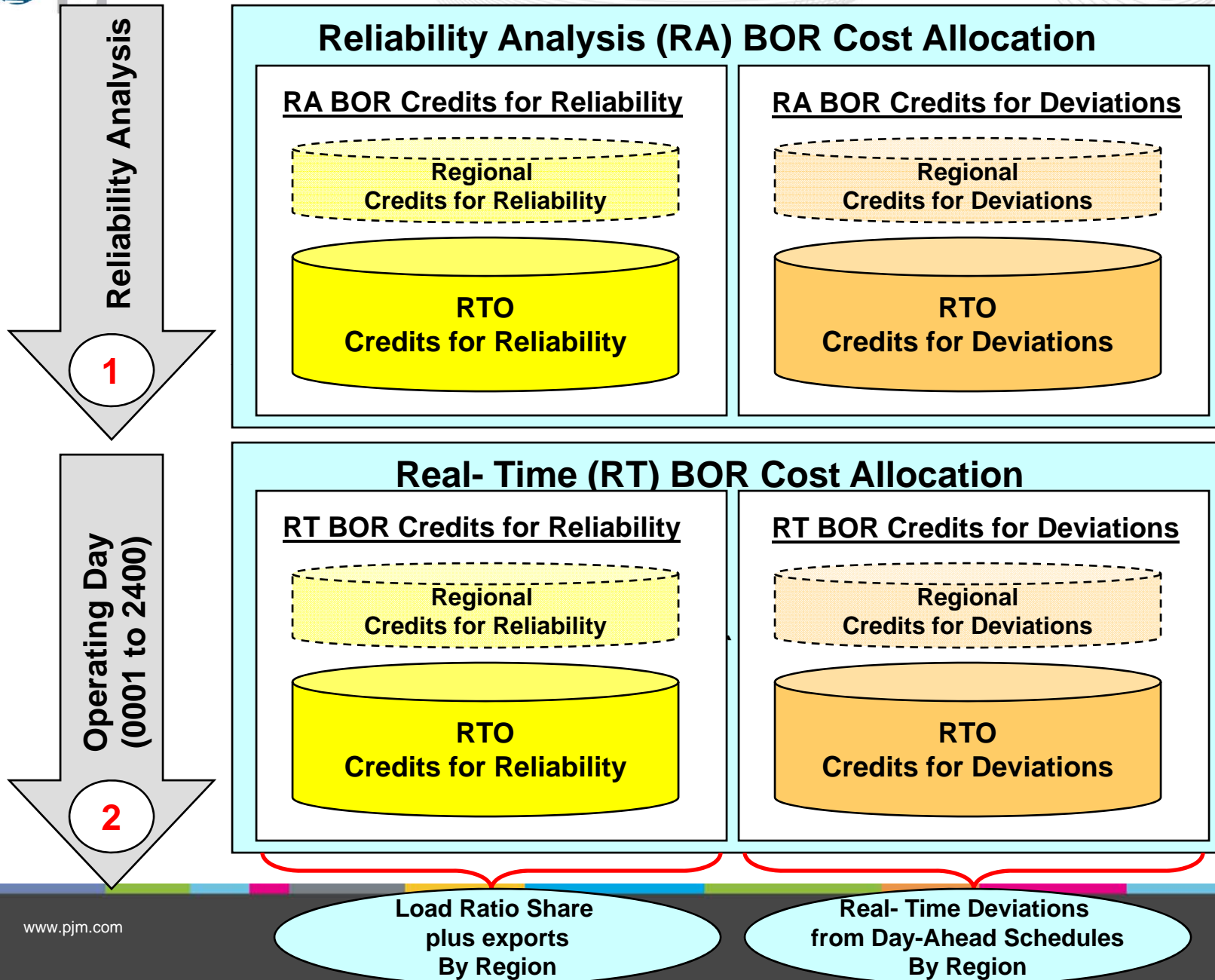


- Current Rule
 - All balancing operating reserve credits are divided equally among all deviations (Supply Bucket, Demand Bucket, and Generator Bucket), to create a single Balancing Operating Reserve Rate across the PJM RTO.
- Desired Outcome
 - Recognize that some Balancing OR credits are accrued to manage local constraints
- Proposed Change
 - Allocate OR charges that were accrued for local constraints to the regions, creating “regional” rates for Balancing Operating Reserve charges.

- As determined during Real Time (RT) or during the Reliability Analysis (RA), Balancing Operating Reserve Credits will be identified for either:
 - a) Reliability or b) Deviations: and
 - will be collected for the RTO and/or each Region based on whether units were committed for transmission constraints and if so, for which constraints they were committed.
- PJM will post the aggregate amount of MWs committed that meet this criteria in all the respective buckets.

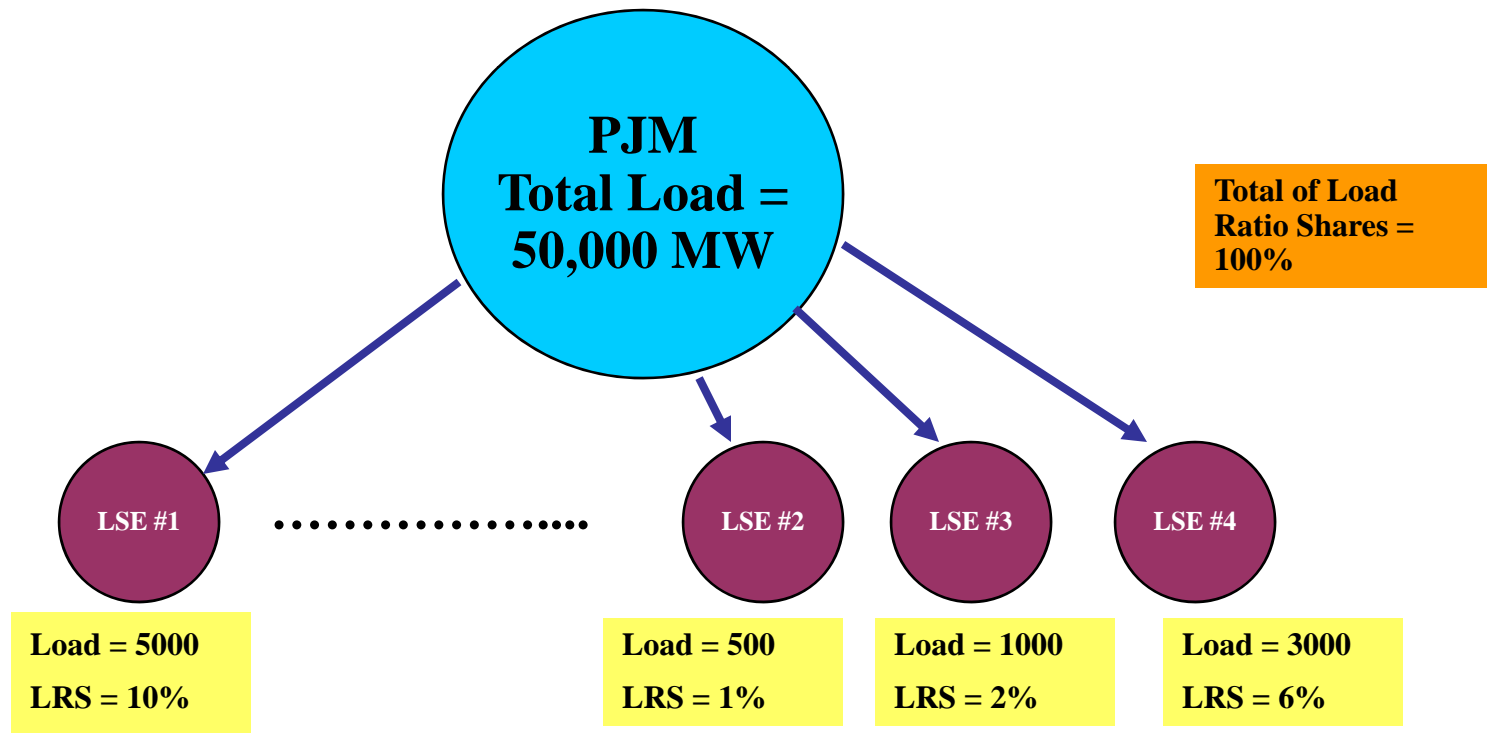


Balancing Operating Reserve Cost Allocation - Regional

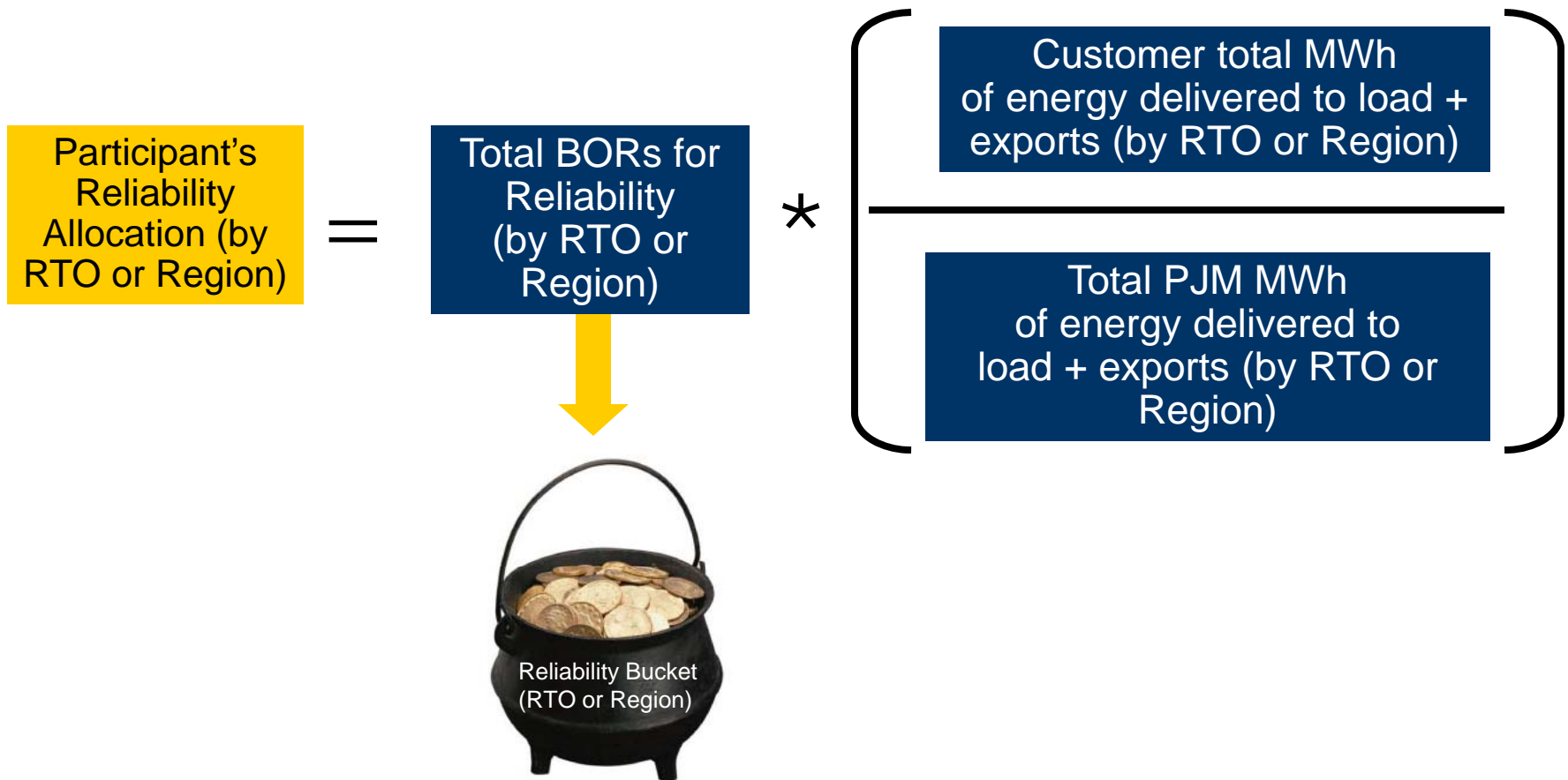


• Definition of Load-ratio Share


- A Market Participant’s portion of a total obligation or charge based on their “load”
 - $(\text{LSE load}) / (\text{PJM Total Load})$



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



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

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


$$\text{Participants Deviation Allocation} = \text{RTO Rate for BORs for Deviations} * \text{Total MW Deviations of Participant}$$

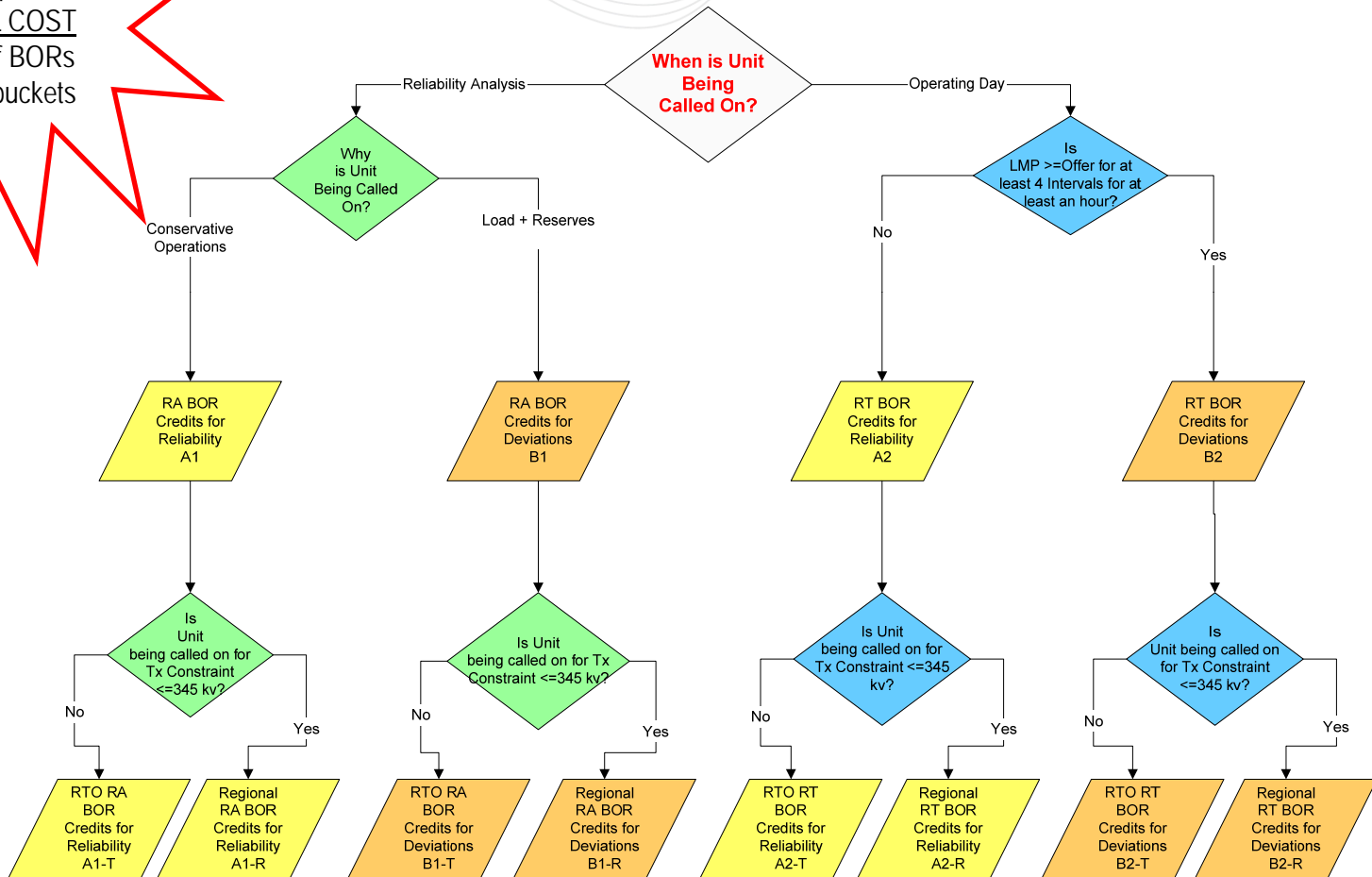
This example shows the calculation for deviations across RTO (not regional)



Balancing Operating Reserve Cost Allocation

This BORCA process separates the TOTAL COST (credits) of BORs into eight buckets

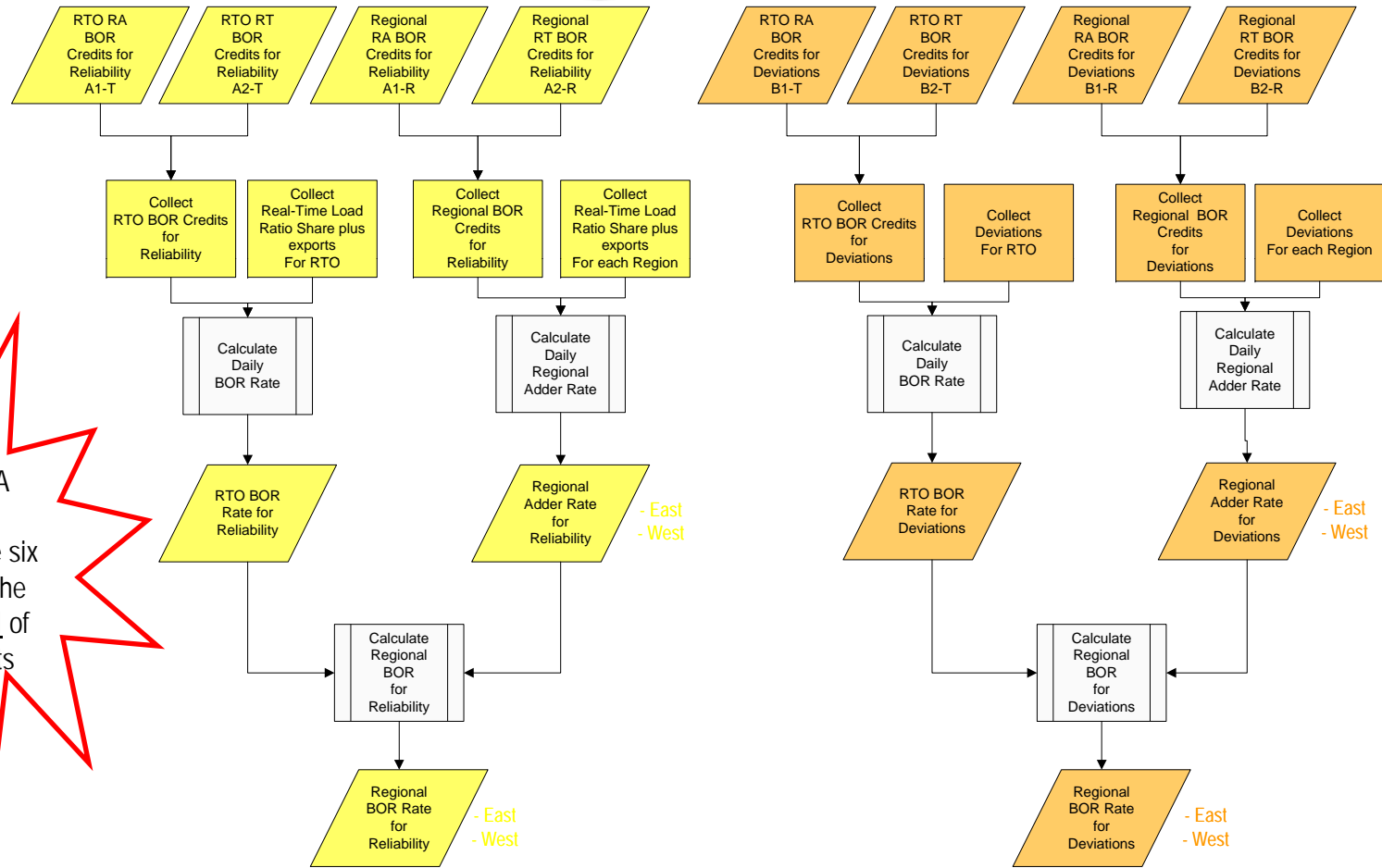
Balancing Operating Reserve Cost Allocation



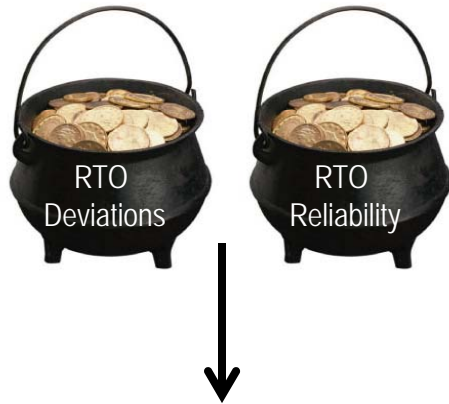


Balancing Operating Reserve Cost Allocation - Regional

Regional Balancing Operating Reserve Cost Allocation



This BORCA process determines the six (6) rates for the ALLOCATION of the total costs



Allocated to LSEs or Deviations across RTO including those who might have charges from the regional bucket

The rate for this bucket will be the RTO rate



Allocated to LSEs or Deviations in region

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

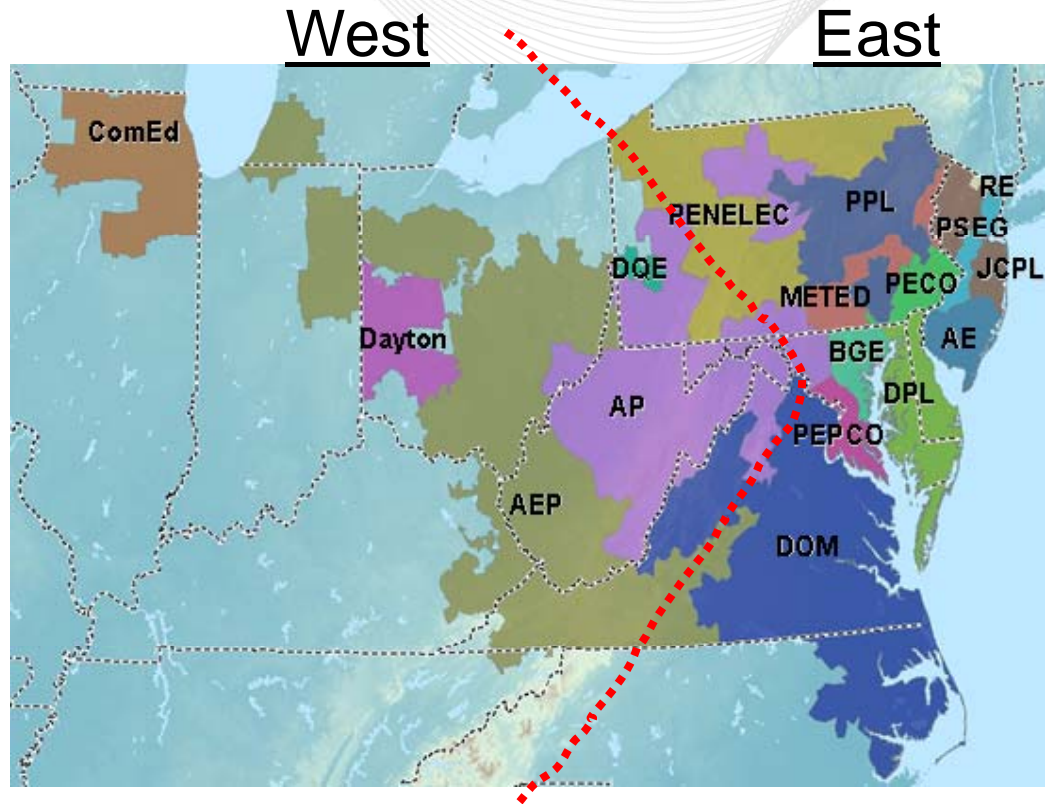
Regional costs allocated regionally

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

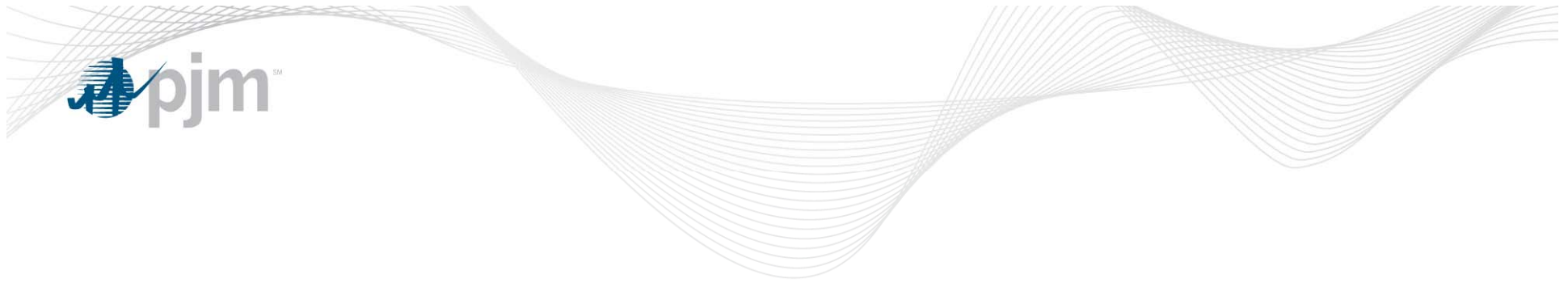


For regions that do not have Regional Adders, the Regional BOR Rate for Deviations and/or Reliability will equal the RTO BOR Rate for Deviations and/or Reliability

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, PEPCO, DPL, PSEG, RECO, AE



The following are some scenarios for Balancing Operating Reserve Cost Allocation (BORCA)...

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

- The Load Ratio Share of Enerwave is:

<u>ComEd</u> – 30%	Western Region – 2%	RTO – 1%	➔	3% Total RTO
<u>BGE</u> – 40%	Eastern Region – 4%	RTO – 2%		

- Cleared Day Ahead Market Bids:

ComEd – 1000 MW Fixed Demand, 50 MW Dec, 10 MW Inc
BGE – 1500 MW Fixed Demand

Daily BOR Rates:

RTO Rate for Reliability: \$3
 Regional Adder for Reliability (East): \$2
 Regional Adder for Reliability (West): \$1
 RTO Rate for Deviations: \$2
 Regional Adder for Deviations (East): \$2
 Regional Adder for Deviations (West): n/a



Scenario #1 – BOR Cost Allocation

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

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

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

How will PJM allocate the BOR charges?

- A) Load Ratio Share plus Exports by RTO
- B) Load Ratio Share Plus Exports by Region
- C) Real Time Deviations from Day-Ahead Schedules by RTO
- D) Real Time Deviations from Day-Ahead Schedules by Region

Scenario #1 – BOR Cost Allocation (cont)

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

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

In ComEd:

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

In BGE:

200MW X \$2 = \$400 (Load dev)

Total BOR charges for Enerwave
 \$720

RTO Rate for Deviations

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)

In BGE:

150MW X \$2 = \$300 (Load dev)

Total BOR charges for Enerwave
 \$620 ***

RTO Rate for Deviations

*** previous rules would calculate \$20 (Inc) in BOR charges due to netting deviations across RTO

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)

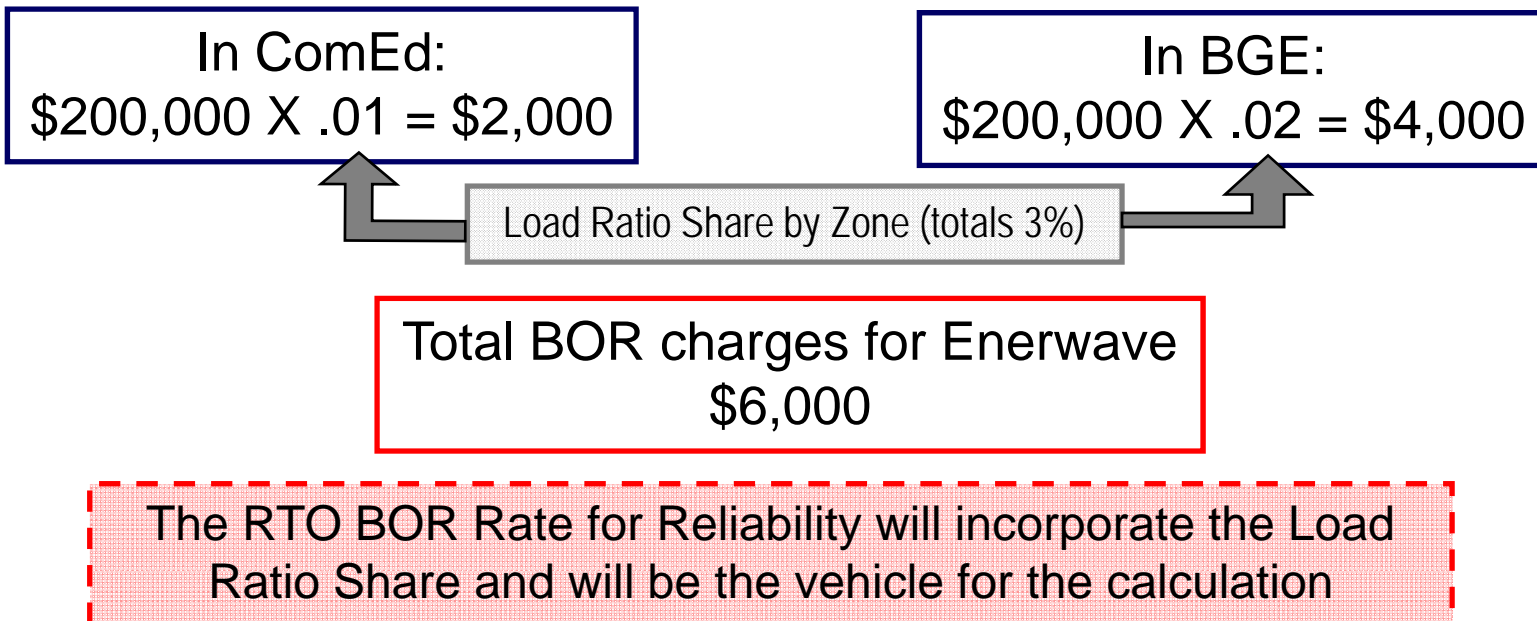
How will PJM allocate the BOR charges?

- 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?



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)

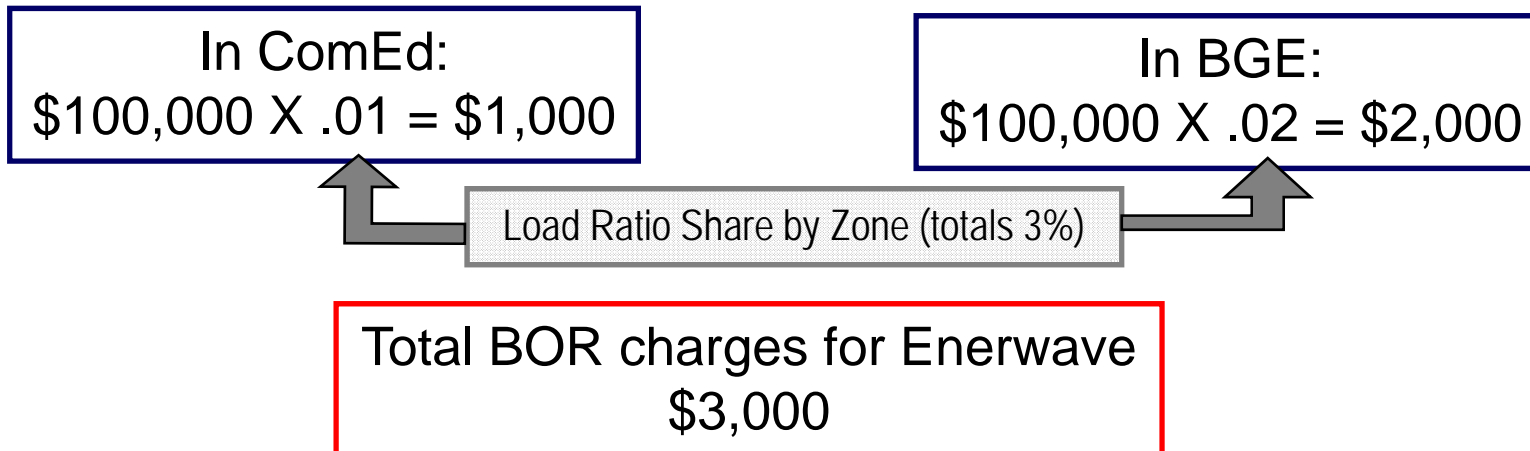
How will PJM allocate the BOR charges?

- 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?



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:
 $200\text{MW} \times \$2 = \$4,000$ (Load dev)

\$2 Regional Adder (East)

Total BOR charges for
PSEG constraint: \$4,000

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

The Regional Adder for Deviations will incorporate the participants deviation from DA position and will be the vehicle for the calculation

Scenario #6 – BOR Cost Allocation

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

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

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

How will PJM allocate the BOR charges?

- A) Load Ratio Share plus Exports by RTO
- B) Load Ratio Share Plus Exports by Region**
- C) Real Time Deviations from Day-Ahead Schedules by RTO
- D) Real Time Deviations from Day-Ahead Schedules by Region

Scenario #6 – BOR Cost Allocation (cont)

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

In ComEd:
 $\$300,000 \times .02 = \$6,000$

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

- The allocation of Balancing Operating Reserve Charges will be more “cost causation” focused
- BOR costs associated with reliability will be allocated based on Load Ratio Share. BOR costs associated with deviations from DA commitments will be allocated to those entities who deviated from DA scheduled quantities.
- Using the above criteria, BORs that are associated with a constraint of $\leq 345\text{kV}$ will be allocated regionally

Information on the PJM Web....

The screenshot shows the PJM website's navigation structure. The top navigation bar includes links for 'careers', 'site map', 'legal & privacy', and 'contact us'. Below this is a breadcrumb trail: '> About PJM > Services > Planning > eTools > Markets > Committees & Groups > Documents'. A dropdown menu is open under 'Markets', listing various categories. The 'Energy' category is highlighted, and its sub-menu is also open, with 'Operating Reserves' selected. A red box highlights the 'Operating Reserves' link in the sub-menu. The main content area shows the 'Operating Reserves' page header and introductory text.

> Home > Markets > Energy > Operating Reserves

Operating Reserves

In the current PJM market design, pool-scheduled generation resources that operate as requested by PJM are guaranteed to fully recover their daily day-ahead offer amounts in order to ensure adequate Operating Reserves and to support the PJM Real-Time ("Balancing") Energy Market. Day-ahead and real-time operating reserve credits are paid to generation owners; these credits are paid by PJM market participants as operating reserve charges.

The Market Implementation Committee (MIC) created the Reserve Markets Working Group to develop proposed modifications to the Operating Reserve mechanism. The working group identified a set of modifications that could improve the Operating Reserve mechanism. Revised business rules were endorsed by the Members Committee in November 2007. They are scheduled for implementation in Fall 2008, pending FERC approval.

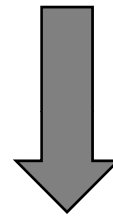
> Energy
> Real Time
> Day Ahead
> LMP Model Information
> Day-Ahead Scheduling Reserve Market
> Operating Reserves

Related Links
[Reserve Markets Working Group \(RMWG\)](#)
[Training](#)

Postings	Posting Date
OA Revisions for Balancing Operating Reserve MC NOV-2007 (PDF)	04.11.2008
Overview of Revised Operating Reserve Rules (PDF)	04.11.2008
Operating Reserve Revised Business Rules v6 (PDF)	04.11.2008

Scroll Down to find postings on Business Rules, Training Links, etc.

PJM Operating Reserve Construct (Business Rules)



See handouts in front of classroom

Also, see Reserve Markets Working Group materials
<http://www.pjm.com/committees/working-groups/rmwg/rmwg.html>



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