Changes to Operating Reserve Accounting Methodology

PJM State & Member Training Dept.

Agenda

- 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

Interrelated Stakeholder Activity

	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

Current Operating Reserves Accounting Methodology

- Separate Operating Reserves for Day-ahead and Balancing Markets
- Cleared offers for <u>pool-scheduled</u> generation in the day-ahead market are guaranteed to be made whole for the day
- Accepted offers for <u>pool-scheduled</u> generation operating in the real-time market <u>as requested</u> 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)

Overview of BOR Credits (Current Rules)

- 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
  - 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

Overview of BOR Charges (Current Rules)

- 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 <u>not</u> 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

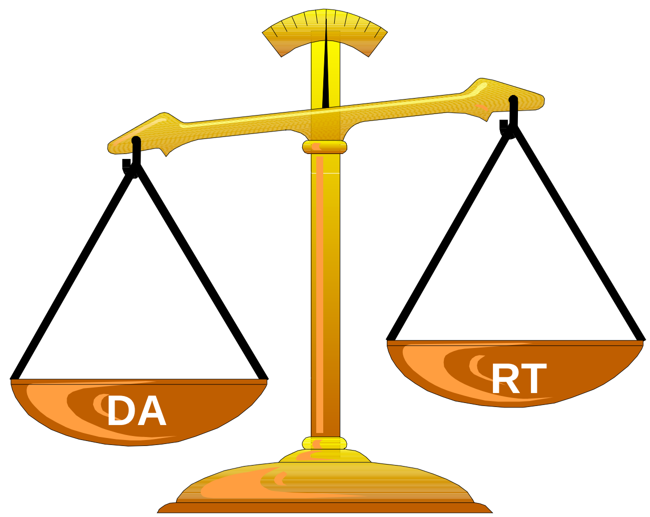
Overview of BOR (Current Rules)

Generator Offer: $100

- $75

$25

Charged to participants that deviate from Day Ahead Market position:

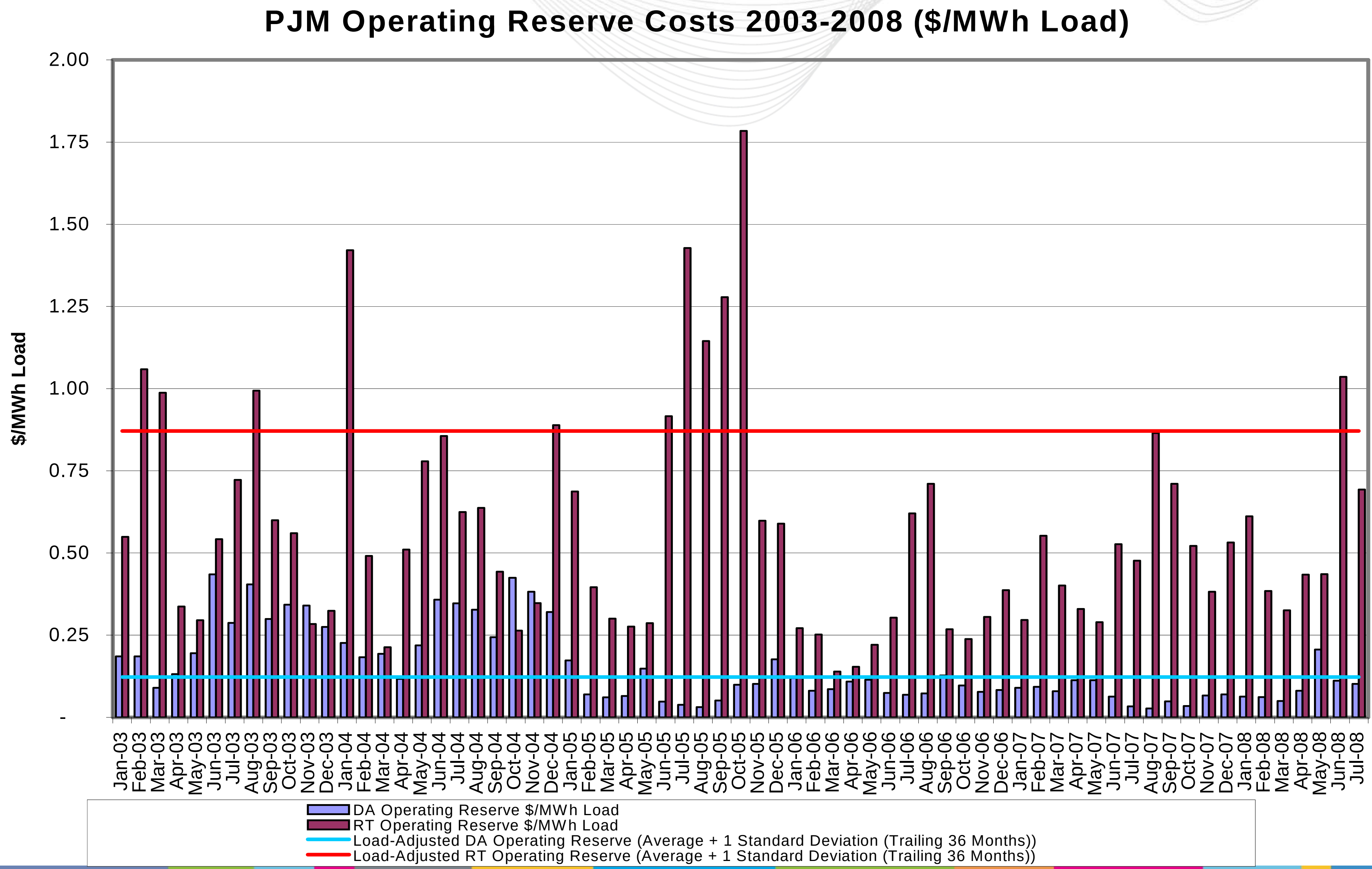


Total Revenue For Generator:

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

= $75

Operating Reserve Costs



Why the Complex Changes???

- 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

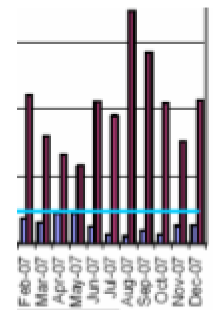
Total Cost:

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

(8)

Rate:

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



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Charge:

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

Total Cost ÷ Charge = Rate

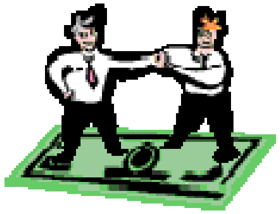
The "Package" of Proposed BOR Changes

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 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

Impact of Changes to Participants

The Members Committee voted on the BOR changes as a "Package." This approach facilitated comprise 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

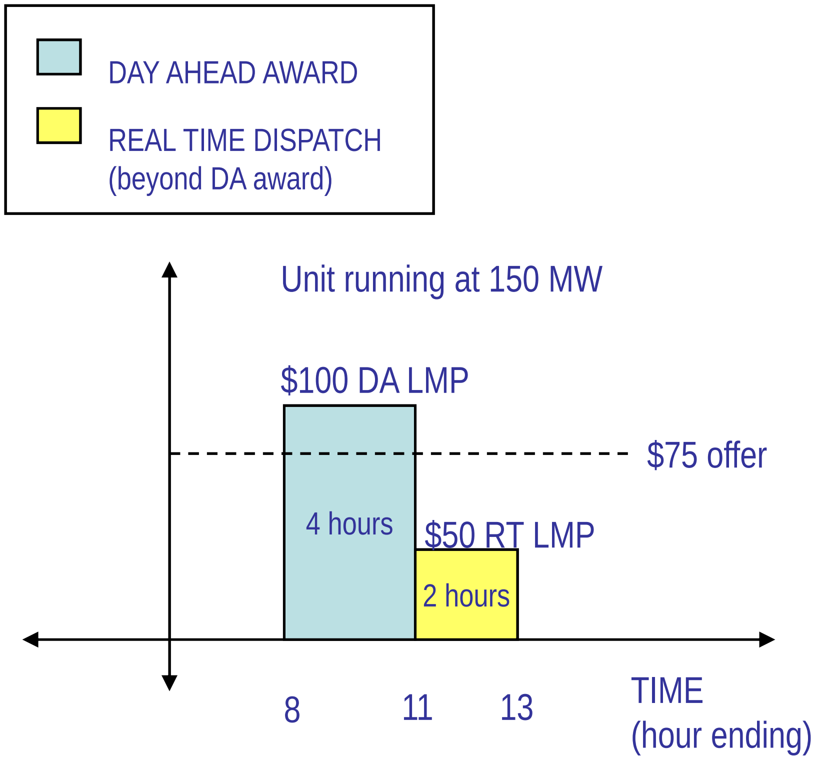
Rule changes applicable to Supply (generators)

Segmented Make Whole Payments

- 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

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

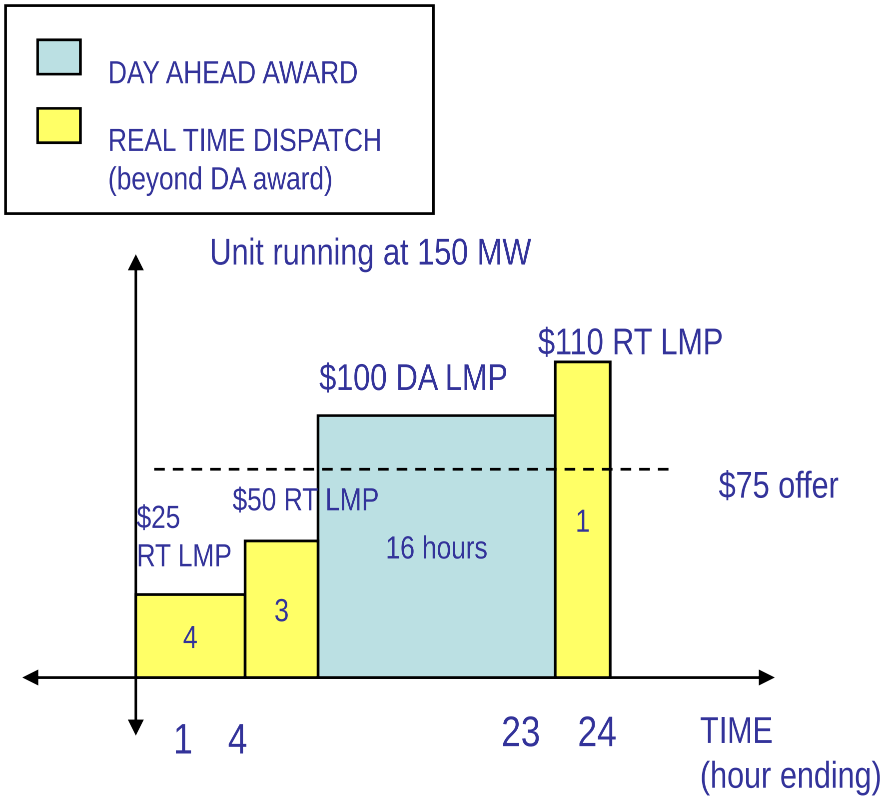
Note: Under current rules, this unit receives a balancing payment of $ 0

Balancing OR Credit = Offer Value (6 hours * $75 * 150MW) – (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

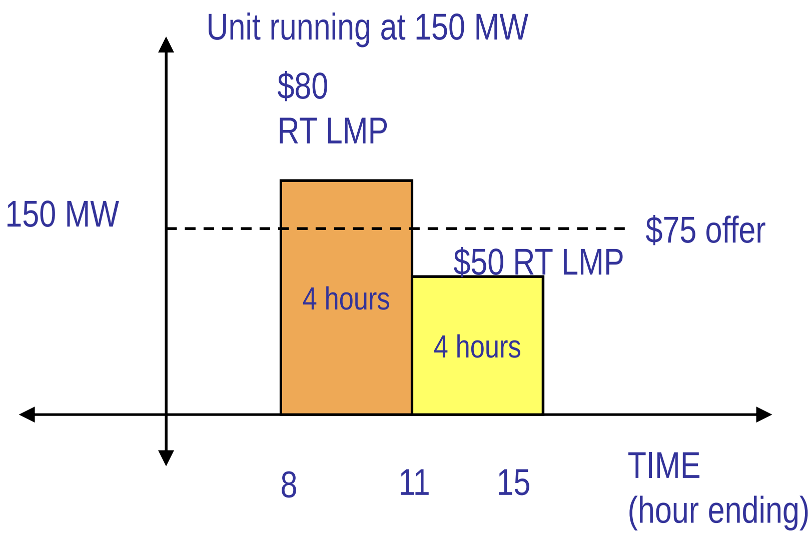
**DA operating reserve credits, regulation revenue, and spinning revenue are also applied against balancing OR credits.

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)

MIN RUN TIME – 4 HOURS

REAL TIME DISPATCH (beyond Min Run Time)



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

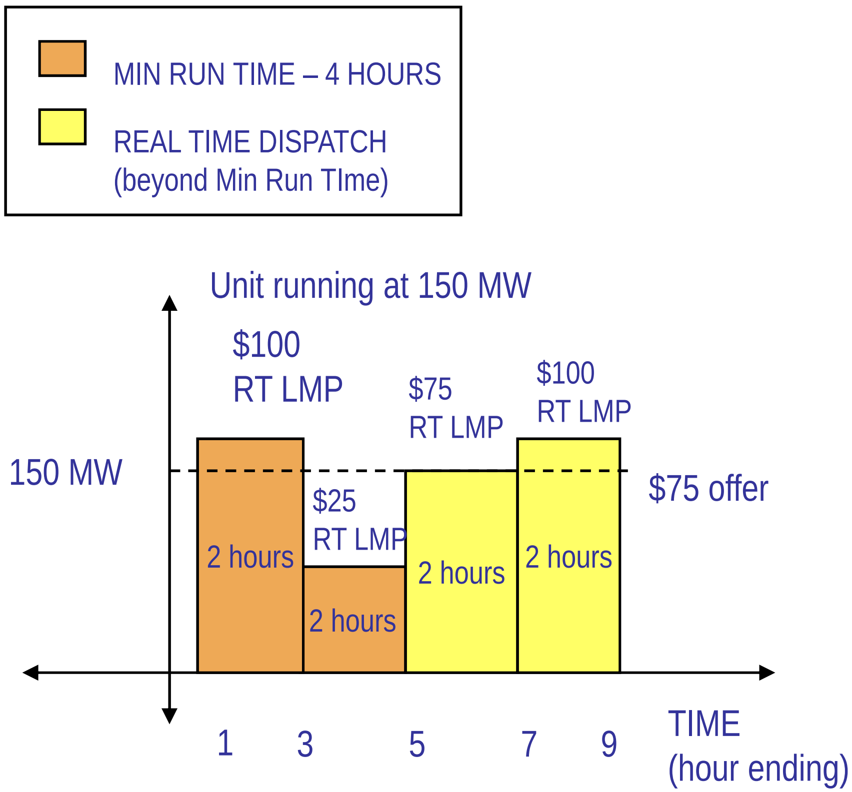
Note: Under current rules, this unit receives a balancing payment of $12,000

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.

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

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

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

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

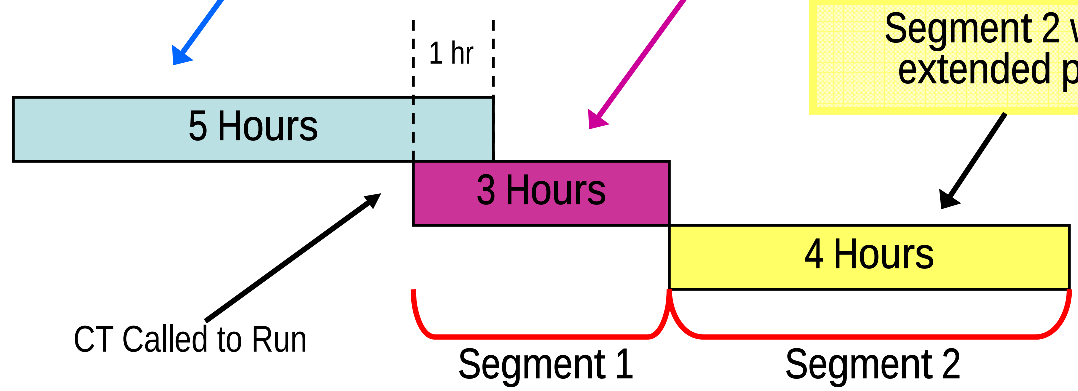
Example 5: CT Unit had DA commitment and was called to run in RT. The DA commitment and the time when the unit was called to run do not align.

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

The first four hours of the DA Award would not be considered for BOR calculations

Even though the CT had a DA commitment, Segment 1 would be the 3 Hour Min Run Time (greater than the 1 Hour DA as shown)

Segment 2 would be for the hours extended past the Min Run TIme



Segmented Make-Whole Payments
Example 6 – CT Unit w / DA Schedule is called in RT

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.

DAY AHEAD AWARD

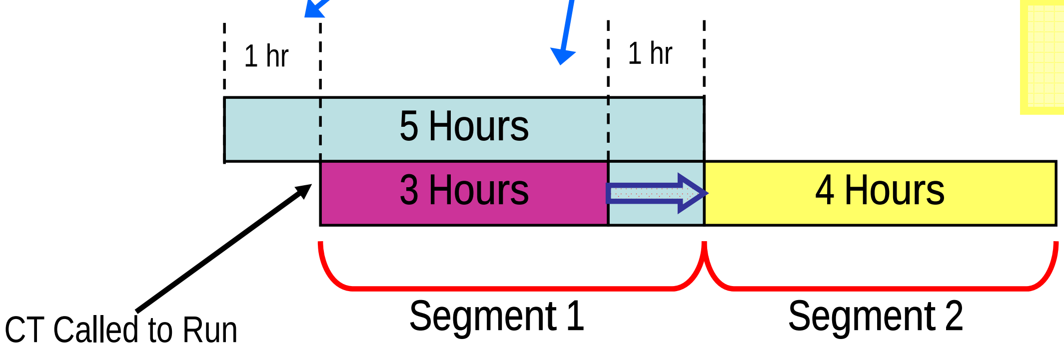
CT Extended past DA Award

MIN RUN TIME

The first hour of the DA Award would not be considered for BOR calculations. Segment 1 would be the remaining 4 hours of the DA award (greater than the 3 hour Min Run Time)

The Min Run Time would not apply for calculation of Segment 1

Segment 2 would be for the hours extended past the DA Award



Segmented Make-Whole Payments – Summary of Key Points

- 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.

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 - 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

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

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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

Without Parameter-Limited Schedules in effect:

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

HE 1 HE 48

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)

HE 1 HE 7

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.

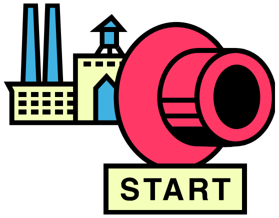
See Appendix for complete list of PJM-defined values

Parameter-Limited Schedules – example for Max Weekly Starts

Without Parameter-Limited Schedules in effect:

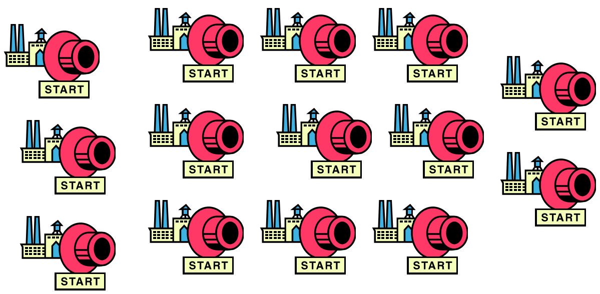
A Combustion Turbine (CT) with a 75MW ICAP submits Maximum Weekly Starts of 1

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.

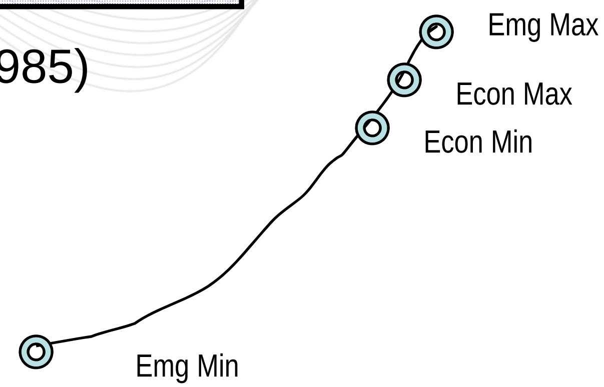
See Appendix for complete list of PJM-defined values

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)

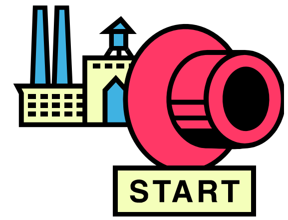
Business Rule 10 - 13: Turn Down Ratio is defined as the ratio of economic maximum MW to economic minimum MW. The minimum acceptable Turn Down Ratio applicable to an individual unit will be the greater of: a) the difference between the minimum of the economic minima and the maximum of the economic maxima 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:

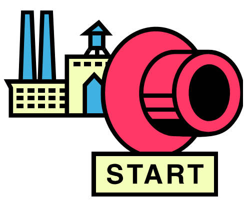
A Combined Cycle unit Maximum Daily Starts of 1

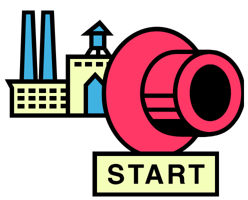


This parameter could result in market power issues (takes away PJM's flexibility to cycle unit)

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

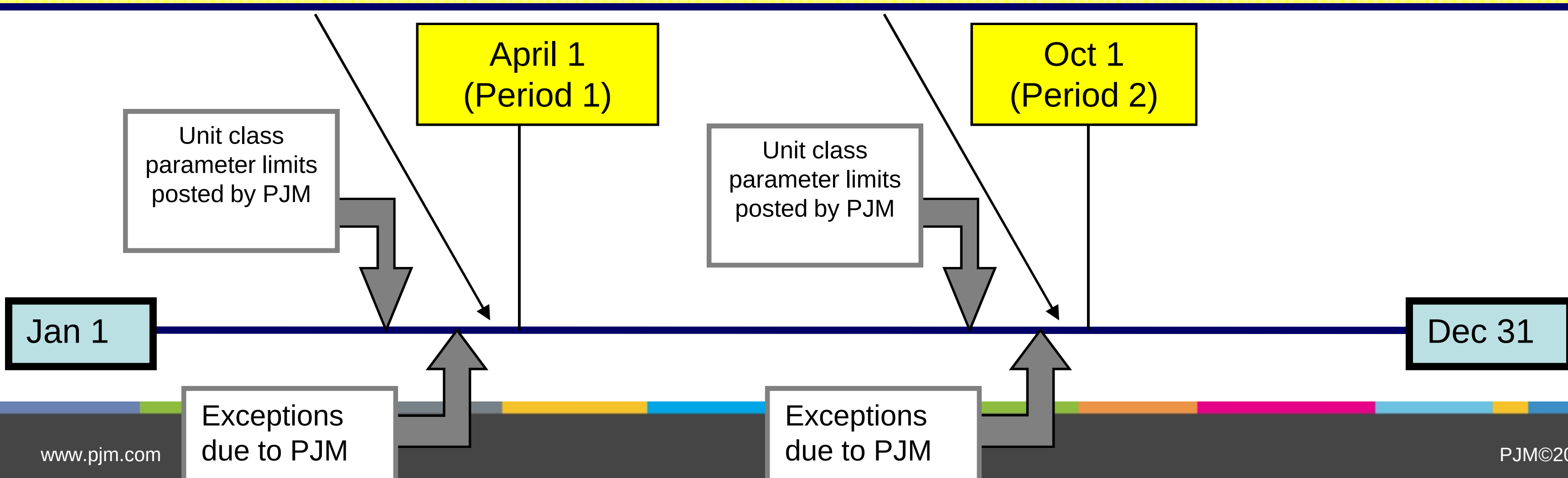
Parameter Limited Schedules - Timeline

- 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 ParametersExceptions@pjm.com

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



Daily Exception Process – Business Rules

- <u>On a daily basis</u>, the generation supplier may submit notification to PJM that changed physical operational limitations at the unit <u>require a temporary exception to the unit's parameters</u>.

- 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.

- 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.

Ramp Limited Desired MW Calculation for Deviations

- 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

Ramp Limited Desired (RLD) – Getting Started

Definitions, Acronyms, and New Terms applicable to RLD

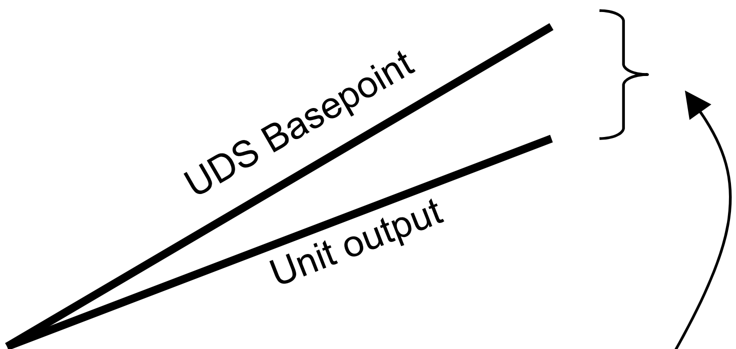
- UDS Basepoint – time weighted individual generator dispatch point (this value is ramp limited)
- Ramp Limited Desired (RLD) MW – achievable MW based on UDS requested ramp rate (this value is ramp-limited)
- UDS LMP Desired MWh - calculated by comparing the hourly integrated UDS LMP to the unit's bid 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

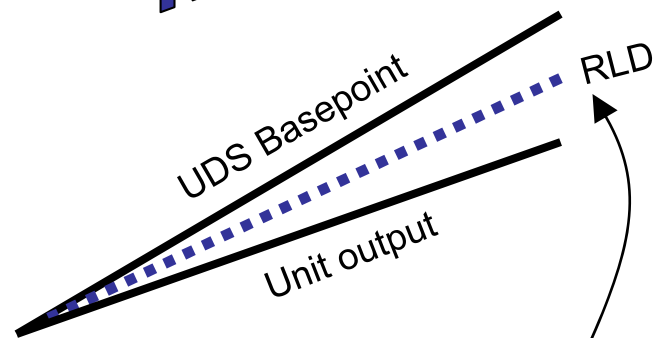
RLD Calculation for Deviations - Comparison

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)

Calculation of Ramp Limited Desired MW

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

$$\text{RL\_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp\_Request}_t * \text{Case\_Eff\_time}_{t-1} \right)$$

- 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 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 ?

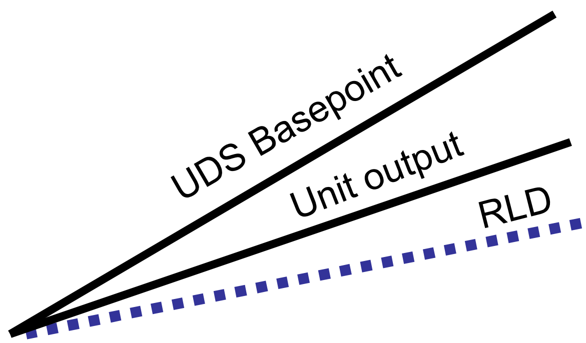
See Business Rules for more details

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

(Dotted line represents Ramp-Limited Desired MW)

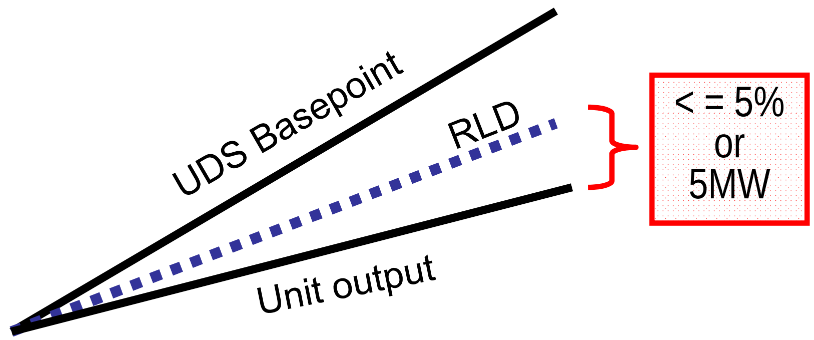


(or its % Off Dispatch is <= 10)

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|

Economic Maximum – 200 MW

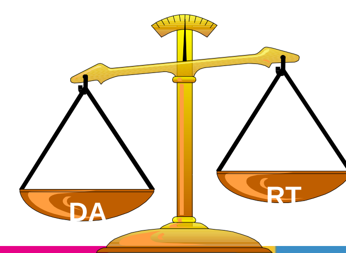
RT Unit Output – 175 MW (Ramps 1 MW / min)

Unit is Self Scheduled

Economic Minimum – 100 MW

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

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



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|

<u>In Summary:</u>

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.)

DA Economic Maximum – 200 MW

Ratio of Eco Max / Eco Min submitted in DA

RT Unit Output – 125 MW (Ramps 1 MW / min)

DA Economic Minimum – 100 MW

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|.

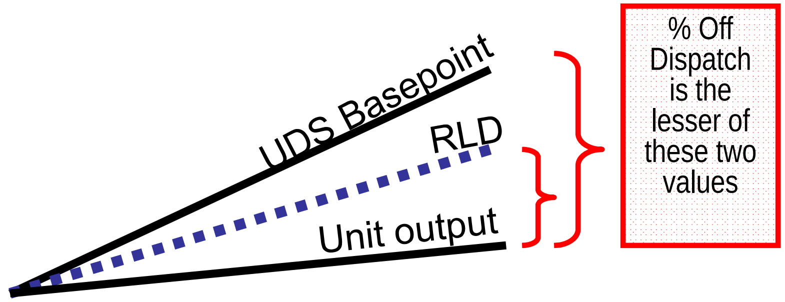
As mentioned earlier, If deviation value is within 5% or 5 MW (whichever is greater) of Ramp Limited Desired MW, no deviations will be calculated

Deviation based on RT MWh – <u>Ramp-Limited Desired MW</u>

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 – <u>UDS LMP Desired MWh</u>

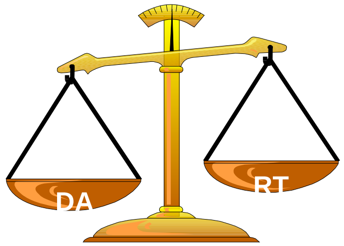
***<u>% Off Dispatch</u>** – percentage off dispatch using the lesser of the difference between the actual output and the UDS basepoint or the actual output and Ramp Limited Desired MW*



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



Ramp Limited Desired MW – Summary of Key Points

- 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.

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

Old Rules

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

Total MWs subject to BOR charges: 34MW

New Rules

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

- 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.

Deviation Calculation (old rules)

Balancing Operating Reserve Charges Applied to:

Day-Ahead		Real-Time
	“Bucket 1”	
Cleared Decrements, DA Load, Sales/Export	⟵ Net Deviation of total ⟶	RT Load, Sales/Export
	“Bucket 2”	
Cleared Increments, Purchases/Imports	⟵ Net Deviation of total ⟶	Purchases/Imports
	“Bucket 3”	
DA Scheduled Generation	⟵ **Individual deviation on each generator not following dispatch** ⟶	RT Generation

Deviation Calculation (new rules)

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

LSE "EnerWave"
Serves load in two different PJM zones

A
DA Fixed Demand = 100
RT Load Served = 0

B
DA Fixed Demand = 0
RT Load Served = 100

Old Rules

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

LSE "EnerWave"
Serves load in two zones in different PJM regions

A
DA Fixed Demand = 100
RT Load Served = 0

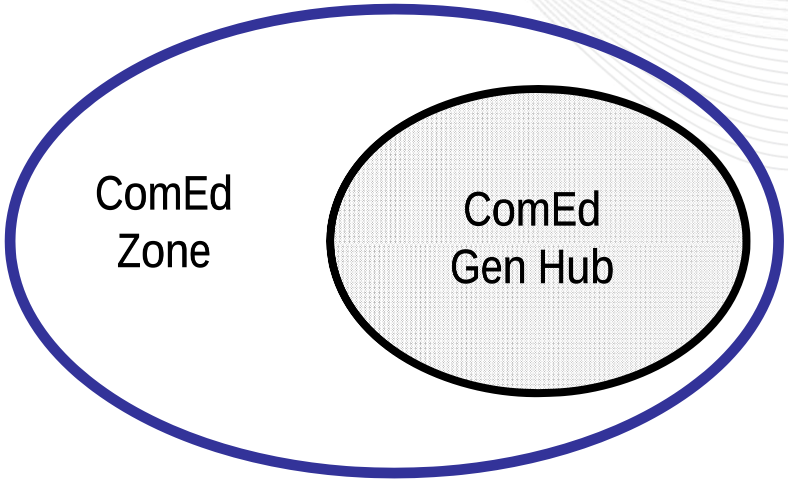
B
DA Fixed Demand = 0
RT Load Served = 100

New Rules

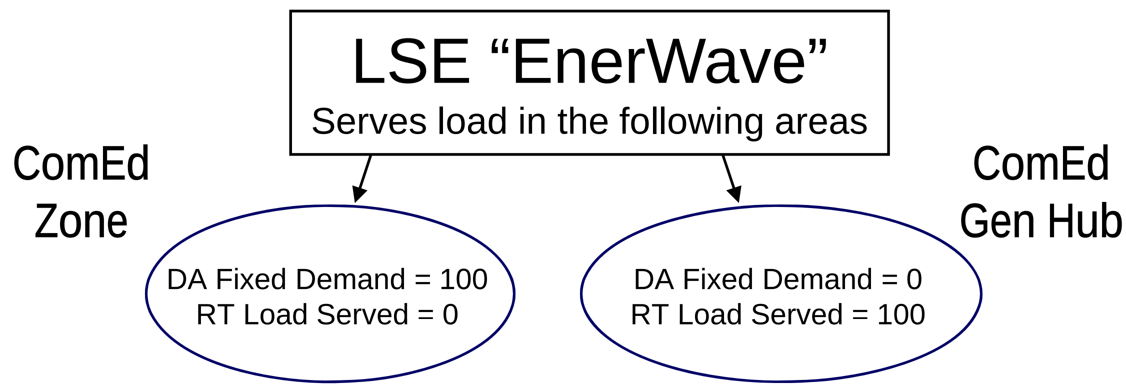
Does not change total COST of BORs. Allocates cost to increased participant base with possible impact to CHARGES.

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)

- 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)

Balancing Operating Reserve Cost Allocation (BORCA)

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)

Reliability Analysis

1

Operating Day
(0001 to 2400)

2

Reliability Analysis (RA) BOR Cost Allocation

RA BOR Credits for Reliability

Units committed due to extenuating conditions that warrant conservative actions to ensure the maintenance of system reliability

(i.e. – to provide reserves over and above the quantity determined by the real time load forecast)

RA BOR Credits for Deviations

Units committed to operate in real time in order to augment the physical units committed in the Day-Ahead Market to meet the forecasted real time load plus the operating reserve requirement

Real- Time (RT) BOR Cost Allocation

RT BOR Credits for Reliability

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

RT BOR Credits for Deviations

All other units operated at PJM's direction in real time

Load Ratio Share plus exports

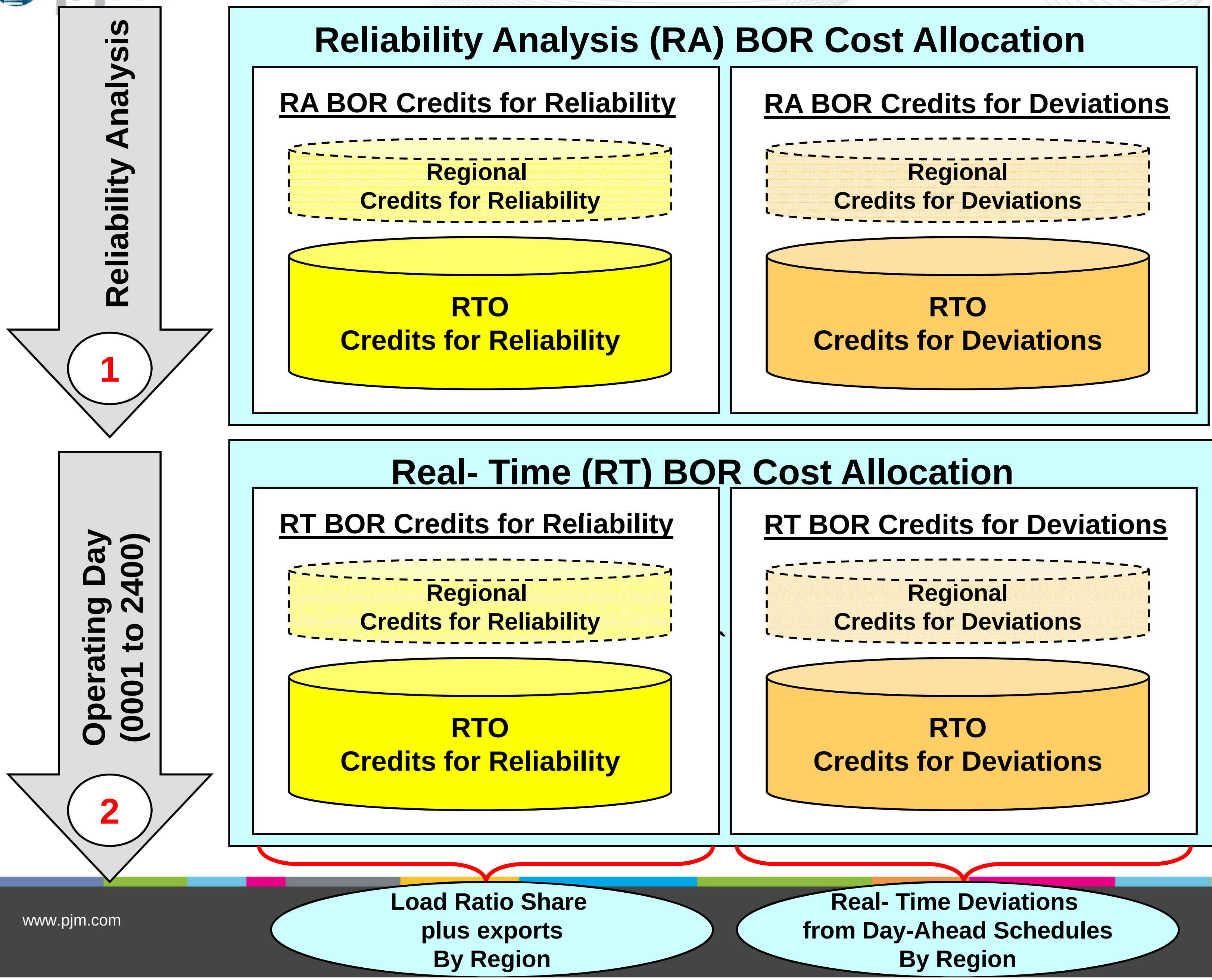
Real- Time Deviations from Day-Ahead Schedules

Balancing Operating Reserve Cost Allocation - Regional

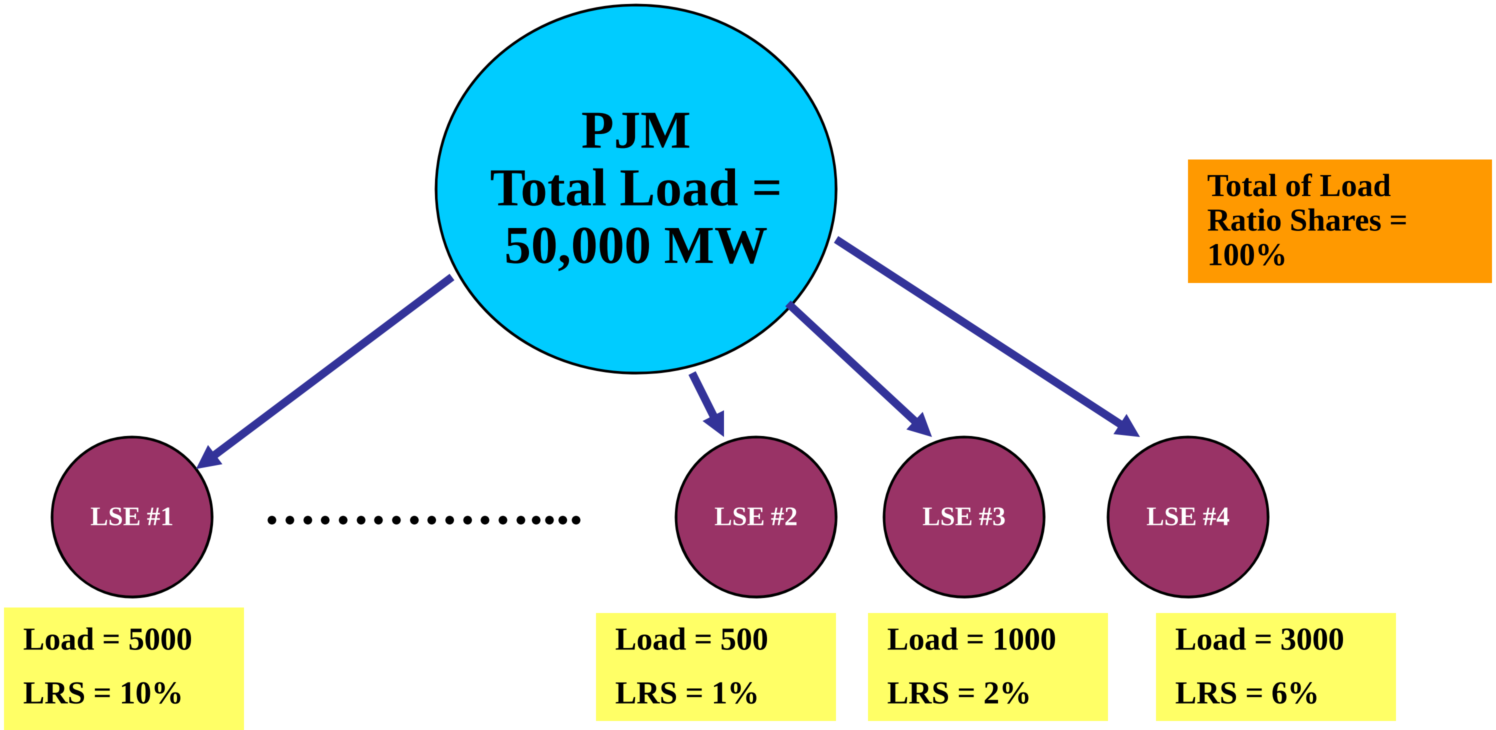
- Current Rule
  - All balancing operating reserve credits are divided equally among all deviations (Supply Bucket, Demand Bucket, and Generator Bucket), to create a single Balancing Operating Reserve Rate across the PJM RTO.
- Desired Outcome
  - Recognize that some Balancing OR credits are accrued 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"
    - (LSE load) / (PJM Total Load)



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) * (Customer total MWh of energy delivered to load + exports (by RTO or Region) / Total PJM MWh of energy delivered to load + exports (by RTO or Region))

Allocation for Deviations

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

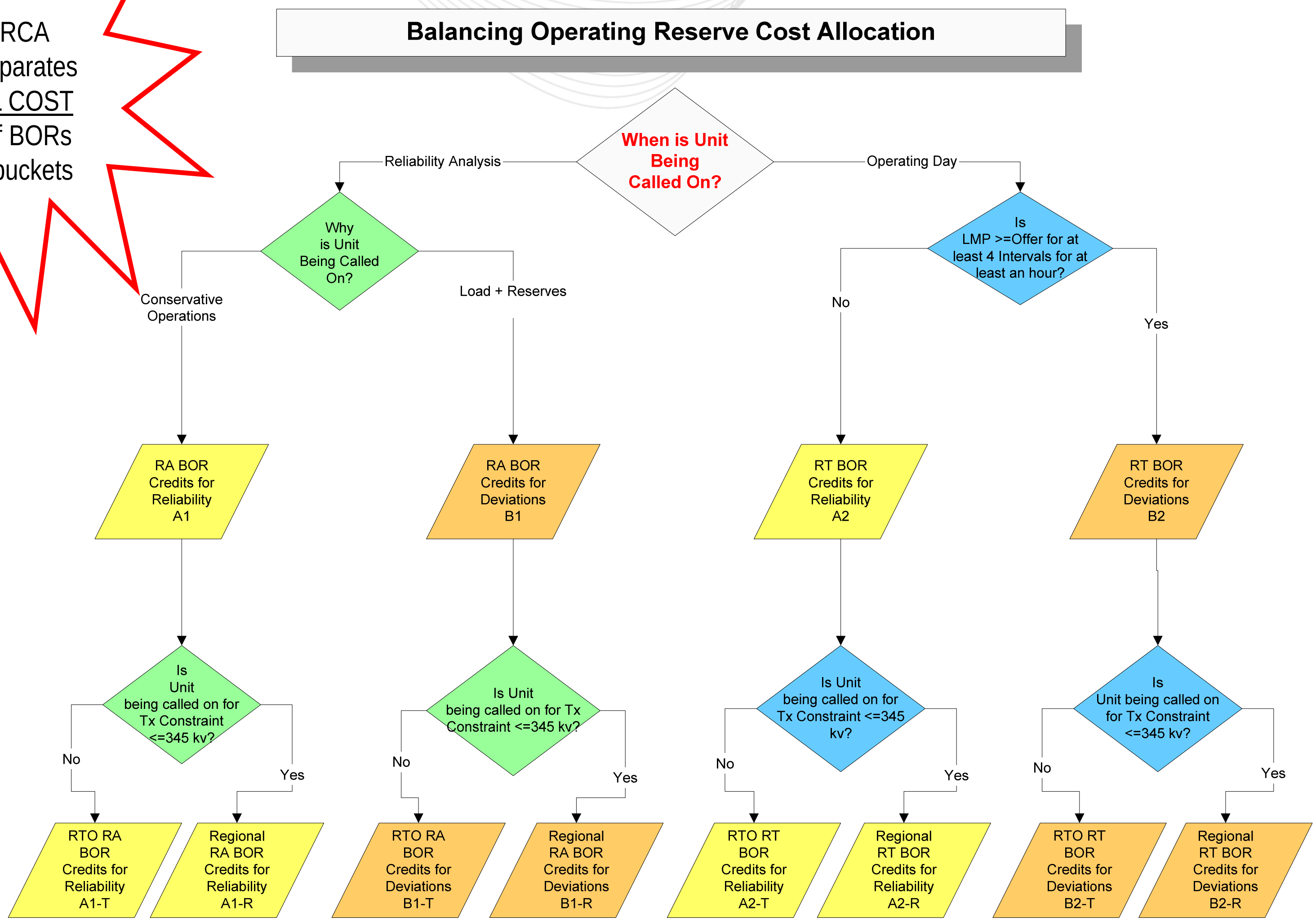
RTO Rate for BORs for Deviations = Total $ Cost of BORs in RTO for Deviations / Total MW Deviations Across RTO (after netting by zone, hub, interface)

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

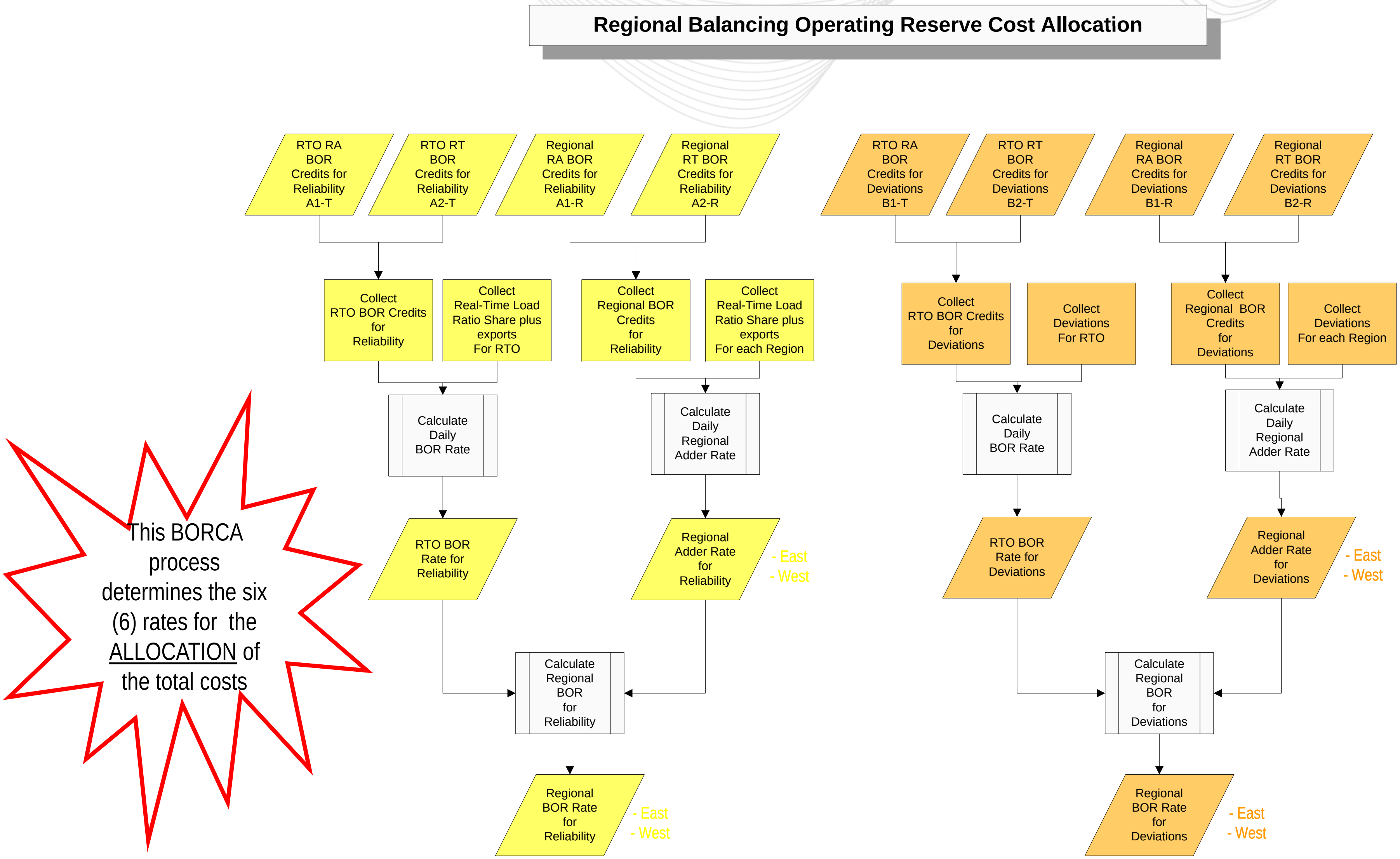
This example shows the calculation for deviations across RTO (not regional)

Balancing Operating Reserve Cost Allocation

This BORCA process separates the <u>TOTAL COST</u> (credits) of BORs into eight buckets



Balancing Operating Reserve Cost Allocation - Regional



Allocation Methodology

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

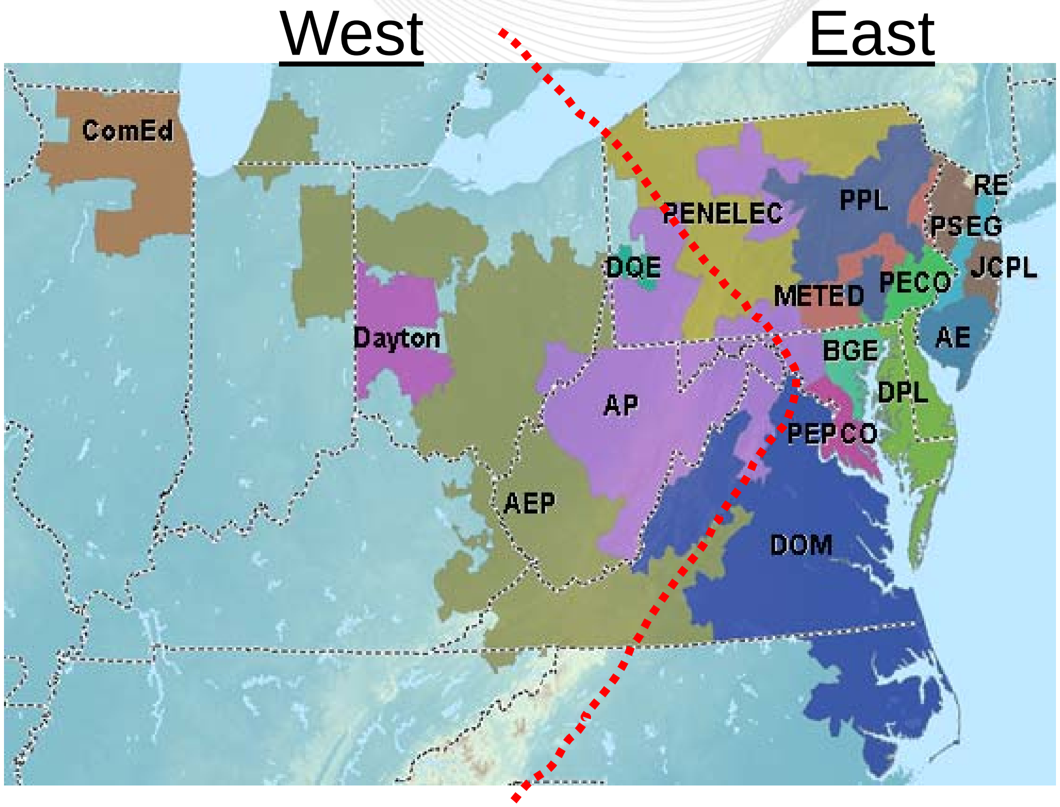
Regional costs allocated regionally

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, PECO, DPL, PSEG, RECO, AE

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

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 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)

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 ***

*** 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?

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

<u>Total BOR charges for Enerwave</u>: 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

Load Ratio Share for Western Region

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

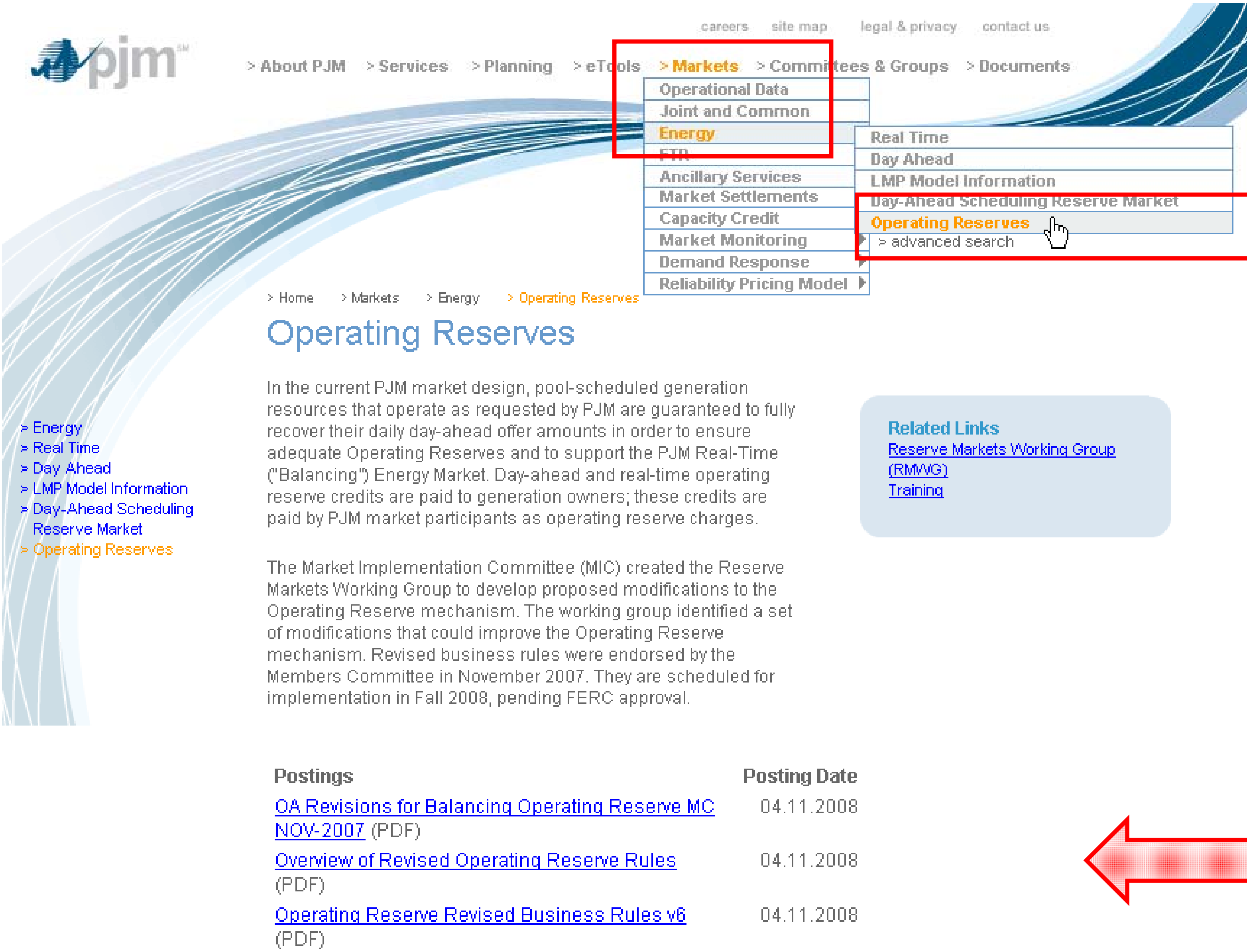
Total BOR charges for Enerwave: something greater than $6,000 (calculation depends on scenario of additional BORs)

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

RTO Rate for Reliability: $3 ← 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 <=345kV will be allocated regionally

Information on the PJM Web….



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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