PJM Proposal: Reserve Market Enhancements

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The PJM Board has determined that a comprehensive package inclusive of the components outlined below, is needed to meaningfully address the reserve procurement and pricing issues.

1. Consolidation of Tier 1 and Tier 2 Synchronized Reserve products
2. Improved utilization of existing capability for locational reserve needs
3. Alignment of market-based reserve products in Day-ahead and Real-time Energy Markets *
4. Operating Reserve Demand Curves (ORDC) for all reserve products
5. Increased penalty factors to ORDCs to ensure utilization of all supply prior to a reserve shortage *
6. Transitional mechanism to the RPM Energy and Ancillary Services (E&AS) Revenue Offset to reflect expected changes in revenues in the determination of the Net Cost of New Entry

* Not previously discussed as part of short-term scope

Component #1: Consolidation of Tier 1 and Tier 2 and Offer Changes

Tier 1 Market Product

Remaining ramping capability on flexible dispatchable generation resources after economic dispatch

- 10-minute response time
- Obligation to respond
- Non-compliance penalty
- Paid for response to an event

Vs.

Tier 2 Market Product

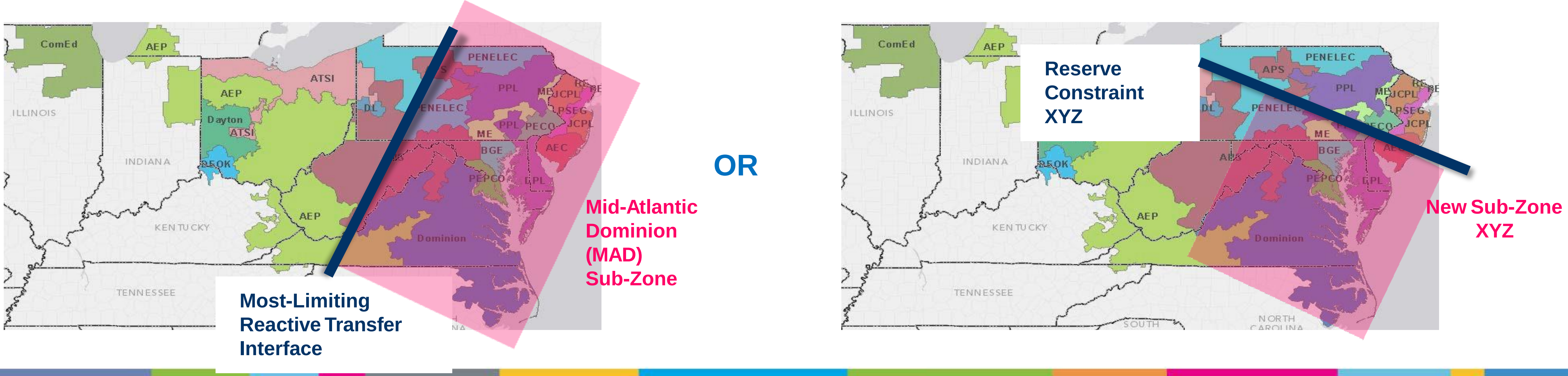
- Generation resources reduced from their economic set point
- Synchronous condensing resources and DR

- 10-minute response time
- Obligation to respond
- Non-compliance penalty
- Paid market clearing price regardless of deployment

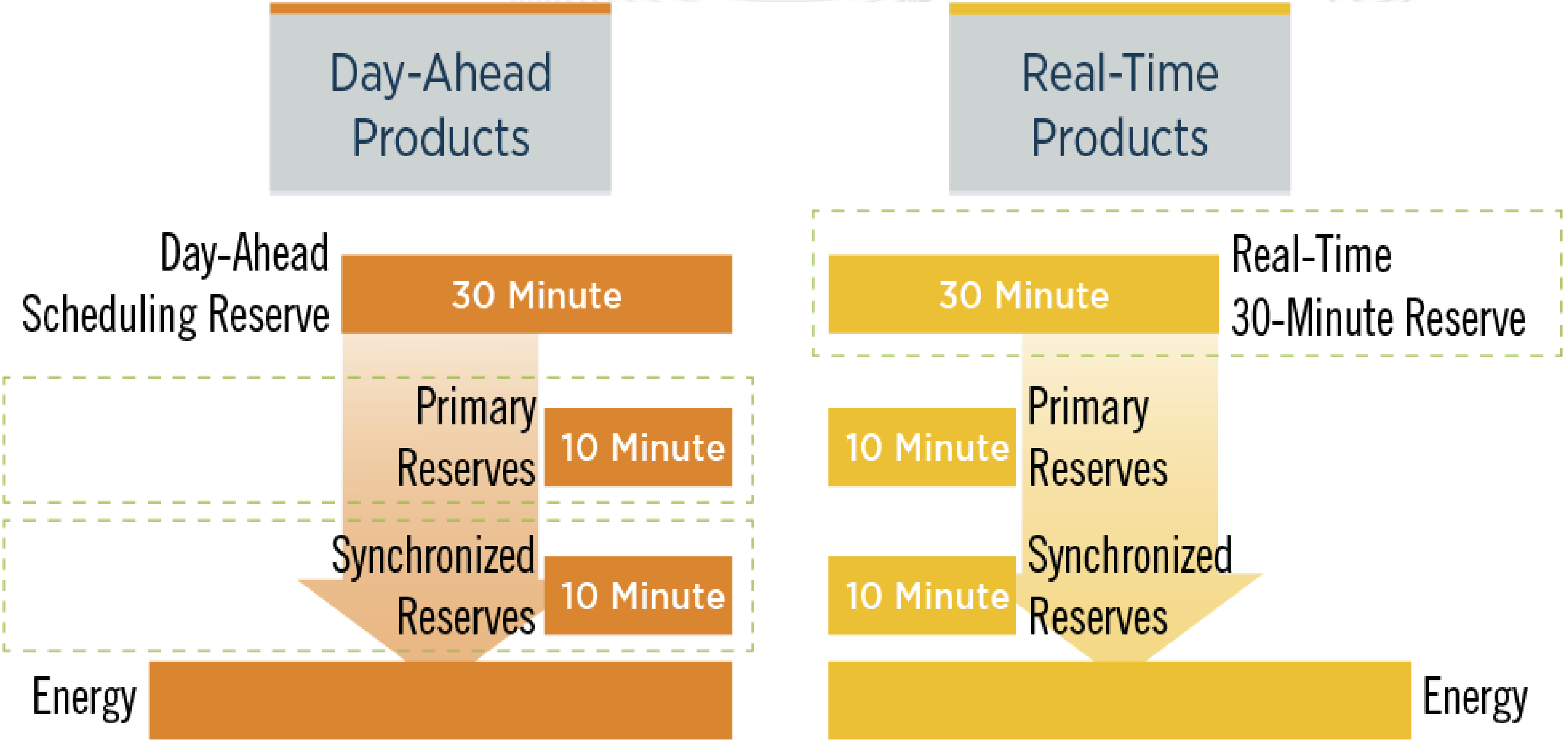
Component #1: Consolidation of Tier 1 and Tier 2 and Offer Changes

- PJM will strengthen the synchronized reserve must offer requirement
- PJM will calculate a resource's availability and reserve offer MW using the availability and unit parameters offered in for energy, with some exceptions
  - Participants will be provided additional flexibility to update energy ramp rates intra-day and to update the Synch Reserve Maximum MW intra-hour to enable more accurate representation of their reserve capability
- The proposal reduces the maximum level of synchronized reserve offers.
  - The Variable Operations & Maintenance component will be removed from SR offers (it is already included in energy offers)
  - The $7.50/MWh offer margin will be reduced to the expected value of the penalty ($0.02 for 2018).

- More Flexible Reserve Sub-Zone Modeling
  - Keep existing RTO reserve zone with closed loop sub-zone structure, but allow flexibility to change the location of the sub-zone on a day-ahead basis, as needed
    - Allow changes intraday on an exception basis
  - Define several reserve sub-zones, of which only one will be used at a time

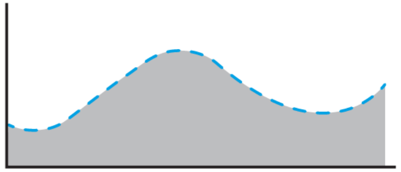


Component #3: Reserve Market Alignment

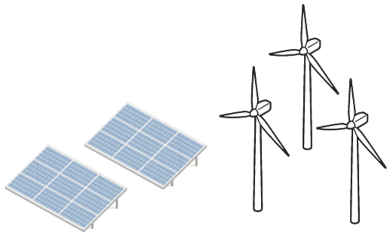


ORDCs and Offer Price Caps will be consistent between DA & RT for each product

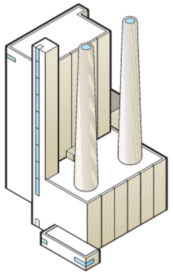
- Basis for value is the cost of a reserve shortage and the uncertainty on the system that could result in falling below the reserve requirement despite procuring sufficient reserves in advance
  - Cost of a reserve shortage is based on the penalty factor
  - Uncertainty is measured from historical data:



Real-time load forecast



Real-time solar and wind forecast



Expectation of conventional generator failure

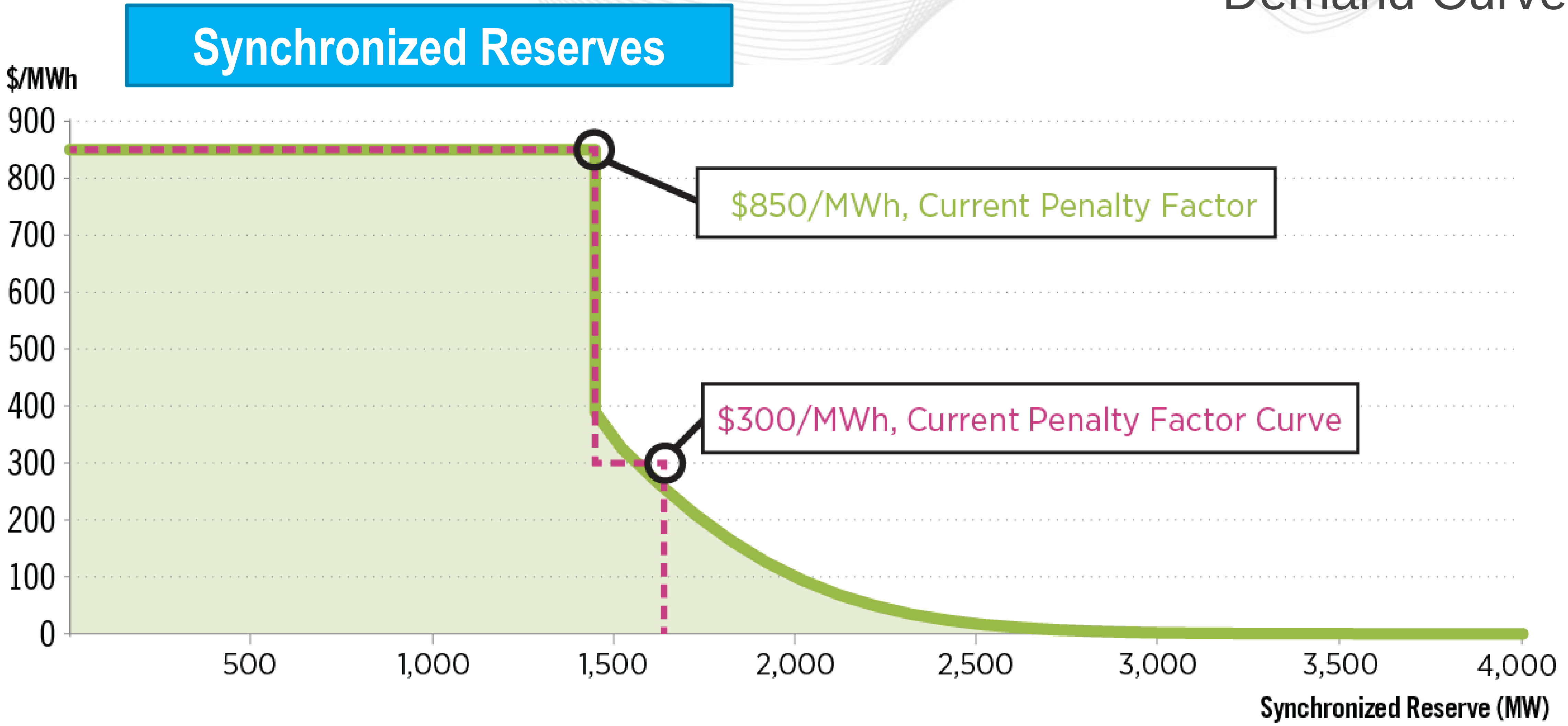
Component #4: Implement Downward-Sloping Demand Curves

- The Regulation Requirement (shown below) is used to deal with the uncertainties mentioned in the previous slides.

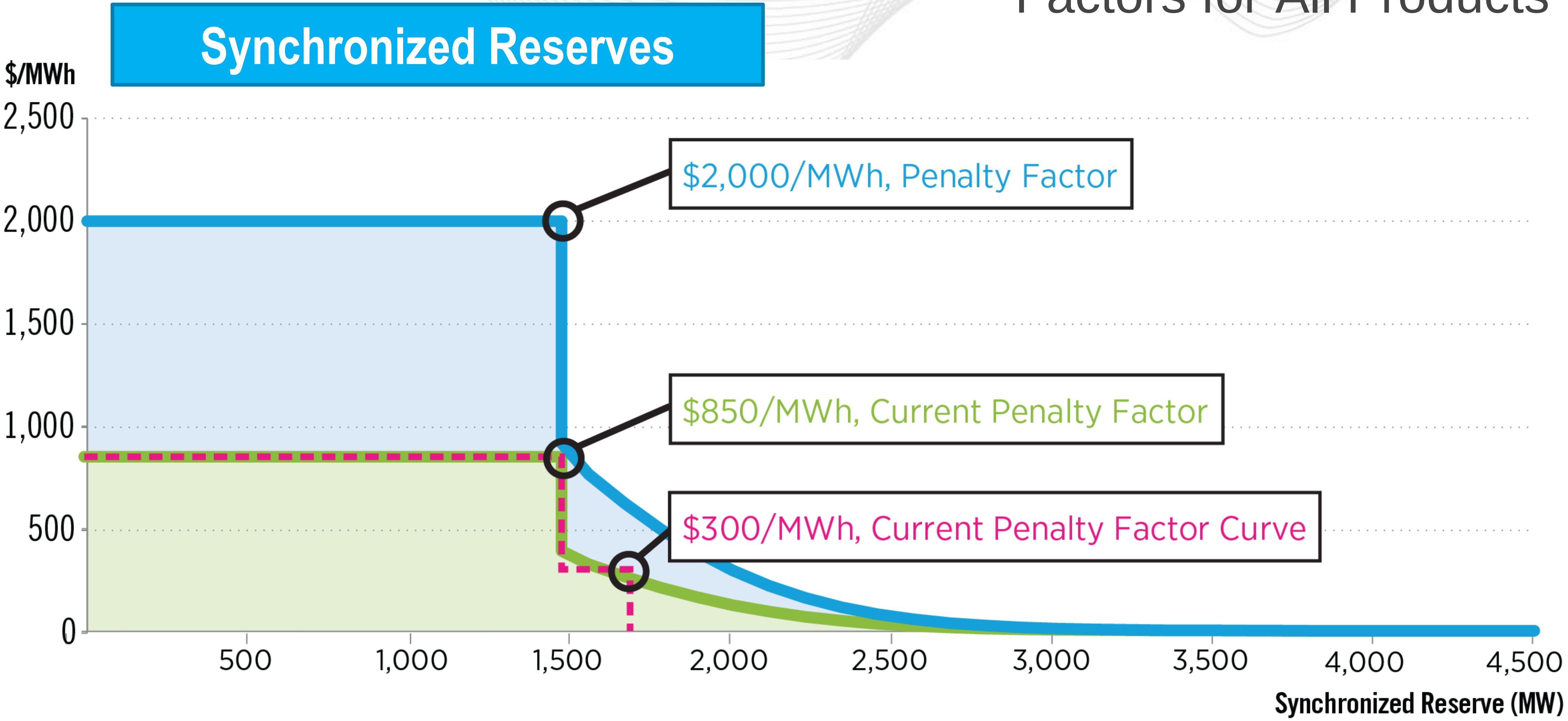
Season	Dates	Non-Ramp Hours	Ramp Hours	Effective MW Requirement
Winter	Dec 1 – Feb 29	HE1 – HE4, HE10 – HE16	HE5 – HE9, HE17 – HE24	Non-Ramp = 525MW Ramp = 800MW
Spring	Mar 1 – May 31	HE1 – HE5, HE9 – HE17	HE6 – HE8, HE18 – HE24	Non-Ramp = 525MW Ramp = 800MW
Summer	Jun 1 – Aug 31	HE1 – HE5, HE15 – HE18	HE6 – HE14, HE19 – HE24	Non-Ramp = 525MW Ramp = 800MW
Fall	Sep 1 – Nov 30	HE1 – HE5, HE9 – HE17	HE6 – HE8, HE18 – HE24	Non-Ramp = 525MW Ramp = 800MW

- The ORDCs can be shifted to the left by the regulation requirement
  - *Update based on feedback:* PJM is studying historic regulation deployment data to determine if there is a better method to account for regulation in the ORDC.

Component #4: Implement Downward-Sloping Demand Curves



Component #5: Implement $2,000/MWh Penalty Factors for All Products



Component #5: Implement $2,000/MWh Penalty Factors for All Products

PJM dispatchers will commit high-cost generation and deploy pre-emergency and emergency load management reductions, which have a cost in excess of the existing $850 penalty factor, in order to maintain Synchronized and Primary Reserves.

- Generation offer cap (for price-setting): $2,000/MWh
- Offer cap for Pre-Emergency and Emergency Load Management Reduction Actions:

Lead Time	Offer Cap Formula	Offer Cap
2 hours	$1,000 plus the Primary Reserve Penalty Factor	$1,100/MWh
1 hour	$1,000 plus (the Primary Reserve Penalty Factor * ½)	$1,425/MWh
30 minutes	$1,000 plus (the Primary Reserve Penalty Factor -$1)	$1,849/MWh

The Penalty Factor should be revised to $2,000/MWh to allow these operator actions to be reflected in market pricing

Also need to revise Pre-Emergency and Emergency Load Management Reduction offer caps to remove circular reference

Component #6: Use Simulation Data for E&AS Offset to Reflect Additional Energy and Reserve Market Revenues

PJM proposes to simulate the Energy and Reserve Market outcomes based on actual operating conditions, but with the proposed reserve market modifications, for Base Residual Auctions held after FERC approval is received

Auction Execution Date	Delivery Year	Revenue Year	Revenue Calculation
May 2020	2023/2024	2017	Simulated
		2018	Simulated
		2019	Simulated
May 2021	2024/2025	2018	Simulated
		2019	Simulated
		2020	Half Simulated + Half Actual
May 2022	2025/2026	2019	Simulated
		2020	Half Simulated + Half Actual
		2021	Actual
May 2023	2026/2027	2020	Half Simulated + Half Actual
		2021	Actual
		2022	Actual
May 2024	2027/2028	2021	Actual
		2022	Actual
		2023	Actual

* For illustration purposes, this chart assumes May 2020 is the first Base Residual Auction held after FERC approval is received and the changes are implemented in June 2020

Supplemental Information: Reserve Balancing Settlement

Why?

1. Eliminate modeling discrepancies between day-ahead and real-time created by reserve market design.

2. Provide opportunity for loads to hedge reserve costs in the Day-ahead Market and protect themselves against real-time volatility.

Day-ahead Market

30-Minute Reserves → ~5,600 MW

Supply to meet cleared demand
(Generation + INCs + Imports)

Real-time Market

Primary Reserves → ~2,400 MW

Synchronized Reserves → ~1,500 MW

Supply to meet real-time load
(Generation + imports)

Enforcing Reserve Requirements

- Imposing reserve requirements will impact the commitment and dispatch of the system
- Imposing different reserve requirements will create different outcomes
- If the products are not aligned, day-ahead and real-time will have different results under the same conditions
- This occurs today due to the misaligned reserve products
- This is a modeling discrepancy created by the market design

Effect of Current Modeling Differences

1. **Scheduled supply to meet demand in day-ahead (load + exports + reserves) does not match real-time.**
   - INCs and DECs fix part of the problem
   - Reserve mismatch is unresolved
2. **Resources needed for reserves in day-ahead may not match real-time.**
   - 30-minute reserves has no value in RT under the current model
   - 10-minute reserves has value in RT
   - Resources providing these services may be different
3. **Of course, prices can be different.**

Effect of ORDC in Real-time

- Simulations indicate increased reserve levels

Variable	Base Case	Simulation Case	Difference
Hourly Average Cleared SR (MW/hour)	2,075	2,964	889
Hourly Average Cleared NSR (MW/hour)	1,215	749	-466
Hourly Average Cleared OR (MW/hour)	N/A	2,828	2,828
	↑ 3,290	↑ 6,541	↑ 3,251

- If not accounted for in day-ahead, this will exacerbate existing discrepancies

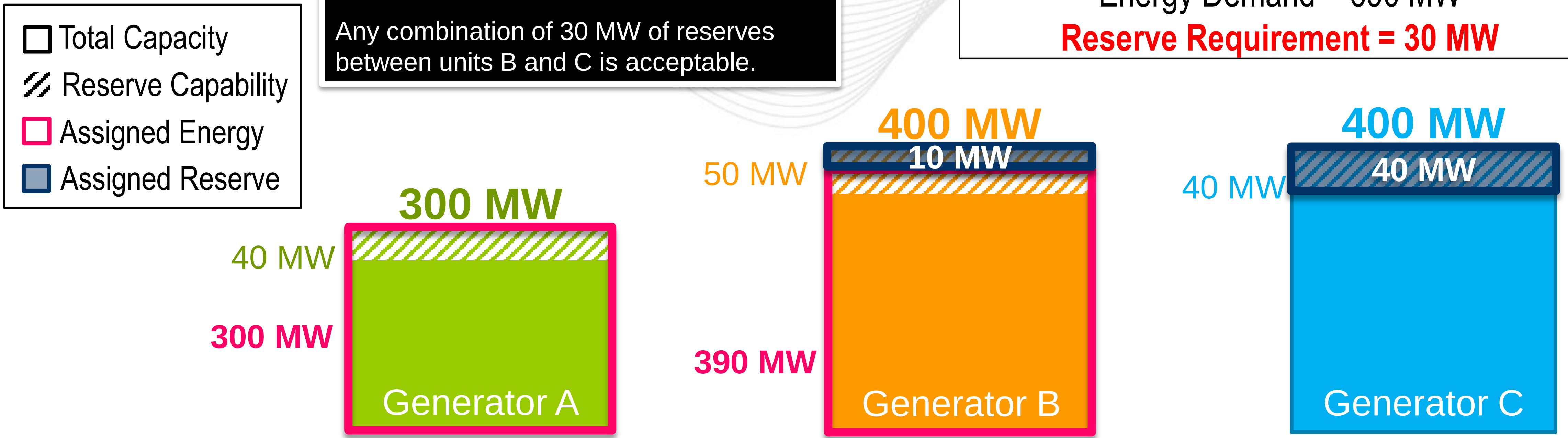
Reserve Requirement = 30 MW

Reserves > Requirement

This is because all reserves are $0/MWh cost in this case.

Any combination of 30 MW of reserves between units B and C is acceptable.

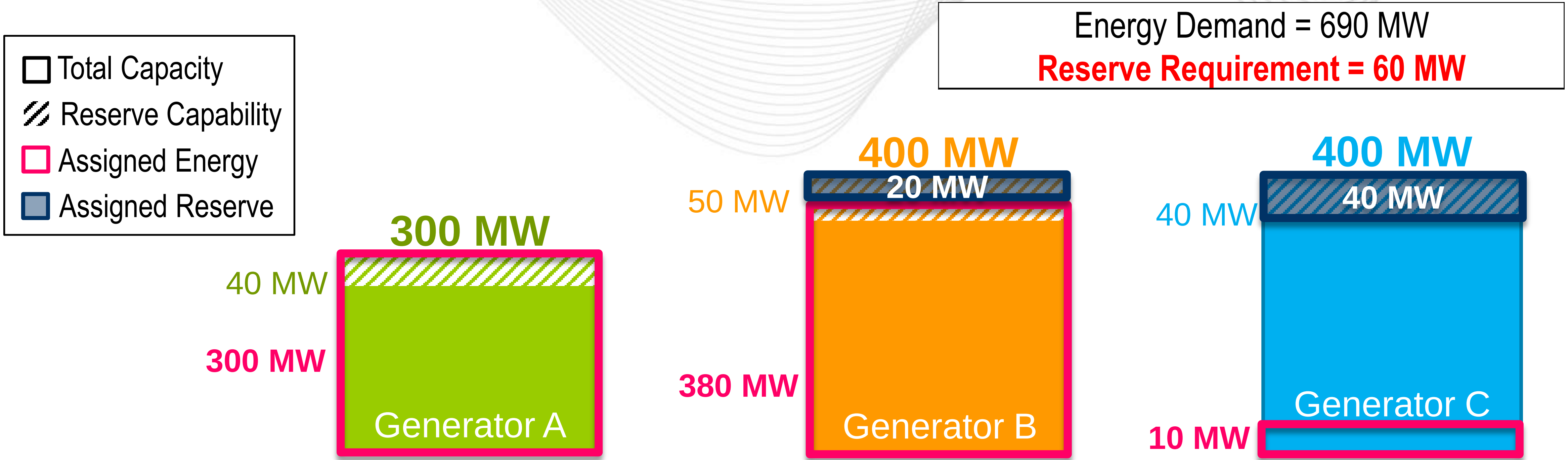
Energy Demand = 690 MW
Reserve Requirement = 30 MW



Energy Offer	$25/MWh	$40/MWh	$50/MWh
Reserve Offer	$0	$0	$0

LMP = $40/MWh – set by Gen B
Reserve Price = $0/MWh – set by Gen C

Reserve Requirement = 60 MW



Energy Offer	$25/MWh	$40/MWh	$50/MWh
Reserve Offer	$0	$0	$0

LMP = $50/MWh – set by Gen C
Reserve Price = $10/MWh – set by Gen B

Example Summary

	Day-ahead	Real-time
Reserve Requirement	30 MW	**60 MW**
Load	690 MW	690 MW
LMP	$40/MWh	**$50/MWh**
Reserve Clearing Price	$0/MWh	**$10/MWh**

- Changing the reserve requirement only (even for the same product) can create different market solutions
- Similarly, having different reserve products in day-ahead and real-time may also result in different market outcomes

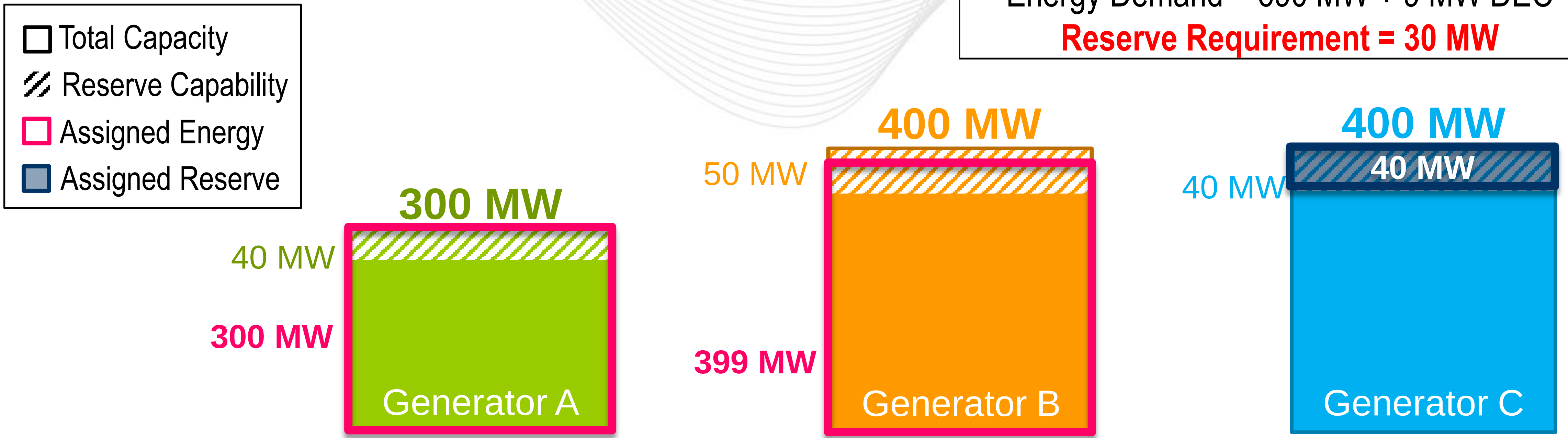
Arbitrage Opportunity

	Day-ahead	Real-time
Reserve Requirement	30 MW	**60 MW**
Load	690 MW	690 MW
LMP	$40/MWh	**$50/MWh**
Reserve Clearing Price	$0/MWh	**$10/MWh**

- When DALMP < RTLMP, a DEC bid is profitable
  - Buy low/sell high!
- In this example, a DEC of up to 9 MW would make a profit

Reserve Requirement = 30 MW

Energy Demand = 690 MW + 9 MW DEC
Reserve Requirement = 30 MW



Energy Offer	$25/MWh	$40/MWh	$50/MWh
Reserve Offer	$0	$0	$0

LMP = $40/MWh – set by Gen B
Reserve Price = $0/MWh – set by Gen C

Effect of this DEC

- Increases day-ahead demand above real-time (690 MW → 699 MW)
- Increases generation award on Generator B (390 MW → 399 MW)
- Removes reserve commitment from Generator B

NOTE: A 10 MW DEC would have converged energy prices and not been profitable. It would have made Generator C set the LMP. Reserve prices would still have diverged.

Doing this would have moved the cleared DA demand 10 MW higher than RT, shifted the commitments on Generator B, and still not reconciled the reserve market modeling difference.

Did it…

- Converge day-ahead and real-time prices? **No.**
- Did it improve the day-ahead commitment? **No.**
- Is it a rationale bid? **Yes!**
- Do we want an environment that incentivizes these types of transactions? **No.**
- *INCs/DECs/UTCs cannot directly reconcile reserve market modeling differences.*

- To give us the best shot at getting as good of a day-ahead commitment as possible and send the right incentives for virtual trading PJM believes we need to align the market reserve models

- The issues created by the current mismatched model have not been measured but we stand to increase them by implementing ORDCs
  - Absent a change we will assign more, and different, reserves in each market

- Loads can hedge some of their real-time reserve costs.

PJM Proposal: Identical ORDCs in DA and RT

Day-ahead Market

30-Minute Reserves ORDC

Primary Reserves ORDC

Synchronized Reserves ORDC

Supply to meet cleared demand
(Generation + INCs + Imports)

Real-time Market

30-Minute Reserves ORDC

Primary Reserves ORDC

Synchronized Reserves ORDC

Supply to meet real-time load
(Generation + imports)

Identical ORDCs

- Current process allows real-time SR/PR requirements to change with the largest unit. Should this be maintained?
- While ORDCs will be identical, it does not mean cleared quantities will be the same.
- Economics in the DA and RT markets will ultimately determine the level of cleared reserves.
- PJM does not plan to change the modeled reserve zone between DA and RT unless there is an operational emergency requiring it.
  - For example, the limiting facility trips.

Balancing Settlement

- Quantity deviations from day-ahead are settled in real-time
- We do this today for energy and will apply the same concept for all reserves

- Awards for Synchronized and Non-Synchronized Reserve cannot occur simultaneously
- Awards for Synchronized or Non-Synchronized and Thirty Minute Reserves will overlap in reality but for these examples they do not
- Secondary Reserves reflect the portion of 30-minute reserves that occurs between 10 and 30 minutes

- Examples show an hourly balancing settlement for simplicity. Actual implementation will be on a 5-minute basis like what is done today.

Day-ahead Settlement

	Day-ahead
Offer ($/MWh)	25
GenMW (MWh)	300
LMP ($/MWh)	40
SynchReserveMW (MWh)	50
SynchReservePrice ($/MWh)	15
NonSynchReserveMW (MWh)	0
NonSynchReservePrice ($/MWh)	10
SecondaryReserveMW (MWh)	0
SecondaryReservePrice ($/MWh)	5

	Day-ahead Revenues ($)
Energy	12,000
SynchReserve	750
NonSynchReserve	0
SecondaryReserve	0

Information

- 350 MW resource
- Ramps at 5 MW/min

- Resource committed for energy and SynchReserve
- No NonSynch award
- No SecondaryReserve award

Adding Real-time and Balancing Out…

	Day-ahead	Real-time
Energy (MWh)	300	325
LMP ($/MWh)	40	50
SynchReserveMW (MWh)	50	25
SynchReservePrice ($/MWh)	15	25
NonSynchReserveMW (MWh)	0	0
NonSynchReservePrice ($/MWh)	10	9
SecondaryReserveMW (MWh)	0	0
SecondaryReservePrice ($/MWh)	5	6

Information

- $25/MWh Offer Price
- Dispatched up 25 MW for energy
- Reduced SynchReserve commitment

In real-time the unit is

- A net seller of energy (25 MWh)
- A net buyer of SynchReserves (25 MWh)

Balancing Settlement	Real-Time (MWh)	Day-ahead (MWh)	Balancing (MWh)	RT Price ($/MWh)	Balancing Position ($)
Energy	325	300	25	50	1,250
SynchReserve	25	50	-25	25	-625
NonSynchReserve	0	0	0	9	0
SecondaryReserve	0	0	0	6	0
TOTAL					625

Who pays for energy?

- Cleared day-ahead demand pays for day-ahead energy $12,000

- Net buy positions in real-time pay for the “extra” 25 MW of energy
  - INCs
  - Unhedged load
  - DA scheduled generators that are short in real-time
  - DA imports that do not schedule in real-time

- If there are none, it becomes negative surplus and is paid by RT loads.

Who pays for reserves?

- Real-time load pays the net cost of reserves
- In this case…
  - DA SynchReserve cost = (50 MWh * $15/MWh) = $750
  - RT SynchReserve credit = (25 MWh * $25/MWh) = $625
  - Net Reserve Cost = $125 (for this resource)

- The resource…
  - Generated 25 MW of energy above its DA commitment for a total of $1,250,
  - Bought out of its day-ahead reserve commitment at $10/MWh for a total of $625,
  - The resource also expended an additional $625 in costs to generate the 25 MW, and
  - The resource breaks even consistent with it being on the margin ($1,250 - $625 - $625).

Other Options are Problematic

- **Option #1:** Allow loads to bid to buy reserves in DA?
  - Will result in different demand curves between DA and RT.
  - Could be argued to require virtual trading for reserves to mitigate monopsony power.

- **Option #2:** Allocate DA reserve costs to DA cleared demand.
  - Would result in charging cleared DECs for reserves.
  - Could create bad incentive to not clear load in DA to avoid reserve payments.
    - Impossible to tell what DA cleared demand is physical load in RT.

Day-ahead Settlement with Two Products

	Day-ahead
GenMW (MWh)	200
LMP ($/MWh)	40
SynchReserveMW (MWh)	50
SynchReservePrice ($/MWh)	30
NonSynchReserveMW (MWh)	0
NonSynchReservePrice ($/MWh)	25
SecondaryReserveMW (MWh)	100
SecondaryReservePrice ($/MWh)	20

	Day-ahead Revenues ($)
Energy	8,000
SynchReserve	1,500
NonSynchReserve	0
SecondaryReserve	2,000

Information

- Same unit ($25/MWh offer)
- 200 MW eco min
- **Ramps at 10 MW/min**

- Resource committed for energy and SynchReserve
- No NonSynch award
- **100 MWh SecondaryReserve award (10-30 minute)**

Balancing Out Energy, Synch and Thirty Minute…

	Day-ahead	Real-time
Energy (MWh)	200	350
LMP ($/MWh)	40	90
SynchReserveMW (MWh)	50	0
SynchReservePrice ($/MWh)	30	40
NonSynchReserveMW (MWh)	0	0
NonSynchReservePrice ($/MWh)	25	35
SecondaryReserveMW (MWh)	100	0
SecondaryReservePrice ($/MWh)	20	30

Information

- Dispatched up 150 MW for energy
- Reduced SynchReserve commitment

In real-time the unit is

- A net seller of energy (150 MWh)
- A net buyer of SynchReserves (50 MWh)

Balancing Settlement	Real-Time (MWh)	Day-ahead (MWh)	Balancing (MWh)	RT Price ($/MWh)	Balancing Position ($)
Energy	350	200	150	90	13,500
SynchReserve	0	50	-50	40	-2,000
NonSynchReserve	0	0	0	35	0
SecondaryReserve	0	100	-100	30	-3,000
TOTAL					8,500

Open Items

1. How to implement dynamic RT requirement in DA without creating model discrepancies?

   Current thinking: Pick a static MRR that closely represents the largest contingency and use it in both.

2. Treatment of inflexible Synch Reserve resources that receive a DA commitment? Similar to CT LOC issue.

   Current thinking: Maintain inflexible reserve commitments in real-time unless dispatched for energy.

3. Negative balancing value for reserves when dispatched for energy.

   Current thinking: Paid on a 5-minute basis to generator and allocated to real-time load. This is similar to opportunity cost credits that are paid today and allocated to real-time load.

- Others?