Price Responsive Demand
Integration into PJM Capacity & Energy Markets

- Definition of PRD
- Eligibility Criteria
- PRD Requirements if Committed in RPM
- PRD Plan Submittal Timeline
- Integrating PRD in RPM
- Integrating PRD in PJM Planning Process
- Measurement and Verification
- Penalties
- Integrating PRD in Energy Dispatch

- Issue Identification
  - What market rules should be designed to integrate Price Responsive Demand in PJM Capacity and Energy Markets, to provide visibility of Price Responsive Demand for improved reliability and market operations?
- Current and Future Drivers in PJM Footprint
  - States that are currently designing retail rate structures for Price Responsive Demand
  - Smart Grid investment that is under development

Vision for PRD in PJM Markets

Increased Reliability
Efficient Use of Resources
Penalties for Non-performance
Supervisory Control Backstop
Reduced RPM Capacity Purchase
PRD In Forecasts → Reduced Demand
PRD Experience → PRD In Forecasts
Price Response → Peak Load Reductions
Dynamic Retail Rates → Price Response
AMI/Smart Grid -- Foundation

Features ("Impacts") of Integrating PRD in PJM Markets

- Evolving Advance Metering Infrastructure (AMI) will allow implementation, measurement and control of PRD

- Price Responsive Demand can achieve savings in Locational Reliability Charges in the capacity market through LSE-specific recognition in the auctions

- Market benefits from capacity clearing prices that reflect the correct amount of demand to be served

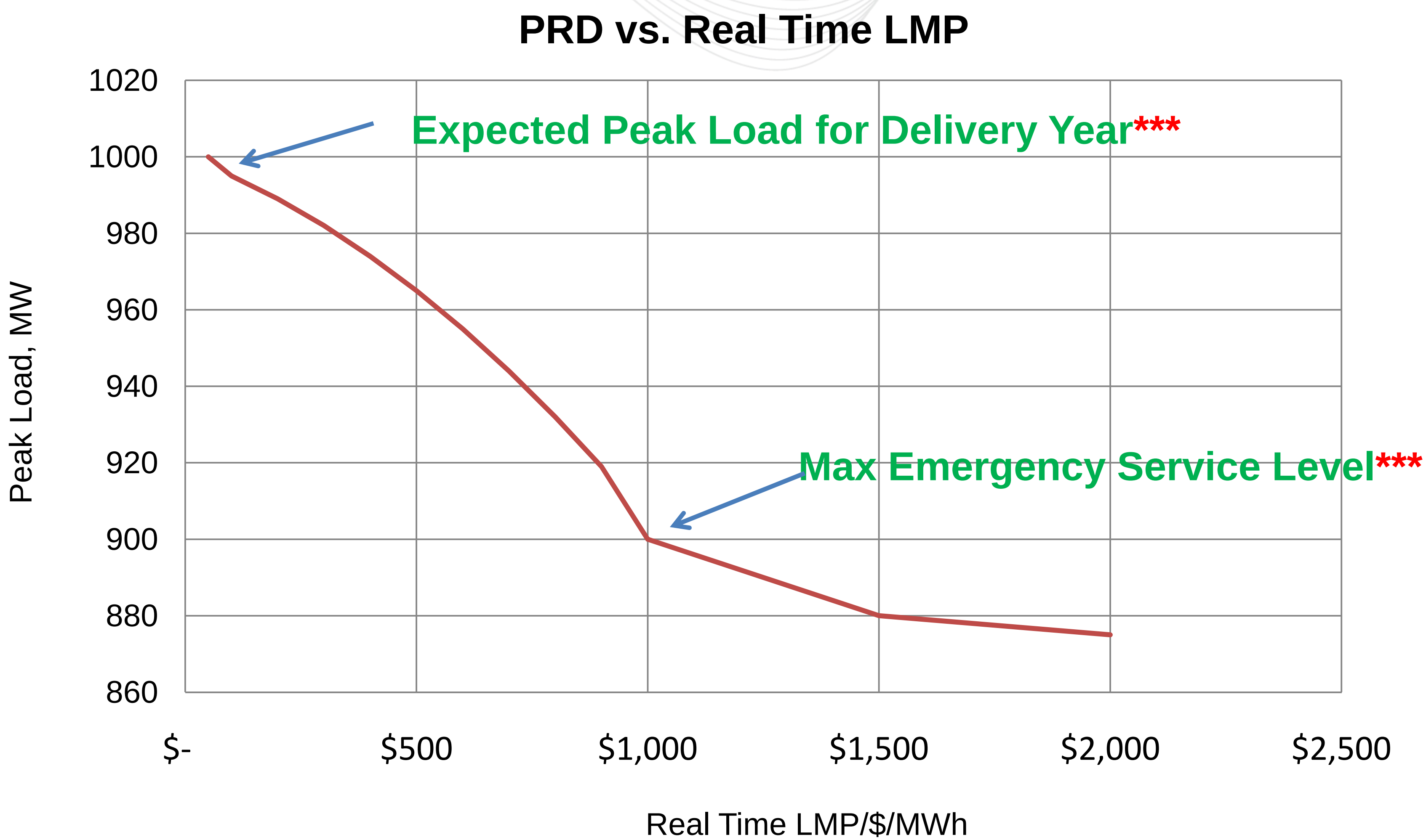
- Greater visibility of Price Responsive Demand for improved reliability and market operations.

- Evolving Advanced Metering Infrastructure (AMI) and dynamic retail rates are increasing the price-responsiveness of retail load.

- Price Responsive Demand (PRD) is demand that is reduced to a lower level in response to rising wholesale prices according to a predictable price/demand curve.

- PJM implementation of PRD will allow LSEs to commit to and purchase capacity based on pre-determined load levels that would not be exceeded during emergency conditions.

Illustration of PRD Curve – PRD vs Real Time LMP



****determined consistent with the 50/50 load forecast that is the input to RPM Auction*

Eligibility Criteria for Price Responsive Demand

- PRD submitted by RPM LSEs or FRR Entities will offset the load forecast developed for use in RPM if that demand is subject to:
  - Advanced Metering and Supervisory Control
    - Advanced metering capable of recording electricity consumption at an interval of one hour or less
    - Supervisory control capable of limiting demand to committed quantity
  - A time-varying, dynamic retail rate based on Real Time LMP such as:
    - Critical Peak Pricing
    - Critical Peak Rebate Pricing
    - Real Time Pricing

What is Supervisory Control and why is it required for PRD?

- Supervisory control of customer load committed as Price Responsive Demand is required on the part of the EDC, LSE or CSP consistent with any retail regulatory authority requirements.
  - The EDC, LSE, or CSP is required to have the remote capability to decrease the load at each location contained in the PRD Plan to the required service level during PJM Maximum Emergency events when the Real-Time LMP is greater than $1,000, to the extent load was not already reduced based on price.
- Since capacity has not been procured for PRD load, supervisory control is necessary to ensure reliability during emergency conditions.

What is the definition of “Time-Varying Retail Rates”?

- To be eligible to be committed as PRD, the retail rates must be based on wholesale prices (real-time LMPs)
- The retail rate structure must be dependent on the Real-time LMP to ensure that PJM has a way to account for price-sensitivity in real-time operations.
  - “…..served under a dynamic retail rate that varies through time and that is linked to or based upon the PJM real-time LMP at the location applicable to the load, and that results in predictable response to varying wholesale electricity prices”

Comparison of DR/ILR, LSE Peak Shaving, PRD

ANOTHER Option to participate on demand-side, rather than supply-side…

	LSE Peak Shaving	PJM DR/ILR Resource	PJM PRD
Characteristics	LSE Manages PLC outside of any PJM program	Offered as Supply Resource in Capacity & Energy Markets	Reduces Load Forecast (and therefore Reliability Requirements) in Capacity Market
Performance Requirements	LSE proactively manages load, especially during expected 5 CP days.	RPM resource (ILR or DR) – 10 events per year on weekdays, up to 6 hours per event. If no event then required to do 1 hour test.	LSE implements dynamic prices that produce predictable reduction in demand during emergency conditions
Financial Impact (Benefit)	Reduce PLC and purchase less capacity in next delivery year.	Receive revenue based on RPM results. Capacity Resource deficiency + event or test deficiency	Reduces LSE capacity obligation during delivery year.
Adjustment to Load Forecasts	No Adjustment . Over time will result in a lower load forecast	Add backs used to come up with “unrestricted load” which is used for forecast.	Explicit reduction in Load Forecast based on PRD amount registered that is tracked at the zonal and LSE level
Metering Requirements	No explicit requirement but if competitive jurisdiction interval meter may be required to see full impact to customer.	Interval metering required unless part of 500 MW pilot or direct load control program	Interval Metering Supervisory Control

What is required to adjust the Load Forecasts for PRD

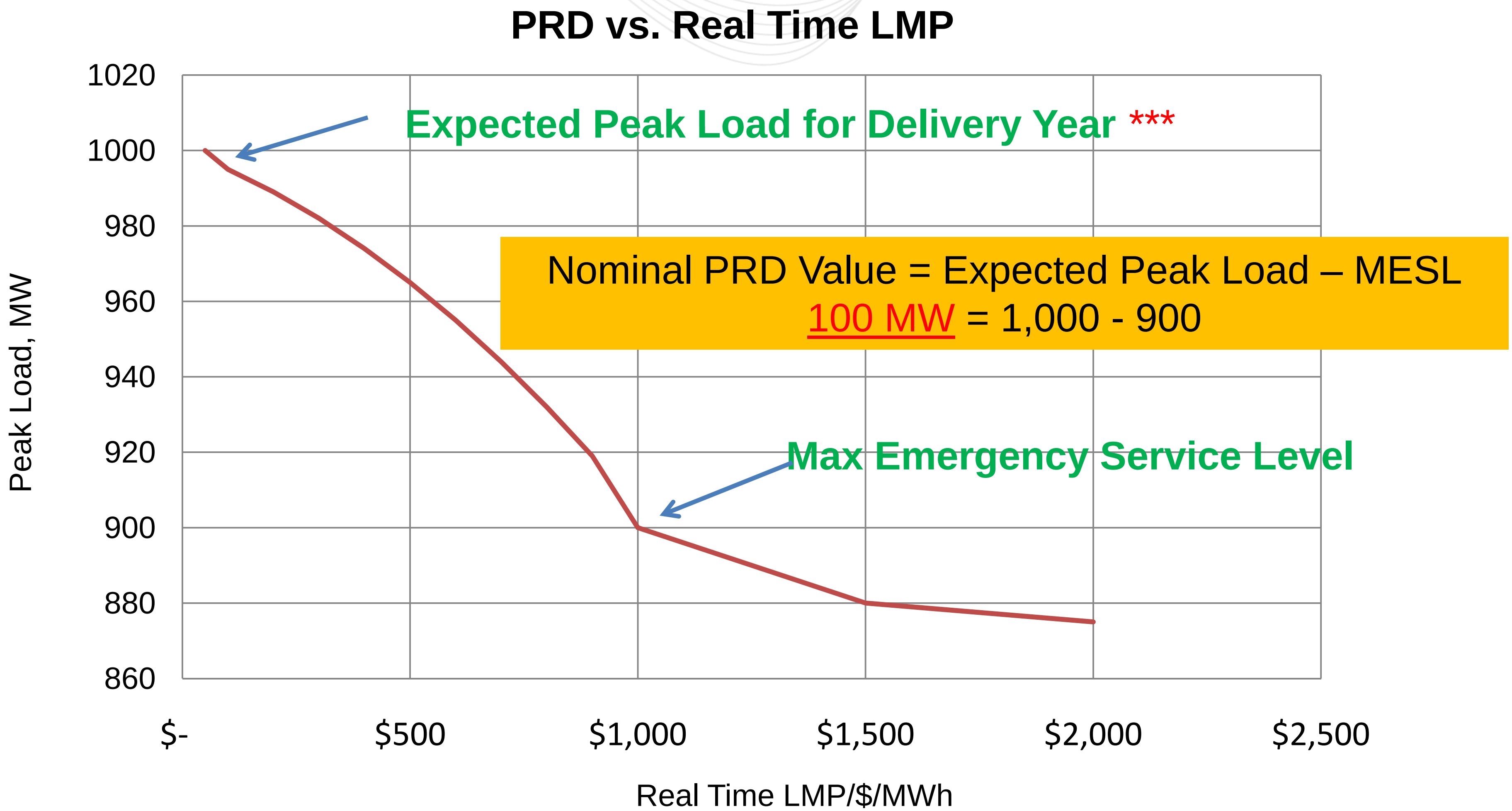
- Development and Review of PRD Plan
  - Submittal Timeline
- Required Key Elements of the PRD Plan
  - PRD Curves (aka Price-Consumption Curves)
    - Indicating relationship between price and demand
  - Estimate of Peak Load during Delivery Year
  - Maximum Emergency Service Level
    - By Substation Location
- Required Supporting Detail
  - Retail Rate Structure
  - Project plan for equipment development

LSE submitting Price Responsive Demand for consideration in RPM must submit the following key information to PJM by December 1:

Key Element	Definition
Maximum Emergency Service Level (MESL)	Maximum Emergency Service Level (MESL) is the level to which the price-responsive load will be reduced during the Delivery Year when Max Emergency is declared and RT LMP $\geq$ \$1000. ***NOTE: This Value is used in Measurement & Verification Process to determine compliance***
Expected Peak Load	**Estimate of the Expected Peak Load of the price-responsive load during the Delivery Year,** determined consistent with the 50/50 load forecast that is the input to RPM Auction
Nominal PRD Value	**Estimate of the Nominal PRD Value,** which is the estimated quantity of load that will reduce based on price ***NOTE: This Value is used in the PJM Load Forecasting Process*** Weather-sensitive load must use Zonal Weighted Temperature Humidity Index Standard posted on the PJM web site

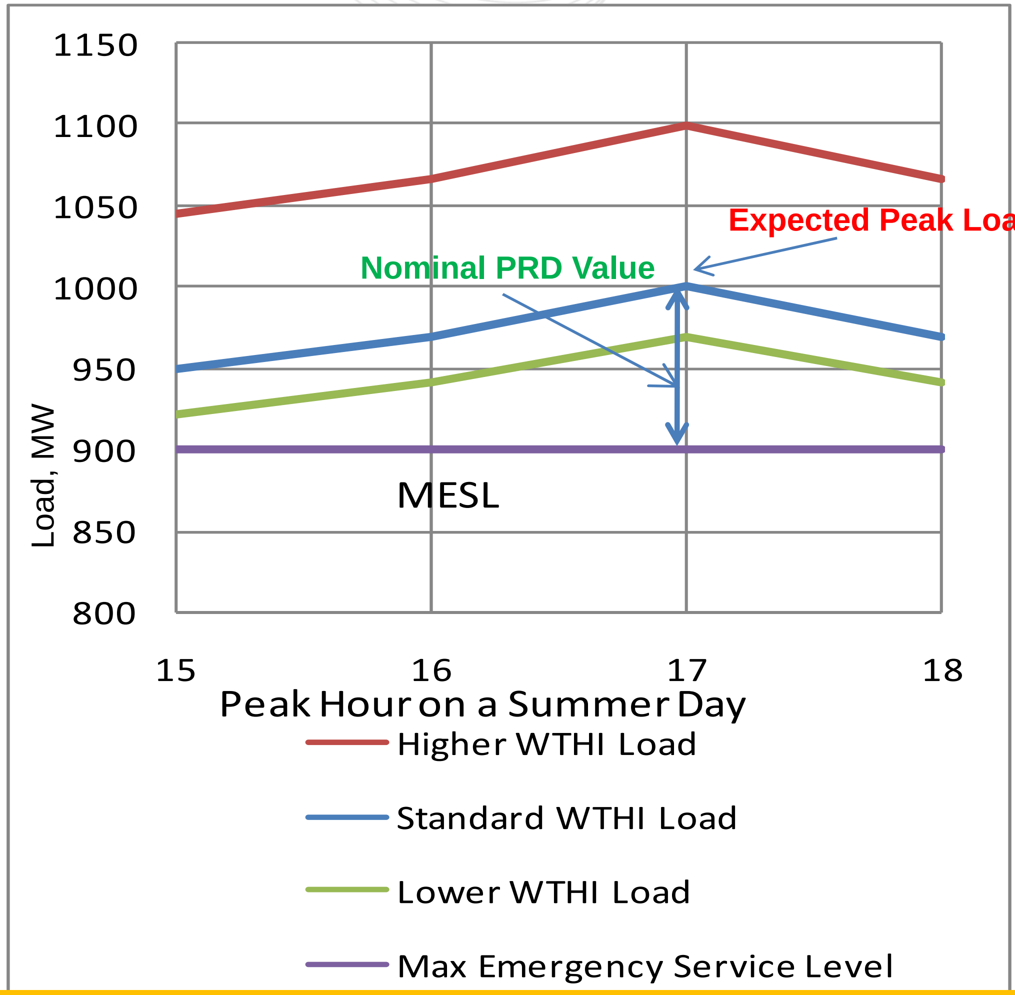
Nominal PRD Value = Expected Peak Load - MESL

Illustration of PRD Curve – PRD vs Real Time LMP



****determined consistent with the 50/50 load forecast that is the input to RPM Auction*

Illustration of PRD Plan Key Elements for weather sensitive load



Nominal PRD Value = Expected Peak Load – MESL

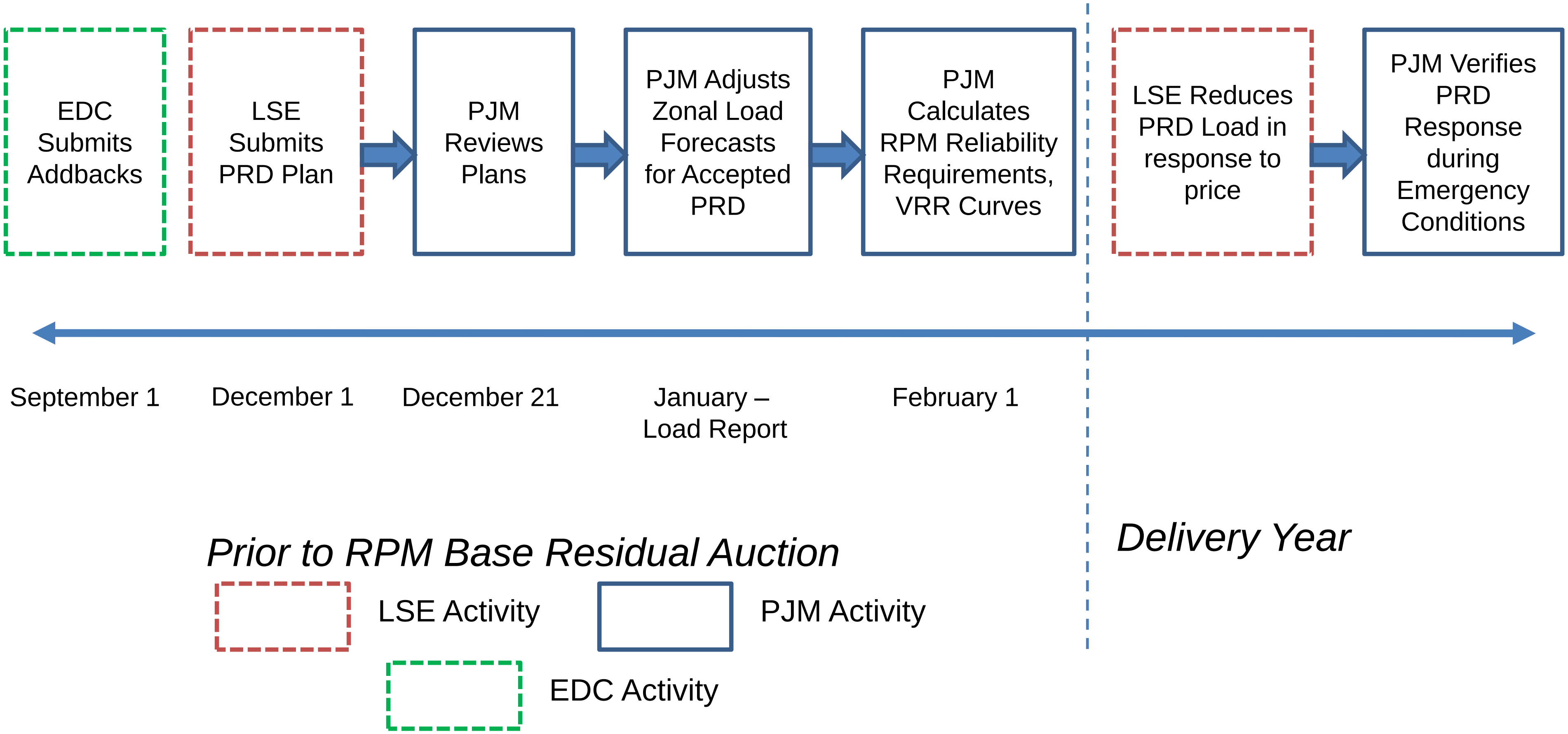
100 MW = 1,000 - 900

- Price Responsive Demand that would like to participate in RPM must submit a plan to PJM by December 1 preceding an RPM auction
- December 1 deadline is to ensure that accepted PRD may be reflected in the PJM Load Forecast Report issued in January
- December 1 deadline would apply to PRD interested in participating in either a BRA or an Incremental Auction

- Once a PRD Plan is accepted, PJM will determine a Nominal PRD Value for use in adjusting the Zonal Load Forecast for the Delivery Year

- The updated Zonal Load Forecast will be used to calculate the LDA and RTO Reliability Requirements used in building the VRR curves used to clear RPM auctions

How is PRD incorporated in Load Forecast, Planning and RPM Clearing Processes?



- **Impact to Load Forecasting Process**
  - PJM receives information from LSEs via PRD Plan that will allow PJM to continue to plan based on an unrestricted load forecast
  - PJM applies the load forecast modified by PRD to RPM clearing process.
  - PJM posts the unrestricted load forecast with and without PRD
    - New table for PRD similar to DR and EE
  - EDCs submit addbacks for hours that PRD load is reduced
  - Capacity obligations assigned based on MESL

Impact of PRD on the Reserve Margin applied to RPM

- IRM as a percentage is dependent on two main factors:
  - projected unit performance
  - Load shape and load forecast uncertainty
- Projected unit performance is independent of PRD.
- PRD with add backs will not change the load shape or load forecast uncertainty and has no effect on calculation of IRM as a percentage.
- PRD reduces the peak load to which the IRM percent is applied, thereby reducing the Reliability Requirement used to procure resources in RPM auction.
- Lower Reliability Requirement due to load committing to reduce when the price goes up.

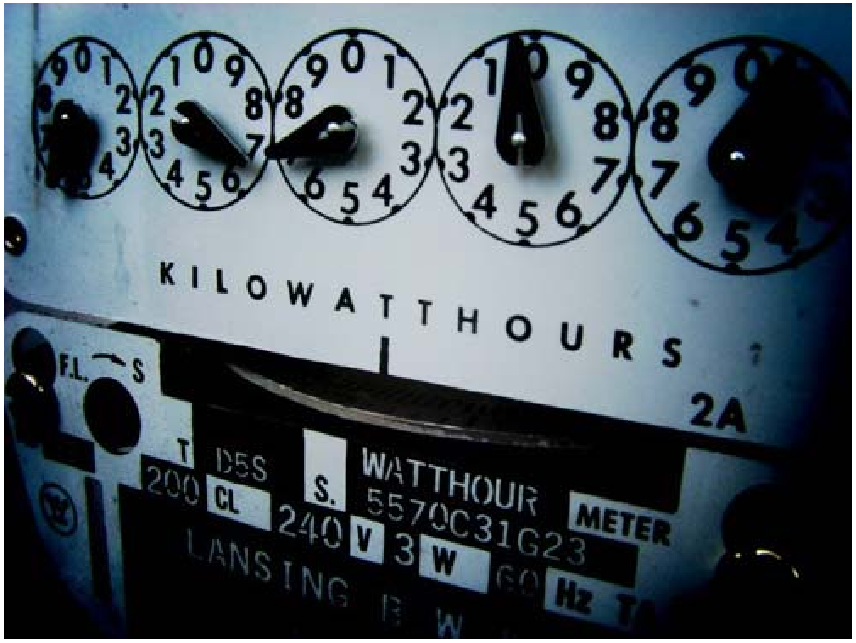
- PRD may participate in Incremental Auctions if:
  - Zonal Load Forecast for the Delivery Year increases relative to the BRA zonal forecast for the DY
  - If the total Nominal PRD Reduction Values in a zone exceeds the increase in the updated Zonal Load Forecast, pro-rata share of the increase may be allocated to qualifying LSEs that submitted PRD for Incremental Auction

Committed Price Responsive Demand in the RTEP Process

Price Responsive Demand that is committed has a direct impact, and becomes a load-side market solution in the RTEP Planning Process

- Accounted for as a reduction to the unrestricted peak 3 years in advance for Base Residual Auction or for Incremental Auctions
- Subject to measurement and verification process
- All PJM approved committed PRD will be netted from unrestricted load forecast, subject to the limitation that total DR in an LDA cannot reduce net load forecast below the 50/50 value
- Load net of committed PRD will be modeled in RPM auctions and RTEP studies
- Committed Price Responsive Demand cannot be offered as a Demand Resource in RPM
- Account for location of PRD

Uncommitted Price Responsive Demand



- Similar to Economic Load Response
- Lowers metered load
- Reduced metered load history feeds into future load forecast

→ Will result in lower load forecast over time

Price Responsive Demand that is NOT committed can only have in indirect impact in the RTEP Planning Process

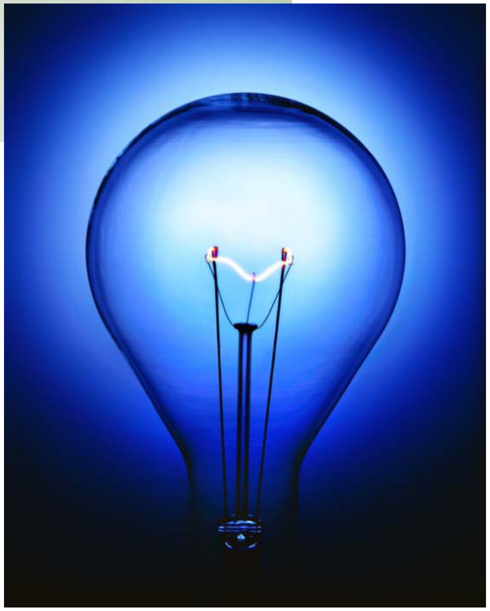
Potential Modeling of PRD in RTEP Studies

Market Efficiency

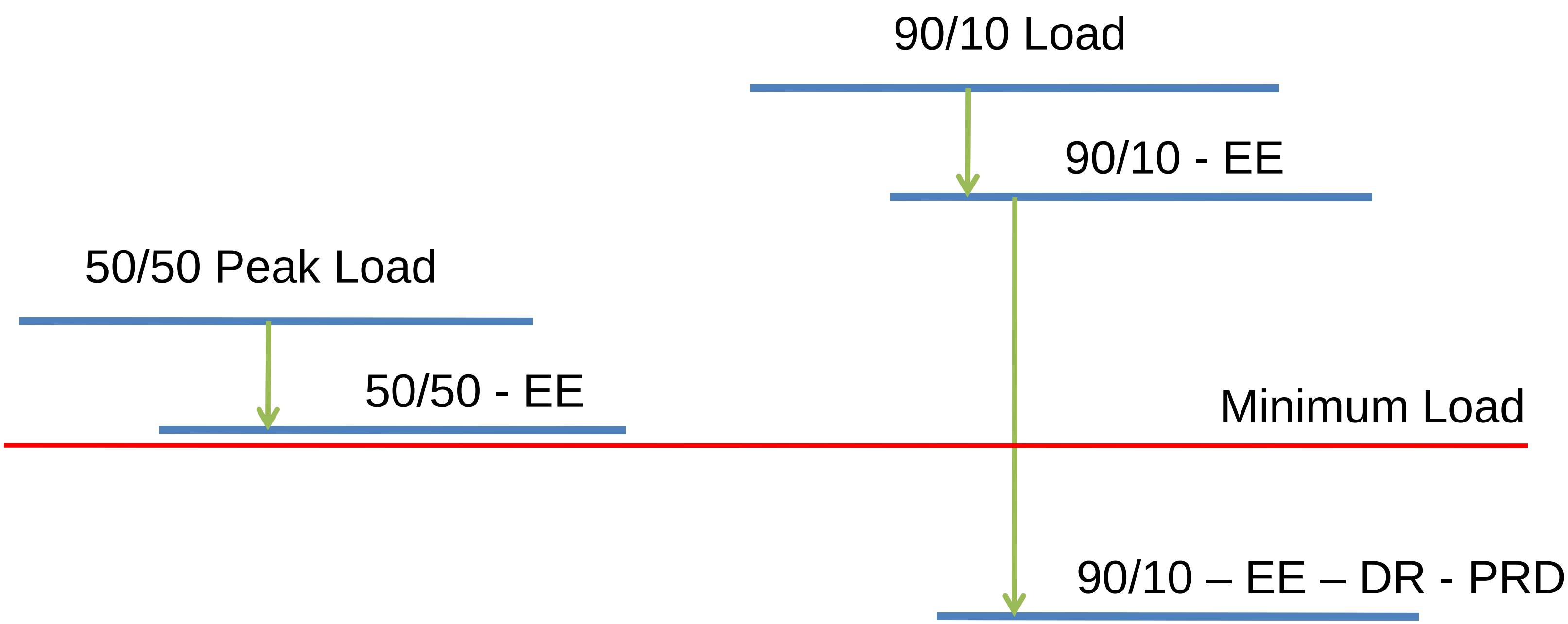
- Develop relationship between LMP and trigger to interrupt PRD

Reliability Analyses

- Develop relationship between load and generator availability and trigger to interrupt PRD
- Load Deliverability
  - Model PRD similar to DR
- Generator Deliverability and NERC Category C
  - Likely would not interrupt PRD



Peak Load Scenario in Planning Studies



- Energy Efficiency
  - Forecast load levels across PJM will be reduced by the amount of EE that cleared in RPM for load and generation deliverability tests
- DR and PRD
  - No impact on generation deliverability test (not an emergency condition)
  - CETO calculation will assume load in the area under test is reduced by the total amount of DR and PRD for the area
  - For CETL calculation, forecast 90/10 load levels in the area under test should be reduced by the amount of DR and PRD that cleared in RPM
    - Except in situations where 90/10 load minus DR and PRD would be less than 50/50 load. In those instances, 50/50 load levels will be used in the area under test.

- PJM monitors and tracks the level of Price Responsive Demand at the zonal level to allow adjustments to zonal unrestricted load forecasts.
- PJM also tracks and monitors the level of Price Responsive Demand at the LSE level to ensure that the load charges to LSE will be based on PLCs adjusted for Price Responsive Demand.

- What happens if end-use customers switch LSEs?
  - LSE needs to separate end-use customers participating in PRD from other customers
  - PJM will separate the PLCs of end-use customers participating in PRD into separate groups in each Zone
  - If an end-use customer participating in PRD switches to another LSE, the customer PLC value and PRD commitment will be transferred to the new LSE
  - Separate grouping of PRD customers and their PLCs would facilitate correct billing of LSEs for load obligations under customer switching

Measurement of Compliance and Penalties

- Compliance is assessed upon Max Emergency Event when LMP >= $1,000/MWh

- Actual Loads during Emergency Events used to measure and verify compliance

- MESL increased by the ratio of actual load to forecast load in zone for the purpose of measurement

- Shortfalls may <u>not</u> be cured using replacement capacity

Example: Compliance during the Delivery Year

- Assessed upon Max Emergency Event when LMP >= $1,000/MWh
- Actual Loads during Emergency Events used to measure and verify compliance.
- A tolerance in MESL value will be applied when the actual load exceeds the forecast in calculating the compliance penalty
- *Measurement of shortfall is based on MESL increased by the ratio of actual load to forecast load in **zone***
- Example
  - MESL = 900 MW; Forecast zonal peak load = 10,000 MW
  - Actual zonal peak load at the Max Emergency condition = 10,500 MW
  - Ratio of actual load to forecast load = 10,500/10,000 = 1.05
  - Tolerance MESL = 900 * 1.05 = 945 MW
  - LSE reduces the load to 955 MW
  - Shortfall = LSE Load in Excess of Tolerance MESL = 955 – 945 = 10 MW

- **Penalty Equation**

MW shortfall

*

[Forecast Pool Requirement]

*

[1.2 * Final Zonal Capacity Price in $/MW-Day * 365].

- Because PRD is demand, not a supply resource, Forecasted Pool Requirement (FPR) should be included in penalty equation.

PRD Compliance Penalty for RPM LSE

(1) Shortfall expressed in terms of a Daily Unforced Capacity Obligation not satisfied (MW)

Shortfall (MW) * Forecast Pool Requirement

(2) RPM PRD Compliance Penalty rate ($/MW-Year)

Final Zonal Capacity Price ($/MW-Day) * 1.2 * 365

PRD Compliance Penalty for RPM LSE ($/Year) = (1) * (2)

(1) Shortfall expressed in terms of a Daily Unforced Capacity Obligation not satisfied (MW)

Shortfall (MW) * Forecast Pool Requirement

(2) **FRR PRD Compliance Penalty rate ($/MW-Year) =**

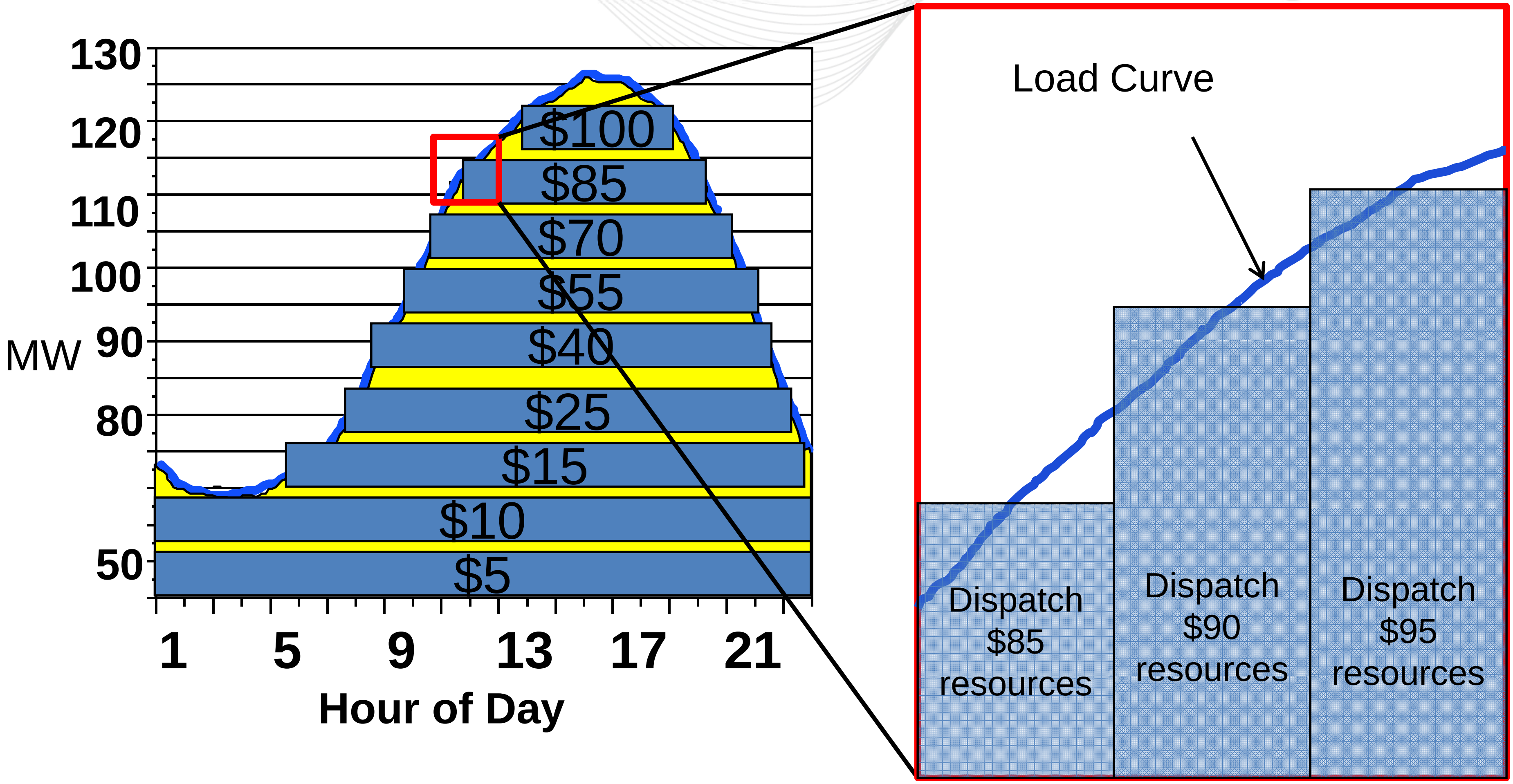
Weighted Capacity Resource Price in LDA encompassing the FRR Entity ($/MW-Day) * 1.2 * 365

PRD Compliance Penalty **for FRR LSE** in $/Year = (1) * (2)

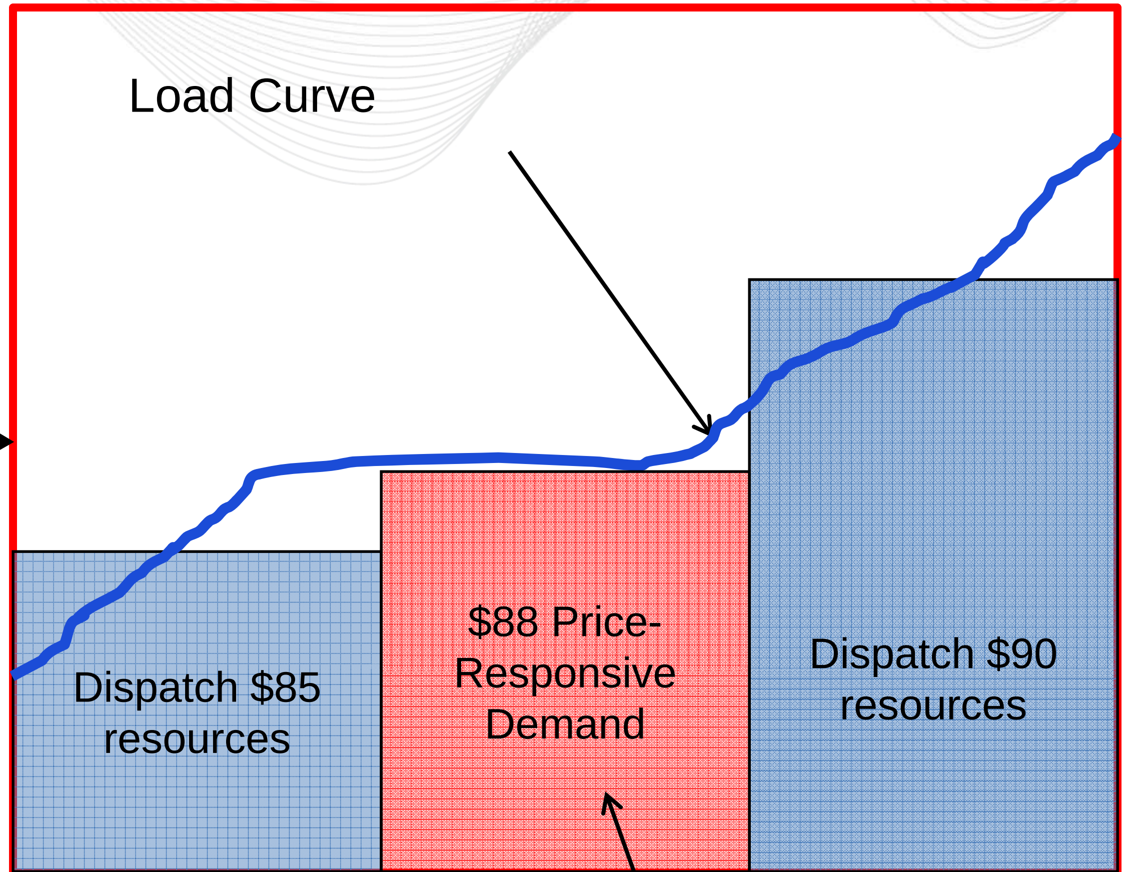
Requirements to Incorporate PRD Into Dispatch

- Close coordination with EDCs on quantities and prices
- Locational detail of PRD quantities
- Recognition in dispatch and pricing software

Today's Economic Dispatch of Supply Resources



Same area of detail



No dispatch of additional resources due to demand response at indicated price level

- Feedback from Participants
- Implementation Details to be Resolved (if any)
- Stakeholder Work Plan to complete
- Next Steps to integrate in Other areas of PJM Markets

Appendix

State Goals for EE and Demand Response in the PJM

State	Energy Efficiency Goal (Energy Use Reduction)	Demand Response Goal (Peak Load Reduction)
Delaware	2% by 2011 and 15% by 2015 (base year 2007)	2% by 2011 and 15% by 2015 (base year 2007)
District of Columbia	None in place or proposed	None in place or proposed
Illinois	Incremental energy savings of 0.2% (two tenths of one percent) each year over the prior year from 2008 to 2015 (2% by 2015 and every year thereafter)	Reduction of 0.1% (one tenth of one percent) over the prior year each year for 10 years (starting in 2008) for eligible retail customers
Indiana	None in place or proposed	None in place or proposed
Kentucky1	Offset at least 18% of the state's projected 2025 energy demand	Offset at least 18% of the state's projected 2025 energy demand
Maryland	5% by the end of 2011 and 10% by the end of 2015 in per capita electricity consumed in each electric company's service territory during 2007 5% reduction by the end of 2015 in per capita electricity consumed (Maryland Energy Administration)	5% by the end of 2011, 10% by the end of 2013, and 15% by the end of 2015 in per capita peak demand of electricity consumed in each electric company's service territory during 2007
Michigan	0.3% energy savings of 2007 total annual retail electricity sales (2008-2009), 0.5% energy savings of preceding year sales (2010), 0.75% energy savings of preceding year sales (2011), and 1.0% energy savings of preceding year sales (2012 and each year thereafter)	0.3% energy savings of 2007 total annual retail electricity sales (2008-2009), 0.5% energy savings of preceding year sales (2010), 0.75% energy savings of preceding year sales (2011), and 1.0% energy savings of preceding year sales (2012 and each year thereafter)
New Jersey2	20% by 2020 (starting in 2010)	5,700 MW3 by 2020 (starting in 2010)

1 Goals in statewide energy plan, not legislation
2 Goals in New Jersey's Energy Master Plan, not legislation
3 A combination of energy efficiency (3,300 MW), combined heat and power (1,500 MW), and demand response programs (900 MW)

(as of November 4, 2009)

State Goals for EE and Demand Response in the PJM

State	Energy Efficiency Goal (Energy Use Reduction)	Demand Response Goal (Peak Load Reduction)
North Carolina	Energy efficiency and renewable energy power savings of 3% of prior-year electricity sales in 2012, 6% in 2015, 10% in 2018, and 12.5% in 2021 and thereafter; energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target (electric public utilities) Energy efficiency and renewable energy power savings of 3% of prior-year electricity sales in 2012, 6% in 2015, 10% in 2018 and thereafter (electric membership corporations and municipalities)	None in place or proposed
Ohio	Savings of at least 0.3% of the total, annual average and normalized kWh sales of the electric distribution utility during the preceding three calendar years to customers in the state, an additional 0.5% in 2010, 0.7% in 2011, 0.8% in 2012, 0.9% in 2013, 1% from 2014 to 2018, and 2% each year thereafter, achieving a cumulative, annual energy savings in excess of 22% by the end of 2025	1% in 2009 and an additional 0.75% each year through 2018
Pennsylvania	1% of 2009-2010 sales by May 31, 2011, increasing to 3% by May 31, 2013 (10% of reductions is to come from federal, state, and local government, including municipalities, school districts, institutions of higher education, and nonprofit entities)	4.5% of 2009-2010 sales by May 31, 2013 (10% of reductions is to come from federal, state, and local government, including municipalities, school districts, institutions of higher education, and nonprofit entities)
Tennessee	None in place or proposed	None in place or proposed
Virginia	10% (from 2006 levels) by 2022	None in place or proposed
West Virginia	Earn credits equivalent to 10% of the electric energy sold in the prior year (2015-2019), 15% (2020-2024), and 25% (2025 and thereafter); one credit earned for each MWh conserved	Earn credits equivalent to 10% of the electric energy sold in the prior year (2015-2019), 15% (2020-2024), and 25% (2025 and thereafter); one credit earned for each MWh conserved

Sources: PJM, ACEEE, FERC, Delaware General Assembly, Michigan Legislature, New Jersey's *Energy Master Plan*, North Carolina General Assembly, Ohio General Assembly, West Virginia Legislature

(as of November 4, 2009)

Smart Grid Investment by State

RECOVERY ACT SELECTIONS FOR SMART GRID INVESTMENT GRANT AWARDS IN PJM FOOTPRINT – AS OF OCTOBER 27, 2009						
HQ State	**HQ City**	**Name of Awardee**	**Brief Project Description**	**Recovery Act Funding**	**Total Project Value Including Cost Share**	**Map of Project Coverage Area**
Illinois	Naperville	**City of Naperville, Illinois**	Deploy more than 57,000 smart meters and install the infrastructure and software necessary to support and integrate various smart grid functions and the two-way flow of information between the utility and customers.	$10,994,000	$21,988,000	http://www.energy.gov/recovery/smartgrid_maps/CityofNaperville.JPG
Maryland	Baltimore	**Baltimore Gas and Electric Company**	Deploy a smart meter network and advanced customer control system for 1.1 million residential customers that will enable dynamic electricity pricing. Expand the utility's direct load control program, which will enhance grid reliability and reduce congestion.	$200,000,000	$451,814,234	http://www.energy.gov/recovry/smartgrid_maps/BaltimoreGasElectric.JPG
New Jersey	Mays Landing	**Atlantic City Electric Company**	Deploy 25,000 direct load control devices, intelligent grid sensors, automation technology, and communications infrastructure to enhance grid reliability, optimize the grid's operations, and empower consumers to better manage and control their energy usage. Will also benefit customers in DC and MD.	$18,700,000	$37,400,000	http://www.energy.gov/recovery/smartgrid_maps/Atlantic CityElectric.JPG
North Carolina	Charlotte	**Duke Energy Business Services LLC**	Comprehensive grid modernization for Duke Energy's Midwest electric system encompassing Ohio, Indiana, and Kentucky. Includes installing open, interoperable, two-way communications networks, deploying smart meters for 1.4 million customers, automating advanced distribution applications, developing dynamic pricing programs, and supporting the deployment of plug-in electric vehicles. Will also benefit customers in IN and OH.	$200,000,000	$851,700,000	http://www.energy.gov/recovery/smartgrid_maps/DukeEnrgyBusinessServices.JPG

Smart Grid Investment by State

HQ State	HQ City	Name of Awardee	Brief Project Description	Recovery Act Funding	Total Project Value Including Cost Share	Map of Project Coverage Area
			RECOVERY ACT SELECTIONS FOR SMART GRID INVESTMENT GRANT AWARDS IN PJM FOOTPRINT – AS OF OCTOBER 27, 2009			
	Charlotte	**Duke Energy Carolinas, LLC**	Install 45 phasor measurement units in substations across the Carolinas and upgrade communications infrastructure and technology at the corporate control center.	$3,927,899	$7,855,797	http://www.energy.gov/recov
Ohio	Akron	**FirstEnergy Service Company**	Modernize the electrical grid and reduce peak energy demand by leveraging the crosscutting nature of different smart grid technologies, including significant communication and information management systems, deploying a smart meter network and automating the distribution system. Will also benefit customers in PA.	$57,470,137	$114,940,273	http://www.energy.gov/recovery/smartgrid_maps/FirstEnergy.JPG
Pennsylvania	Philadelphia	**PECO Energy Company**	Deploy smart meters to all 600,000 customers, upgrade communication infrastructure to support a smart meter network, install 7 "intelligent" substations, and accelerate deployment of more reliable and secure smart grid technologies that will reduce peak energy load and increase cost savings.	$200,000,000	$422,570,000	http://www.energy.gov/recov ry/smartgrid_maps/PECO E nergy.JPG
	Allentown	**PPL Electric Utilities Corp.**	Deploy a distribution management system and smart grid technologies to monitor and control the grid in real-time, improve system reliability and energy resource optimization, and provide the infrastructure for distributed generation and broader energy efficiency efforts.	$19,054,516	$38,109,032	http://www.energy.gov/recov ery/smartgrid_maps/PPL.J P G
	Norristown	**PJM**	Deploy over 90 phasor measurement units and other digital monitoring and analysis technologies across 10 states that will provide real-time data on the operating conditions of the transmission system, improving reliability and reducing congestion. Will also benefit customers in IL, IN, KY, MD, MI, NC, NJ, OH, PA, VI, and WV.	$13,698,091	$27,840,072	http://www.energy.gov/recov ery/smartgrid_maps/PJM.J P G

RECOVERY ACT SELECTIONS FOR SMART GRID INVESTMENT GRANT AWARDS IN PJM FOOTPRINT – AS OF OCTOBER 27, 2009					
HQ City	**Name of Awardee**	**Brief Project Description**	**Recovery Act Funding**	**Total Project Value Including Cost Share**	**Map of Project Coverage Area**
Wellsboro	**Wellsboro Electric Company**	Implement the "Smart Choices" project, which will deploy smart meter network systems throughout the utility's service territory	$431,625	$961,195	http://www.energy.gov/recov
Manassas	**Northern Virginia Electric Cooperative**	Expand substation and distribution automation and control, including adding a new two-way communication infrastructure to the existing fiber optic and microwave communications, which will improve system reliability and reduce peak demand	$5,000,000	$10,000,000	http://www.energy.gov/recovery/smartgrid_maps/NorthernVirginia.JPG
Washington DC	**Potomac Electric Power Company (PEPCO)**	In the Maryland service area, install 570,000 smart meters with network interface; institute dynamic pricing programs, and deploy distribution automation and communication infrastructure technology to enhance grid operations.	$104,800,000	$209,600,000	http://www.energy.gov/recovery/smartgrid_maps/PEPCOMD.JPG
Washington DC	**Potomac Electric Power Company (PEPCO)**	Install 280,000 smart meters equipped with the network interface, institute dynamic pricing programs, and deploy distribution automation and communication infrastructure technology to reduce peak load demand and improve grid efficiency. Will also benefit customers in MD.	$44,600,000	$89,200,000	http://www.energy.gov/recovery/smartgrid_maps/PEPCO