

PJM Demand Side Response Overview

PJM State and Member Training

- Overview
- Economic Load Response
- Customer Baseline Examples & Verification
- Load Management in RPM
- eLRS

Potential benefits of Demand Side Response:

- Bulk Electric System reliability
- Increased competition
- Operational savings
- Lower market prices
- Reduced price volatility
- Elasticity – wholesale to retail
- Improved customer options
- Providing ancillary services
- Positive environmental benefits



Delivery Year 2011-2012 Active Participants in PJM Load Response Program:
as of 8/8/2011 (page 1 of 2)

State	Zone	EDC	Economic Program		Emergency Energy Only		Emergency ILR		Emergency DR		Emergency Total
			Sites	MW	Sites	MW	Sites	MW	Sites	MW	MW
DC	PEPCO	PEPCO	4	8.6			169	74.3	8	15.8	90.0
DE	DPL	DEMEC					23	9.1	1	0.3	9.4
DE	DPL	DOVDE					7	8.5			8.5
DE	DPL	DPL	25	56.9			134	104.6	7	5.9	110.5
DE	DPL	ODEC	2	0.3			5	2.9	1	0.2	3.0
IL	COMED	BATAV					1	0.5			0.5
IL	COMED	COMED	71	82.5			2,115	1,581.4	63	36.8	1,618.2
IL	COMED	IMEAA1					2	46.3			46.3
IN	AEP	AEPSCT					1	0.0	24	216.9	216.9
IN	AEP	HEREC					1	14.4			14.4
IN	AEP	WVSDI					1	23.1			23.1
KY	DEOK	DEK							29	40.9	40.9
MD	APS	AETSAP	6	22.5			137	90.6	29	4.7	95.3
MD	APS	AETSHG					4	2.3	2	0.7	3.1
MD	BGE	BC	58	528.7			661	449.7	129	521.5	971.2
MD	DPL	DPL	4	2.8			141	52.3	24	23.1	75.3
MD	DPL	EASTON					1	1.4	2	0.9	2.3
MD	DPL	ODEC	1	0.5			16	7.9	5	1.3	9.2
MD	PEPCO	PEPCO	8	1.5			390	105.4	16	76.3	181.7
MD	PEPCO	SMECO	6	1.9			61	12.6	29	28.0	40.6
MI	AEP	AEPSCT					4	9.0	2	2.1	11.0
NC	DOM	DOMEDC					5	93.8			93.8
NJ	AECO	AE	33	15.6			217	84.3	1	0.1	84.4
NJ	AECO	VMEU	3	1.0			11	5.4	3	2.5	8.0
NJ	JCPL	AECI					1	0.3			0.3
NJ	JCPL	JCBGS	31	96.1			407	204.5	10	5.6	210.1
NJ	PSEG	PSEG	95	34.7			966	388.8	31	28.5	417.3
NJ	RECO	RECO	1	0.3			14	6.4			6.4
NY	PENELEC	PaElec					1	0.4			0.4
OH	AEP	AEPCLL					9	21.1			21.1
OH	AEP	AEPSCT	60	30.1			636	626.7	103	227.6	854.3
OH	AEP	AMPO					53	154.4	5	6.2	160.7
OH	AEP	BUCK					4	38.7			38.7
OH	ATSI	AMPO							32	299.5	299.5
OH	ATSI	CPP							16	79.3	79.3
OH	ATSI	OEEDC							530	811.2	811.2
OH	DAY	AMPO					17	44.4			44.4
OH	DAY	BUCK					1	3.4			3.4
OH	DAY	DAYEDC	15	7.7			239	171.0	2	0.5	171.5

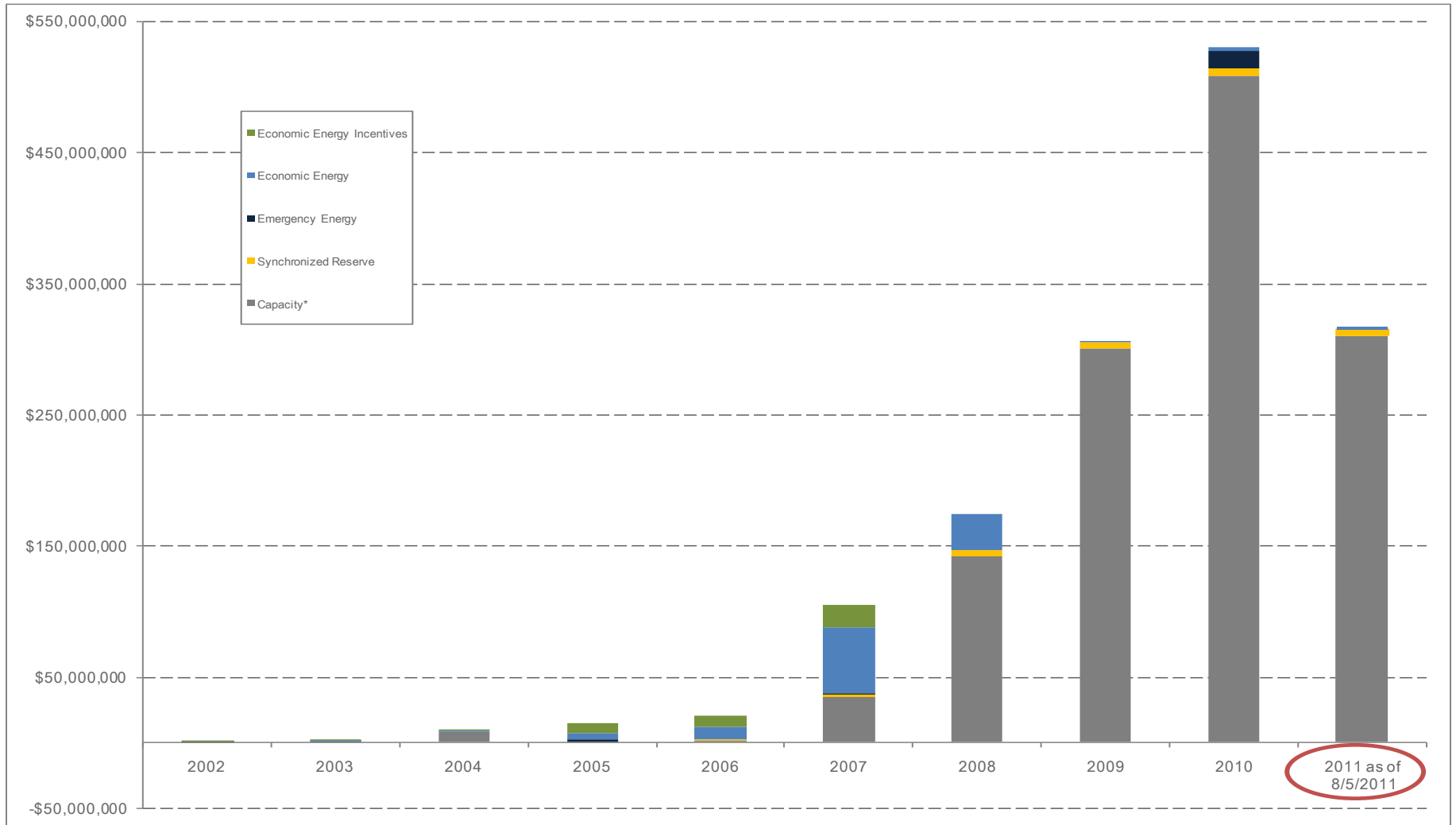
Delivery Year 2011-2012 Active Participants in PJM Load Response Program:
as of 8/8/2011 (page 2 of 2)

State	Zone	EDC	Economic Program		Emergency Energy Only		Emergency ILR		Emergency DR		Emergency Total MW
			Sites	MW	Sites	MW	Sites	MW	Sites	MW	
OH	DEOK	AMPO							1	28.0	28.0
OH	DEOK	DEOHIO							193	229.5	229.5
PA	APS	AECI					3	2.7			2.7
PA	APS	AETSAP	199	52.7			690	479.6	10	2.0	481.6
PA	APS	CHBDTE					4	2.2			2.2
PA	ATSI	PAPWR	6	75.5					31	48.5	48.5
PA	DUQ	DLCO	36	58.8					309	211.4	211.4
PA	METED	AECI					1	1.6			1.6
PA	METED	MetEd	91	89.8			368	241.7	13	5.1	246.8
PA	PECO	PE	264	134.7			1,303	573.3	34	13.1	586.4
PA	PENELEC	AECI					12	17.0	3	0.2	17.1
PA	PENELEC	PaElec	164	108.0			548	357.6	17	18.0	375.7
PA	PENELEC	WELLSB					1	0.1			0.1
PA	PPL	AMPO					8	2.6	4	0.2	2.8
PA	PPL	CTZECL	1	1.9			5	4.2			4.2
PA	PPL	PPL	232	228.8			1,263	716.4	39	11.6	728.0
PA	PPL	UGI-UI					18	10.7			10.7
TN	AEP	AEPSCT					2	13.0			13.0
VA	AEP	AEPSCT	5	58.6			190	280.7	32	3.3	284.0
VA	AEP	AMPO					15	25.6			25.6
VA	APS	AETSAP					1	2.2			2.2
VA	APS	AMPO					3	1.0			1.0
VA	APS	ODEC					37	44.9	8	1.5	46.4
VA	DOM	CVEC							5	3.5	3.5
VA	DOM	DOMEDC	81	85.2			852	716.5	39	31.7	748.2
VA	DOM	DOMVME	1	1.0			15	99.5			99.5
VA	DOM	NVEC	5	43.2			19	27.1			27.1
VA	DOM	ODEC	1	67.0			38	88.4	9	1.6	90.0
VA	DPL	ODEC					8	2.0			2.0
WV	AEP	AEPSCT	39	14.0			348	296.9	12	42.4	339.3
WV	AEP	APWVP					10	6.3			6.3
WV	APS	AETSAP	11	27.2			331	282.5	2	2.6	285.1
Total			1,559	1,938	0	0	12,548	8,736	1,865	3,091	11,826

Note:

- 1) Data as of 08/05/2011.
- 2) Emergency MW are in ICAP.
- 3) Residential Direct Load Control (DLC) registrations reported as one site not a total number of end use customers in that program.
- 4) Sites and corresponding MWs in the Duke Energy Ohio Kentucky Zone (DEOK) will not become effective until 01/01/2012.

PJM Demand Side Response Estimated Revenue



*Capacity Net Revenue inclusive of Capacity Credits and Charges.

- Demand Side Response is critical to the operation of efficient and competitive energy markets
- Demand Side Response provides critical market enhancements to Independent System Operators (ISOs) & Regional Transmission Organizations (RTOs)
- Demand Side Response provides savings and cost reductions to all energy market participants when retail end users have the ability to respond to wholesale prices (elasticity).

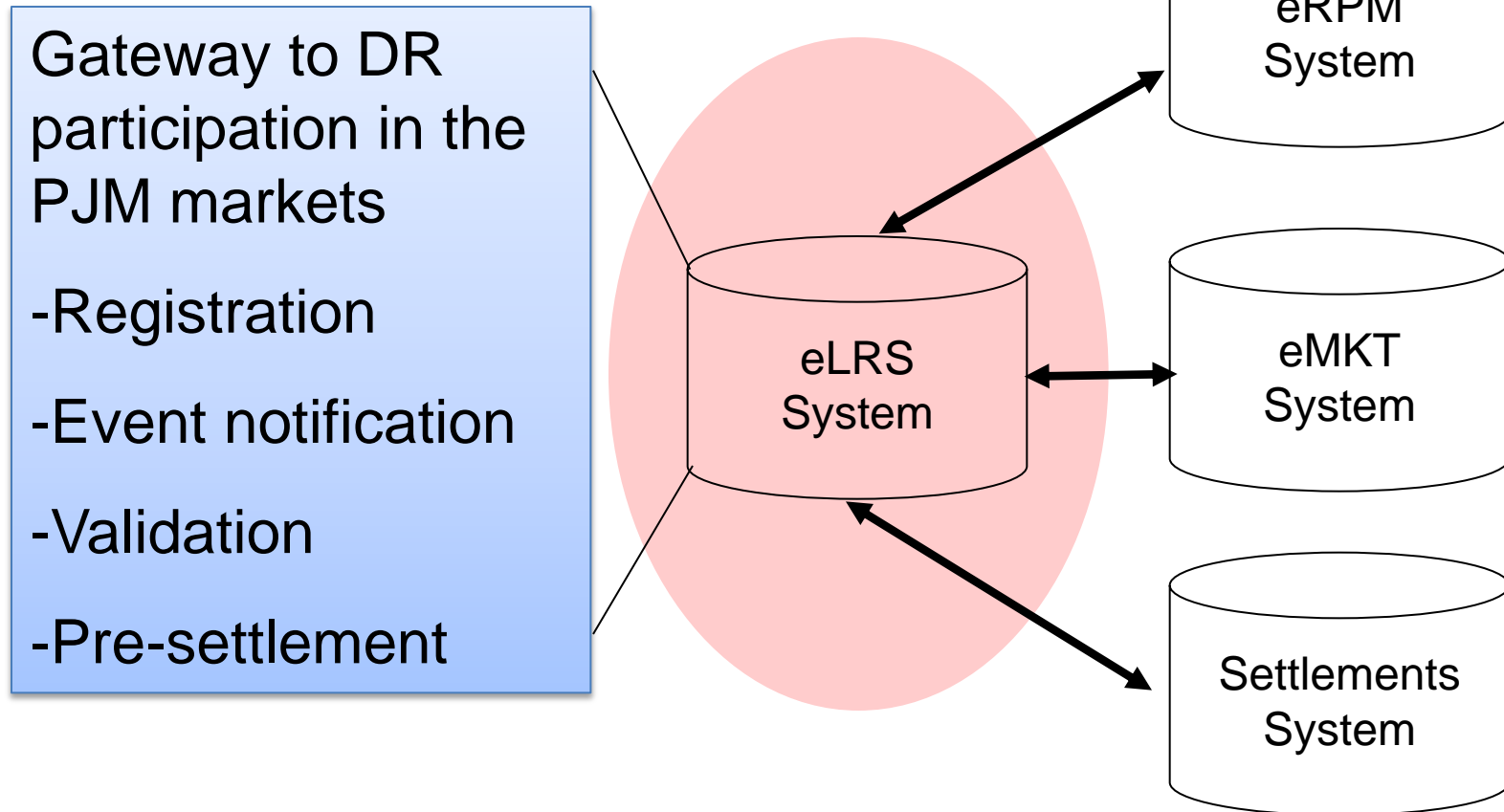
PJM Demand Side Response

The purpose of PJM Demand Response is to enable Demand Resources under the direction and control of Curtailment Service Providers to respond to economic prices.

Demand Response can participate within the various PJM markets:

- *Energy*
 - *Day Ahead*
 - *Real Time*
 - *Dispatched*
 - *Self Scheduled*
- *Ancillary Services*
 - *Synchronized Reserve*
 - *Day Ahead Scheduling Reserve*
 - *Regulation*
- *Capacity*
 - Offer into auction up to 3 years in advance
 - nominate 3 months prior to delivery year (this option expires in March 2011)

System Scope



Replace existing application and upgrade integration to other PJM Systems

PJM Market Participants in Demand Side Response

Load Serving Entity (LSE):

PJM Member, including Load aggregator or power marketer, serving end-users within the PJM Control Area, to sell electric energy to end-users with the PJM Control Areas.

Electric Distribution Company (EDC):

PJM Member that owns, or leases, electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Control Areas.

End Use Customer:

*Cannot directly participate
Unless it is a PJM Member
(e.g. as an LSE or CSP)*

Curtailment Service Provider (CSP):

PJM Members that will act on behalf of end-use customers who wish to participate in PJM Load Response opportunities.

Who Can be a CSP?:

- Any LSE
- Any EDC
- Any third party (PJM member) specializing in Demand Response

PJM Opportunity by Wholesale Market

Wholesale Service	Demand Side Response
Capacity	Yes
Energy	Yes
Day Ahead Scheduling Reserves (30 min)	Yes
Synchronized Reserves (10 min)	Yes
Regulation	Yes

Demand Response in Ancillary Service Markets

- **Day ahead scheduling reserves (30 minute spin)**
 - Must reduce net load within 30 minutes if dispatched by PJM
 - Hourly market price (DAMCP)
- **Synchronized Reserves (10 minutes spin)**
 - Reduce load during reserve shortage, must reduce net load within 10 minutes.
 - Hourly market price (SRMCP)
- **Regulation – real time load change (increase or decrease) based on real time system conditions**
 - Hourly market price (RMCP)

Reliability service - must be there when system operator needs it.

Demand Side Response in PJM

Energy	Capacity <i>PJM capacity procured via RPM</i>	Ancillary Services
<ul style="list-style-type: none"> • Economic • Emergency – Energy Only <p>Voluntary load reductions for <u>energy</u>, even during a PJM emergency event</p>	<ul style="list-style-type: none"> • Emergency – Full (also gets an energy payment) • Emergency – Capacity Only <p>Mandatory reduction for PJM Load Management emergency event if committed in RPM</p>	<ul style="list-style-type: none"> • Synchronized Reserves <ul style="list-style-type: none"> • Regulation • Day Ahead Scheduling Reserves <p>Load bids into these markets and responds to an event similarly to a generator</p> <p>Mandatory response to a Synchronous Reserve (SR) event if cleared in SR market</p> <p>Mandatory response to a PJM regulation signal if cleared in Regulation market</p>

EMERGENCY – Full

Participants eligible to receive an energy payment for reductions during an emergency event and a capacity value; Reduction is mandatory

EMERGENCY – Capacity Only

Provides compensation mechanism for capacity; Reduction is mandatory

EMERGENCY – Energy Only

End-use customers may be compensated by PJM for voluntarily reducing load during an emergency event.

ECONOMIC

Designed to provide an incentive to customers or curtailment service providers to reduce consumption when PJM LMP prices are high

Emergency Program (Capacity and Energy)

- Mandatory
 - Penalties for non-performance
- Load Management (ILR or DR)
 - DR participates directly in RPM auction
- Quantity tied to retail peak load contribution (PLC)
- Interval metering required
- Non-interval metering for direct load control
- Load reduced is incorporated back into forecast requirement for next year (Aka - “add back”)

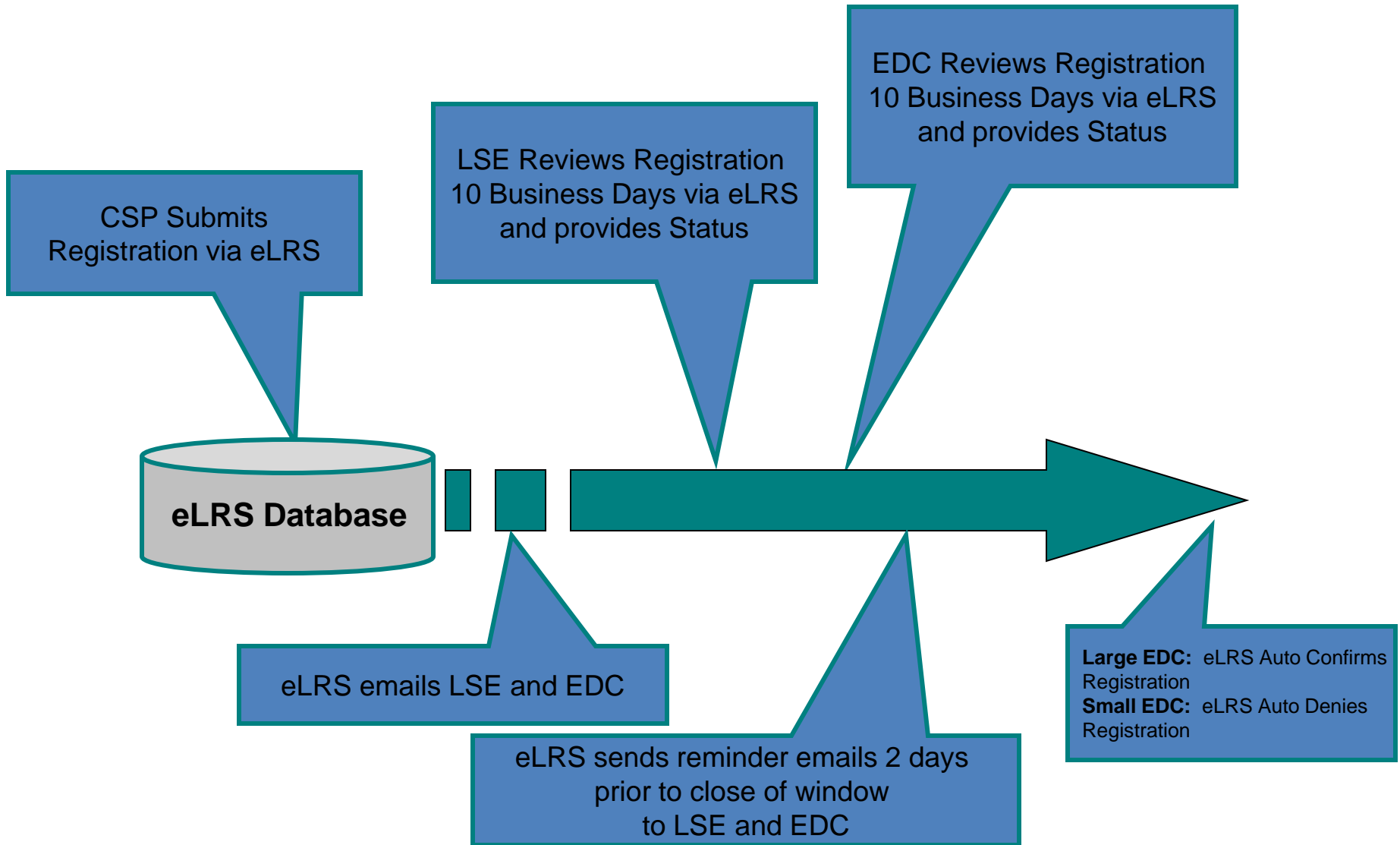
- Overview
- Economic Load Response
- Customer Baseline Examples & Verification
- Load Management in RPM
- eLRS

- The intent of Economic DSR is for participants to respond to price (RT and DA LMP)
 - The following is a list of activities that are not permitted
 - Settlements where load reductions are based on normal variability of load
 - Daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL
 - Settlement based on on-site generation data where on-site generation is not supporting reduction executed in response to price
 - Settlements based on shift of activity from one site in PJM to another site in PJM (unless to mitigate congestion)
- Settlement hours must align with Event hours
 - If an event spans 10 hours, then a settlement will be created for 10 hours
- The CSP, EDC and LSE behavior will be monitored
 - Registration & Settlement issues

Creating Locations and Registrations

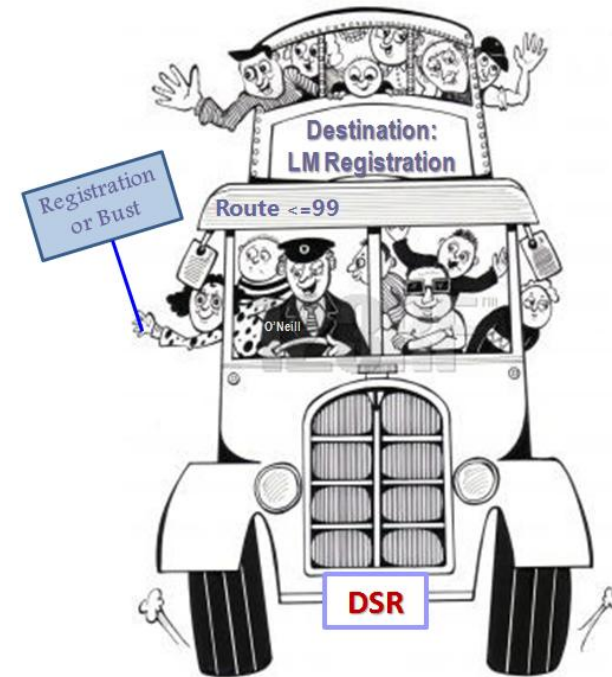
- Locations are created in eLRS and represent the Customer Site at the EDC Account Number level.
 - The EDC Account Number is a unique number assigned by the EDC to the metering at the customer site.
- Economic and Emergency Registrations are created in eLRS from the Locations.
 - A registration can be created from a single location.
 - An aggregate registration can be created from multiple locations per the business rules for aggregate registrations.
- Registrations are required for Market participation

Registration Process Timeline



Business Rules for Creating Aggregate Registrations

- All Locations in the aggregate must have the same EDC and LSE
- The aggregate will be created using functionality in the eLRS software
- All registrations must total $\geq 100\text{kW}$
 - multiple Locations will need to be selected in eLRS to form one (1) single registration $\geq 100\text{kW}$
- Only one (1) individual location in the aggregate can be $\geq 100\text{kW}$
- All Locations in the aggregate must meet all other requirements for market participation
- There is no limit to the number of Locations in an aggregate



Metering Requirements

- Metering requirements shall meet:
 - 1) Electric Distribution Company requirements for accuracy or,
 - 2) Have a maximum error of two (2) percent over the full range (end-to-end) of the metering equipment (including Potential Transformers and Current Transformers)
 - For pulse data recorders (PDR), this includes the PDR error plus EDC meter error
- Metering equipment can be either:
 - 1) The metering equipment used for retail electric service
 - 2) Customer-owned metering equipment
 - 3) Metering equipment acquired by the CSP for the customer



Rules are outlined in Manual 11, section 10 - Interval Meter Equipment and Load Data R

Implementation of Metering Rules

- CSP submits quality assurance plan
 - Indicate how CSP ensures installation is correct and that meter equipment & load data remain accurate overtime.
- CSP indicates “customer owned” meter on eLRS location that is part of a registration
- CSP submits “DSR customer owned meter qualification form” to dsr_ops@pjm.com
 - <http://www.pjm.com/markets-and-operations/etools/~media/etools/elrs/20090904-dsr-customer-ownder-meter-qualification-form.ashx>
- PJM reviews registration & contacts CSP as necessary
 - Registration must be approved by PJM
- CSP uploads 90 consecutive days of hourly load data on an annual basis near effective date of registration (if new) or termination date (if renewal) to eLRS.
 - Use eLRS “daily file format” for meter data upload
 - LSE / EDC may download meter data as needed for additional review
 - If CSP has emergency registration and will use generator data for GLD compliance (90 days of load data not required)
 - If meter data is not loaded, PJM will request from CSP as needed

Current Payments, Costs, & Risks

Prior to implementation of FERC ORDER 745

Energy & Capacity Markets	Participation	Payment to CSP	Cost to Energy Market	Risks to CSP
Emergency	Emergency Event - Dispatched by PJM	PJM pays Zonal LMP <ul style="list-style-type: none"> • Made whole to offer • Full Emergency participants also get capacity value • Cap Only Emergency get capacity value only 	Costs recovered for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases over DA mkt	<p style="text-align: center;">Energy Only Option: No charges for non-performance</p> <p style="text-align: center;">Full & Cap Only Emergency Option: Compliance Penalty Charge (ILR & DR) Capacity Deficiency Charge (DR)</p> <p style="text-align: center; color: red;">NOTE: Testing will be required if no event</p>
Economic	<ul style="list-style-type: none"> • Day Ahead Market • Real Time Market - Dispatched by PJM - Self Scheduled 	<p style="text-align: center;">PJM pays LMP - Retail Rate [Retail Rate = Generation + Transmission]</p> <p style="text-align: center;"><i>Separate make whole payment up to bid parameters for dispatched resources</i></p>	<p style="text-align: center;">PJM recovers LMP less Retail Rate from LSE</p>	<p style="text-align: center;">Day Ahead participation: If load reduction is committed in Day Ahead Market and does not perform in Real Time:</p> <p style="text-align: center; color: red;">Real Time LMP * Shortfall + Balancing Operating Reserves Charges</p>
Economic – Real Time LMP Based Customers (NOTE: payments to CSP calculated based on savings, not LMP-G&T)	<ul style="list-style-type: none"> • Real Time Market Only • Must be dispatched by PJM 	<p style="text-align: center;"><i>For duration of the load reduction dispatched by PJM,</i></p> <p style="text-align: center;"><u>Total Bid Value</u> [(Strike Price * MW Reduction) + Shutdown Costs] minus <u>Actual Savings</u> [RT LMP * MW Reduction]</p>	Costs recovered based on Balancing Operating Reserve rules (i.e. deviations from DA position)	<p style="text-align: center;">No Charges for Non-Performance</p>

FERC Final Rule on Demand Response Compensation (Docket RM10-17-000)

- On March 15, 2011 FERC issued its final rule regarding DR compensation
- FERC final rule stipulates that DR be compensated full LMP when two conditions are met:
 - DR has the capability to balance supply and demand; and
 - Payment of LMP to DR is cost effective.
- Costs are to be allocated to load where DR reduces LMP
- Implementation timeline is dependant upon FERCs acceptance of PJM compliance filing

Order 745 details the requirements of the Net Benefits Test as follows:

- Implement net benefits test to define a threshold point where the net benefit exceeds the cost to load.
- The net benefit is the point where $(\text{Delta LMP} \times \text{MWh consumed}) > (\text{LMPNEW} \times \text{DR})$, where LMPNEW is the market clearing price after DR is dispatched and Delta LMP is the price before DR is dispatched minus the LMPNEW).
- The supply curve analysis should be updated monthly, by the 15th day of the preceding month in advance of the effective date, to allow demand response providers as well as other market participants to plan, while still reflecting current supply conditions.

To create the curve:

- Pick a curve representative of the study month using the prior year's curve
- Adjust for resource availability
- Adjust for fuel prices
- Smooth the curve using numerical methods
- Find price/quantity pair above which a one megawatt reduction in quantity that is paid LMP would result in a larger percentage decrease in price than the corresponding percentage decrease in quantity.

Customer Data

- Shutdown Costs = \$1,500
- Minimum Down Time = 2 Hours
- MW Reduction = 5 MW
- Retail Rate (G&T) = \$35 /MWh

Marginal Cost Example including Shutdown Cost:

$$\left(\frac{\$ 1,500}{2 \text{ Hours}} * \frac{1}{5 \text{ MW}} \right) + \$ 35 /\text{MWh} = \$185.00/\text{MWh}$$

Action

- Customer Forecasts Real Time LMP > \$185.00/MWh Hours Ending 16 – 17
- Customer Decides to curtail load in the Real Time Market

Self Schedule Example

Prior to implementation of FERC ORDER 745

Hour Ending 16

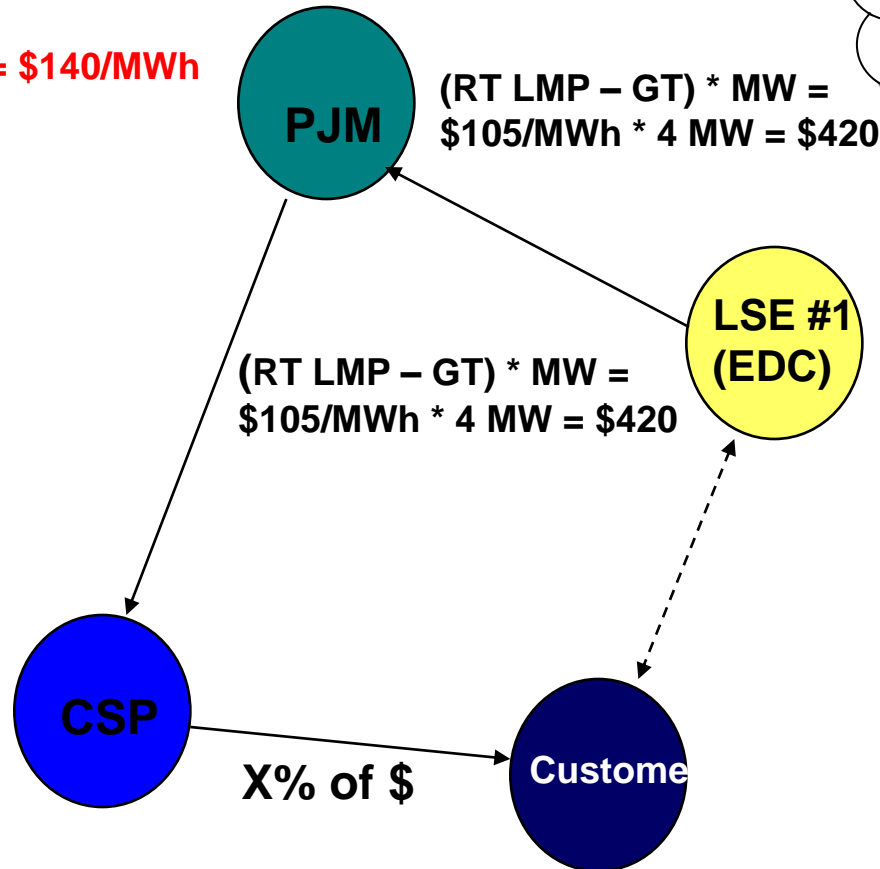
Scheduled MW Reduction = 5

Actual MW Reduction = 4

Real Time Hourly Zonal LMP = \$140/MWh

Retail Rate (GT) = \$35/MWh

*RT LMP
less than
forecast*



Self Schedule Example

Prior to implementation of FERC ORDER 745

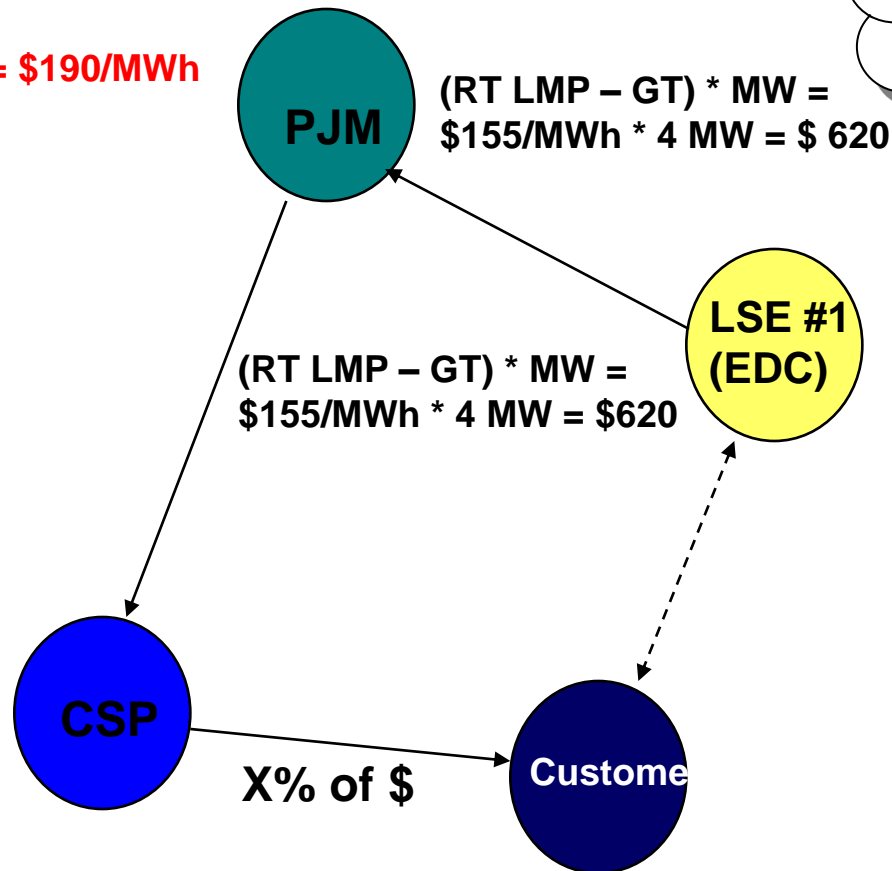
Hour Ending 17

Scheduled MW Reduction = 5

Actual MW Reduction = 4

Real Time Hourly Zonal LMP = \$190/MWh

Retail Rate (GT) = \$35/MWh



Real Time Dispatch Example

Prior to implementation of FERC ORDER 745

Hour Ending 16

Bid Price = \$187.00

Shutdown Cost = \$1,500

Bid Quantity (MW) = 5

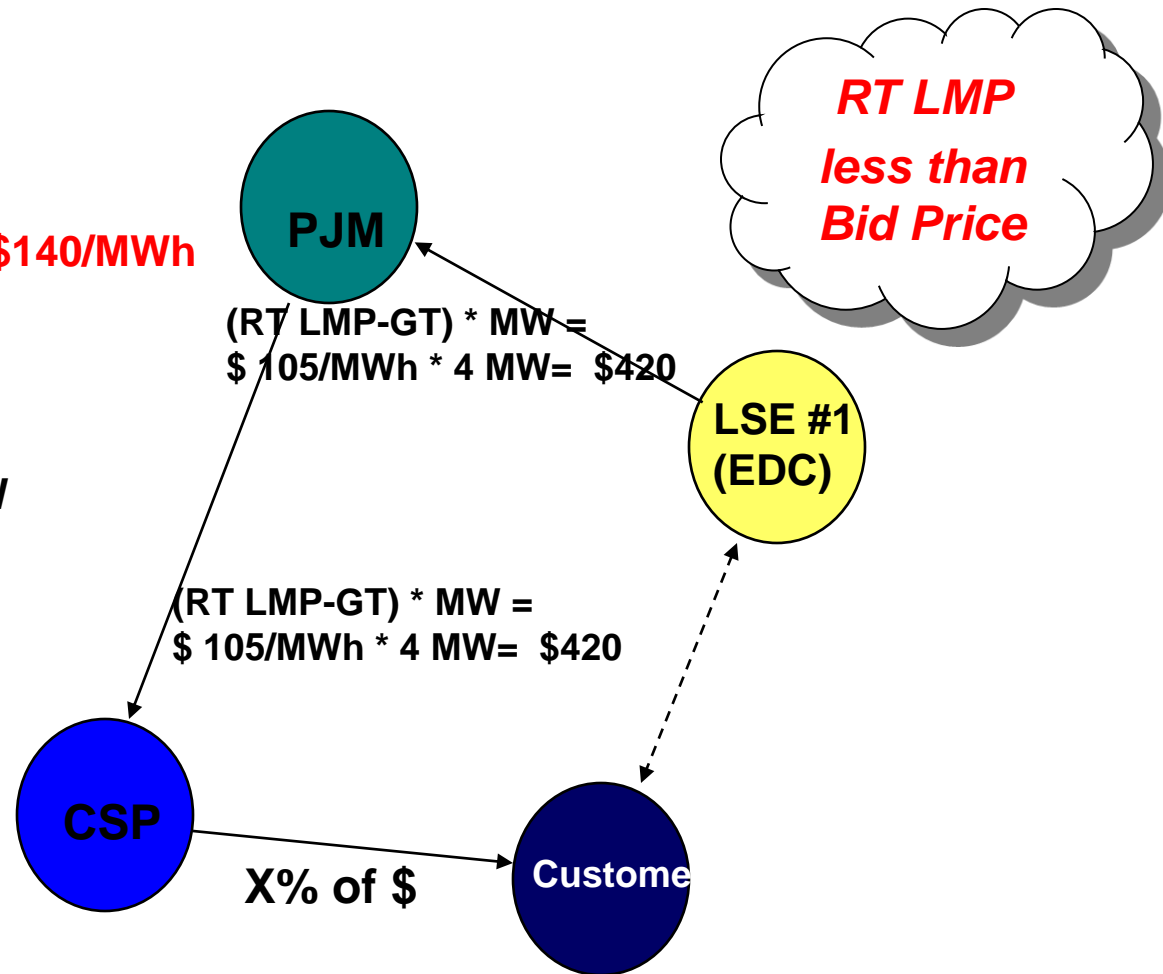
Real Time Hourly Zonal LMP = \$140/MWh

Actual MW Reduction = 4

Retail Rate (GT) = \$35/MWh

Bid Value = (Bid Price-GT) * MW

\$ 152/MWh * 4 MW = \$608



******Operating Reserves are calculated on a daily basis – see next slide**

Real Time Dispatch Example

Prior to implementation of FERC ORDER 745

Hour Ending 17

Bid Price = \$187.00

Shutdown Cost = \$1,500

Bid Quantity (MW) = 5

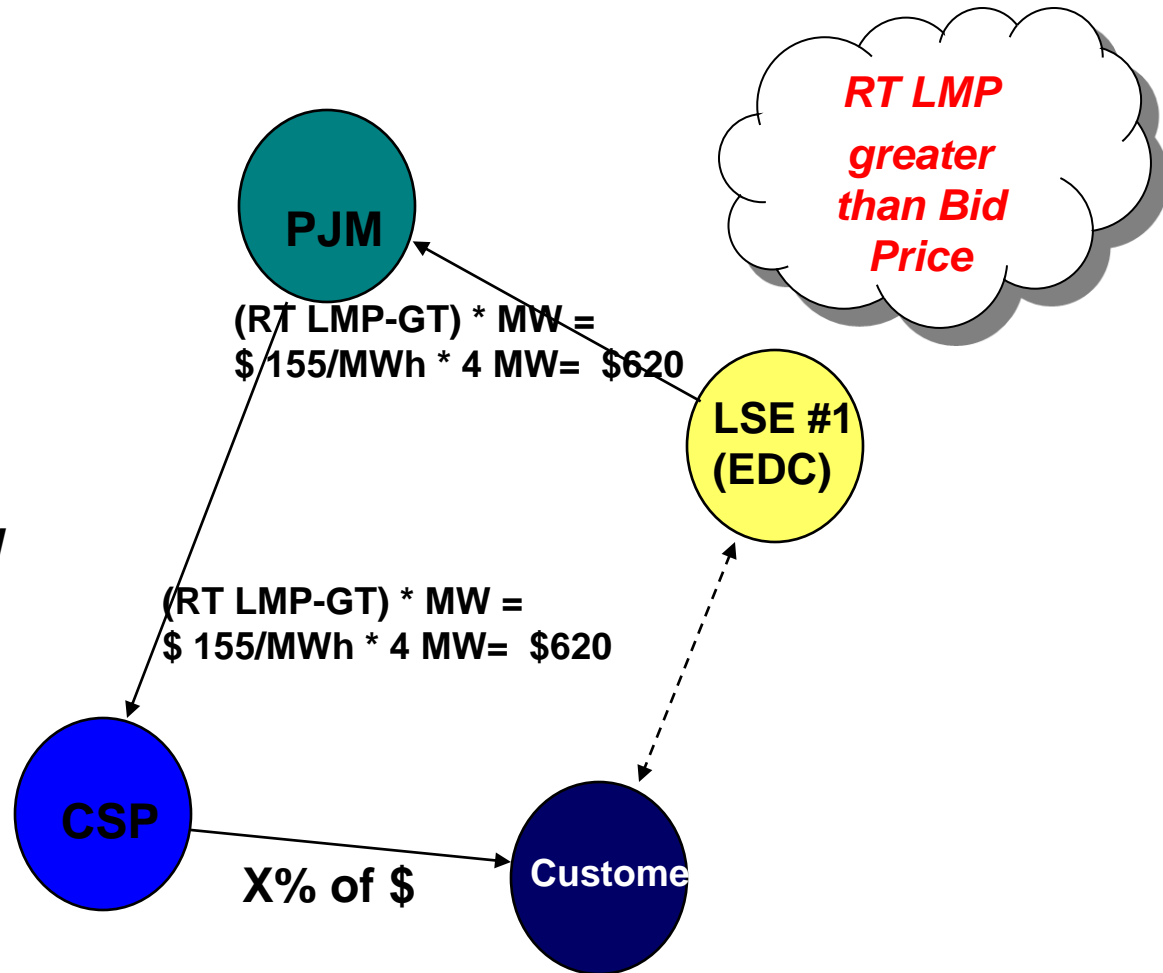
Real Time Hourly Zonal LMP = \$190/MWh

Actual MW Reduction = 4

Retail Rate (GT) = \$35/MWh

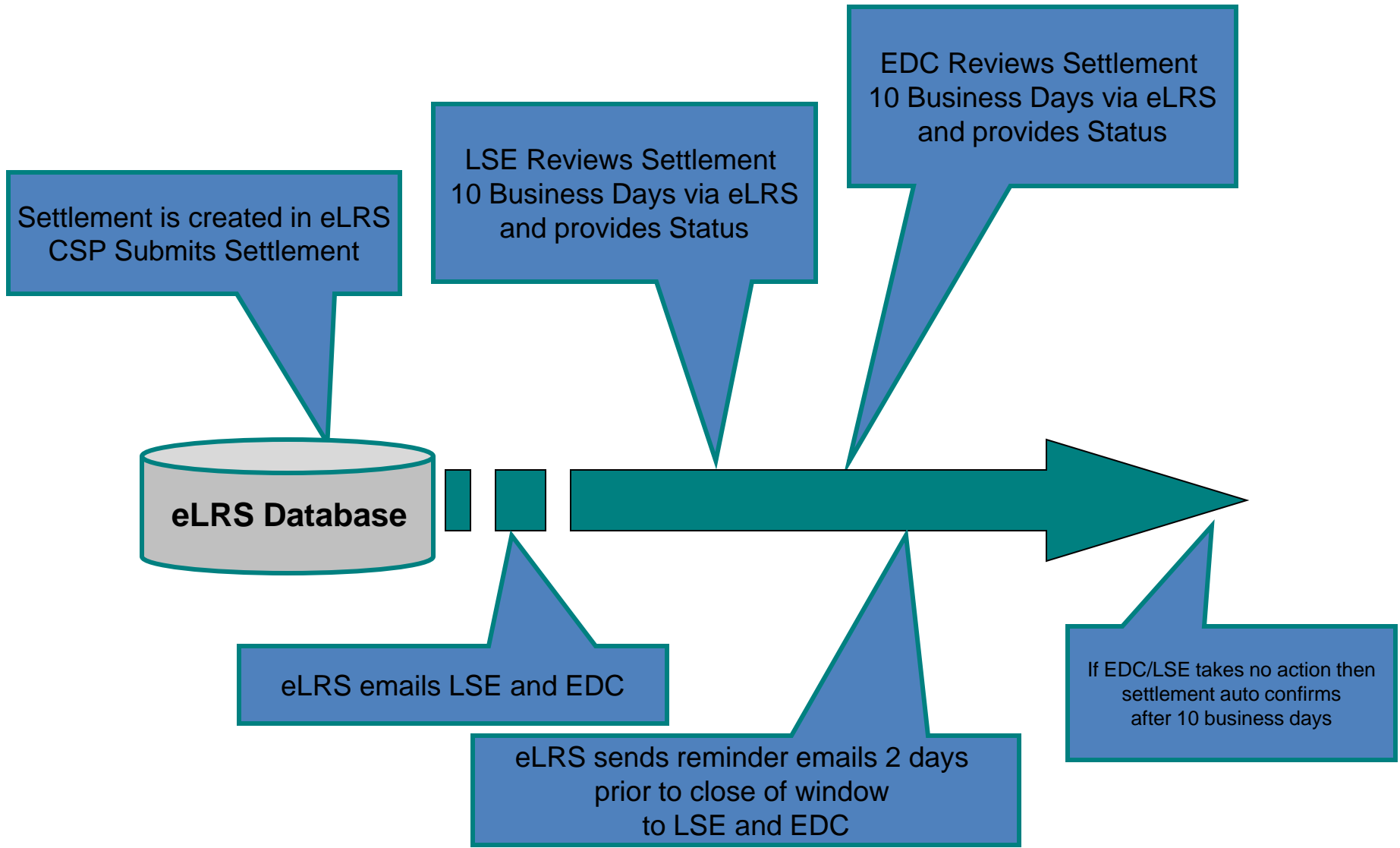
Bid Value = (Bid Price-GT) * MW

\$ 152/MWh * 4 MW = \$608



******CSP Operating Reserves Credit: $(\$608 + \$608) - (\$420 + \$620) = \$176$**

Settlement Process Timeline



A brief word on Ancillary Services.....

Other Options for Participation

- PJM Ancillary Service Markets
 - PJM Regulation Market (Mandatory online training required)
 - Automatic adjustment of load in response to PJM regulation control signal
 - PJM Synchronized Reserve Market (Mandatory online training required)
 - Ability to achieve required reduction of load in a 10 minute period when notified by PJM
 - PJM Day Ahead Scheduling Reserve (DASR) Market
 - Providing 30-minute reserves on a Day-Ahead basis

Separate training materials for these markets are covered in “Load Response for Ancillary Services” and the “Day Ahead Scheduling Reserve Market” training presentations

Payments, Costs, & Risks

Ancillary Service Markets	Participation	Payment to CSP	Cost to Energy Market	Risks to CSP
Synchronized Reserves	<ul style="list-style-type: none"> • Ten-minute reduction requirement • One-minute interval metering • Minimum .5 MW offer • 24-hour All-Call availability <p>Tier 1: Voluntary reduction during a PJM Synchronized Reserve event</p> <p>Tier 2: Offers that clear in hourly market. Mandatory reduction during PJM Synchronized Reserve event</p>	<p>Tier 1: PJM pays \$50 premium above event LMP</p> <p>Tier 2: • PJM pays Synchronized Reserve Market Clearing Price (SRMCP) * MW assigned • Economic payment for reduction during event</p>	<p>Synchronized Reserve costs allocated to load servers:</p> <p>Tier 1: • Based on percentage share of total Tier 1 credits paid</p> <p>Tier 2: • Based on obligation share</p>	<p>Nonperformance:</p> <p>Tier 1: No Penalties</p> <p>Tier 2:</p> <ul style="list-style-type: none"> • Forfeiture of Tier 2 revenue over contiguous hours assigned • Additional obligation in the amount of shortfall for next three same-peak days
Regulation	<ul style="list-style-type: none"> • Ability to receive and react to a dynamic regulation control signal from PJM • Real time telemetry • Five-minute response (raise or lower load within specified bandwidth) • Minimum .5 MW offer • Resource certification and testing requirements 	<ul style="list-style-type: none"> • PJM pays Regulation Market Clearing Price (RMCP) * MW Assigned • Economic payment net reduction during hour 	<p>Regulation costs allocated to load servers: (RMCP * Adjusted Obligation) + Share of Opportunity Cost above RMCP</p>	<p>Nonperformance for assigned Regulation resource:</p> <ul style="list-style-type: none"> • Forfeiture of revenue for assigned MW's • Periodic testing below 75% score requires re-certification process

Payments, Costs, & Risks

Ancillary Service Markets	Participation	Payment to CSP	Cost to Energy Market	Risks to CSP
Day-Ahead Scheduling Reserves (DASR)	<ul style="list-style-type: none"> • 30-minute reduction requirement • One-minute interval metering • Offer needs to be submitted in the PJM Day-Ahead Market • Load Response needs to be dispatched by PJM in Real Time 	<ul style="list-style-type: none"> • PJM pays DASR Market Clearing Price * MW assigned 	<p>DASR costs allocated to load servers: (DASRCP * Adjusted Obligation) + Share of Opportunity Cost above DASRCP</p>	<p>Nonperformance: Forfeiture of revenue over hours assigned for the day</p>

- Overview
- Economic Load Response
- Customer Baseline Examples & Verification
- Load Management in RPM
- eLRS

In Economic Load Response..... End-use customers that wish to measure load reductions by comparing metered load against an estimate of what metered load would have been absent the reduction may calculate a customer baseline (CBL) for the following timeframes:

Average Day CBL for Weekdays

Average Day CBL for Saturdays

Average Day CBL for Sundays/Holidays

Detailed CBL language found in the [PJM Operating Agreement, Section 3.3A](http://www.pjm.com/documents/downloads/agreements/oa.pdf)
<http://www.pjm.com/documents/downloads/agreements/oa.pdf>

Customer Baseline Calculation

PJM contracted with Kema to perform an Empirical Analysis of Demand Response Baseline Methods. The objective was to evaluate the accuracy, bias and variability of a variety of CBL methods.

The recommendation was to use the PJM Economic CBL with the symmetric additive adjustment.

Step # 1: Weekday CBL Basis Window

Monday	Tuesday	Weds	Thursday	Friday	Sat	Sun
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
Prior Event 20	21	22	Prior Event 23	24	25	26
27	Event²⁸	29	30	31		

- ◆ **Select 5 most recent non-event day**
 - ◆ **Event days are non-denied settlement days**
- ◆ **Exclude the following day-types:**
 - **NERC holidays**
 - **Weekend Days**
 - **Event Days**
- ◆ **Replace excluded days with next valid day**
- ◆ **Final Weekday CBL Basis Window must contain 5 days** (unless look-back window is reached)

Step # 2: Weekday CBL Basis

Monday	Tuesday	Weds	Thursday	Friday	Sat	Sun
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
Prior Event 20	21	22	Prior Event 23	24	25	26
27	Event 28	29	30	31		

- ◆ For each of the 5 Days in Weekday CBL Basis Window calculate:
 - **Average daily event period usage** = simple average of the participants usage over the event hours in the day
- ◆ For all 5 Days in Weekday CBL Basis Window calculate:
 - **Average event period usage level** = simple average of 5 average daily event period usage values
- ◆ Exclude any day which the day's average daily event period usage is less than 25% of the average event period usage level (25% rule) and replace
- ◆ Rank all remaining 5 days, and eliminate 1 day with lowest average daily event period usage
- ◆ Weekday CBL Basis must contain 4 days

“Look-back” Window

Monday	Tuesday	Weds	Thursday	Friday	Sat	Sun
		1	Prior Event 2	NERC Holiday 3	4	5
Prior Event 6	Prior Event 7	Prior Event 8	Prior Event 9	Prior Event 10	11	12
Prior Event 13	Prior Event 14	Prior Event 15	Prior Event 16	17	18	19
Prior Event 20	Prior Event 21	Prior Event 22	Prior Event 23	24	25	26
27	Event 28	29	30	31		

◆ **CBL “Look-back” Window is limited to 45 days (60 days under certain conditions per PJM tariff)**

◆ *If 5 days can not be selected within the look-back window, then:*

◆ *Use only 4 days*

◆ *If there are not 4 eligible days, then event days will be used. The event days with the highest loads will be used.*

◆ **Saturdays and Sundays/Holidays : use “High 2 of 3” criteria rather than “High 4 of 5”**

Symmetric Additive Adjustment

The purpose is to more properly reflect an accurate CBL

Starting on the event day:

- Skip one hour prior to the start of the event
- Counting back, average the next three hours (Basis Average)
- Use this Basis Average to compare to the CBL for the same hours
- The difference is used to ratchet up (or down) the CBL value

	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16
Event Day	600	700	800	900	900	950	1000	1050
CBL	450	550	650	750	850	950	1050	1150
Additive Adjustment	→				150	150	150	150
Adjusted CBL	→				1000	1100	1200	1300
Calculated Load Reduction	→				100	150	200	250

Additive Adjustment
Period

Hours curtailed
during event day

Example:
In this scenario, usage is much higher than normal on event day. Using the Additive Adjustment will result in a positive (higher) adjustment to the CBL.

Alternative CBL Nomination Process

- **Alternative CBL nomination process**
 - Alternative CBLs are nominated only during the registration processes (changes require new registration)
 - Backup Generation meter data to represent load reduction is considered Alternative CBL
 - Entity that proposes an alternative CBL must provide analytical support that method is more accurate and reasonable to administer
 - 30 days to decide on CBL after it is proposed
 - If no agreement, PJM will decide on the CBL within 20 days

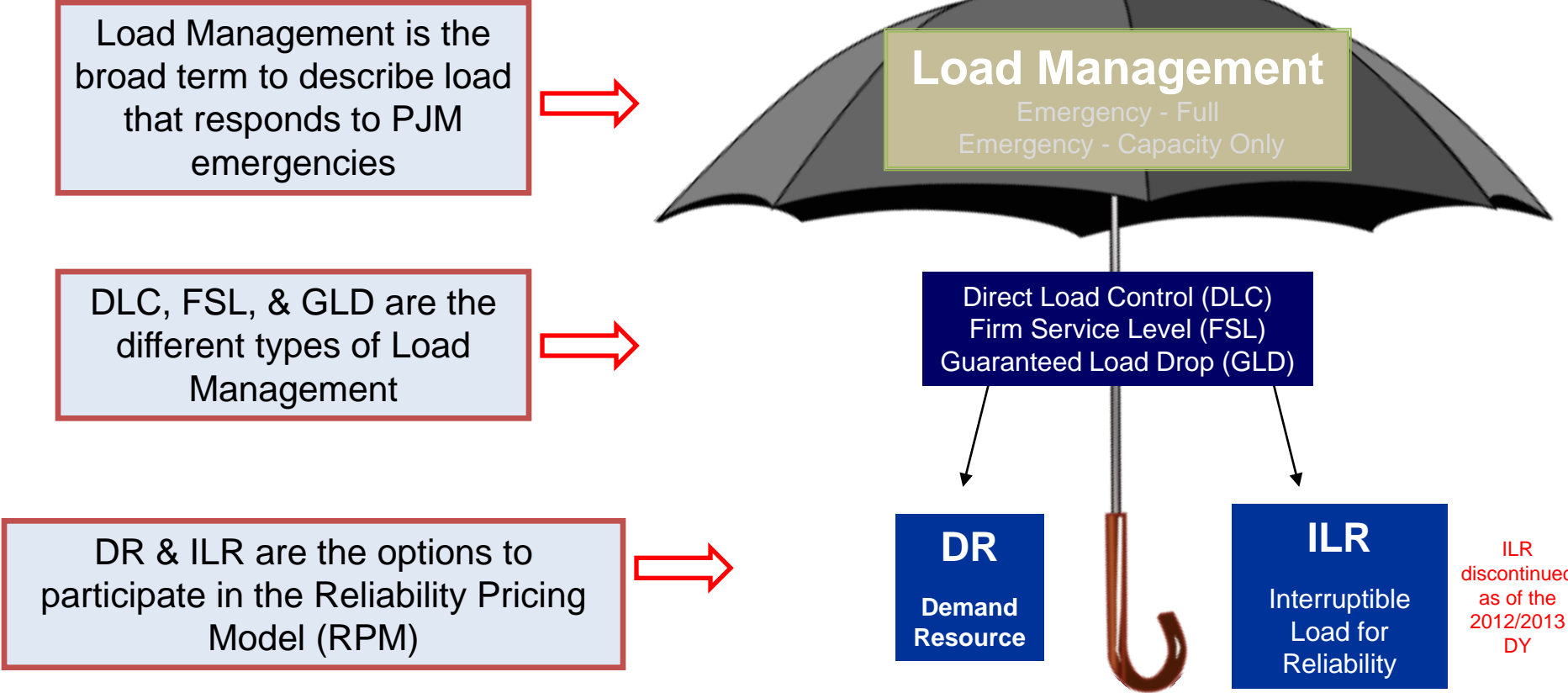
Goal of Alternative CBL is to provide flexibility for unique load patterns

Alternative CBL Approval Process

- Select Request Alternative CBL in eLRS while registration is pending
 - For example, “Alternative 5 Day Types”, where a CBL is calculated for each day type (Mon, Tues, etc.)
- Email proposed Alternative CBL analysis template to all interested parties
 - If CSP proposes then email goes to EDC, LSE and PJM (dsr_ops@pjm.com)
 - If LSE proposes then email goes to CSP, EDC and PJM
- If no agreement, then PJM reviews, discusses and finalizes within 20 days
 - 1 year of interval data should be submitted to PJM
- After alternative CBL method decision, the final method will be displayed on registration
- Settlements will use Alternative CBL method after its approval. Settlements will be allowed to submit after the final decision is made on the Alternative CBL
- PJM will publish Alternative CBLs with associated load characteristics to Manual 11

- Overview
- Economic Load Response
- Customer Baseline Examples & Verification
- Load Management in RPM
- eLRS

<h2 style="text-align: center;">Energy</h2>	<h2 style="text-align: center;">Capacity</h2> <p style="text-align: center;"><i>PJM capacity procured via RPM</i></p>	<h2 style="text-align: center;">Ancillary Services</h2>
<ul style="list-style-type: none"> • Economic • Emergency – Energy Only <p>Voluntary load reductions for <u>energy</u>, even during a PJM emergency event</p>	<ul style="list-style-type: none"> • Emergency – Full (also gets an energy payment) • Emergency – Capacity Only <p>Mandatory reduction for PJM Load Management emergency event if committed in RPM</p>	<ul style="list-style-type: none"> • Synchronized Reserves <ul style="list-style-type: none"> • Regulation • Day Ahead Scheduling Reserves <p>Load bids into these markets and responds to an event similarly to a generator</p> <p>Mandatory response to a Synchronous Reserve (Spinning) event if cleared in Synch market</p> <p>Mandatory response to a PJM regulation signal if cleared in Regulation market</p>



Load Management is the broad term to describe load that responds to PJM emergencies

DLC, FSL, & GLD are the different types of Load Management

DR & ILR are the options to participate in the Reliability Pricing Model (RPM)

Load Management

Emergency - Full
Emergency - Capacity Only

Direct Load Control (DLC)
Firm Service Level (FSL)
Guaranteed Load Drop (GLD)

DR
Demand Resource

ILR
Interruptible Load for Reliability

ILR discontinued as of the 2012/2013 DY

Note: Energy Efficiency is not dispatchable and therefore not considered Load Management

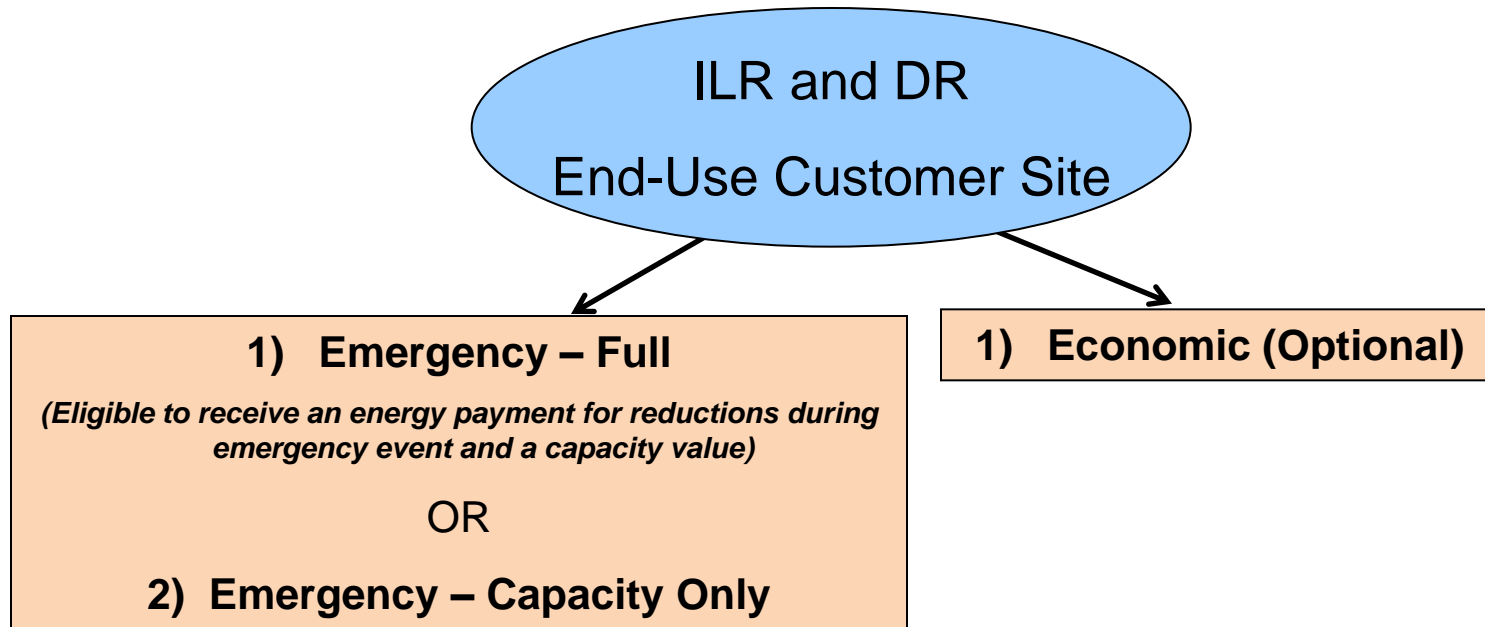
Limited DR Load Management Qualification

- Availability for up to ten (10) PJM-initiated interruptions at any time during the planning period.
- Interruptions of up to six (6) consecutive hours' duration between 12:00 PM (Noon) to 8:00 PM (Eastern Prevailing Time) for the months of May through September and 2:00 PM to 10:00 PM for the months of October through April, on weekdays other than PJM Holidays.
- Load management must be able to be implemented within two hours (2) of notification to the resource provider of a PJM-initiated load management event.
 - Participant will specify either one or two hours during registration process
- Initiation of load interruptions upon request of PJM must be within the authority of the resource provider dispatcher without any additional approvals being required.

- Effective with the 2014/2015 DY, a load management resource (i.e., demand resource) may be one of three product types:
 - ❖ **Limited Demand Resource**
 - ❖ **Extended Summer Demand Resource**
 - ❖ **Annual Demand Resource**

Product Type Requirements – Beginning with the 2014/2015 DY

Requirement	Limited DR	Extended Summer DR	Annual DR
Availability	Any weekday, other than NERC holidays, during June – Sept. period of DY	Any day during June-October period and following May of DY	Any day during DY (unless on an approved maintenance outage during Oct. - April)
Maximum Number of Interruptions	10 interruptions	Unlimited	Unlimited
Hours of Day Required to Respond <i>(Hours in EPT)</i>	12:00 PM – 8:00 PM	10:00 AM – 10:00 PM	Jun – Oct. and following May: 10 AM – 10 PM Nov. – April: 6 AM- 9 PM
Maximum Duration of Interruption	6 Hours	10 Hours	10 Hours
Notification	Must be able to reduce load when requested by PJM All Call system within 2 hours of notification, without additional approvals required		
Registration in eLRS	Must register sites in Emergency Load Response Program in Load Response System (eLRS)		
Event Compliance	Must provide customer-specific compliance and verification information within 45 days after the end of month in which PJM-initiated LM event occurred.		
Test Compliance	In absence of the PJM-initiated LM event, CSP must test load management resources and provide customer-specific compliance and verification information.		



Each customer site may have 2 registrations – 1 Economic and 1 Emergency

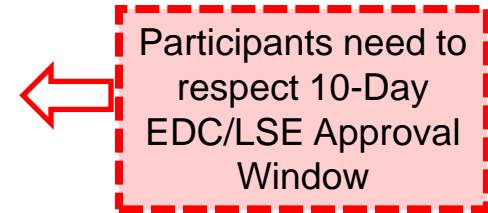
*** Special Case: If one CSP has the economic registration, a second CSP can register the site, but only as Emergency- Capacity only. ***

-Registration done through eLRS Application-

DR Registration timeline & requirements

- Timeline
 - DR
 - Registration must be confirmed by 5/31
- General Requirements
 - Interval metering that complies with PJM standard, fully operational and tested
 - **24 hours of interval meter data required for compliance submittal**
 - Full PJM member
 - CSP must have registrations that total $\geq 100\text{kW}$ by registration
 - Locations may be aggregated to reach minimum registration value
 - Must set up to receive and acknowledge ALL CALL with adequate personnel and land line.
- **New Requirements (2014/2015 DY)**
 - Each registration must indicate product type (Annual, Extended Summer, Limited)
 - Each registration may only be linked to a single DR Resource modeled in eRPM and the linked DR Resource must be of the same product type and zone as the registration

Participants need to respect 10-Day EDC/LSE Approval Window



Registration must be complete and approved by the end date. The EDC and LSE have 10 business days to approve.

Notification of Load Management Tests and Retests in eLRS

- CSP is required to simultaneously test all their DR and ILR resources in a zone if PJM has not called an event in that zone by August 15
 - If an event is called between August 16 and September 30, no test will be required
- Testing details
 - All resources in same zone will test at the same time for 1 hour (non-holiday weekday, 12 Noon – 8 PM EPT)
 - Test can be conducted between June 1 and September 30
 - Data will be submitted in a format similar to event data submissions
 - Data must be submitted between October 1 and November 14
 - Notify PJM of intent to test 48 hours in advance
 - **Test and Retest notifications must be submitted in eLRS**
 - No limit on the number of tests a CSP can perform
 - Only submit data for the test which PJM will use to determine the Test Failure Charge



ALL TEST and RETESTS MUST BE COMPLETED BY SEPTEMBER 30

PJM recognizes three types of LM:

- Direct Load Control (DLC) – Load management which is initiated directly by the CSP's market operations center to non-interval metered sites, employing a communication signal to cycle equipment. This is typically done for AC or hot water heaters.
- Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the CSP's market operations center
- Guaranteed Load Drop (GLD) - Load management achieved by a customer reducing its load by a pre-determined amount (the guaranteed load drop) when compared to the amount the customer would have consumed, upon notification from the CSP's market operations center

Nominated Value of Load Management = ICAP Value

- The nominated value is the maximum load reduction of an end-use customer site.
- The process to determine this value is consistent with the process for the determination of the capacity obligation for the customer.

Load Management Program Type	Nominated Value
Direct Load Control	# Customers * Per Participant Impact * Loss Factor
Firm Service Level	Peak Load Contribution – (Firm Load Level * Loss Factor)
Guaranteed Load Drop	Min (Peak Load Contribution or Customer Load Reduction Value * Loss Factor)

The maximum load reduction for each resource is adjusted to include system losses.

UCAP Value of Demand Resource

Unforced Capacity (UCAP) value of a Demand Resource is calculated as:

$$\text{Unforced Capacity Value Of DR X} = \text{Nominated DR Value} * \text{DR Factor} * \text{Forecast Pool Requirement (FPR)}$$

For Example:

$$\text{10.3 MW} = 10 * 0.956 * 1.0809$$

$$\text{Unforced Capacity Value For DR} = \text{10.3 MW}$$

DR Factor is determined by PJM's Reliability Study and represents the reliability benefit of active load management based on the specification of 10 interruptions for PJM use.

Forecast Pool Requirement: The amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region.

Effective with 2012/2013 Delivery Year, the DR Factor and Forecast Pool Requirement is not finalized until the Third IA for the DY.

'11/'12 Auction Results

LDA	System Marginal Price	Locational Price Adder	2011/12 Prelim Zonal Peak Load Forecast	ILR Forecast Obligation	Base UCAP Obligation	Cleared Internal Capacity (including Demand Resources)	Cleared Demand Resources	Make Whole	Make Whole Credits	Auction Credits + Make Whole Credits	Resource Clearing Price
	[\$/MW-day]	[\$/MW-day]	[MW]	[MW]	[MW]	[MW]	[MW]	[MW]	[\$/day]	[\$/day]	[\$/MW-day]
RTO	\$110.00	\$0.00	120,611.6	1,593.8	133,815.3	132,221.5	1,364.9	43.0	\$ 4,730.00	\$14,549,095.00	\$110.00

Note: Since there are no constrained LDAs, there will be no CTRs allocated to load, no Incremental CTR Credits, and no cleared Qualifying Transmission Upgrades.

A complete list of Auction Results are located at the following link:
<http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx>


Once at the RPM webpage, click the appropriate Delivery Year and scroll to "20##/20## Base Residual Auction Results"

Zone	Preliminary Zonal Capacity Price	Base Zonal CTR Credit Rate	Base Zonal CTR Settlement Rate	Preliminary Zonal ILR Price
	[\$/MW-day]	[\$/MW-day of UCAP oblig.]	[\$/MW-day of CTRs]	[\$/MW-day]
AE	\$110.04	\$0.00	\$0.00	\$110.04
AEP *	\$110.04	\$0.00	\$0.00	\$110.04
APS	\$110.04	\$0.00	\$0.00	\$110.04
BGE	\$110.04	\$0.00	\$0.00	\$110.04
COMED *	\$110.04	\$0.00	\$0.00	\$110.04
DAYTON	\$110.04	\$0.00	\$0.00	\$110.04
DOM	\$110.04	\$0.00	\$0.00	\$110.04
DPL	\$110.04	\$0.00	\$0.00	\$110.04
JCPL	\$110.04	\$0.00	\$0.00	\$110.04
METED	\$110.04	\$0.00	\$0.00	\$110.04
PECO	\$110.04	\$0.00	\$0.00	\$110.04
PENLC	\$110.04	\$0.00	\$0.00	\$110.04
PEPCO	\$110.04	\$0.00	\$0.00	\$110.04
PL	\$110.04	\$0.00	\$0.00	\$110.04
PS	\$110.04	\$0.00	\$0.00	\$110.04
RECO	\$110.04	\$0.00	\$0.00	\$110.04

Calculating Load Management Revenue - Example

	A	B		C	D	E	F	G
Type	Peak Load Contribution (MW)	Managed Load (MW)	# of Sites Multiplier	Capacity Factor	Nominated ICAP (MW)	DR Factor	FPR Factor	Nominated UCAP (MW)
FSL	28.5	10	1	1.0634	17.866	0.957	1.0795	18.457
					$D=A-(B*C)$			$G=D*E*F$
GLD	28.5	16.8	1	1.0634	17.865	0.957	1.0795	18.456
					$D=B*C$, where max = A			$G=D*E*F$
DLC		0.002	200	1.0634	0.425	0.957	1.0795	0.439
					$D=C*D*E$			$G=D*E*F$

Total Nominated UCAP (MW)	Market Price (\$/MW-day)	Days/Year	Annual Revenue (\$)
37.352	\$110.04	365	\$1,500,228.14


 See PJM Web for appropriate Planning Year Parameters

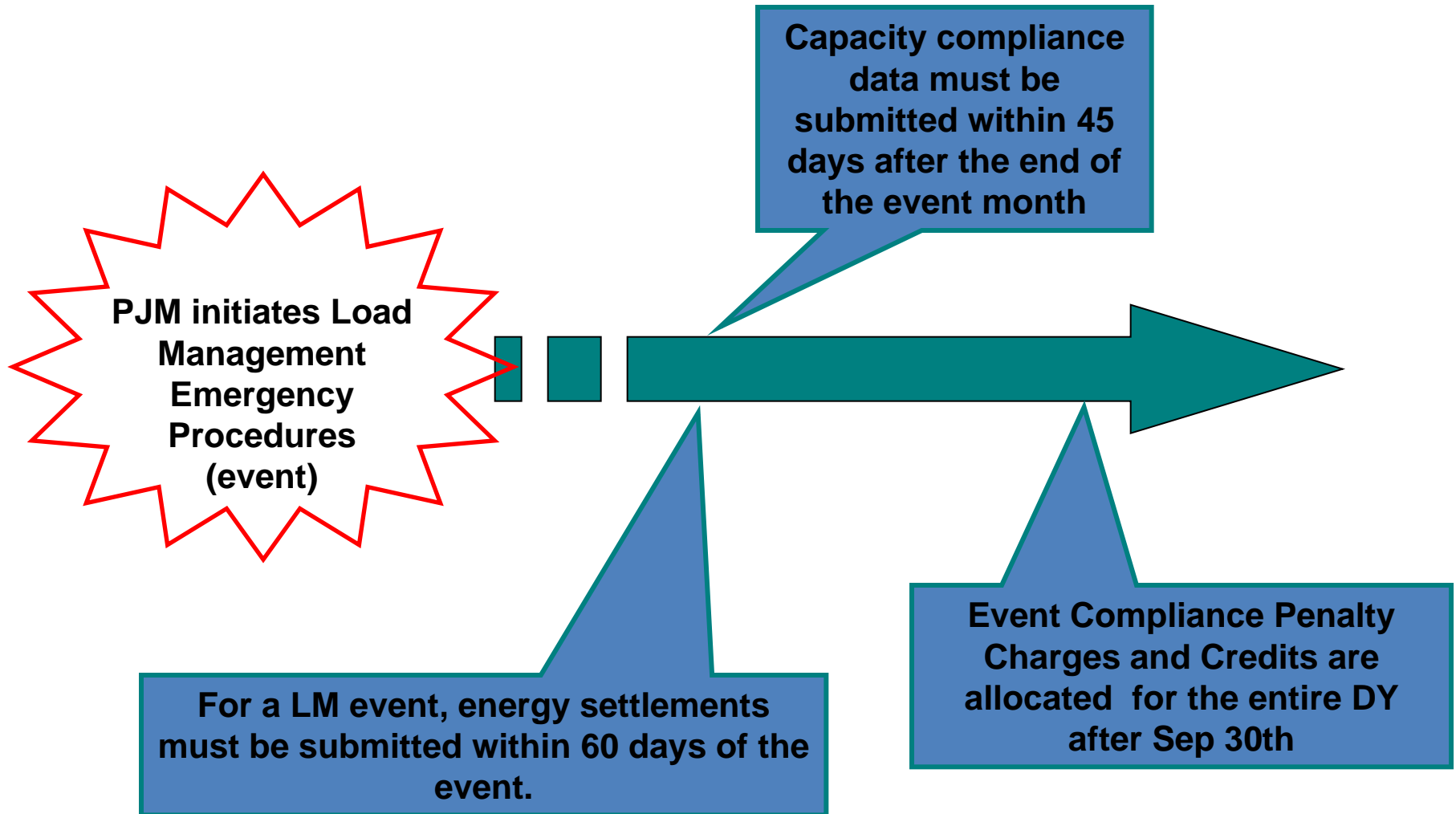
- Market Price for DR is the clearing price from the auction in which the DR cleared
- Market Price for ILR is the Final Zonal ILR Price for the Zone for the Delivery Year

Load Management Event - Notification Process

The primary notification for PJM Load Management Events is the PJM All-Call

- Based on system conditions, PJM calls a Load Management Event.
- Load Management Event is announced on the PJM All-Call
- The eLRS sends out emails to the CSPs about the Load Management Event
- The CSPs determine which Load Response Registrations need to respond to the Load Management Event and begins to deploy the reductions within the notification time
- PJM announces the end of the Load Management Event on the PJM All-Call.
- The eLRS sends out emails to the CSPs announcing the end of the Load Management Event
- The CSPs terminate the Load Reductions

Compliance Data and Settlement Timeline



- CSP compliance is determined by event and is aggregated by Zone (ILR & DR combined)
- Compliance is measured from June through September
- Compliance hours are defined as full hours of an LM event, for each customer or DLC program.
 - For example, if event starts at 12:15 and ends @16:45 then compliance will be measured from hours ending 14:00 through 16:00 for a total of 3 “full” hours.
- CSP must submit Event Compliance data within 45 days from the end of the month in which the event took place
- No compliance credit will be given for the incremental load drop below zero (i.e. exported energy).
- **Missing interval meter data results in a 0 MW reduction for the location**

Load Management Reductions for Compliance (cont')

- **Compliance Shortfall = Committed Capacity – Average Reduction during the compliance hours.**
- Firm Service Level (FSL) – The hourly Load Reduction = (PLC – (Actual load * capacity loss factor).
 - CSPs must submit 24 hours of actual load data for the Load Management Event.
- Guaranteed Load Drop (GLD) – The hourly Load Reduction = (Comparison Load - Actual load) * capacity loss factor.
 - CSPs must submit 24 hours of actual load and comparison load data for the Load Management Event. Comparison loads must be developed from the guidelines included in Attachment A of Manual 19, and note which method was employed.
- Direct Load Control (DLC) – reduction based on timing of control signal.
 - CSPs must submit the Start and Stop times of the Load Management Event.

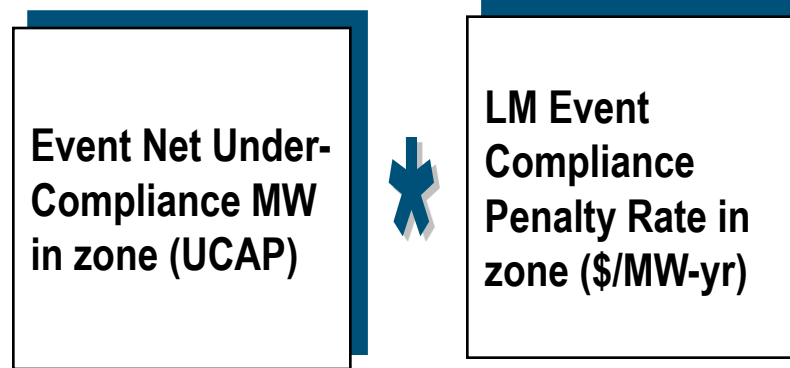
Compliance Penalty Rate

- LM Compliance Penalty Rate = Lesser of (1/# of Events or 50%) * Weighted Annual Revenue Rate
 - Not to exceed total revenue
 - The number of Events are measured between June 1st and September 30th

LM Type	Annual Revenue Rate (\$/yr)
Demand Resource	Resource Clearing Price (\$/MW-day) * 365 days/yr (or 366 days/yr)
ILR Resource	Final Zonal ILR Price (\$/MW-day) *365 days/yr (or 366 days/yr)

Load Management Event Compliance Penalty Charge

Load Management Event Compliance Penalty Charge =



- Load Management Compliance Penalty charges are assessed to those CSPs that under-complied in zone during an event.
- Lump sum payment is required to reflect amounts due, as a result of Event noncompliance for the entire DY. Event Penalties billed in one lump sum after all three of the following criteria are met:
 1. The number of Events have been determined (after September 30th)
 2. The date is beyond the Event Compliance data submission deadline. The Event Compliance Data Submission Deadline is 45 days after the end of the month in which the event took place (i.e. Load Management Event on June 15th, the Event Compliance Data Submission Deadline is August 14th).
 3. Compliance Data has been reviewed by PJM (Generally within 2 weeks after the Event Compliance Data Submission Deadline).
- Total Charges assessed for all events will be capped at Annual Revenues received by CSP in DY.



- Zonal Load Management Test Failure Charge:

- {Weighted Annual Revenue Rate + higher of (0.2 * Weighted Annual Revenue Rate) or (\$20 * 365)} * net capability testing shortfall (UCAP)

- Weighted Annual Revenue Rate represents what the resource would be paid during that DY
- 0.2 represents an additional 20%
- \$20 (multiplied for all days in the DY)

The higher of these two values would apply

Weighted Average Revenue Rate in LDA is determined by calculating (the weighted average of resource clearing prices in the LDA across all RPM Auctions, weighted by a party's cleared and make-whole MWs in an LDA) * 365

Capacity Resource Deficiency Charges

Daily Capacity Resource Deficiency Charge =



*Daily Deficiency Rate = Party's Weighted Average RCP + Higher of (20% * Party's Weighted Average RCP OR \$20/MW-day)

- Party's Weighted Average Resource Clearing Price (WARCP) for such resource is determined by calculating the weighted average of resource clearing prices for such resource, weighted by a party's cleared and makewhole MWs for such resource.
- If a Party's WARCP for such resource is \$0/MW-day, a PJM WARCP in the LDA is used.
- PJM WARCP is determined by calculating the weighted average resource clearing prices in the LDA across all RPM Auctions, weighted by the total cleared and make-whole MWS in the LDA.
- Charges are allocated on a pro-rata basis to those LSEs who were charged a Daily Locational Reliability Charge based on their Daily UCAP Obligation.
- The Resource Provider may still receive an RPM Auction Credit.

- Overview
- Economic Load Response
- Customer Baseline Examples & Verification
- Load Management in RPM
- eLRS

PJM Objectives for Demand Response Participation

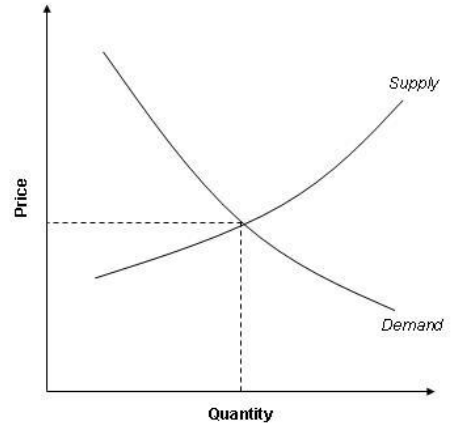
- 1) Reduce barriers to entry
- 2) Streamline workflow management
- 3) Flexible wholesale market participation for DR
- 4) Improve transparency to all participants
- 5) Improved measurement and verification

Objective: Reduce barriers to entry

30% of the DR locations registered are under 100kW

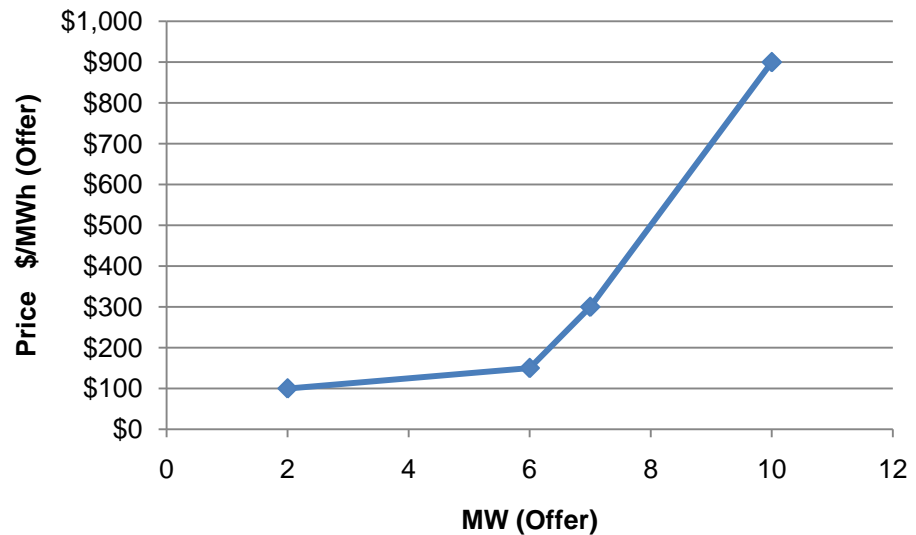


DR resource Market participation much like generation resource



Objective: Flexible wholesale market participation

- Incremental offer curve
- Day-Ahead vs. Real Time market availability
- Hourly availability
- Offer curve and schedule can change daily



Use generation offer flexibility in eMKT system for demand resources

Objective: Transparency to all participants

- Tasks
- Locations
- Events
- Registrations
- Settlements

Filter & Download

ns1:settlementType	ns1:startTime	ns1:endTime	ns1:CBLMethod	ns1:contractType	ns1:priceNode	ns1:name
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store
Economic Energy	2009-11-05T09:00:00.000-05:00	2009-11-05T20:00:00.000-05:00	Standard (3 Day Types)	Flat Fixed	PECO	Joe's Store

User access to all information with ability to download based on flexible criteria

Questions?