Steven L. Beshear
Governor

Leonard K. Peters
Secretary
Energy and Environment Cabinet

Commonwealth of Kentucky
Public Service Commission
211 Sower Blvd.
P.O. Box 615
Frankfort, Kentucky 40602-0615
Telephone: (502) 564-3940
Fax: (502) 564-3460
psc.ky.gov

David L. Armstrong
Chairman

James W. Gardner
Vice Chairman

Linda Breathitt
Commissioner

January 16, 2013

PARTIES OF RECORD

Re: Case No. 2012-00169
Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC

Attached is a copy of the memorandum which is being filed in the record of the above-referenced case. If you have any comments you would like to make regarding the contents of the informal conference memorandum, please do so within five days of receipt of this letter. If you have any questions, please contact Richard Raff, Staff Attorney, at 502-782-2588.

Sincerely,

Jeff Derouen
Executive Director

RR/kar

Attachments

INTRA-AGENCY MEMORANDUM

KENTUCKY PUBLIC SERVICE COMMISSION

TO: Case File

FROM: Richard Raff, Staff Attorney

DATE: January 16, 2013

RE: Case No. 2012-00169
Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC

Pursuant to the Commission Staff's notice issued October 1, 2012, an informal conference was held at the Commission's offices on October 12, 2012 for the purposes of discussing all issues in the case and to provide an opportunity to PJM Interconnect, LLC to present an overview of its operations including, but not limited to, participation in capacity markets, reserve margin requirements, reliability must run units, and demand response programs.

PJM made a formal presentation of its operations and markets, a copy of which was provided to all parties and is attached hereto (but is not being served with this memo due to its voluminous nature). The parties also discussed the issues and the potential for resolving some of the pending issues.

By Staff notice issued on October 17, 2012, an additional conference was held on October 19, 2012, and by staff notice issued on October 25, 2012, a further conference was held on October 26, 2012, both for the purposes of clarification of the issues and discussing potential resolution of outstanding issues. A list of the attendees at each conference is attached hereto.

Attachment – Lists of Attendees

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. TO TRANSFER FUNCTIONAL CONTROL OF CERTAIN TRANSMISSION FACILITIES TO PJM INTERCONNECTION, LLC	)	CASE NO. 2012-00169

October 12, 2012

Please sign in:

NAME	REPRESENTING
MARK D. GOSS	GOSS SAMFORD Attys for EKPC
Don Mosier	EKPC
David Crews	EKPC
Anthony Campbell	EKPC
Mark Stallons	Owen Electric
Mike Kurtz	Gallatin Steel
PAUL THOMPSON	LKE
Derek Rahn	LKE
Chris Balmer	LKE
Duncan Crosby	SKO for LKE
Lonnie Bellar	LKE
ED STATON	LKE
Allyson Sturgeon	LGE/KU

Case No. 2012-00169
October 12, 2012

NAME	REPRESENTING
John Gdowik	PJM
Kerry Stroup	PJM
Pauline Foley	PJM
Denise Foster	PJM
Steven Herling	PJM
Fran Koza	PJM
Jeff Bastian	PJM
Aaron Greenwell	PSC
Jennifer Black Hans	OAG
Larry Cook	OAG
Bob Russell	PSC
Errol K Wagner	PSC
Eric Bowman	PSC
Fereydoon Gorjian	PSC
Rick Lovekamp	LG&E / KU

Case No. 2012-00169
October 12, 2012

NAME	REPRESENTING
DARRIN ADAMS TRANSMISSION PLANNING MGR	EKPC
Chuck Dugan MGR. Market Operations	EKPC
Ann Wood	EKPC
[illegible] SKO	LG&E and KO
RICHARD RAFF	PSC-LEGAL
[illegible]	PSC
Talina R. Mathews	PSC

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. TO TRANSFER FUNCTIONAL CONTROL OF CERTAIN TRANSMISSION FACILITIES TO PJM INTERCONNECTION, LLC	)	CASE NO. 2012-00169

October 19, 2012

Please sign in:

NAME	REPRESENTING
RICHARD RAFF	PSC-LEGAL
Daryl Newby	PSC - F/A
Aaron Greenwell	PSC
Mark R. Goss	Goss Samford for EKPC
David Crews	EKPC
Don Mosier	EKPC
FRANK KOZA	PJM
Pauline Foley	PJM
JEFF JOHNSON	PSC

Case No. 2012-00169
October 19, 2012

NAME	REPRESENTING
Frank Koza	PJM
Pauline Foley	PJM
Denise Foster	PJM
Jason Bentley	MMLK/PJM
Denver York	EKPC
Julie Tucker	EKPC
Ann Wood	EKPC
Chuck Dugan	EKPC

Case No. 2012-00169
October 19, 2012

NAME	REPRESENTING
[illegible]	SKO LG&E/KU
Lonnie Bellar	LGE/KU
Rick Lovekamp	LG&E/KU
Mike Kurtz	Gallatin Steel
Duncan Crosby	SKO for LGE/KU
Chris Balmer	LGE/KU
Allyson Sturgeon	LG+E/KU
Fereydoon Gorjian	PSC
Errol K Wagner	PSC-FA
Bob Russell	PSC-FA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. TO TRANSFER FUNCTIONAL CONTROL OF CERTAIN TRANSMISSION FACILITIES TO PJM INTERCONNECTION, LLC	)))))	CASE NO. 2012-00169

October 26, 2012

Please sign in:

NAME	REPRESENTING
RICHARD RAFF	PSC-LEGAL
Talina Mathews	PSC
K R Ryan	SKO for LG&E-KU
PAUL THOMPSON	LG&E & KU
Connie Bellar	LGE/KU
Duncan Crosby	SKO for LGE/KU
JENNIFER BLACK HANS	OAG
Don Mosier	EKPC
Chuck Dugan	EKPC
Allyson Sturgeon	LG&E/KU
RICK LOVEKAMP	LG&E/KU
JASON Bentley	PJM
Chris Balmer	LGE/KU
David Crews	EKPC

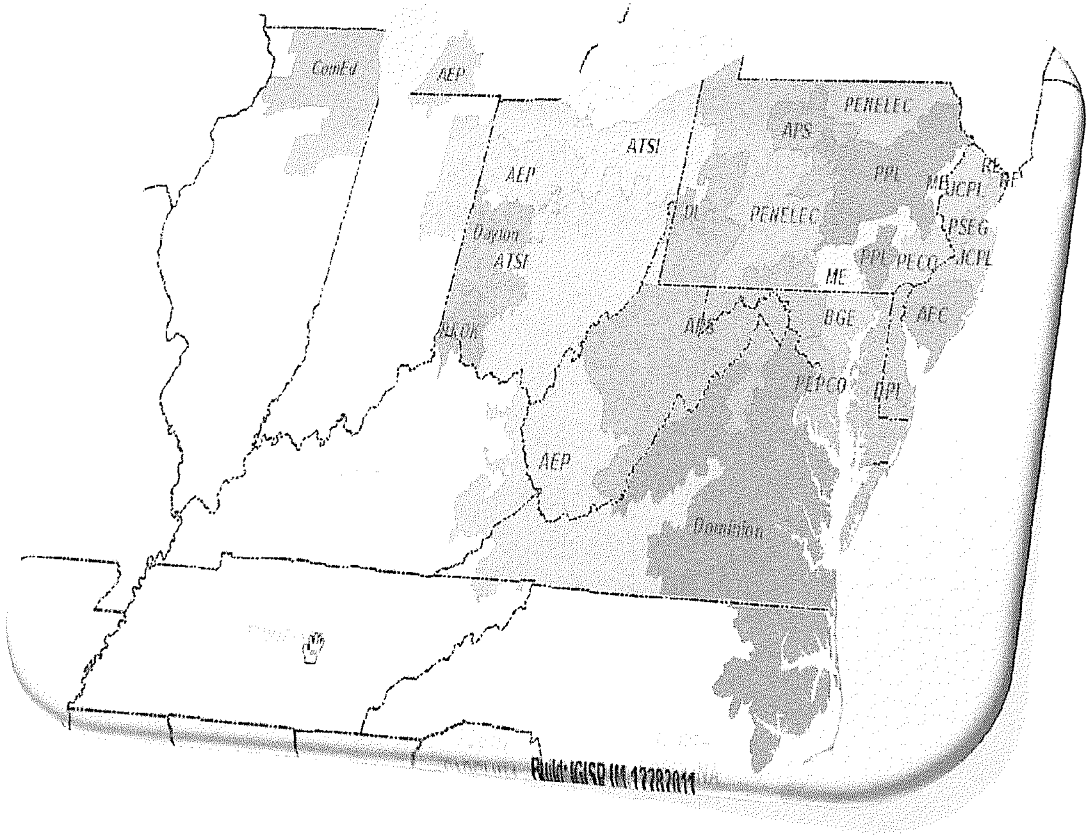
Case No. 2012-00169
October 26, 2012

NAME	REPRESENTING
ANN WOOD	EKPC
Denver York	ekpc
On Phone:	
Denise Foster	
Frank Koza	PJM
Bridgid Cummings	
Kerry Stroup	
Steve Pincus	

PJM Grid Operations and Energy Markets Overview

Kentucky Public Service
Commission Office
October 12, 2012

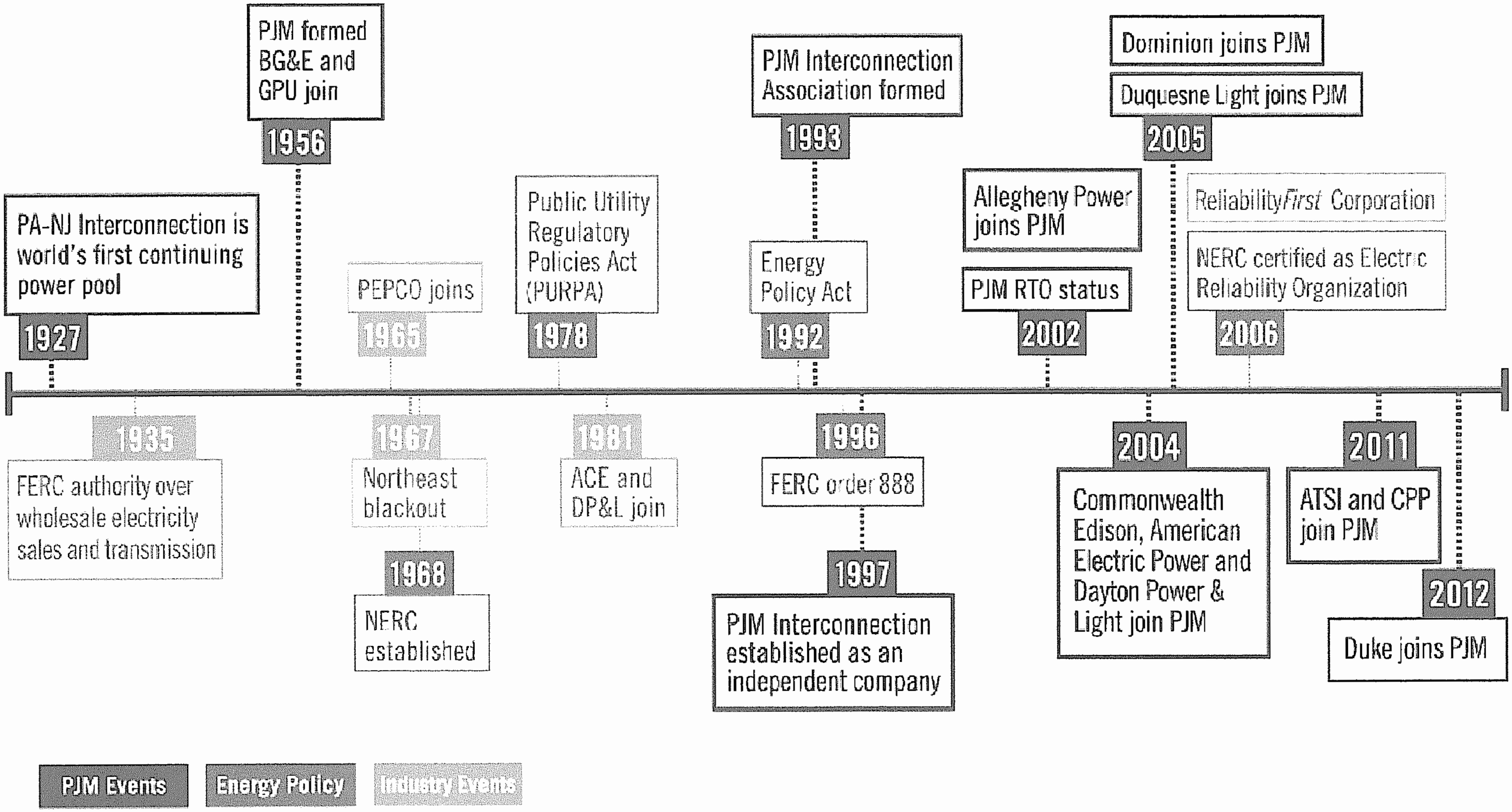
Agenda



- Introduction
- Operations
  - Dispatch Functions
- Energy Markets
  - LMP
  - FTRs/ARRs
  - Capacity
    - Reliability Pricing Model
  - Demand Response

Introduction
PJM Organization

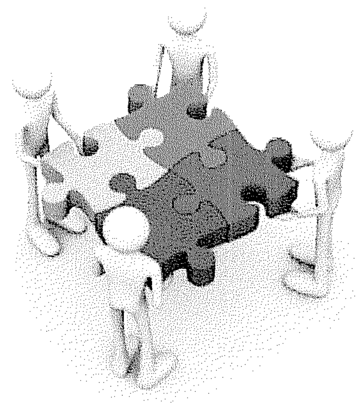
The History of PJM



What is an RTO?

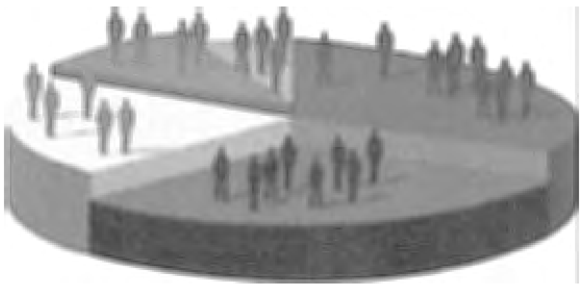
A **Regional Transmission Organization** (RTO) is:

- Independent from all market participants
- Responsible for grid operations and reliability
- Responsible for transmission service within region

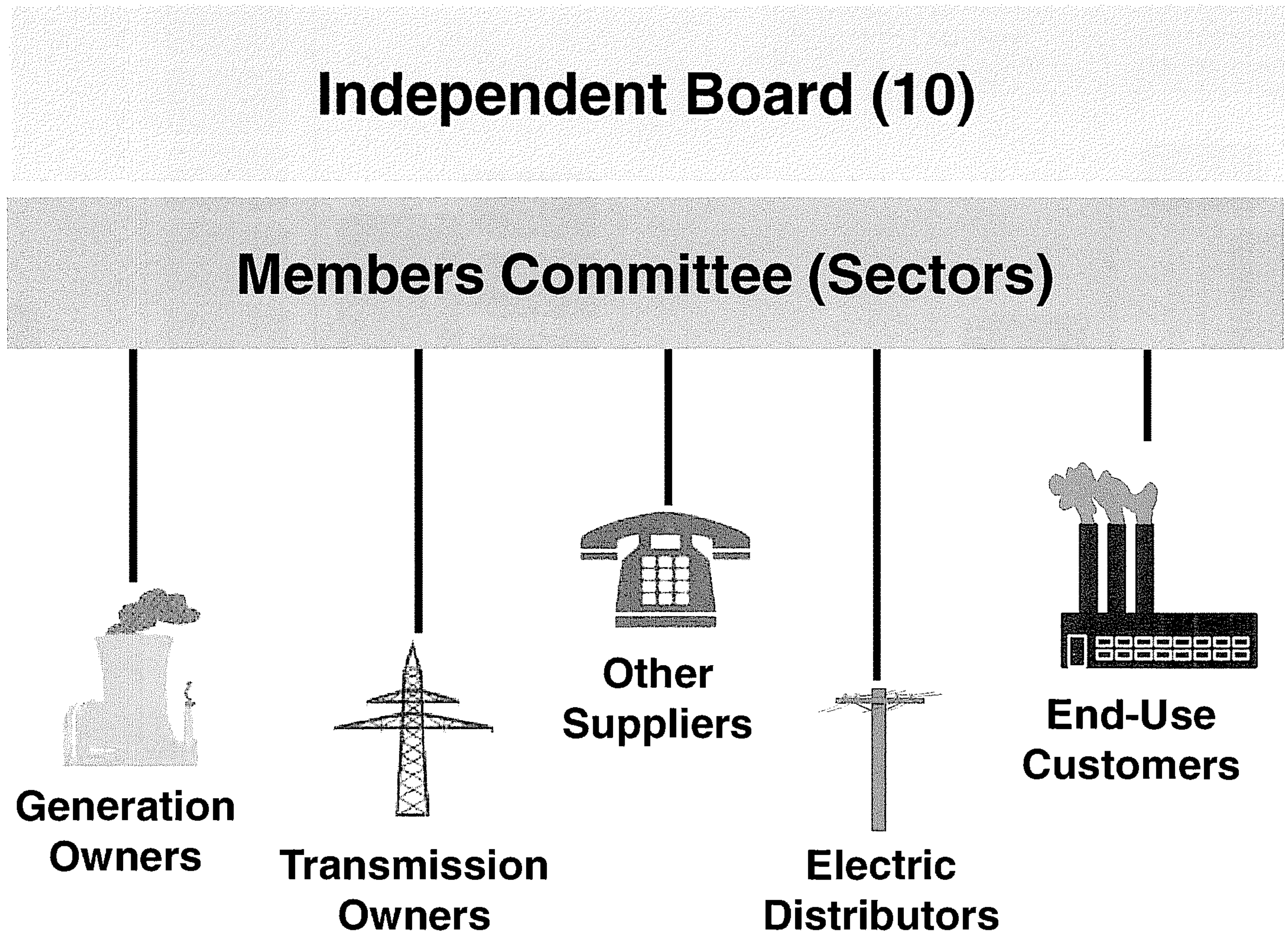


PJM Demographics

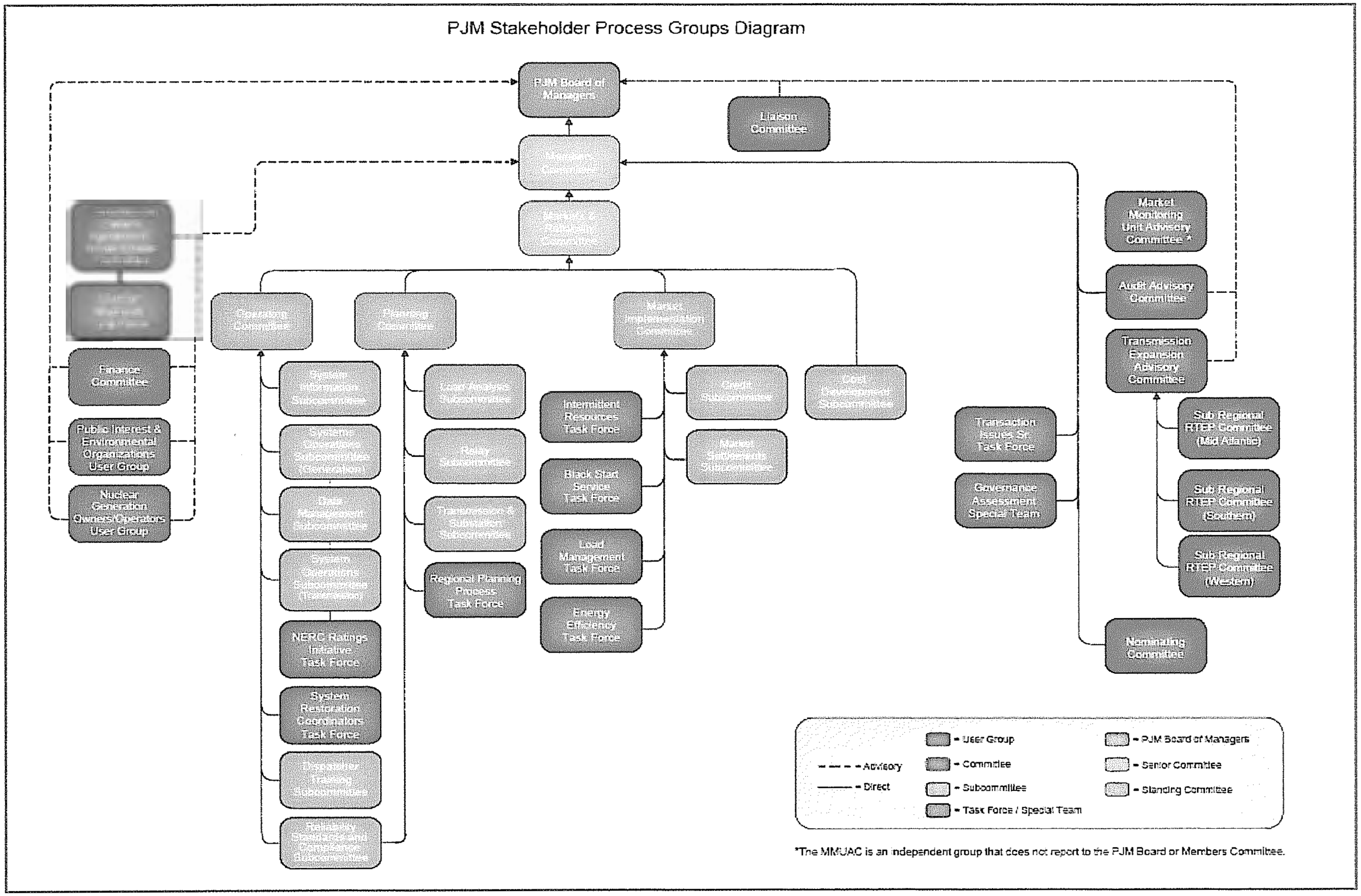
- Complexity
  - 185,600 MW of Generating Capacity
  - Over 65,441 Miles of Transmission Lines
  - Over 60 Million People Served
- Uniqueness
  - Single Control Area in NERC Region
  - Area Served: 13 States + DC
- Members/Customers
  - Member Companies ~ 800+
  - Transmission Svc. Customers ~ 100 +
  - 158,448 MW Peak Load (July 21, 2011)



Two Tier Governance



PJM Committee Structure

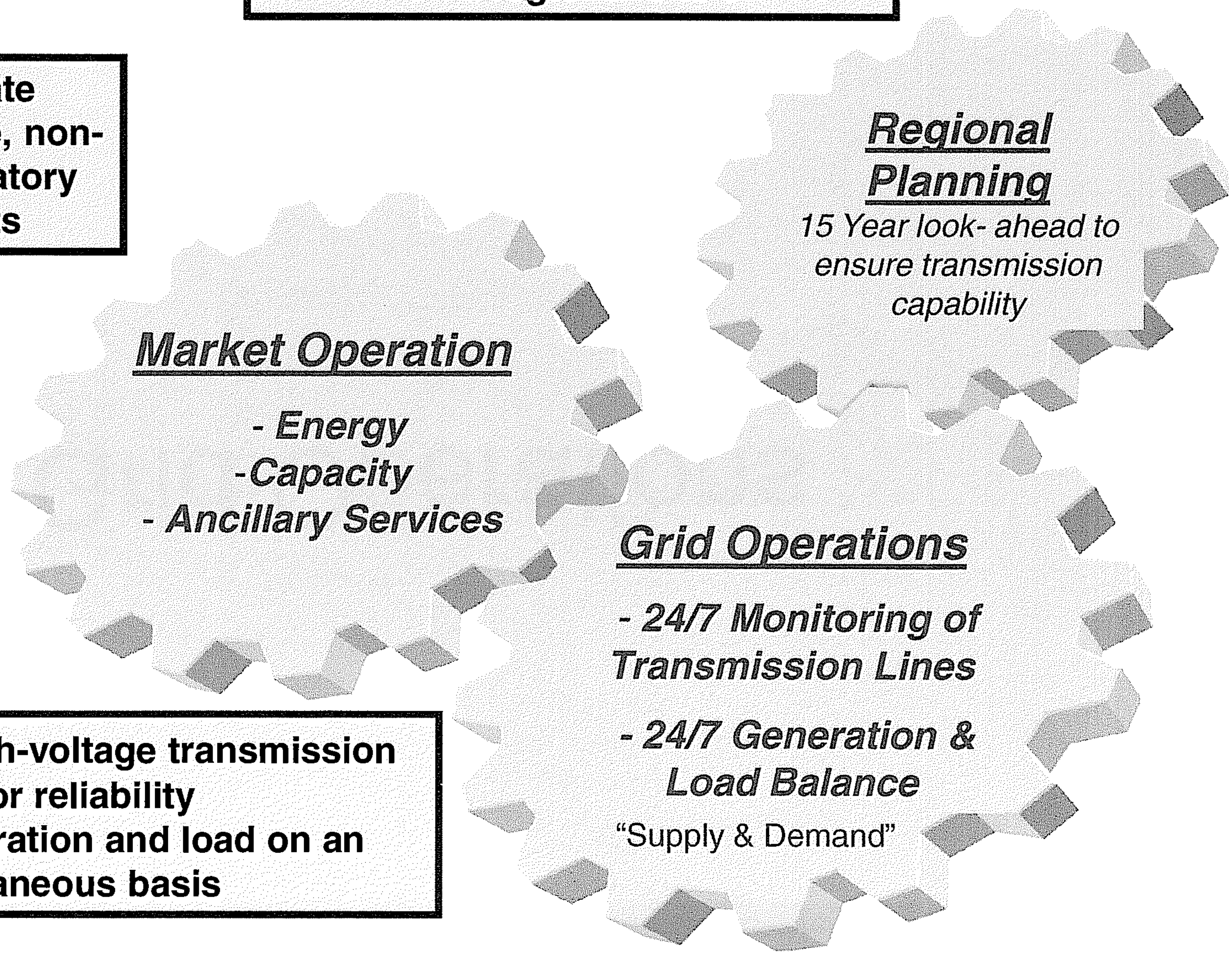


*The MMUAC is an independent group that does not report to the PJM Board or Members Committee.

PJM Basic Functions

– Plan for transmission expansion on a regional basis

– Operate competitive, non-discriminatory markets

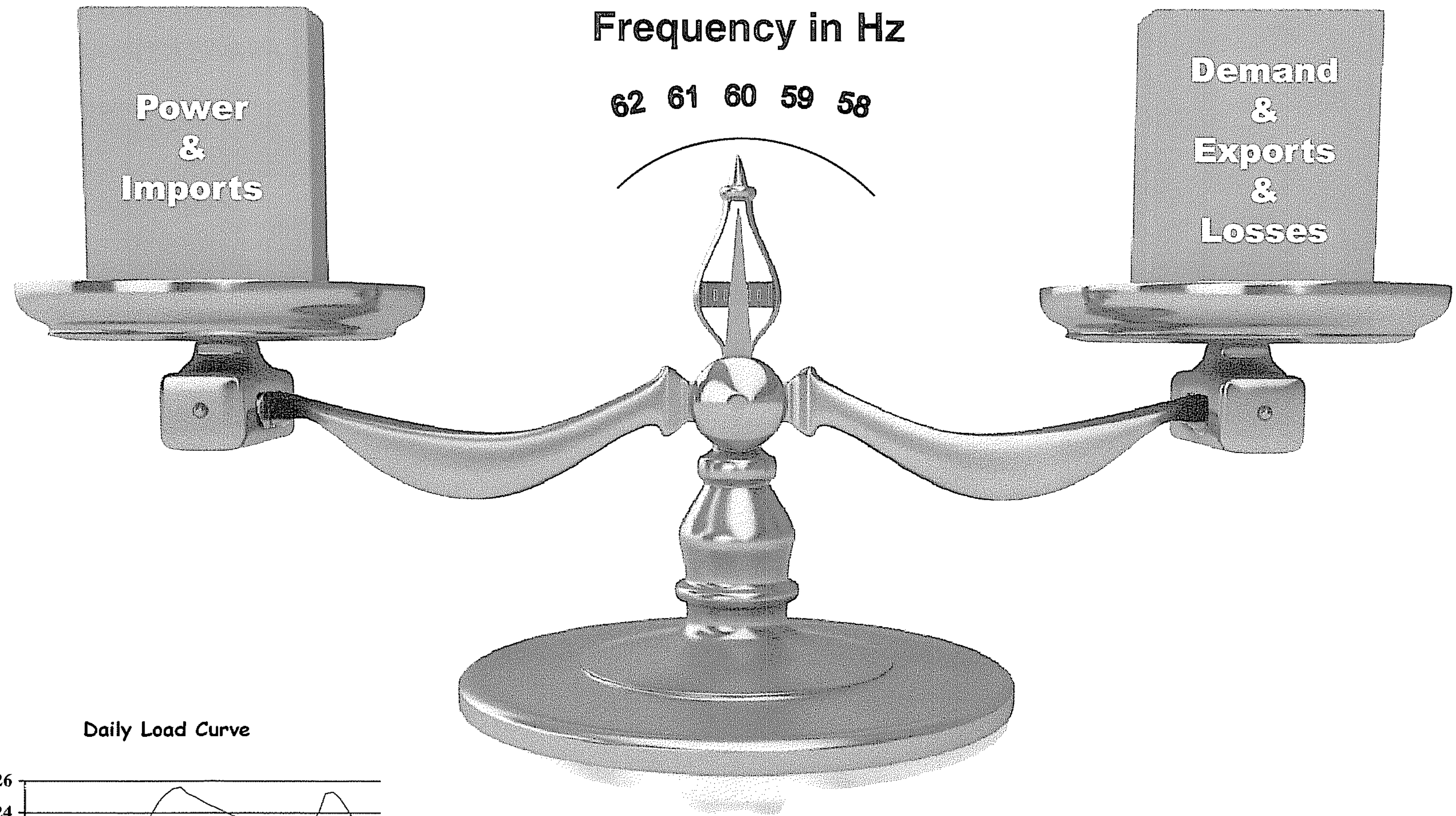


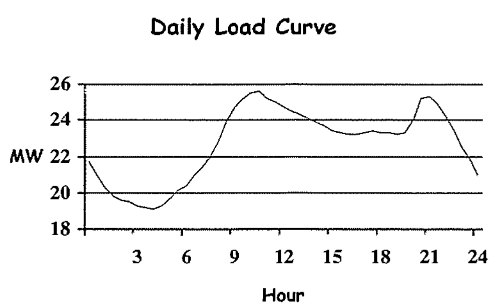
– Monitor the high-voltage transmission grid for reliability
– Balance generation and load on an instantaneous basis

Grid Operations

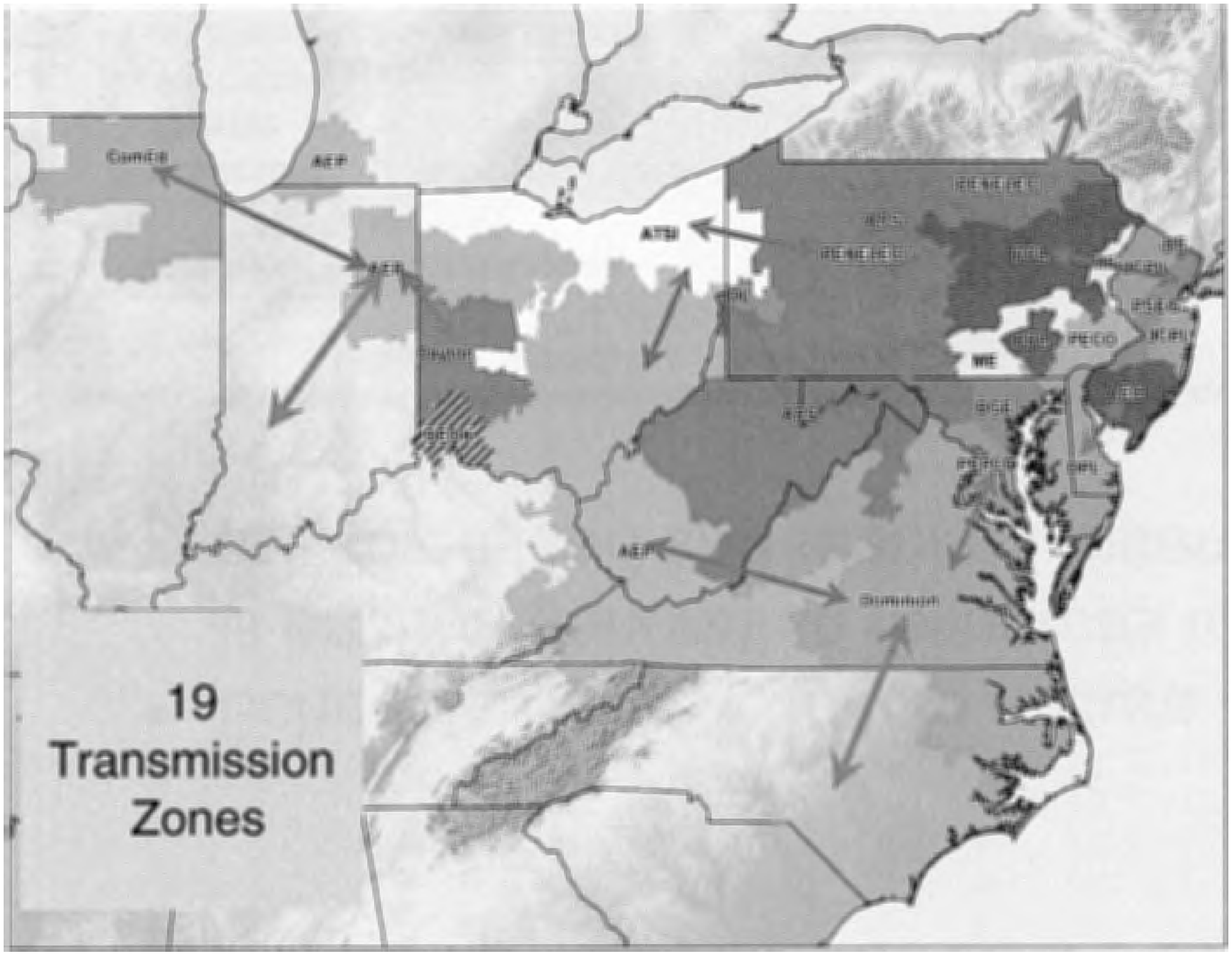
Grid Operations Control Room

Achieving Energy Balance in the Control Area





Single Control Area



Free flowing ties

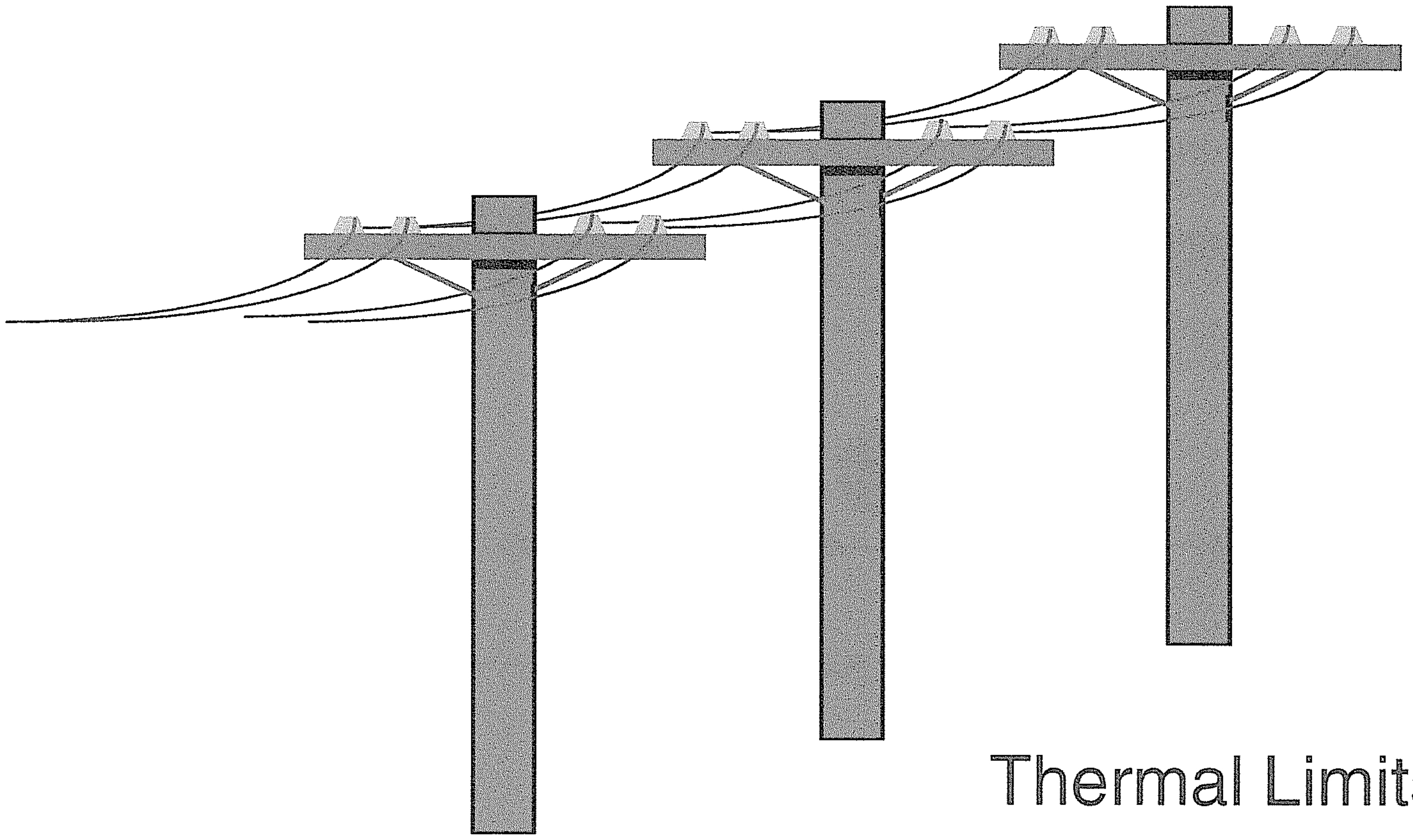
Scheduled
Interchange

Additional Reserves

- Schedule PJM System to ensure that there is enough generation resources to cover projected load and required reserves.

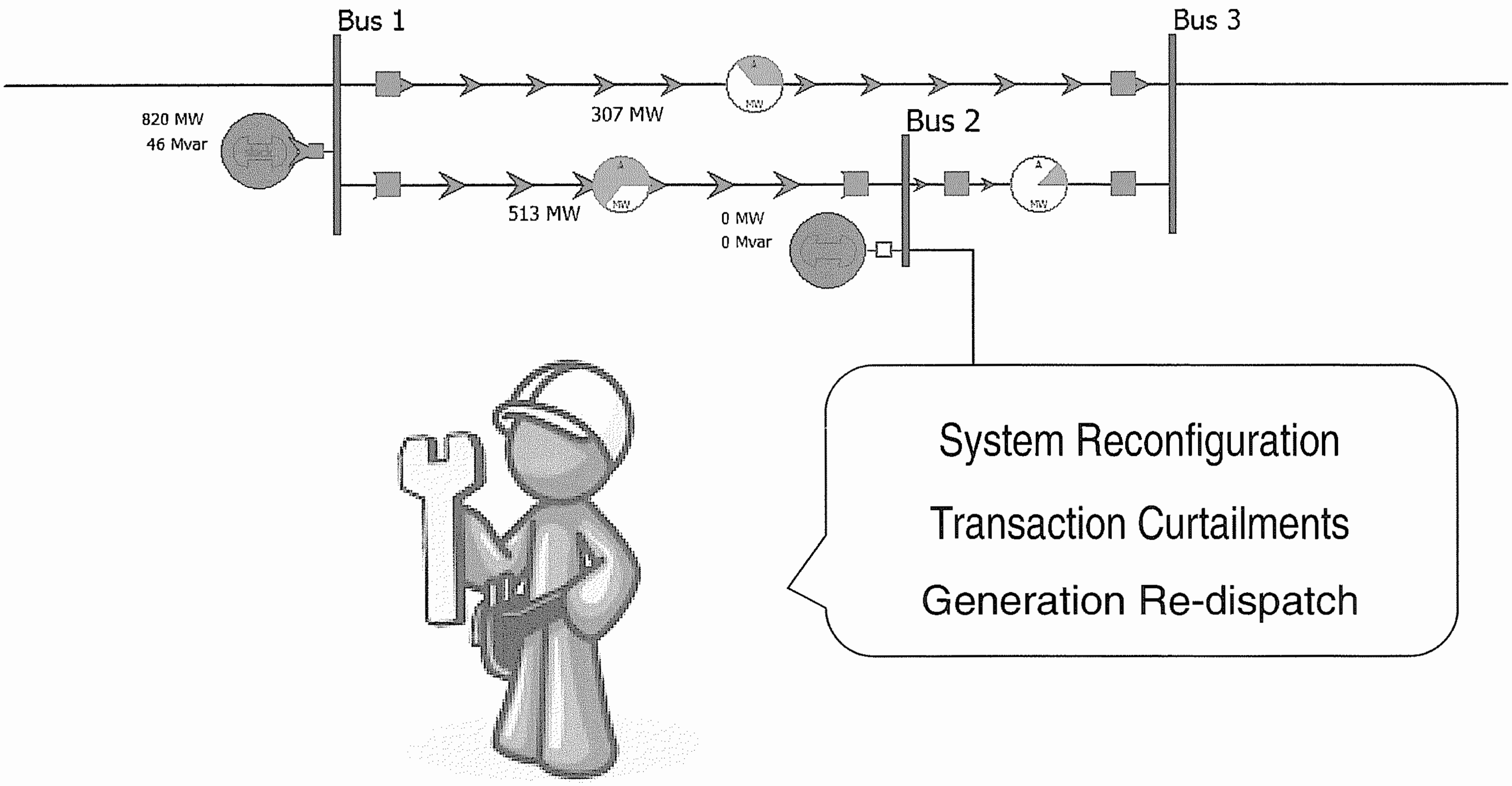
<table>
<tr><td colspan="3">Day-ahead Scheduling (Operating) Reserve
(T ≤ 30 Minutes)</td><td rowspan="3">Reserve Beyond 30 Minutes</td></tr>
<tr><td colspan="2">Contingency (Primary) Reserve
(T ≤ 10 Minutes)</td><td rowspan="2">Secondary Reserve
(10 Min. ≤ 30 Minutes)</td></tr>
<tr><td>Synchronized Reserve
(Synchronized)</td><td>Non-Synchronized Reserve
(Off-Line)</td></tr>
<tr><td colspan="4">T = Time Interval Following PJM Request</td></tr>
</table>

Power Transfer Limits

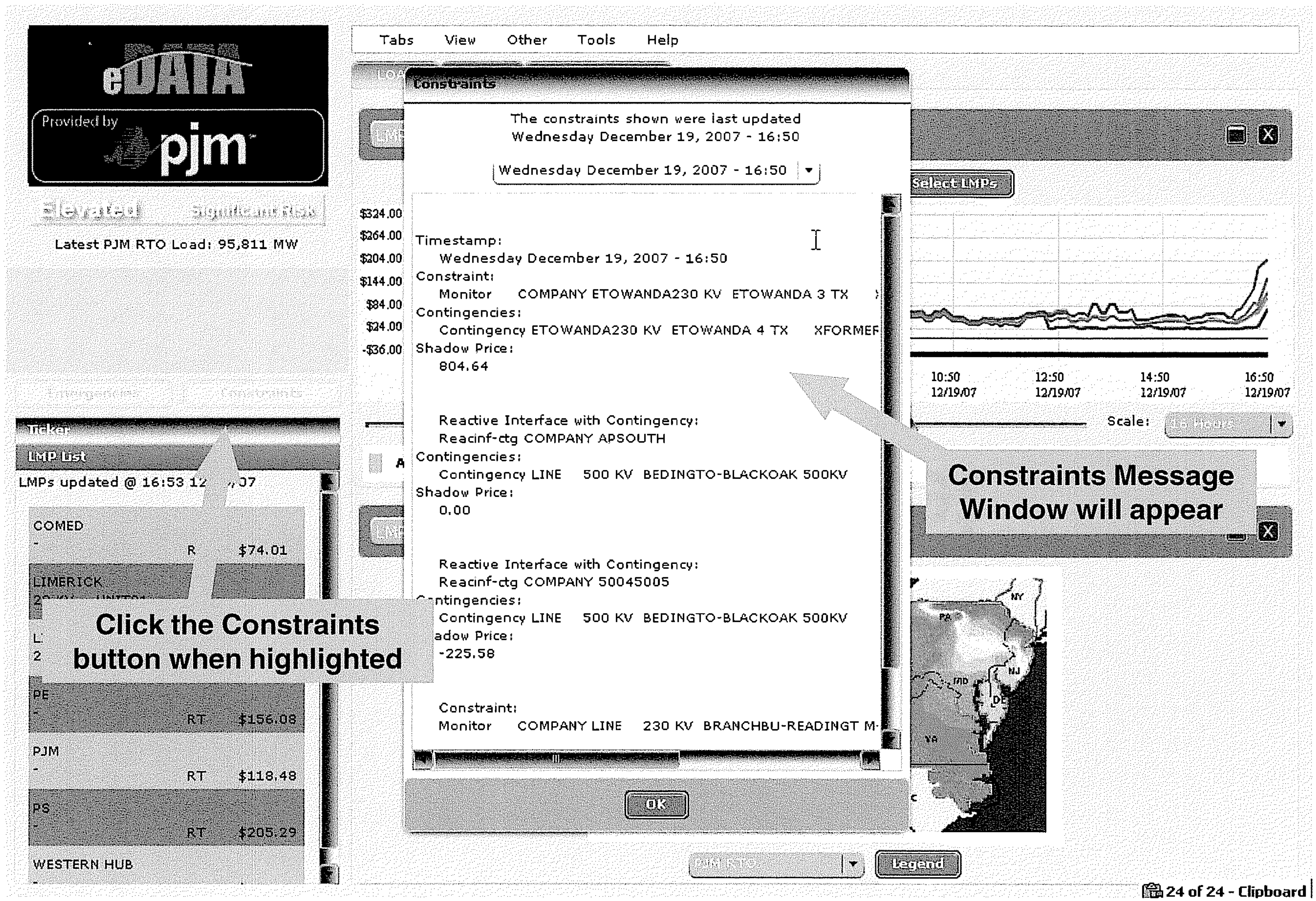


Thermal Limits
Voltage Limits
Stability Limits

Control Actions

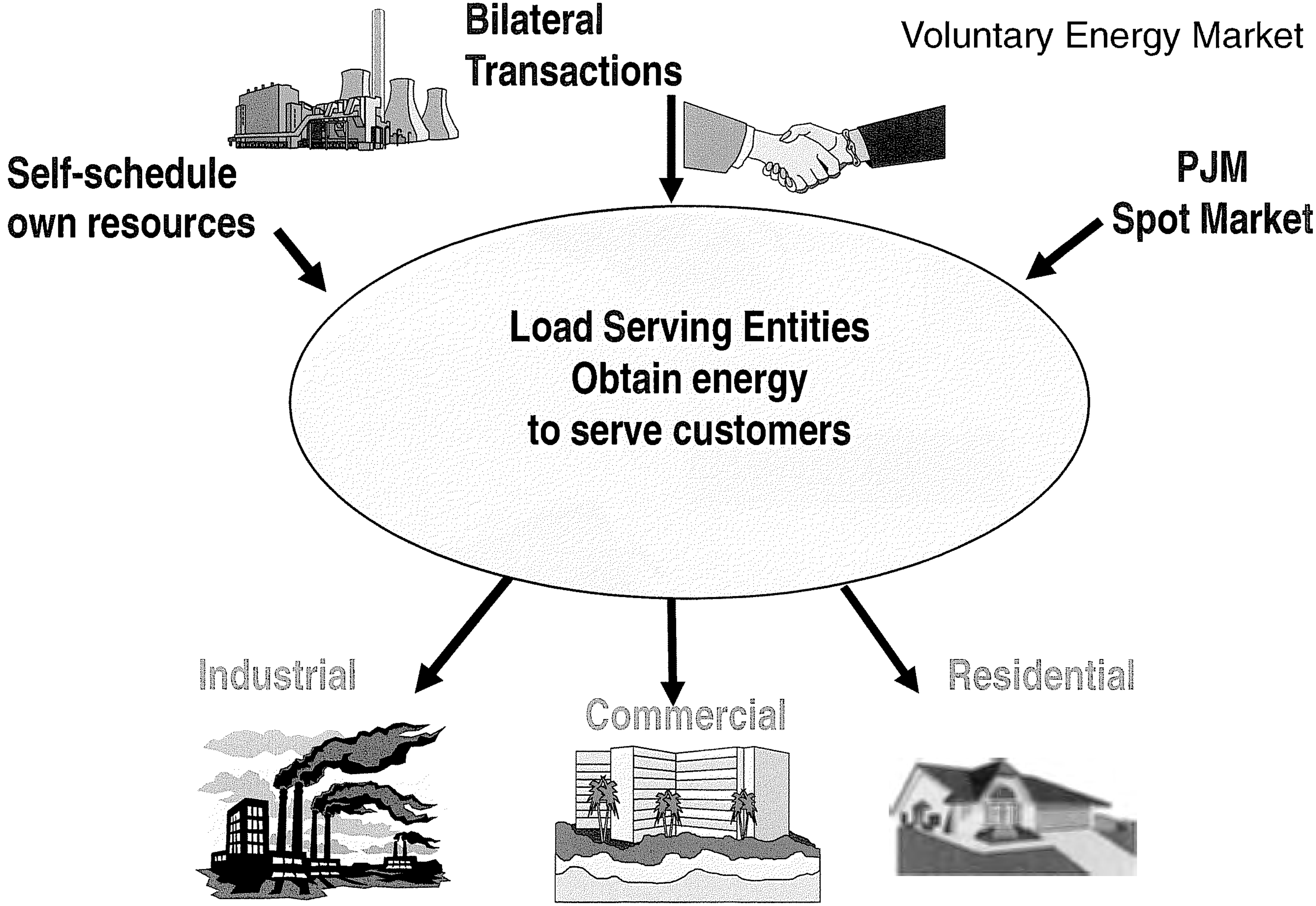


Viewing Constraints - eData

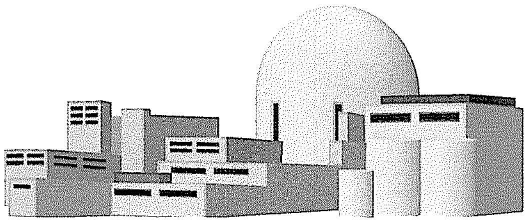


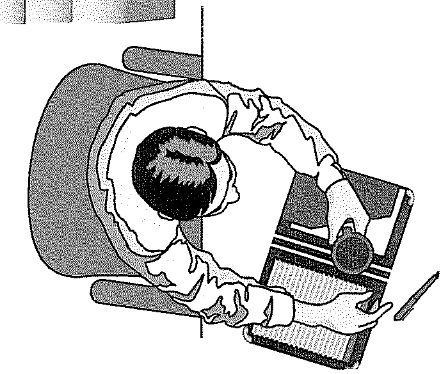
Energy Market

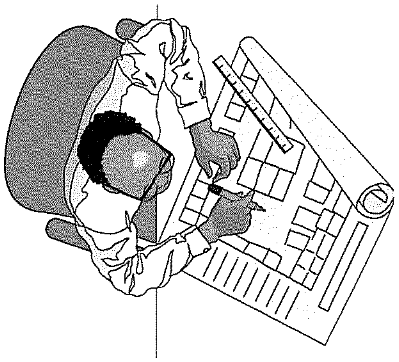
Options for Electric Supply



Offers Received from Generators





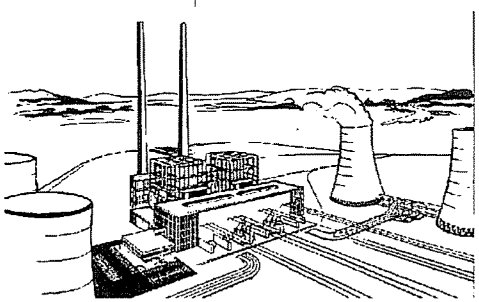


10MW @$30

40MW @$5

20MW @$10

15MW @$25

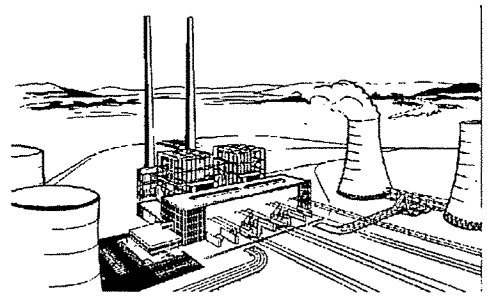


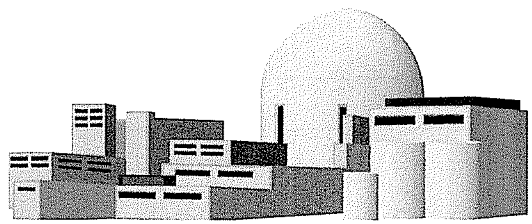
25MW @ $15

Generator Offers are Sorted in Merit Order

Commitment of Generators to meet the Load Forecast plus Reserves

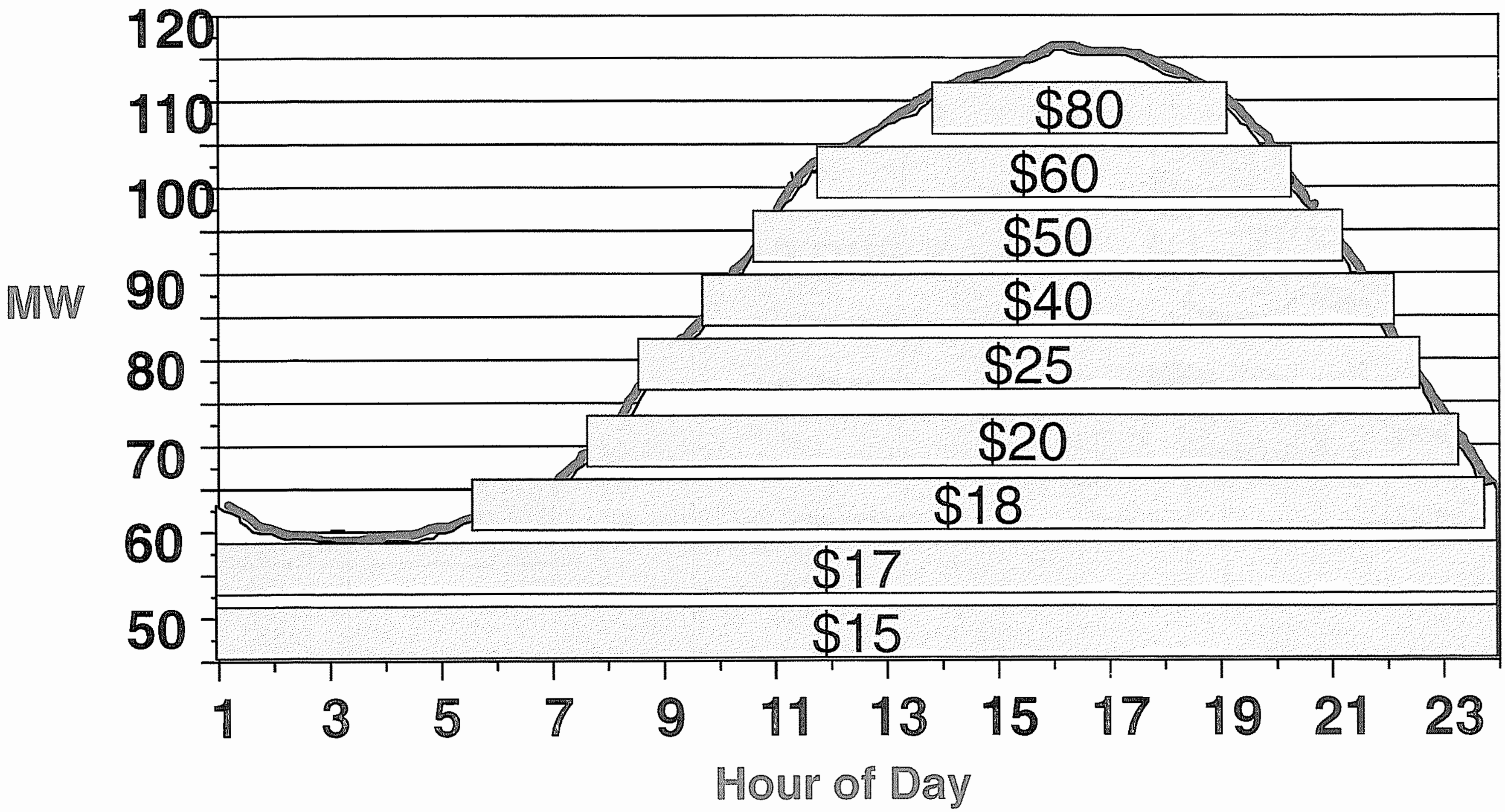
100 MW @ $90	5 Offers
125MW @$50	10 Offers
150MW @$25	15 Offers
175MW @$20	20 Offers
195MW @$10	30 Offers





Typical Summer Load Shape

- Generation selected and dispatched in economic merit order in order to meet load.



LMP Basics

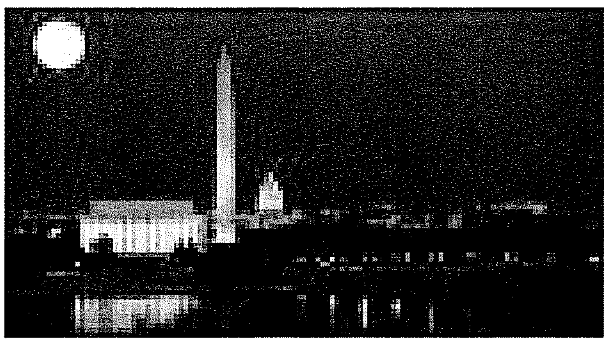
What is LMP?

- Pricing method PJM uses to:
  - price energy purchases and sales in PJM Market
  - price transmission congestion costs to move energy within PJM RTO
  - price losses on the bulk power system
- Physical, flow-based pricing system:
  - how energy actually flows, NOT contract paths

How is LMP Used?

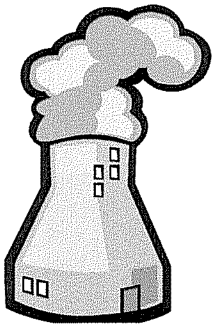
PJM Settles the market:

Electric Generators (Sellers) get paid the clearing price at their interconnection point (node)



Loads (**Buyers**) pay at their zonal LMP

Economic Dispatch Exercise



MW
$20
Capacity
200 MWs

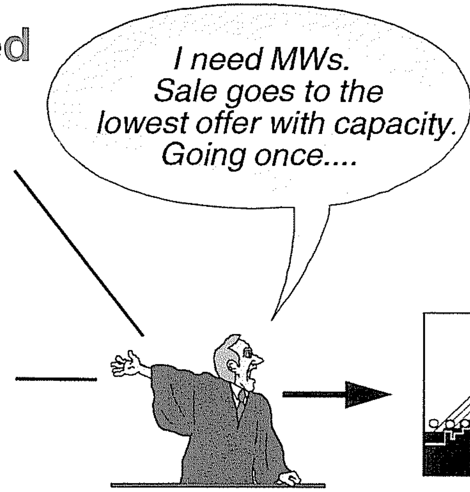
Not Dispatched

MW
$15
Capacity
200 MWs

199 MWs @ $15

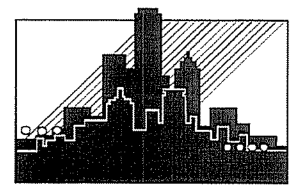
MW
$10
Capacity
300 MWs

300 MWs @ $10



PJM

Load
499MWs



$15
LMP

LMP Components - System Energy Price

LMP = System Energy Price + Transmission Congestion Cost + Cost of Marginal Losses

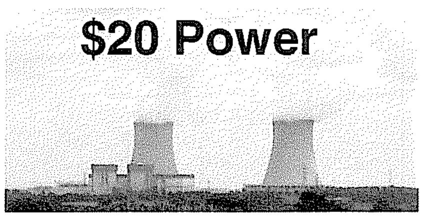
☑ System Energy Price

- Represents optimal dispatch ignoring congestion and losses
- Same price for every bus in PJM
- Calculated both in day ahead and real time

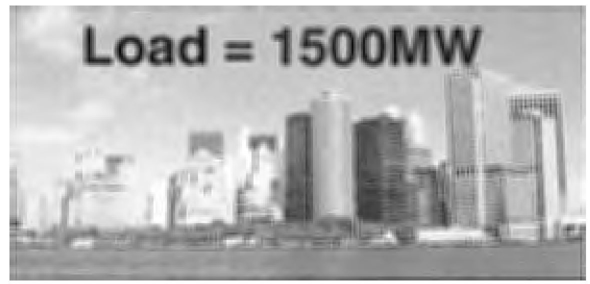
LMP Components – System Energy Price

System Energy Price =	$20
Congestion =	
Losses =	
LMP=	$20

Dispatch 1500 MW



Transmission path



System Energy Price =	$20
Congestion =	
Losses =	
LMP =	$20

LMP Components - Congestion

LMP = System Energy Price + Transmission Congestion Cost + Cost of Marginal Losses

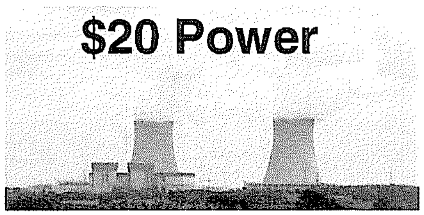
☑ Congestion Price

- Represents price of congestion for binding constraints
  - Calculated using cost of marginal units controlling constraints and sensitivity factors on each bus
- Will be zero if no constraints
  - Will vary by location if system is constrained
- Calculated both in day ahead and real time

LMP Components - Congestion

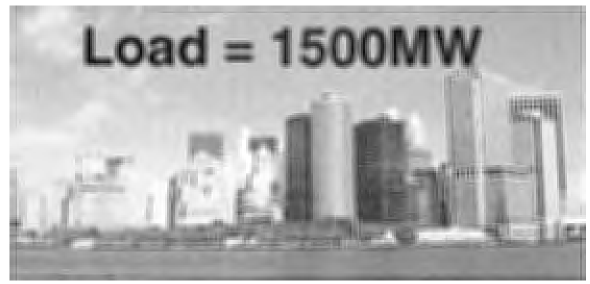
System Energy Price =	$20
Congestion =	$30
Losses =	
LMP=	$50

Dispatch 1000 MW



Flow = 1000 MW

Limit = 1000 MW



System Energy Price =	$20
Congestion =	$ 0
Losses =	
LMP =	$20

Dispatch 500 MW

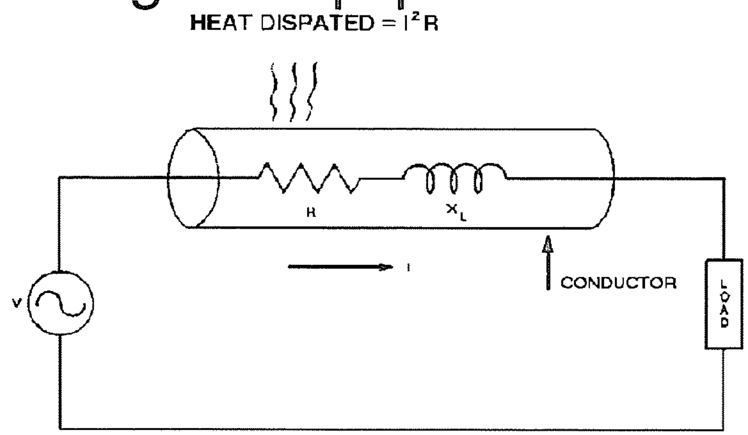
LMP Components – Marginal Losses

LMP = System Energy Price + Transmission Congestion Cost + Cost of Marginal Losses

☑ Loss Price

- Represents price of marginal losses
  - Calculated using penalty factors
  - Will vary by location
- Calculated both in day-ahead and real-time

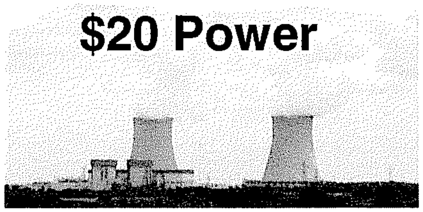
- Real Power (MW) Losses
  - Power flow converted to heat in transmission equipment
  - Heat produced by current (I) flowing through resistance (R)
  - Losses equal to I^2R
  - Heat loss sets the "thermal rating" of equipment
- Losses increase with:
  - Lower voltage
  - Longer lines
  - Higher current



LMP Components Marginal Losses

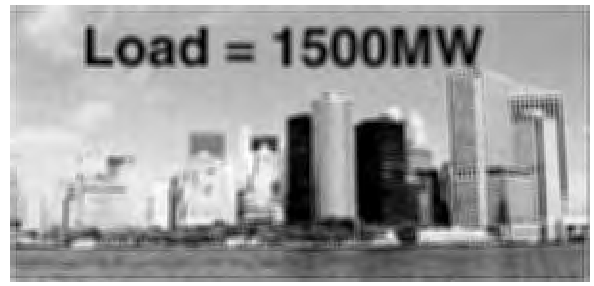
System Energy Price =	$20
Congestion =	$30
Losses =	$ 2
LMP=	$52

Dispatch 1000 MW



Flow = 1000 MW

Limit = 1000 MW

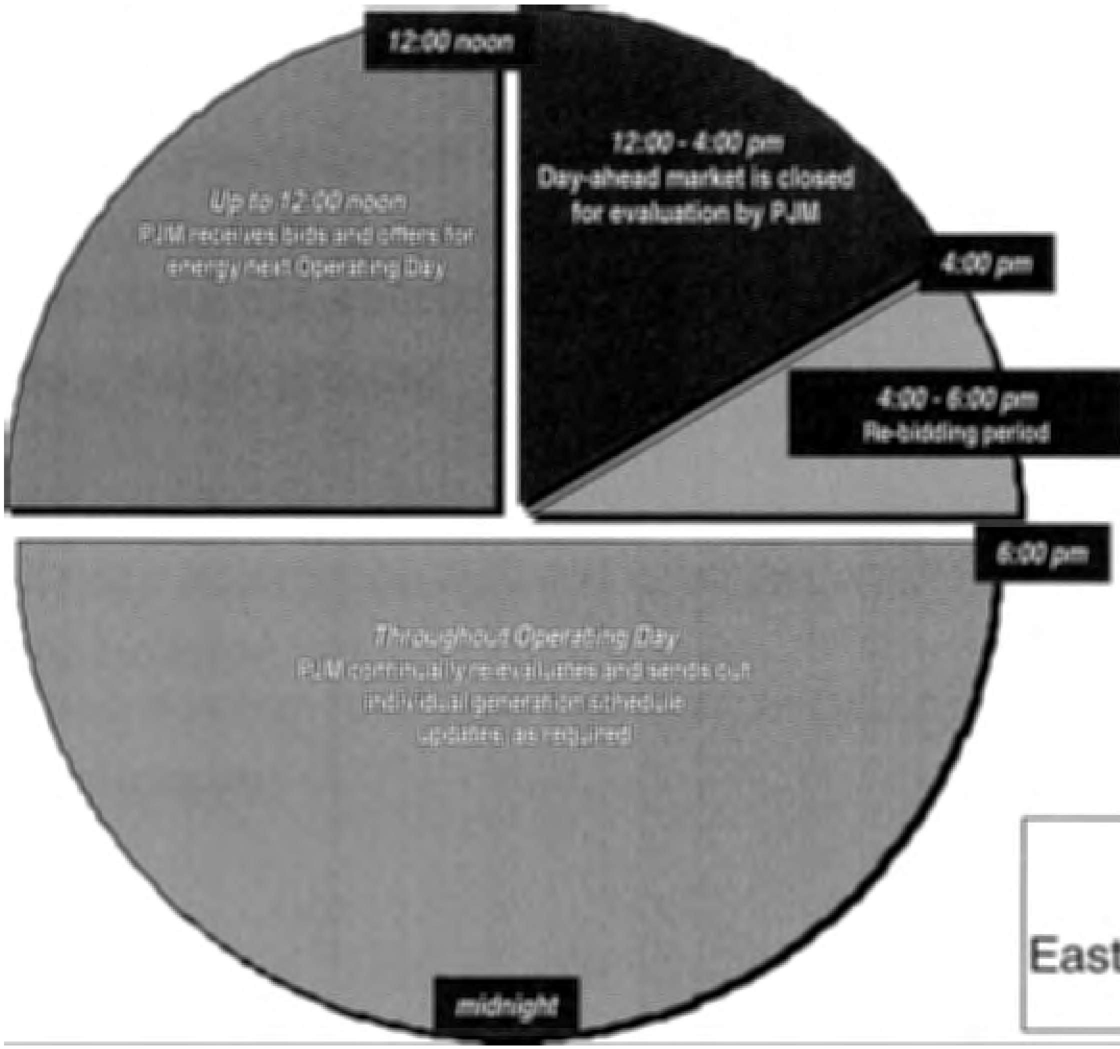


System Energy Price =	$20
Congestion =	$ 0
Losses =	($ 1)
LMP =	$19

Dispatch 500 MW

Two Settlement

Day-Ahead Market Timeline



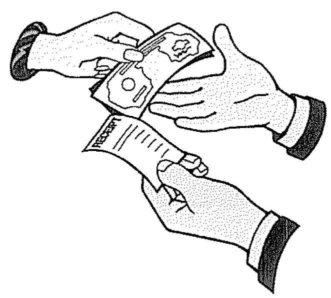
4:00 pm
PJM posts day-ahead LMPs & hourly schedules

All times are Eastern Prevailing Time

Two-Settlement Markets

- **Day-ahead Market**
  - Day-ahead schedule uses least-cost unit commitment and economic dispatch programs
  - Hourly LMPs for next Operating Day calculated using generation offers, demand bids, and bilateral transaction schedules

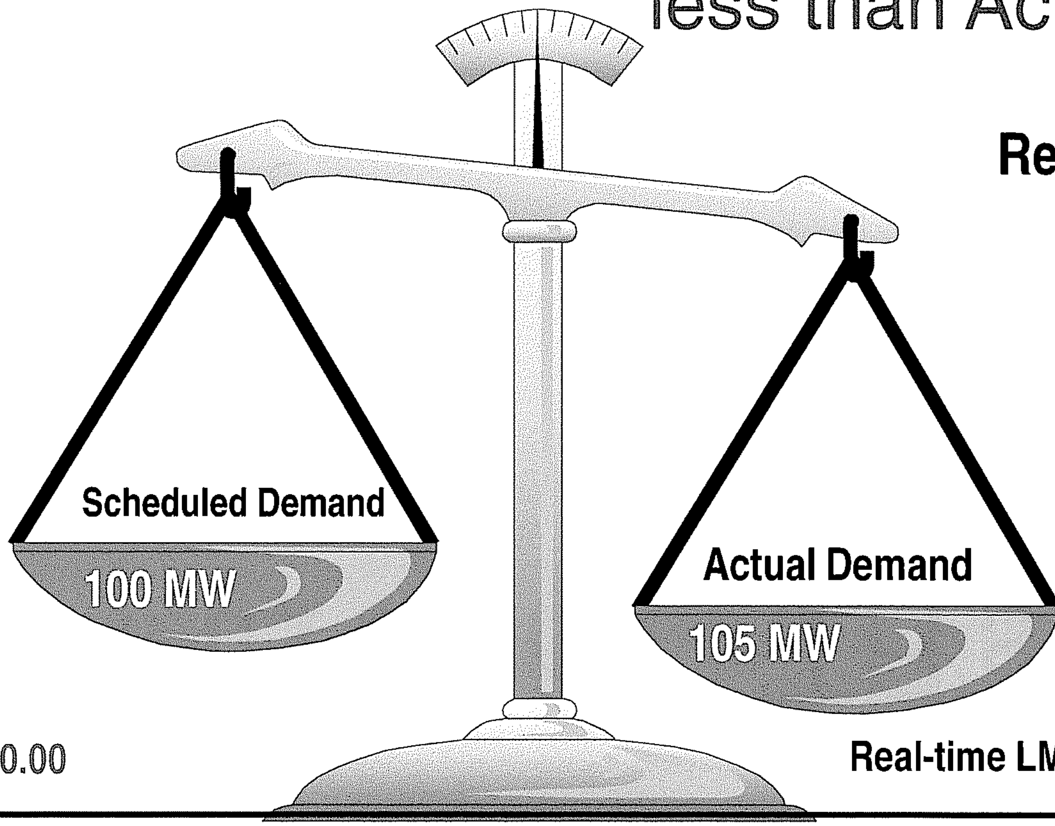
- **Real-time Energy Market**
  - Calculate hourly LMPs based on actual operating conditions
  - LMP calculated every 5 minutes
  - Settlements based on hourly integrated LMP



Simple Example :LSE with Day-Ahead Demand less than Actual Demand

Day Ahead Market

Real-time Market



Day Ahead LMP = $20.00

Real-time LMP = $23.00

*= 100 * 20.00 = $2000.00*

= (105 - 100)* 23.00 = $115.00

Total Charge = $2000 + $115 = $2115

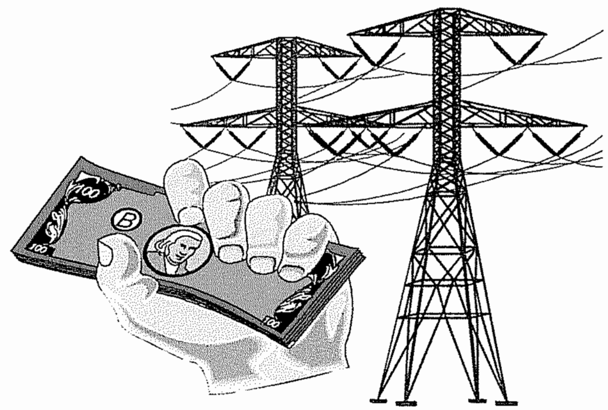
If Day-ahead Demand had been 105 MW = $2100.00

ARR's and FTR's

What are ARR's?

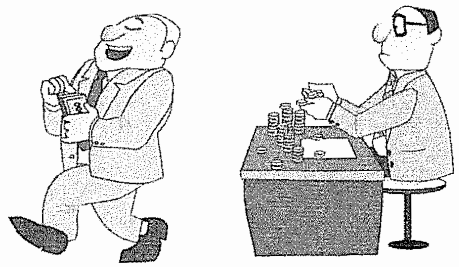
Auction Revenue Rights

are entitlements allocated annually to Firm Transmission Service Customers that entitle the holder to receive an allocation of the revenues from the Annual FTR Auction.



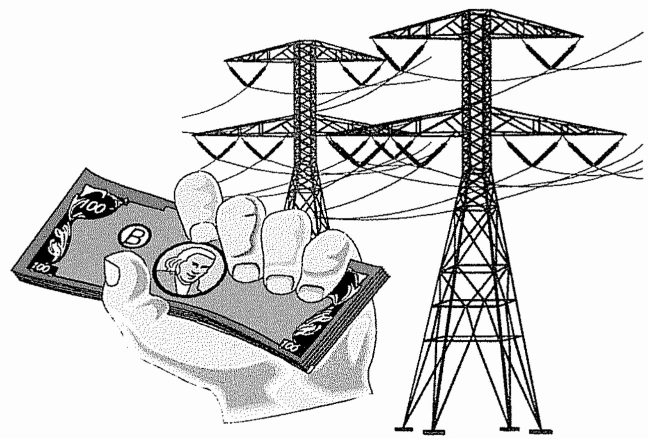
What can the holder do with the ARR?

- "Self Schedule" ARR into FTR Annual Auction on exact same path as ARR
- Reconfigure ARR by bidding into Annual Auction to acquire FTR on alternative path or for alternative product
- May retain allocated ARR and receive associated allocation of revenues from the auction



What are FTR's?

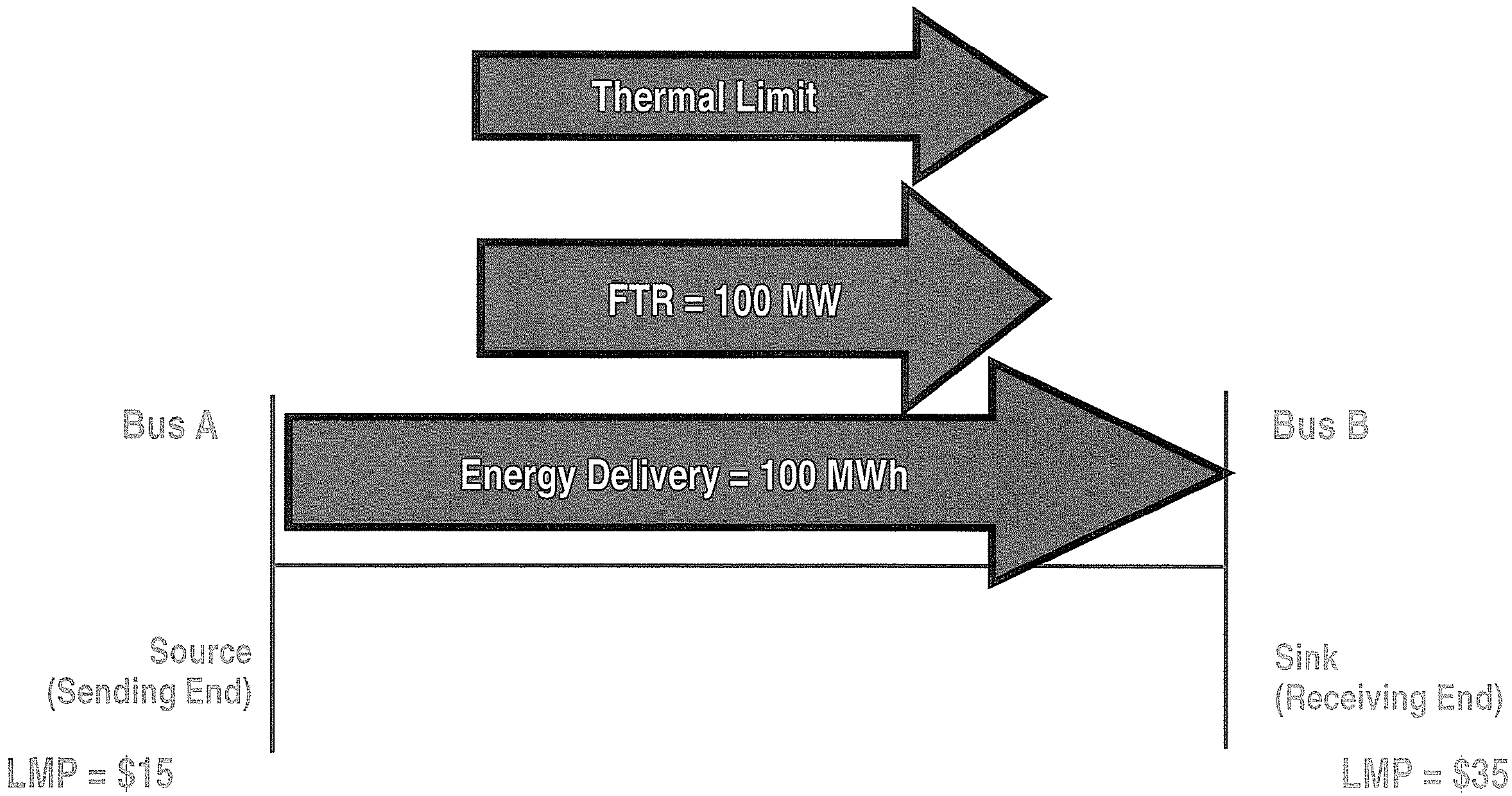
Financial Transmission Rights are financial instruments <u>awarded to bidders in the FTR Auctions</u> that entitle the holder to a stream of revenues (or charges) based on the hourly Day Ahead congestion price differences across the path



Note: Actual valuations for FTR's use the congestion component of LMP. For illustration purposes, this presentation will reference "LMP" rather than "congestion component of LMP."

LMP = System Energy Price + Marginal Loss Price + Congestion Price

Energy Delivery Consistent with FTR



Congestion Charge to the buyer = 100 MWh * ($35-$15) = $2000

FTR Credit to the FTR Holder = 100 MW * ($35-$15) = $2000

Reliability Pricing Model (RPM)

Capacity vs. Energy

Capacity

- A commitment of a resource to provide energy during PJM emergency under the capped energy price.
- Capacity revenues paid to committed resource whether or not energy is produced by resource.
- Daily product

Energy

- Generation of electrical power over a period of time
- Energy revenues paid to resource based on participation in PJM's Day-Ahead & Real-Time Energy Markets
- Hourly product

Capacity, energy & ancillary services revenues are expected, in the long term, to meet the fixed and variable costs of generation resources to ensure that adequate generation is maintained for reliability of the electric grid.

Objectives of RPM

- Resource commitments to meet system peak loads three years in the future
- Three year forward pricing which is aligned with reliability requirements and which adequately values all capacity resources
- Provide transparent information to all participants far enough in advance for actionable response

Purpose of RPM is to enable PJM to obtain sufficient resources to reliably meet the needs of electric consumers within PJM.

Resource Adequacy Requirement

- Determines the amount of capacity resources required to serve the forecast peak load and satisfy the reliability criterion.
- The reliability criterion is based on Loss of Load Expectation (LOLE) not exceeding one event in ten years.

An Installed Reserve Margin (IRM) = 15.4% satisfies the reliability criterion for the 2015/16 Delivery Year.

Resource Adequacy ICAP Requirement = Forecast Peak Load * (1+ IRM)

Installed Reserve Margin & Forecast Pool Requirement

Installed Reserve Margin (IRM)

- Used to establish level of **installed** capacity resources that will provide acceptable level of reliability

Forecast Pool Requirement (FPR)

- Used to establish level of **unforced** capacity resources that will provide acceptable level of reliability
- FPR = (1 + IRM)*(1 - pool-wide avg. EFORd)

Example: 2015/2016 DY Base Residual Auction

IRM = 15.4%, Forecast Peak Load = 163,168 MW, Pool-wide avg. EFORd = 0.0590

ICAP Requirement = Forecast Peak Load * (1+ IRM) =188,295.9 MW

FPR = (1+0.154)*(1- 0.0590) = 1.0859

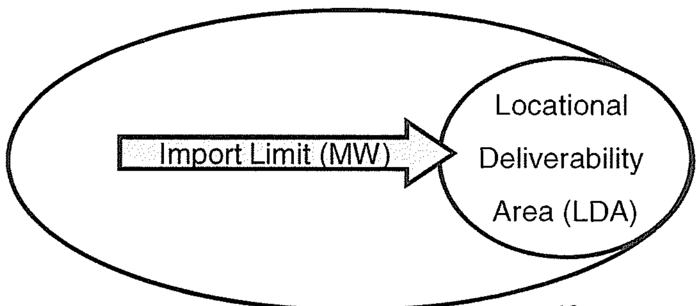
UCAP Requirement = Forecast Peak Load * FPR = 177,184.1 MW

What are Locational Constraints?

- Locational Constraints are capacity **import capability limitations** that are caused by
  - transmission facility limitations, or
  - voltage limitations.

- PJM determines constrained sub-regions (i.e., locational deliverability areas) to be included in RPM Auctions to recognize and quantify the locational value of capacity.

- Constrained regions are determined by comparing the import limit of a region (CETL) to the amount of capacity that needs to be imported into a region to meet the reliability criterion (CETO).



CETL = Capacity Emergency Transfer Limit

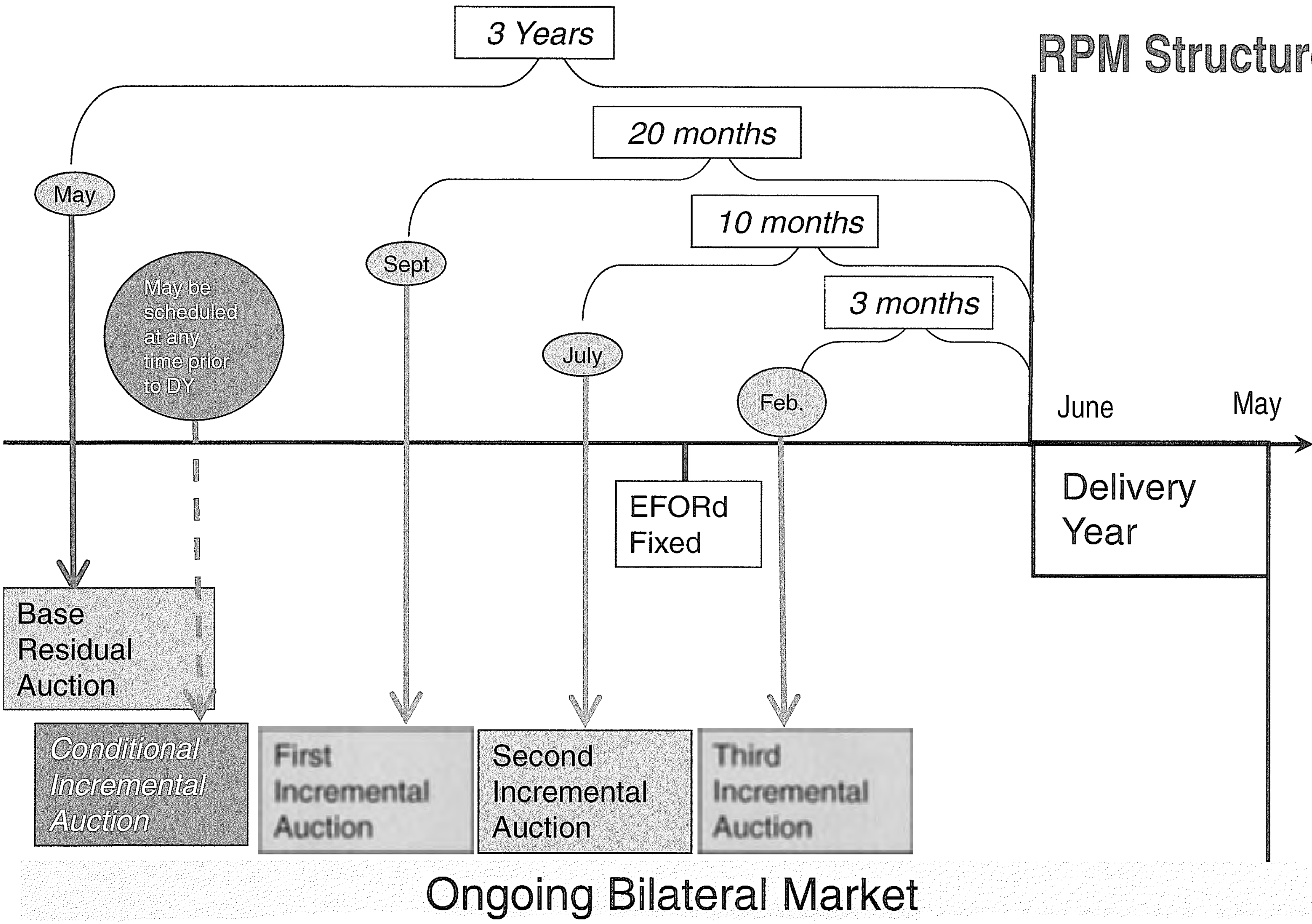
CETO = Capacity Emergency Transfer Objective

Locational Deliverability Areas

RTEPP has currently identified 25 sub-regions as Locational Deliverability Areas (LDAs) for evaluating the locational constraints.

- Regions
  - Western PJM (ComEd, AEP, Dayton, APS, Duquesne, ATSI, Duke)
  - Mid-Atlantic Area Council (MAAC) Region
  - Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL & RECO)
  - Southwestern MAAC (PEPCO & BG&E)
  - Western MAAC (Penelec, MetEd, PPL)
- Zones
  - AE, AEP, APS, ATSI, BGE, Comed, Dayton, DUQ, Dominion, DPL, Duke, JCPL, MetEd, PECO, Penelec, PEPCO, PPL, PSEG
- Sub-Zones
  - PSEG Northern Region (north of Linden substation)
  - DPL Southern Region (south of Chesapeake and Delaware Channel)

RPM Structure



RPM Auctions (Starting with 12/13 DY)

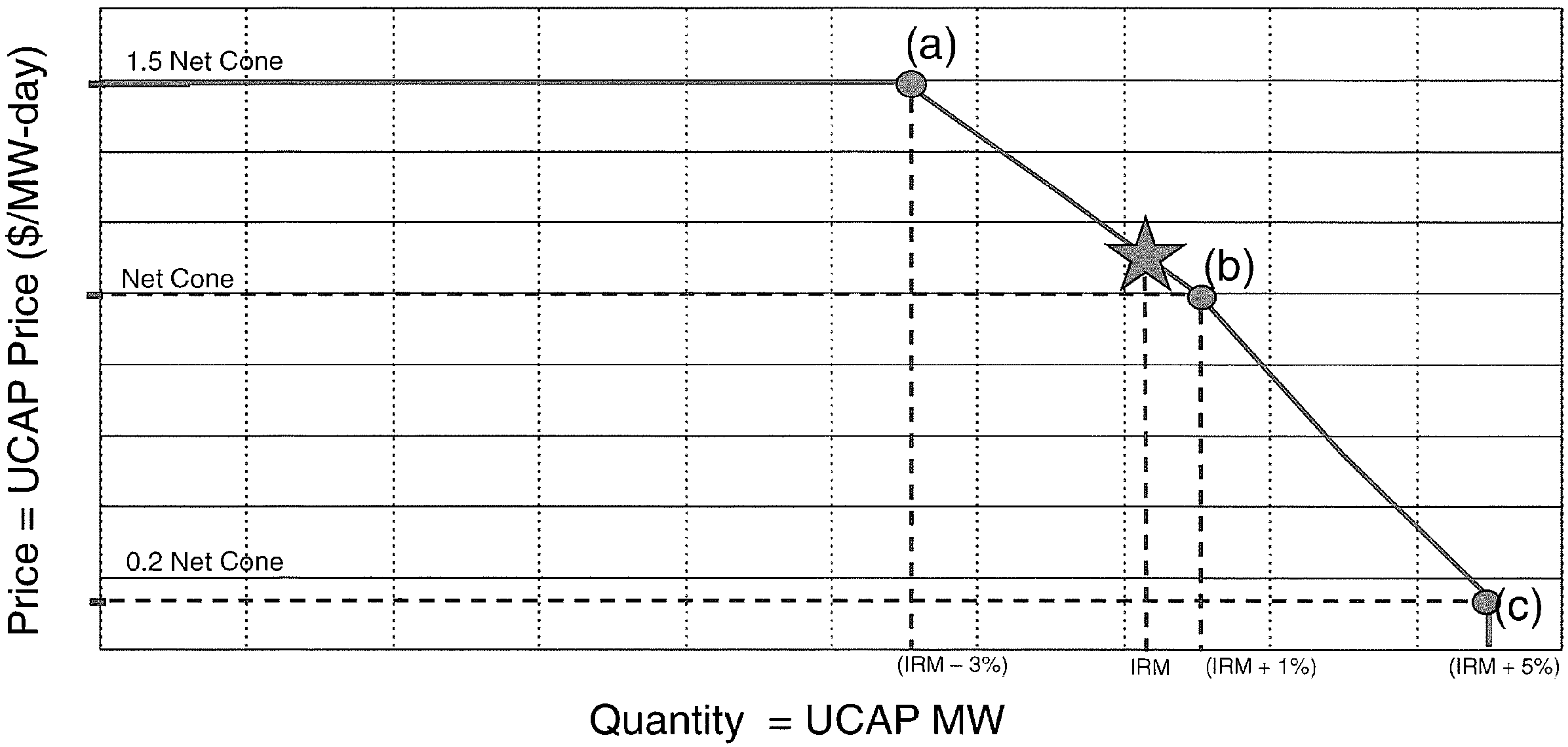
Activity	Purpose	Cost of Procurement
Base Residual Auction	Procurement of RTO Obligation less an amount reserved for short term resources, less FRR Obligation	Allocated to LSEs through Locational Reliability Charge
1st Incremental Auction	Allows for: (1) replacement resource procurement (2) increases and decreases in resource commitments due to reliability requirement adjustments; and (3) deferred short-term resource procurement	Allocated to resource providers that purchased replacement resources and LSEs through Locational Reliability Charge
2nd Incremental Auction		
3rd Incremental Auction		
Conditional Incremental Auction	Procurement of additional capacity in a LDA to address reliability problem that is caused by a significant transmission line delay	Allocated to LSEs through Locational Reliability Charge

What is the VRR?

The Variable Resource Requirement (VRR) Curve is a downward sloping demand curve that relates the maximum price for a given level of capacity resource commitment relative to reliability requirements.

- The price is higher when the resources are less than the reliability requirement and lower when the resources are in excess.
- VRR Curves are defined for the PJM RTO and for each constrained Locational Deliverability Area (LDA) within the PJM region.

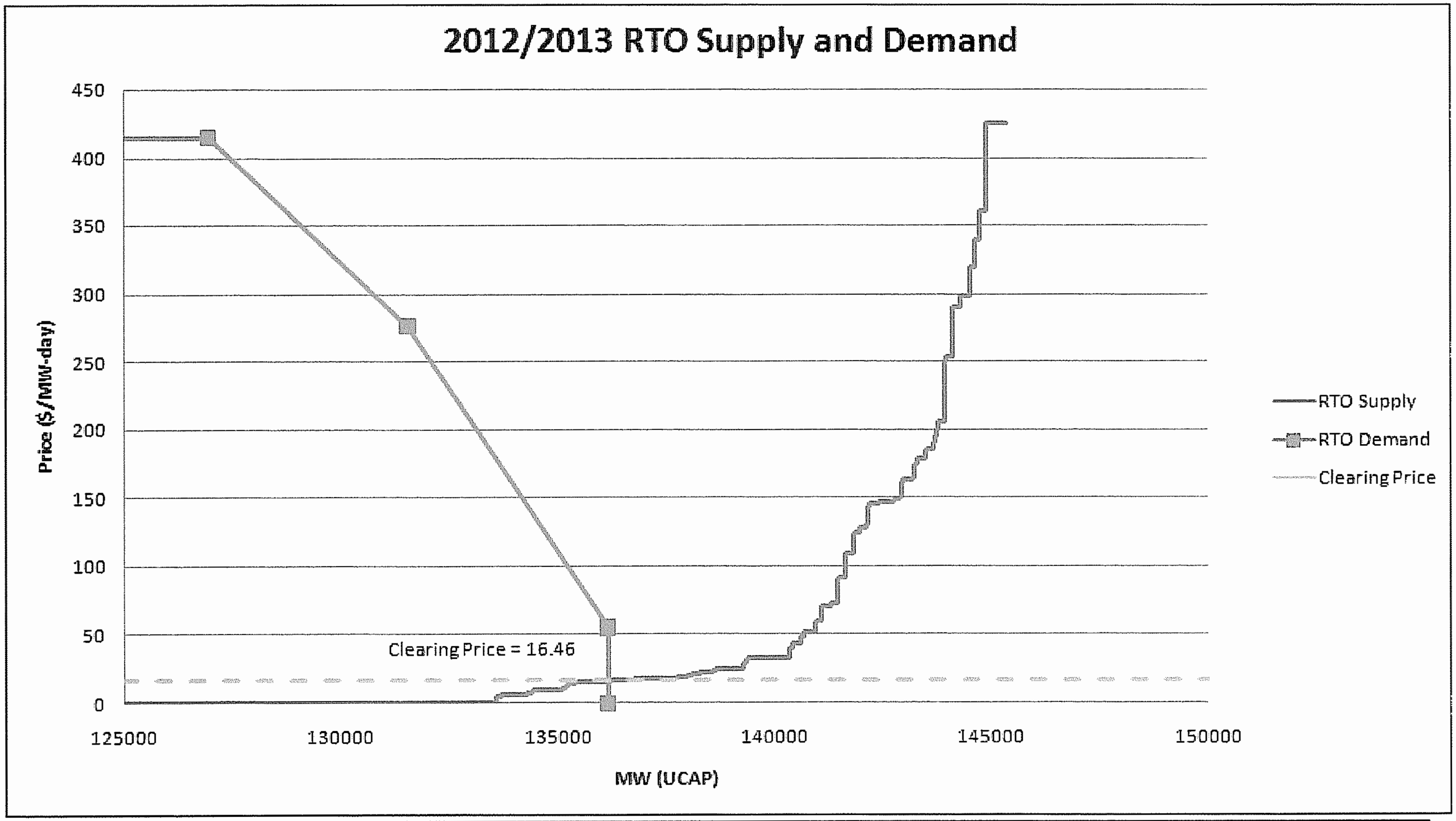
Illustrative Example of a VRR Curve



A VRR Curve is defined for the PJM Region.

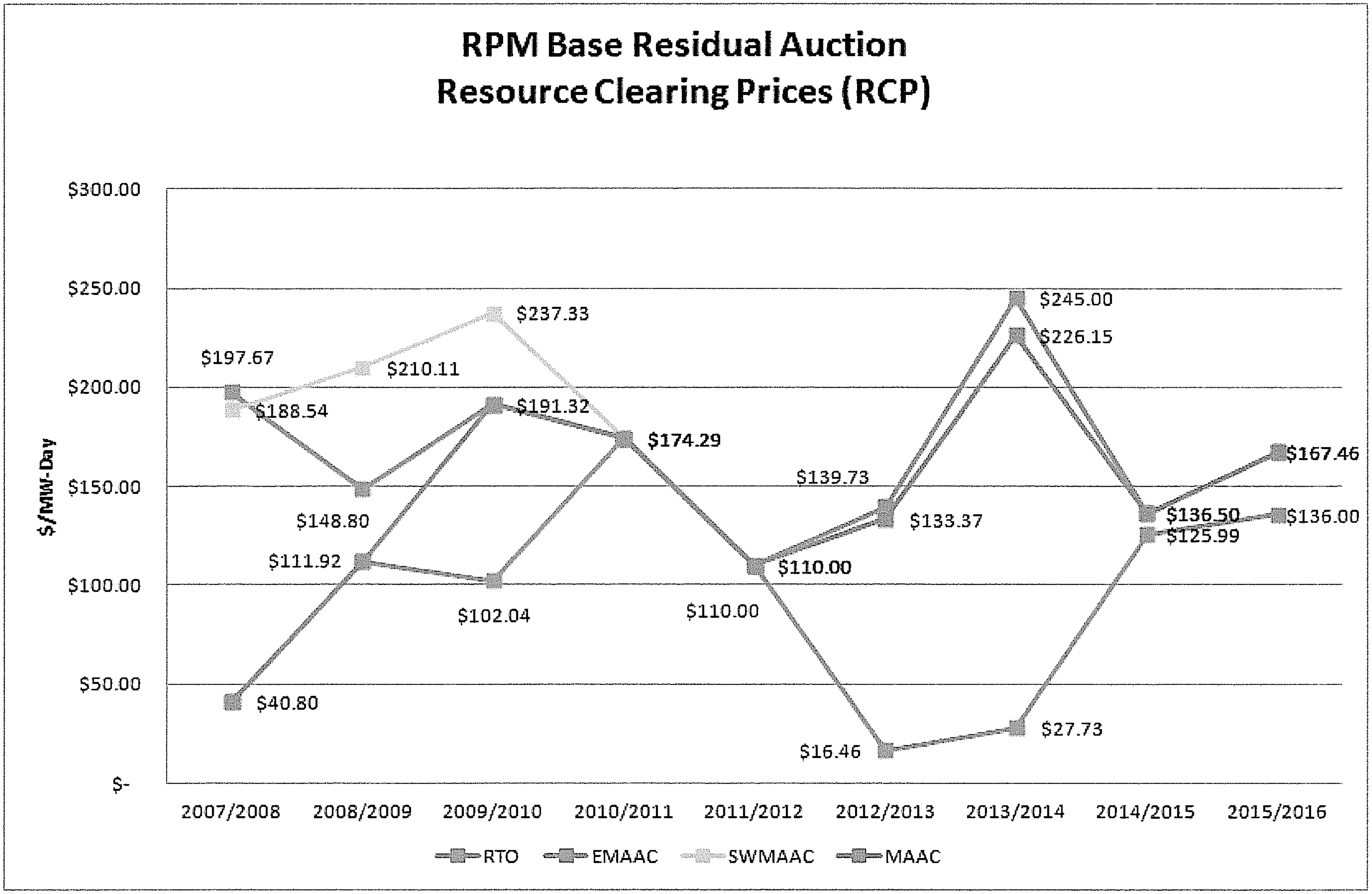
Individual VRR Curves are defined for each Constrained LDA.

Clearing 2012/2013 Base Residual Auction



Clearing determined by the intersection of the supply and the demand curves.

Base Residual Auction



What is a Supply Resource in RPM?

In RPM, **Resources** are =

Generation Resources	Demand Resources (DR)	Energy Efficiency Resources (EE) (Effective with 11/12 DY)	Qualifying Transmission Upgrades (QTU)

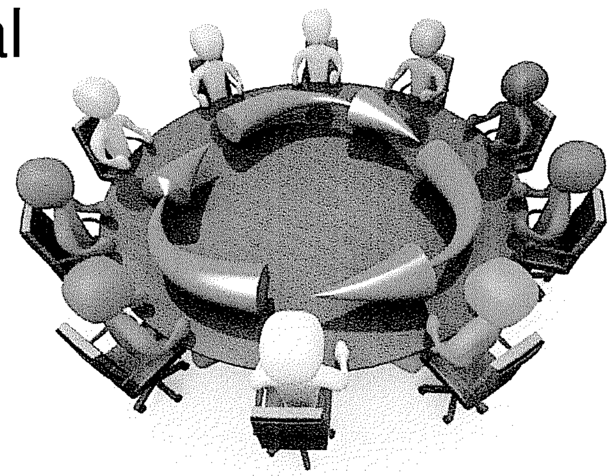
Regional Planning Process

Regional Planning Objectives

- 15 year outlook to identify reliability standards violations
- Test the transmission system against mandatory national standards and PJM regional standards
- Reliability and economic efficiency drivers

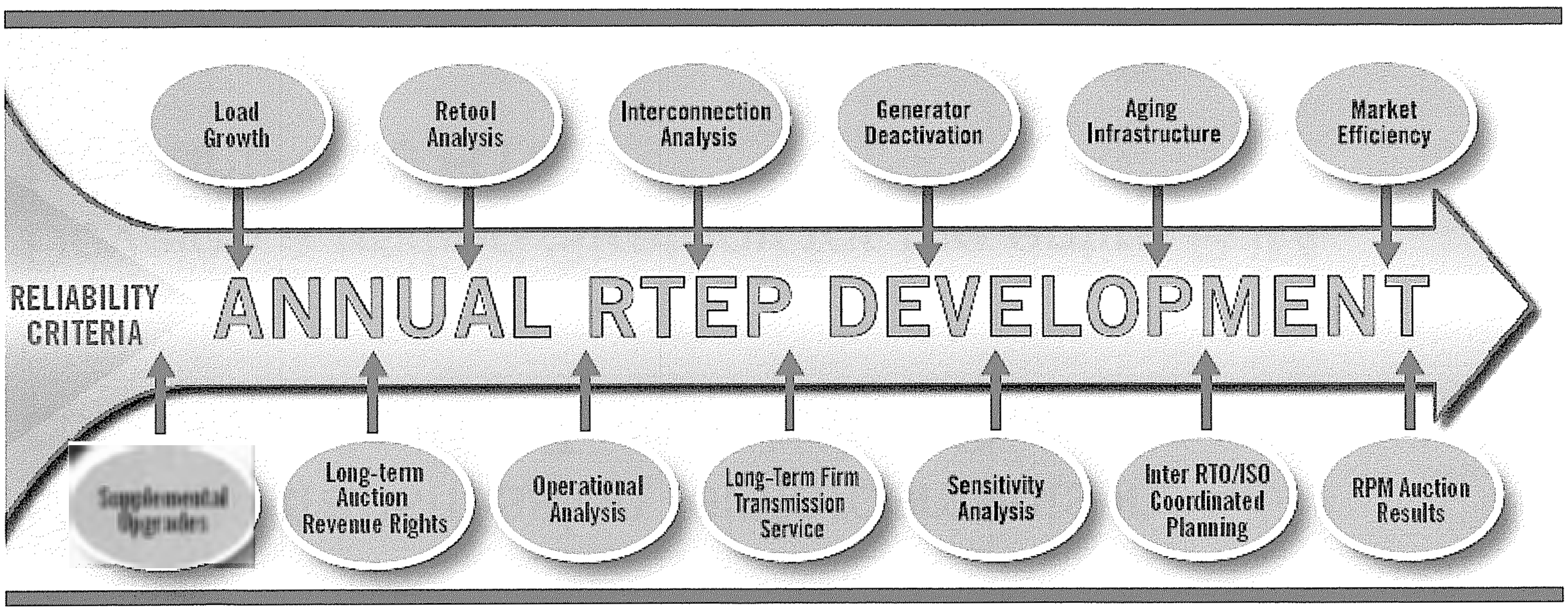
Regional Planning Objectives

- Develop transmission reinforcements in collaboration with Transmission Owners
- Develop a unified Strategy for the entire PJM footprint – the RTEP
- Submit Plan to PJM's independent governing Board for consideration and approval



RTEP Process Definition

PJM's RTEP process identifies transmission enhancements to preserve regional transmission system reliability, taking into consideration numerous driving factors.



Interconnection Request Process

1. Queue open (90 days)
2. Feasibility Study (90 days)
3. Customer review report and return Impact Study Agreement (30 days)
4. Impact Study (120 days)
5. Customer review report and return Facility Study Agreement (30 days)
6. Facility Study (6 months)
7. Customer review report and return ISA (CSA) or UCSA (60 days)
8. PJM prepare CSA (45 days) [Required only if CSA not tendered with ISA]
9. Customer review and return CSA (90 days)
10. Remaining timeline defined by ISA milestones, CSA/UCSA schedule and rights to suspend

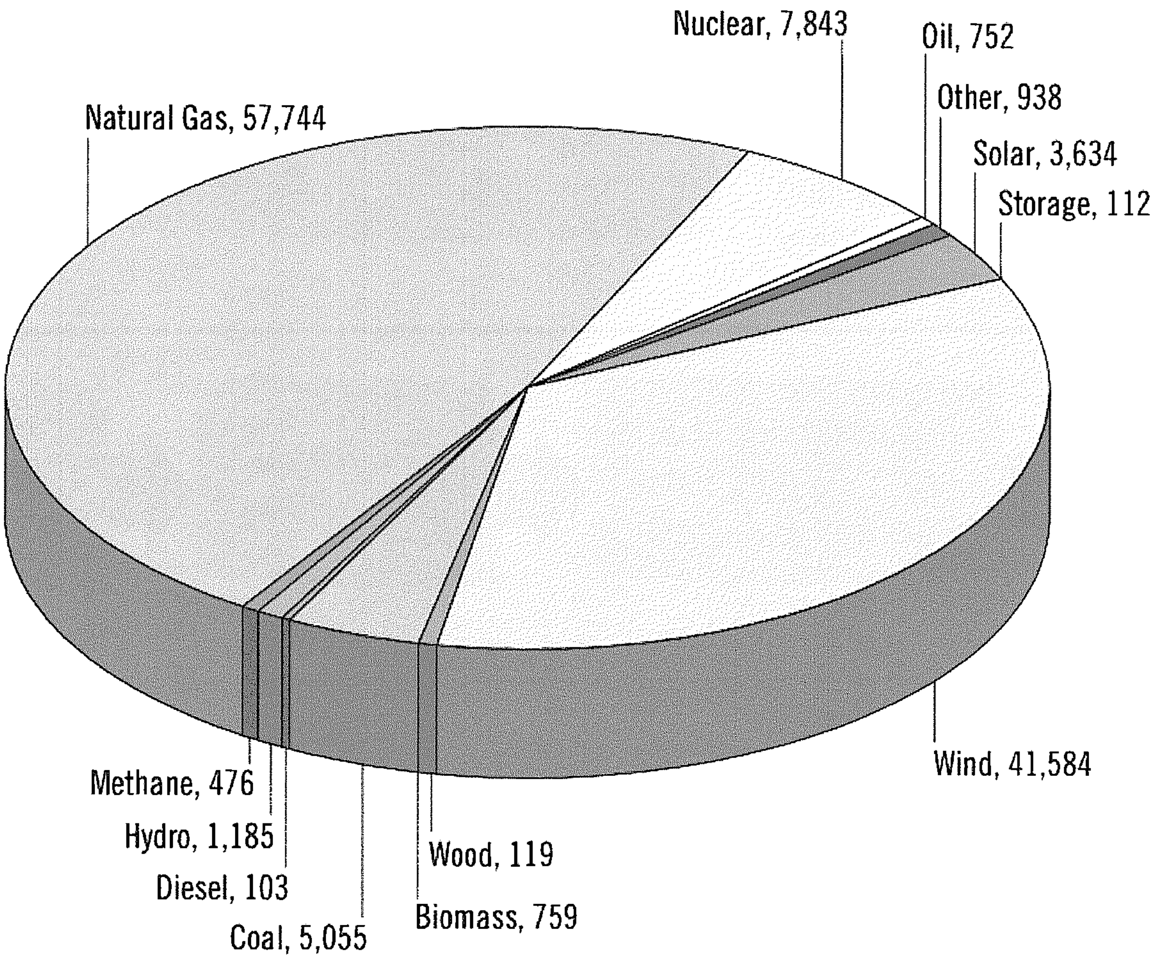
Approximately 1 ½ years from queue entry until ISA tendered (assuming no delays)

ISA = Interconnection Service Agreement
CSA = Construction Service Agreement
UCSA = Upgrade Construction Service Agreement

Note: Projects May Drop Out of the Queue at any Time

Fuel Mix of Queued Generation Interconnection Requests

Figure 1.5: Fuel Mix of All Queued Generation Interconnection Requests Received since 1999 (Nameplate Energy) (January 31, 2012)



Source: 2011 PJM RTEP Report

PJM Demand Side Response Basic Overview

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*
- *Ancillary Services*
- *Synchronized Reserve*
- *Day Ahead Scheduling Reserve*
- *Regulation*
- *Capacity*
- Offer into auction up to 3 years in advance

Active Participants in PJM Load Response Program

Economic Sites: 1,008
Economic MW: 2,282

Emergency DR Sites: 12,610
Emergency DR MW: 8,548

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 Demand Side Response

- Like a generator, a DSR resource participates in the Day Ahead and Real-Time energy markets
- Unlike a generator that is a capacity resource, DSR participation in the energy market is voluntary
- After a DSR either clears in the Day-Ahead market or is dispatched in the Real-Time market, a settlement is created and a reduction needs to be calculated in eLRS.
  - Reduction = CBL – metered load
- Like a generator, a DSR resource participates in the Reliability Pricing Model (RPM)
  - Load Management

Customer Baseline Calculation

A Customer Baseline Load (CBL) is a proxy for what the load would have been absent the load reduction. A CBL is calculated 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

DR Products for Load Management

- Effective with the 2014/2015 DY, two additional Product Type will be added:
  - Extended Summer Demand Resource
  - Annual Demand Resource

Three Product Types available beginning in 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 *(Hours in EPT)*	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.		

Load Management Types

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

Questions?

Contact PJM:

http://www.pjm.com/about-pjm/who-we-are/contact-us.aspx

www.pjm.com

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