PJM Organization and Markets

Saudi Delegation
Columbus Ohio
May 22, 2012

Agenda

- Introduction & Governance
- Energy Markets
  - LMP
  - FTRs/ARRs
  - Two Settlement
  - Virtual Bids
  - Ancillary
  - Capacity - Reliability Pricing Model

Introduction

What is an RTO?

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

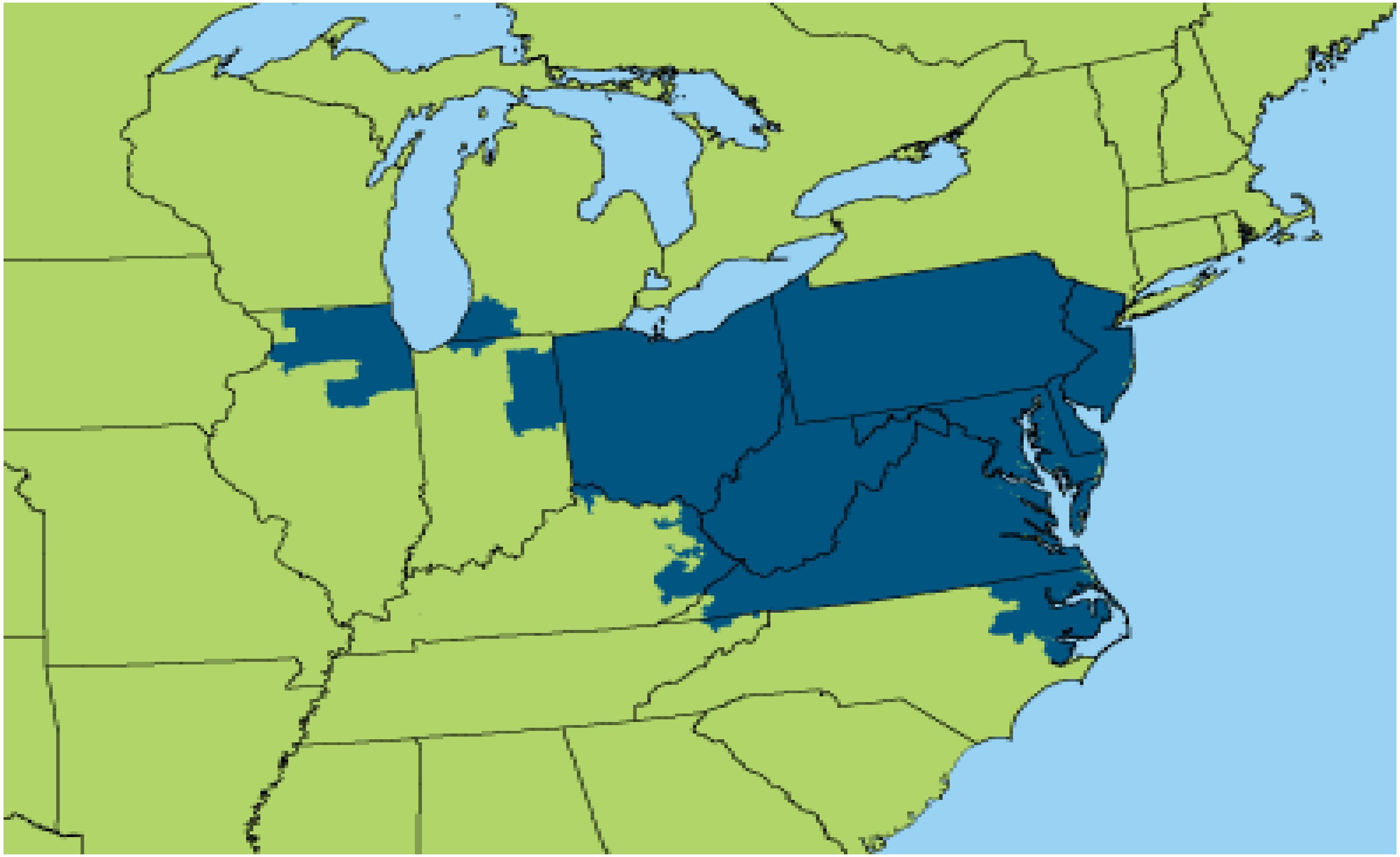
- Independent from all market participants
- Responsible for grid operations and reliability
- Responsible for transmission service within region

PJM Demographics

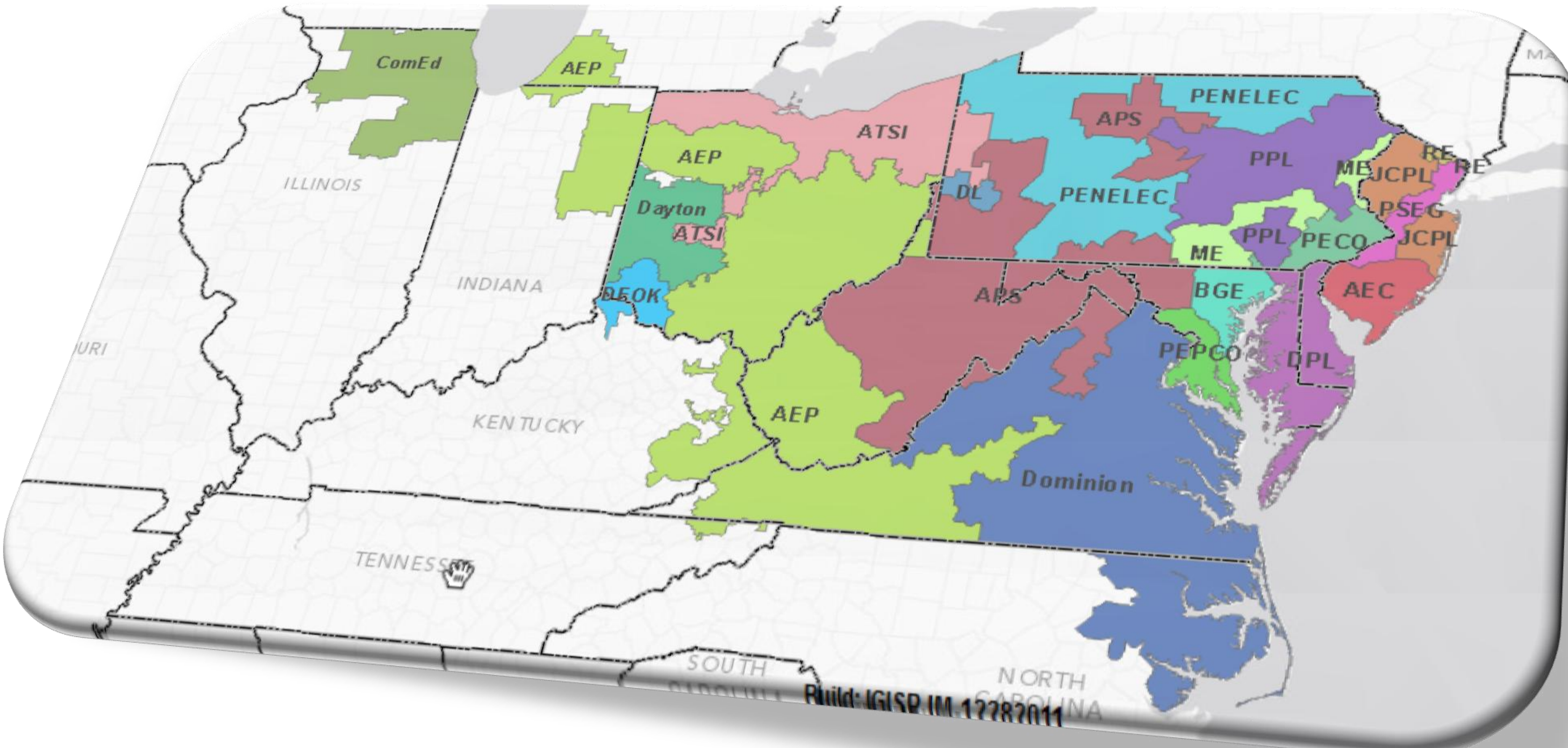
- Complexity
  - 1365 Generation Resources with Diverse Fuel
  - Over 56,250 Miles of Transmission Lines
  - Over 60 Million People Served

- Uniqueness
  - Single Control Area in NERC Region
  - Area Served: 13 States + DC
- Members/Customers
  - Member Companies ~ 760 +
  - Transmission Svc. Customers ~ 100 +
  - 158,450 MW Peak Load (July 21, 2011)

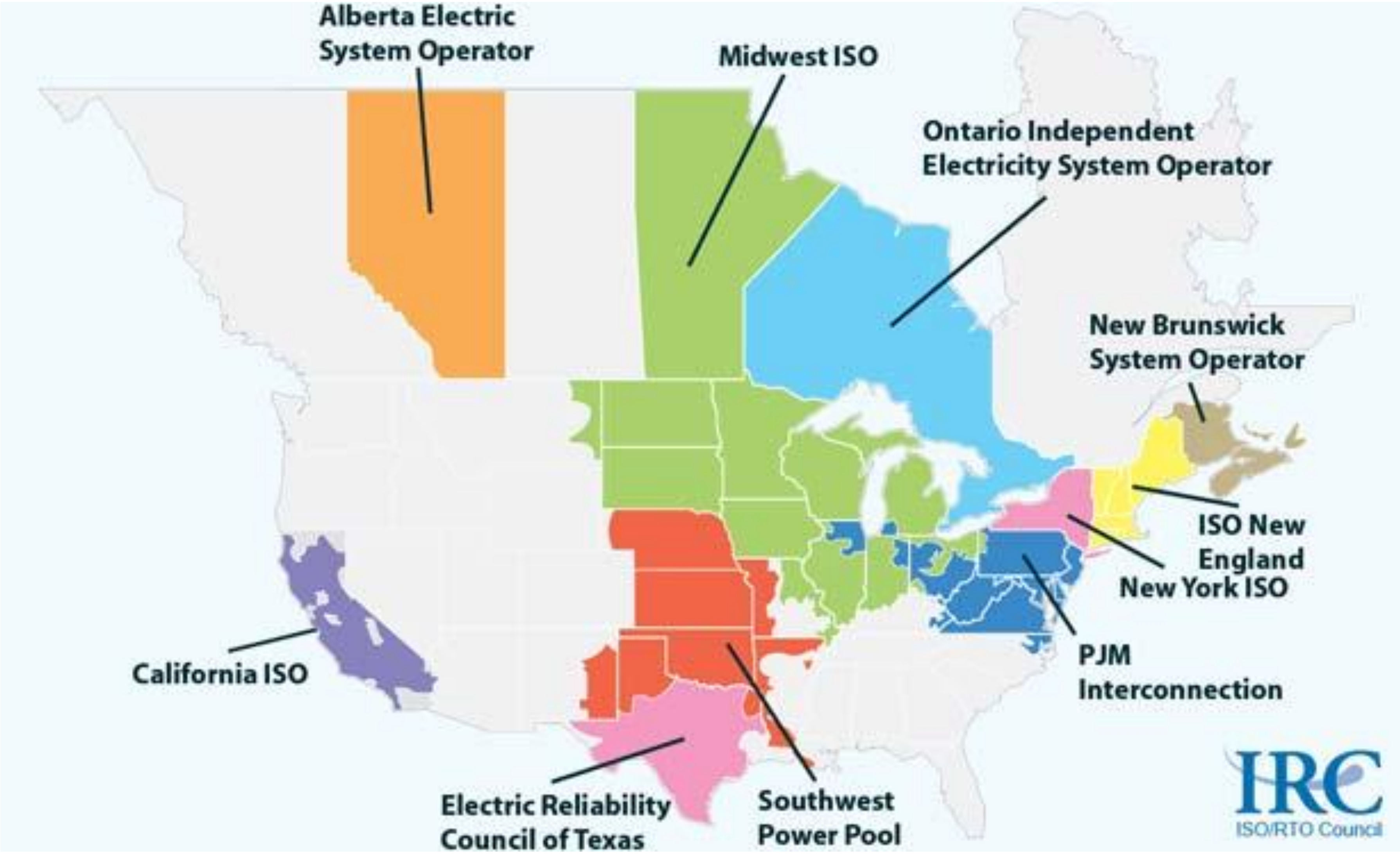
PJM Service Territory



Transmission Owner Zones



Nine Major North American RTOs / ISOs



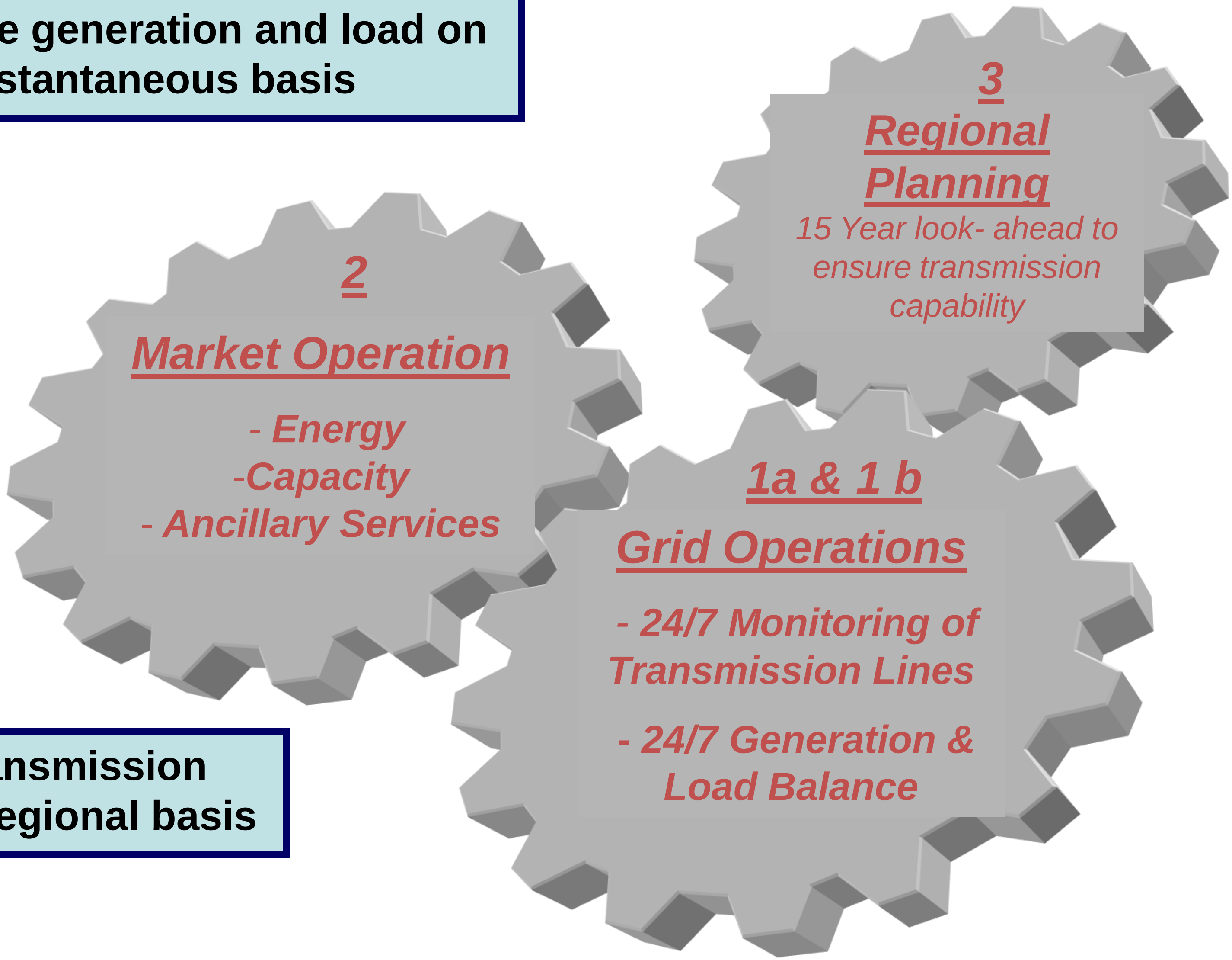
PJM Functions

1a – Monitor the high-voltage transmission grid for reliability

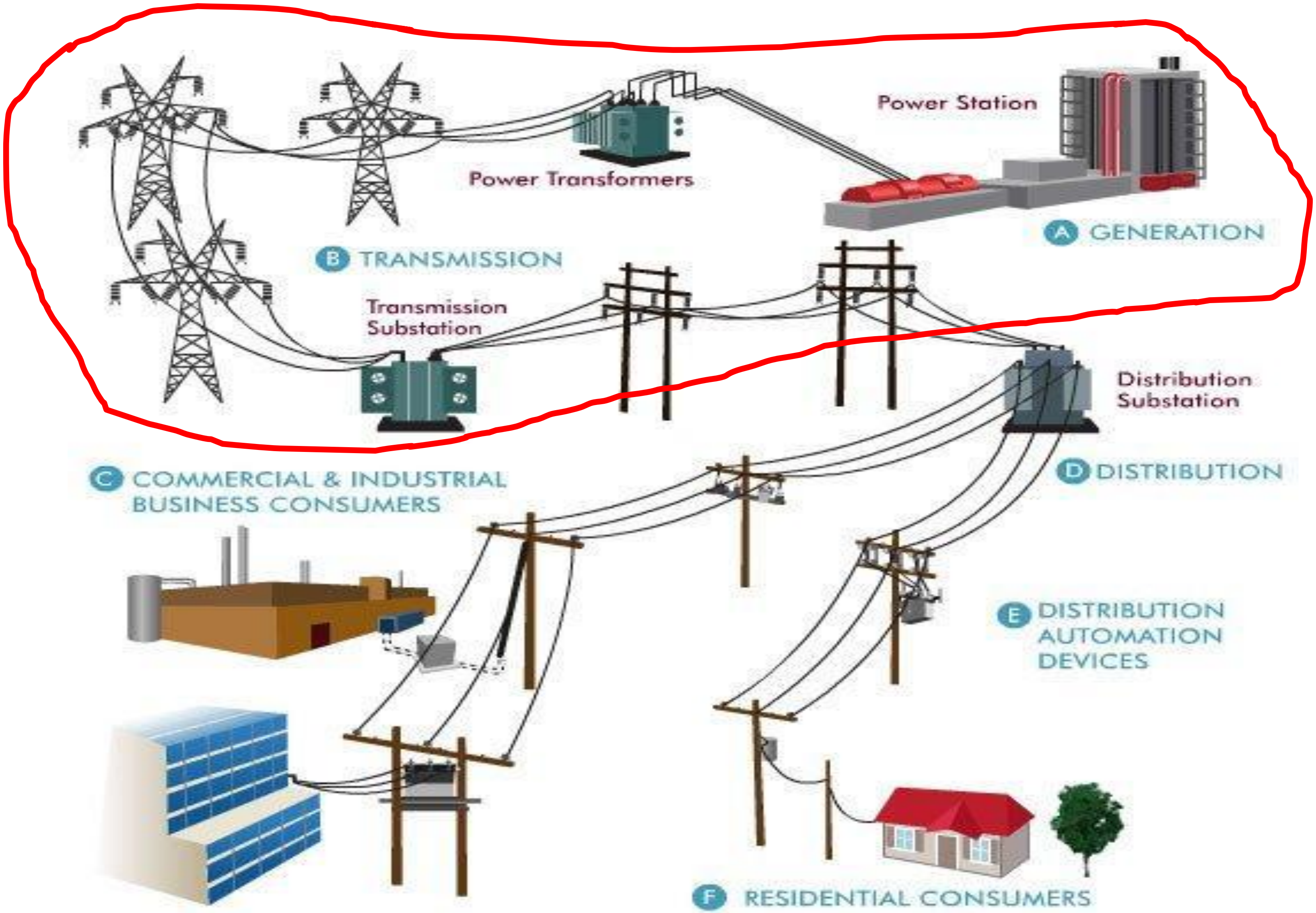
1b – Balance generation and load on an instantaneous basis

2 – Operate competitive, non-discriminatory markets

3 – Plan for transmission expansion on a regional basis

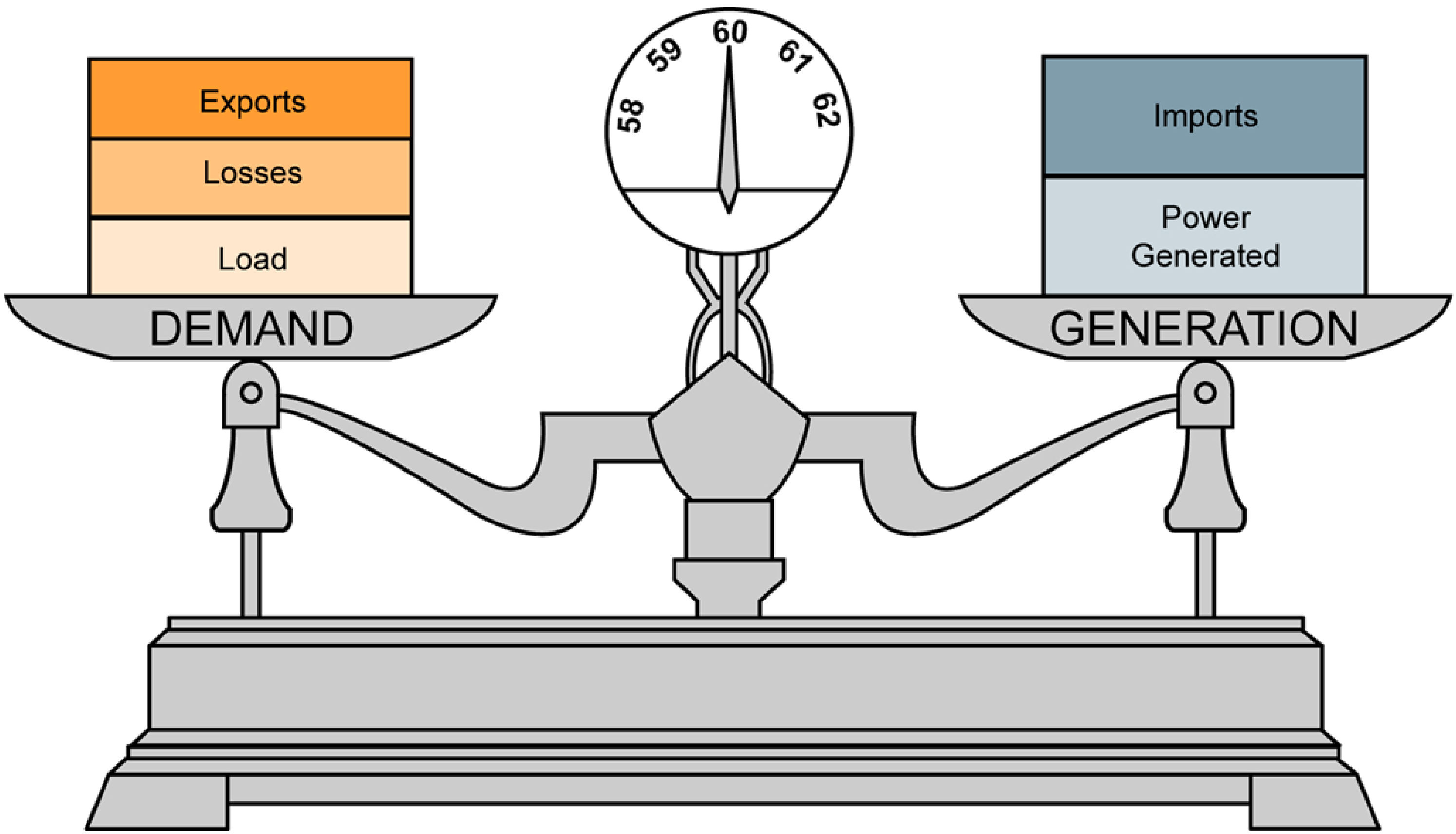


Function 1a - Monitoring the Bulk Power System for Reliability



Operations Goal – Keeping the RTO in Balance at All Times while Respecting Transmission Limitations

Function 1b



Electricity Markets - Match Buyers and Sellers

Function 2

Sellers - Supply Resources
Fossil, Hydro, Nuclear, Renewable
FERC Approved Power Marketers

Buyers - Wholesales Entities
Load Serving Entities
FERC Approved Power Marketers

Planning an Adequate and Reliable Transmission System

Function 3

The Regional Transmission Expansion Planning Process identifies upgrades to meet customers' requirements:

- operational
- economic
- reliability requirements

Merchant Generation

Base Line Upgrades

How is PJM different from the local utility?

PJM <u>does</u>:

- Direct operation of the transmission system
- Remain profit neutral
- Maintain independence from PJM members
- Coordinate maintenance of grid facilities

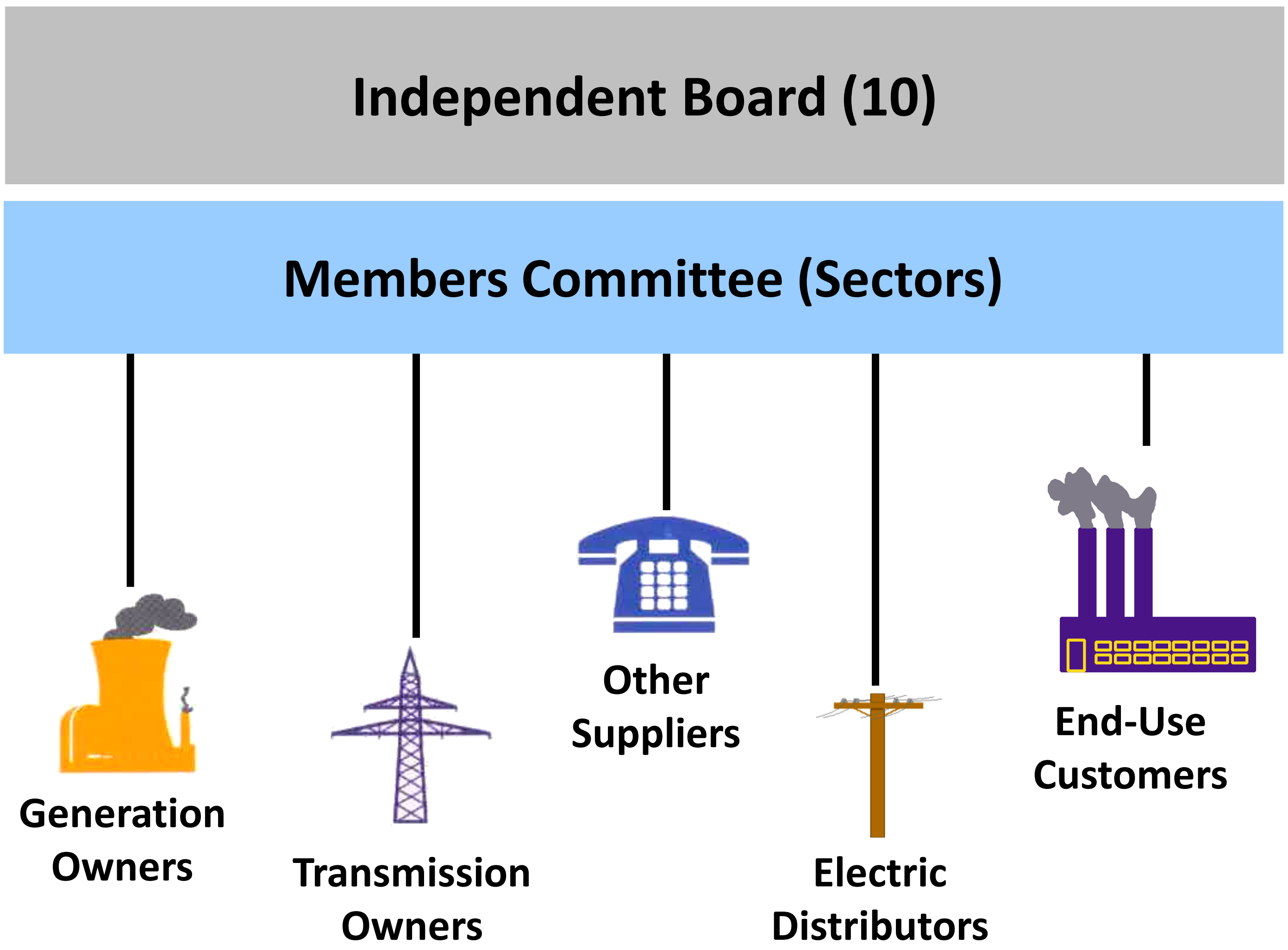
How is PJM different from the local utility?

PJM <u>does not</u>:

- Own any transmission or generation assets.
- Function as a publicly traded company.
- Take ownership of the energy on the system.
- Perform the actual maintenance on generators or transmission systems.
- Serve, directly, any end use (retail) customers.

Governance

Two Tier Governance Structure



Members Committee Voting Protocol

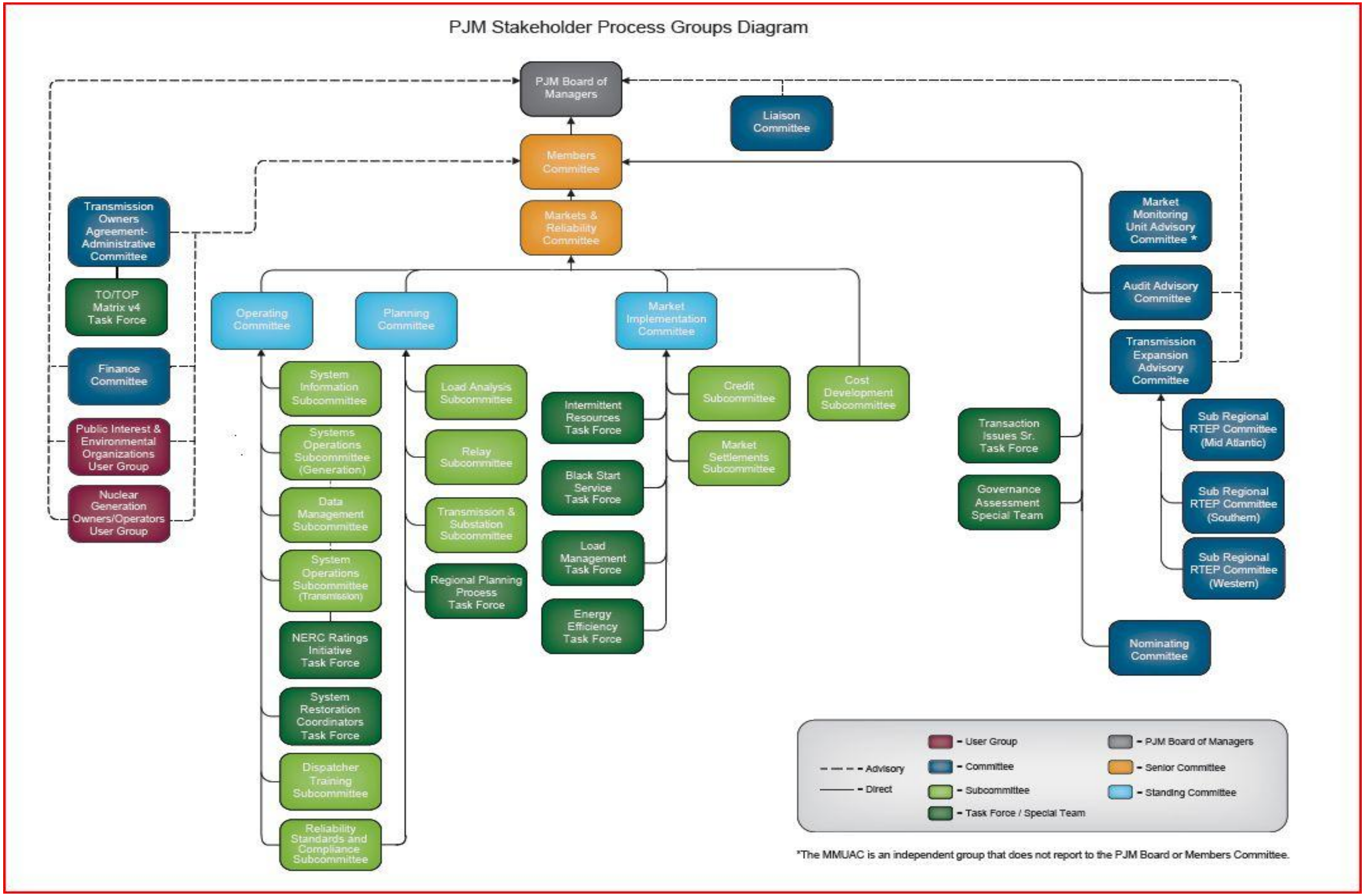
Generation Owners	5/7	0.71
Transmission Owners	2/8	0.25
Other Supplier	21/23	0.91
End Use Customers	5/5	1.00
Electric Distributors	3/5	0.60
		3.47

Required to pass = 0.667

Number of Sectors = 5

Required Affirmative = 5 x 0.667 = 3.335

PJM Committee Structure



Dispatch Function

Valley Forge Control Room

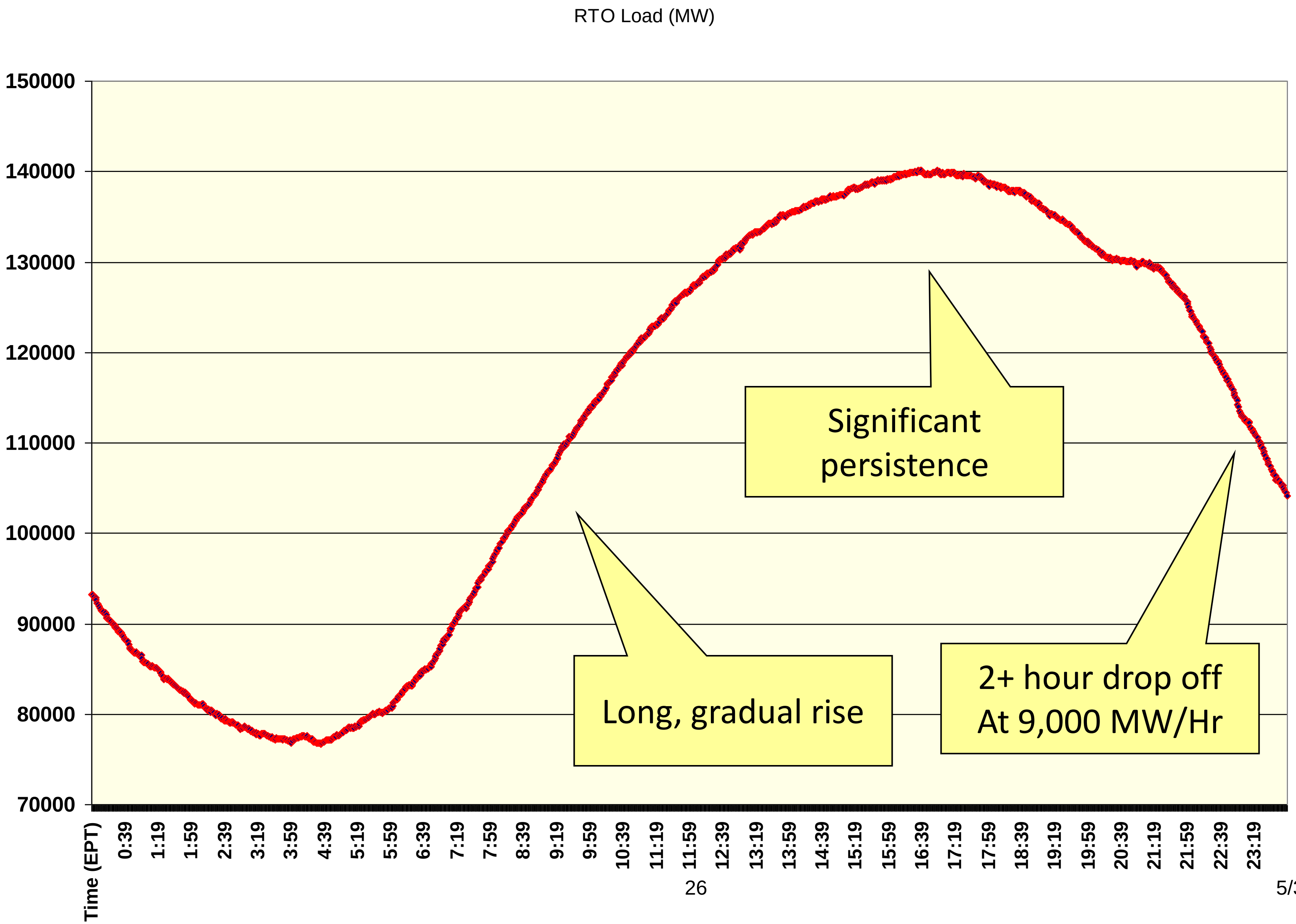
Milford Control Room

Dispatch Functions

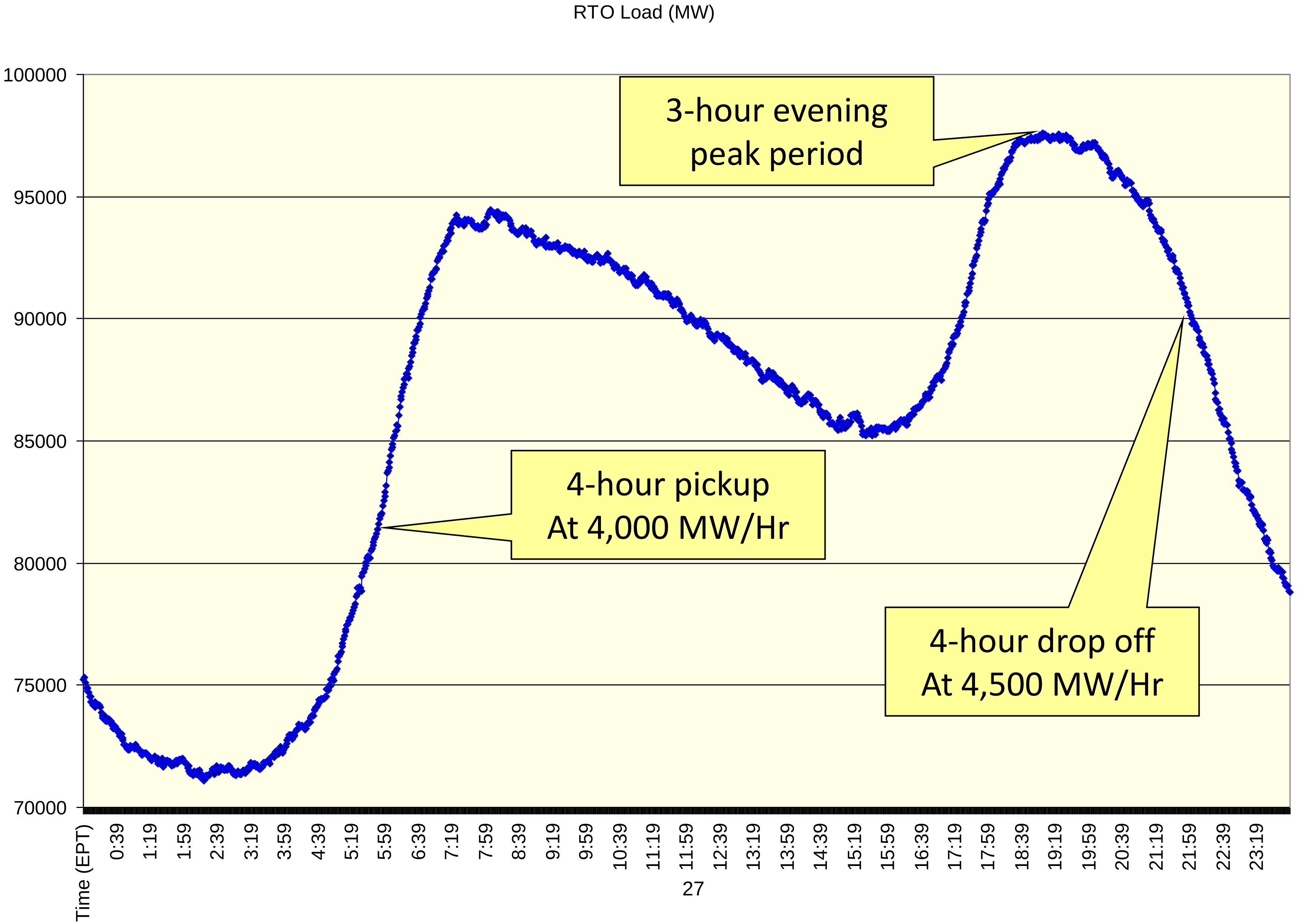
- Ensure sufficient generation is available or running to satisfy the demand at any hour of the day including maintaining adequate reserves. This is called ***Generation Control***.

- Monitor, operate and control the high voltage transmission system in a reliable manner. This is called ***Transmission Control***.

Load Curve – Summer Profile



Load Curve – Winter Profile



Locational Marginal Price

What is Locational Marginal Price?

- 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 does PJM Use LMP?

- ☑ Generators get paid at generation bus LMP
- ☑ Loads or Customer Demand pay at load bus LMP
- ☑ Bilateral Transactions pay differential in source and sink LMP
- ☑ PJM LMPs are the result of the physical flow of energy, not a contract path

Locational Marginal Price

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

LMP is made up of 3 independent components

LMP Components - System Energy Price

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

☑ System Energy Price

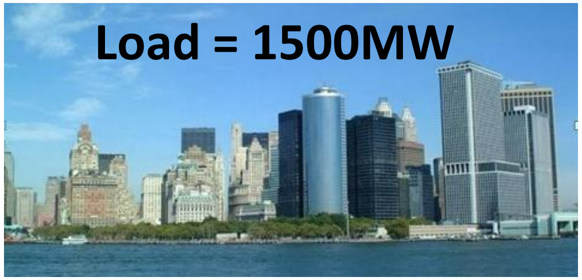
- Represents optimal dispatch ignoring congestion and losses
- Same price for every bus in PJM
- Calculated both in day ahead and real time
- Intersection of the Supply and Demand Curve

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

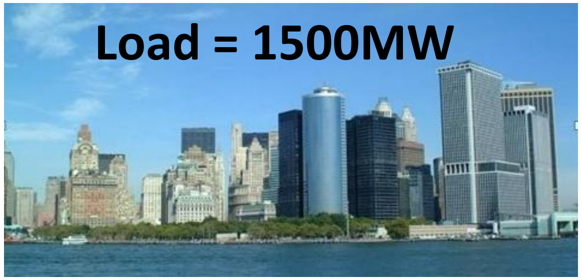
LMP Components - Congestion

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

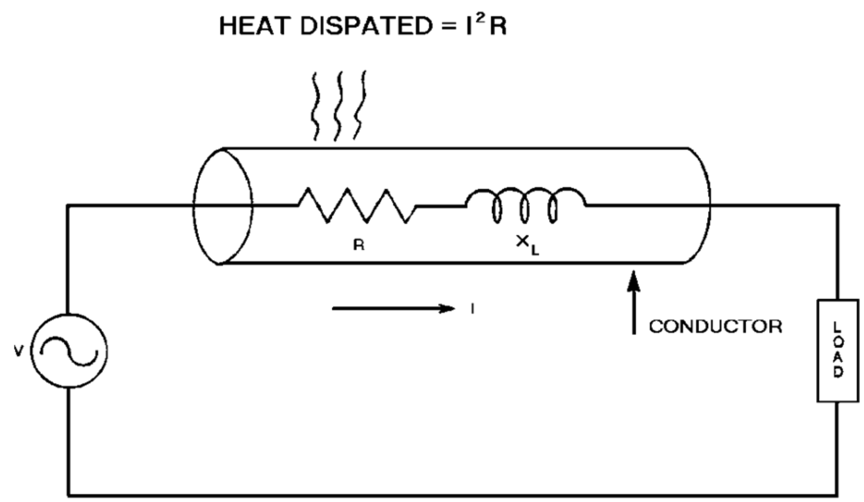
LMP = System Energy Price **+** Transmission Congestion Cost **+** Cost of Marginal Losses

☑ Loss Price

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

Transmission Losses

- 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



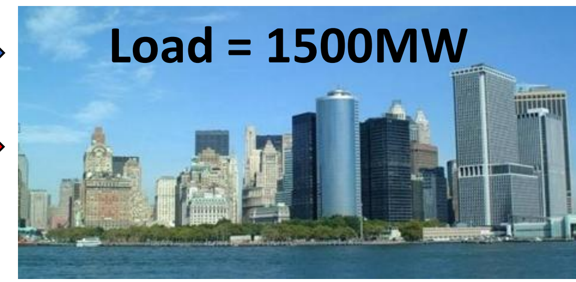
LMP Components Marginal Losses

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

Dispatch 1000 MW

Flow = 1000 MW

Limit = 1000 MW



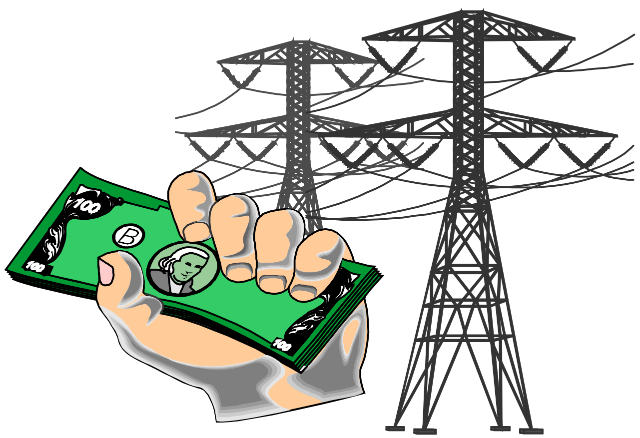
Dispatch 500 MW

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

Hedging Transmission Congestion Financial Transmission Rights

Financial Transmission Rights are …

financial instruments awarded to bidders in the FTR Auctions that entitle the holder to a stream of revenues (or charges) based on the hourly Day Ahead congestion price differences across the path



LMP	=	System Energy Price		Congestion Price	+	Marginal Loss Price

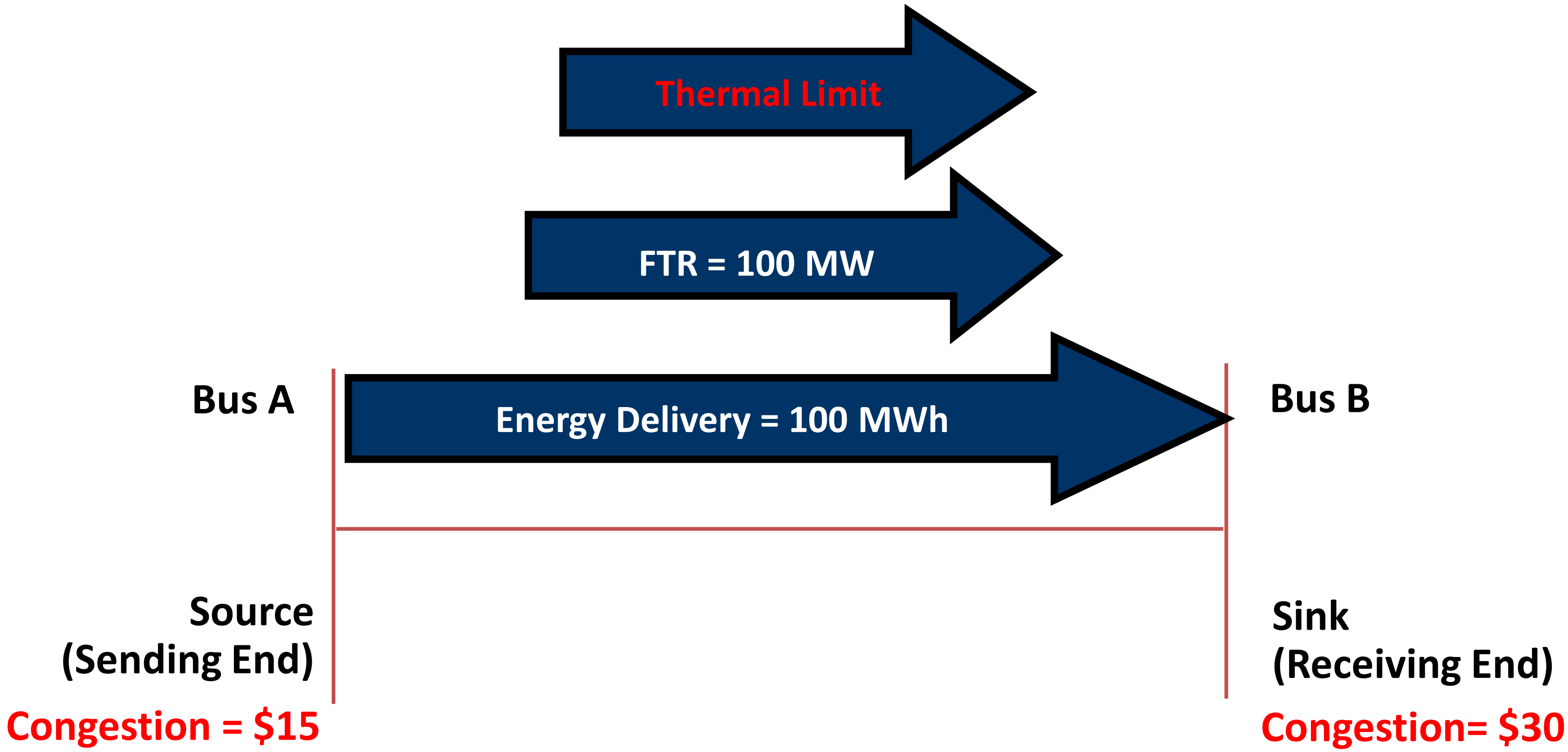
Why do we need FTRs?

- **Challenge:**
  - Protect Load Servers from price uncertainty for congestion charges
  - Redistribute excess congestion charges
- **Solution:**
  - FTR credits equal congestion charges on same path
  - FTRs provide hedging mechanism that can be traded separately from transmission service

Characteristics of FTRs

- Economic value based on Day Ahead Congestion Component of LMP
- Defined from source to sink
- Financial entitlement, *not* physical right
- Independent of energy delivery

Energy Delivery Consistent with FTR



Congestion Charge = 100 MW * ($30-$15) = $1500

FTR Credit = 100 MW * ($30-$15) = $1500

FTRs as a Benefit

Source
LMP = $18
System Energy = $20
Congestion = ($3)
Marginal Loss = $1

100 MW FTR

Sink
LMP = $29
System Energy = $20
Congestion = $7
Marginal Loss = $2

FTR Value = 100 MW * (7 - (-3)) = $1,000 Credit

"Prevailing Flow" FTRs point in the same direction as the congestion"

FTRs as a Liability

Sink
LMP = $18
System Energy = $20
Congestion = ($3)
Marginal Loss = $1

100 MW FTR

Source
LMP = $29
System Energy = $20
Congestion = $7
Marginal Loss = $2

FTR Value = 100 MW * ((-3) - 7) = $1,000 Liability

"Counterflow" FTRs point in the opposite direction of the congestion"

Obtaining FTRs

- **Annual Auction**
  - Multi-round
  - Multi-period
  - Multi-product
  - Entire System Capability

- **Secondary market** -- bilateral trading
  - FTRs that exist are bought or sold

- **Monthly & Balance of Planning Period FTR Auction -- centralized market**
  - purchase “left over” capability

What are FTRs Worth?

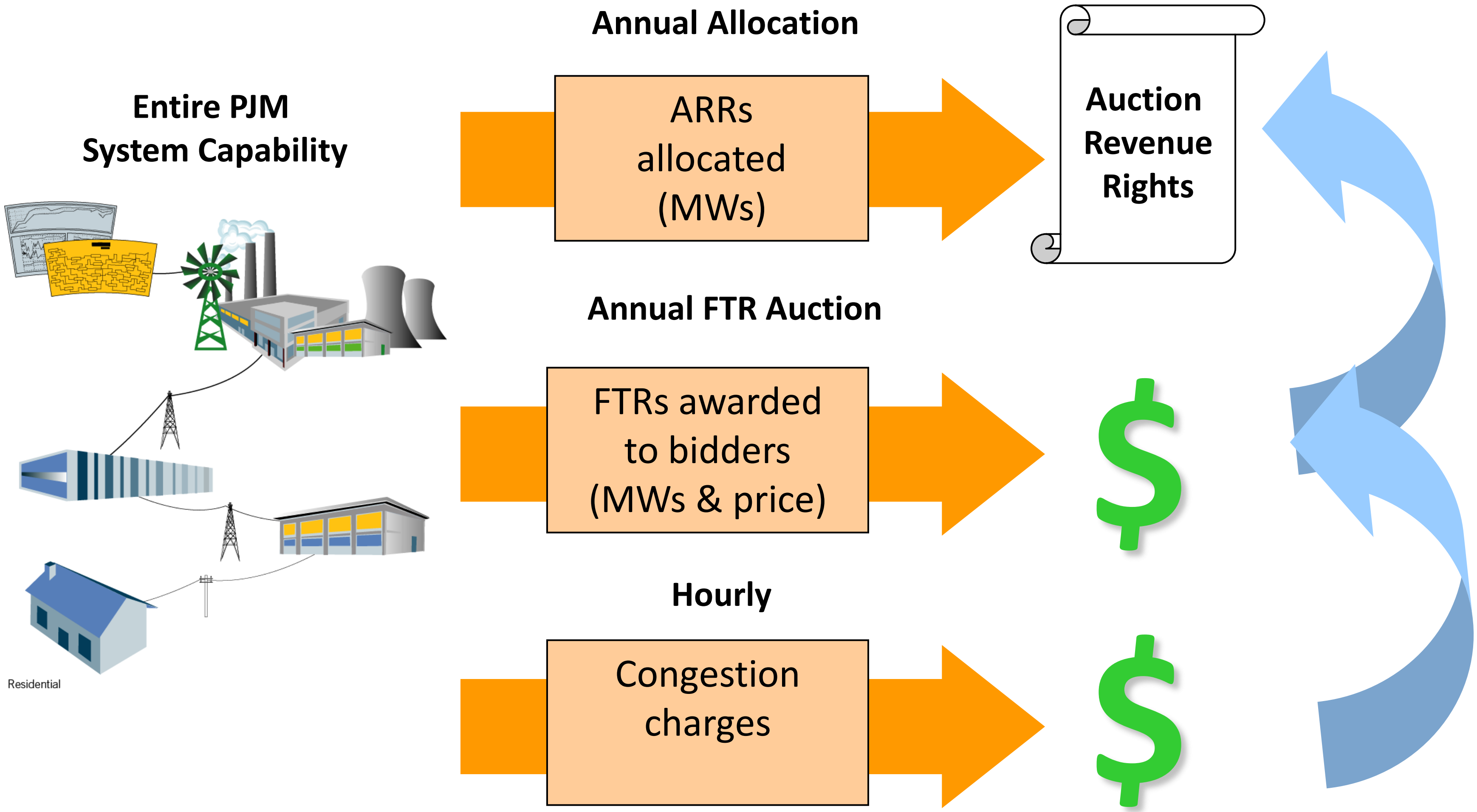
- **Economic value determined by Day ahead hourly LMPs**
- **Benefit (Credit)**
  - Prevailing Flow
- **Liability (Charge)**
  - Counterflow
- **FTR Options available**
  - Never negatively valued

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

ARR / FTR Relationship

ARRs provide a revenue stream to the firm transmission customer to offset purchase price of FTRs



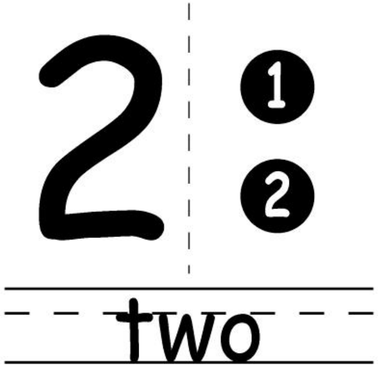
What can the holder do with the FTR?

- "Self-Scheduling" FTR into 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

Two Settlement

What is Two–Settlement?

- It provides PJM Market Participants with the option to participate in a forward market for electric energy in PJM
  - Consists of two markets
  - Separate settlements performed for each market



Two-Settlement Markets

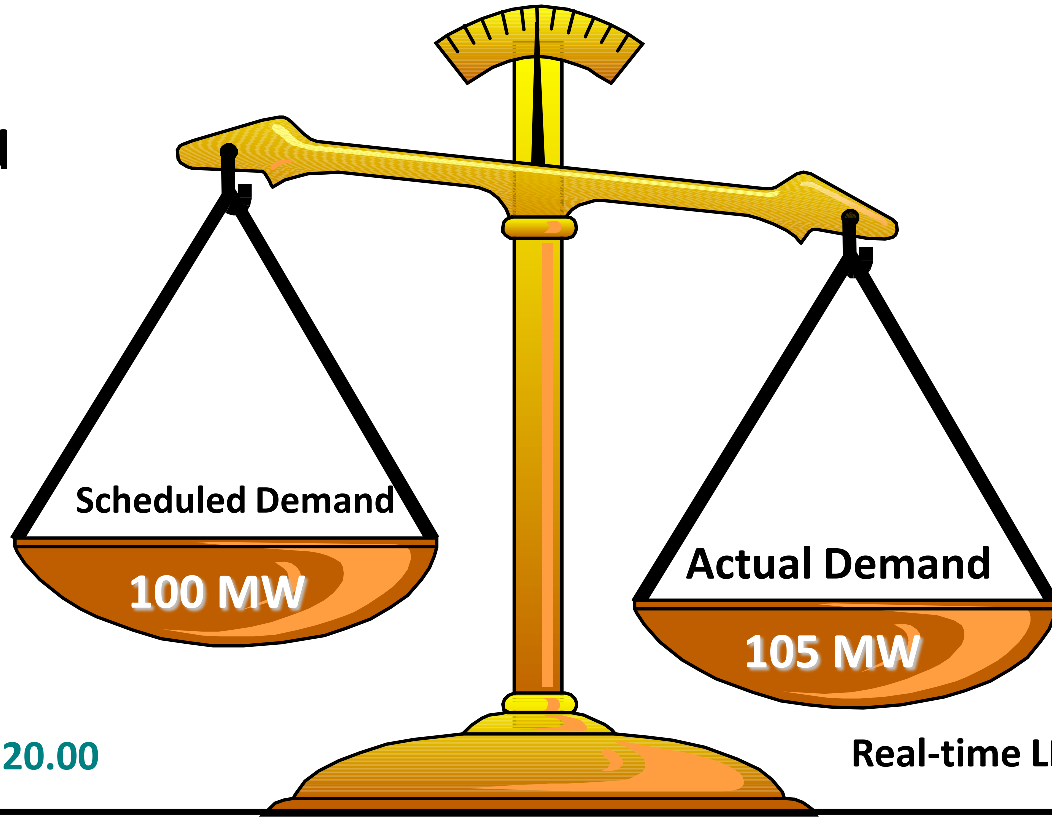
- **Day-ahead Market**
  - Financial market using Bid-In Load
  - Prices calculated hourly / Hourly settlements
  - Includes virtual bids and price sensitive demand

- **Real-time Market**
  - Physical Market based on actual system conditions
  - Prices calculated every 5 minutes
  - Hourly Settlements based on *deviations* from Day-Ahead position

LSE with Day-Ahead Demand Less than Actual Demand

Day Ahead Market

Real-time Market



Day Ahead LMP = $20.00

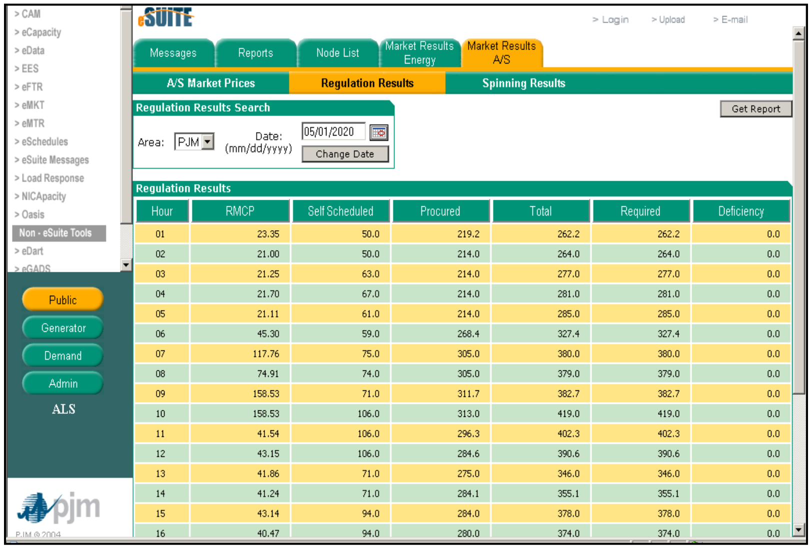
Real-time LMP = $23.00

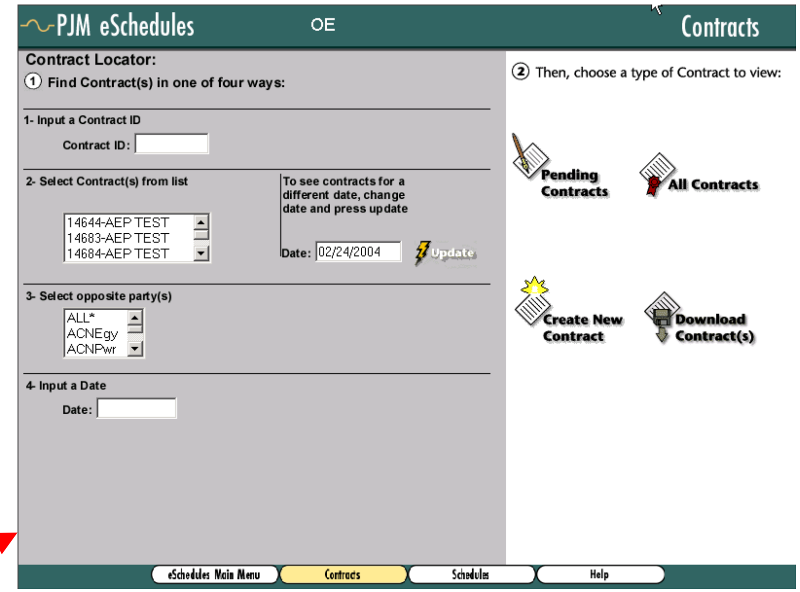
*= 100 * 20.00 = $2000.00*

= (105 - 100) 23.00 = $115.00*

Total Charge = $2000 + $115 = $2115

Two-Settlement User Interface



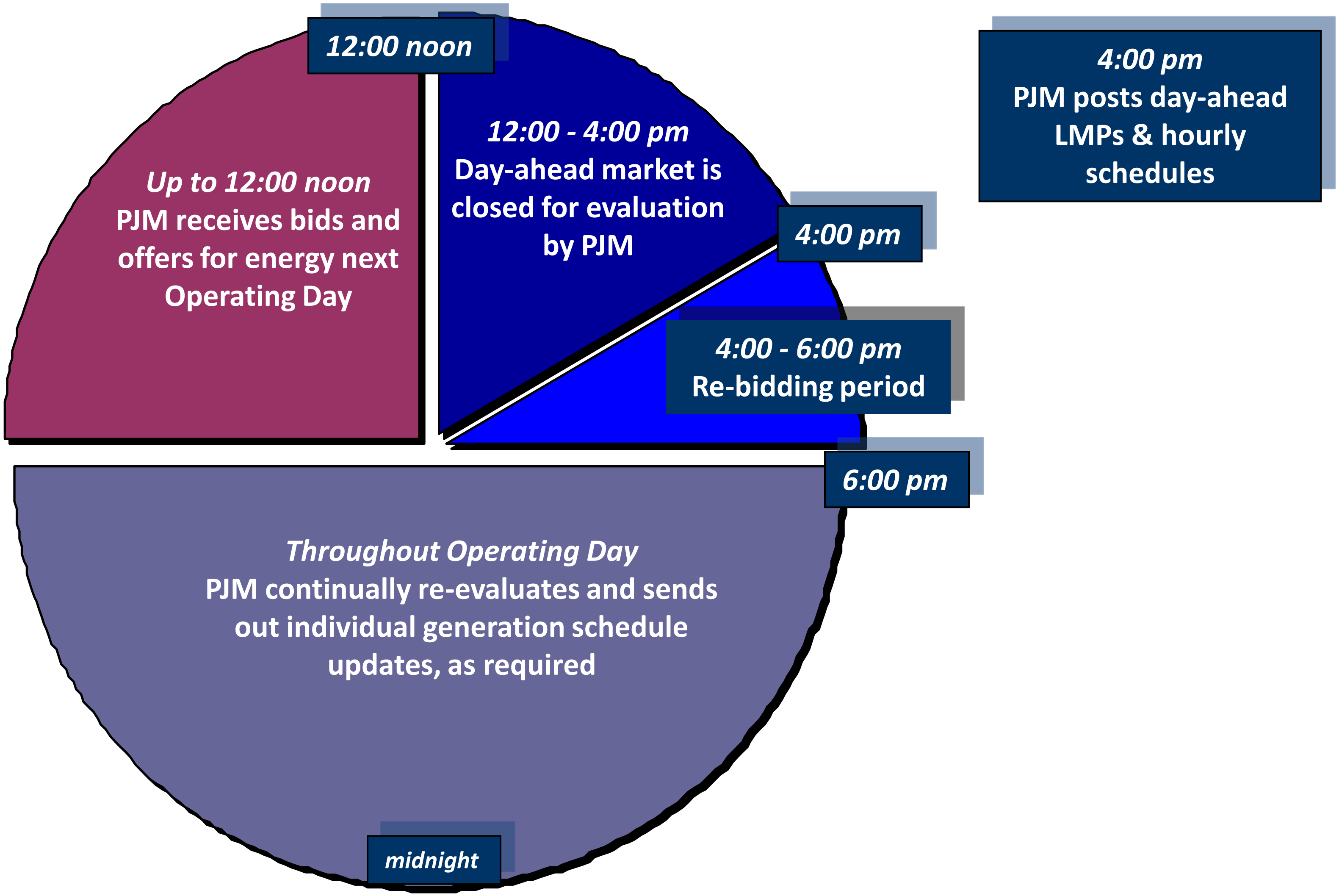


eMKT **-** Unit bids, load bids

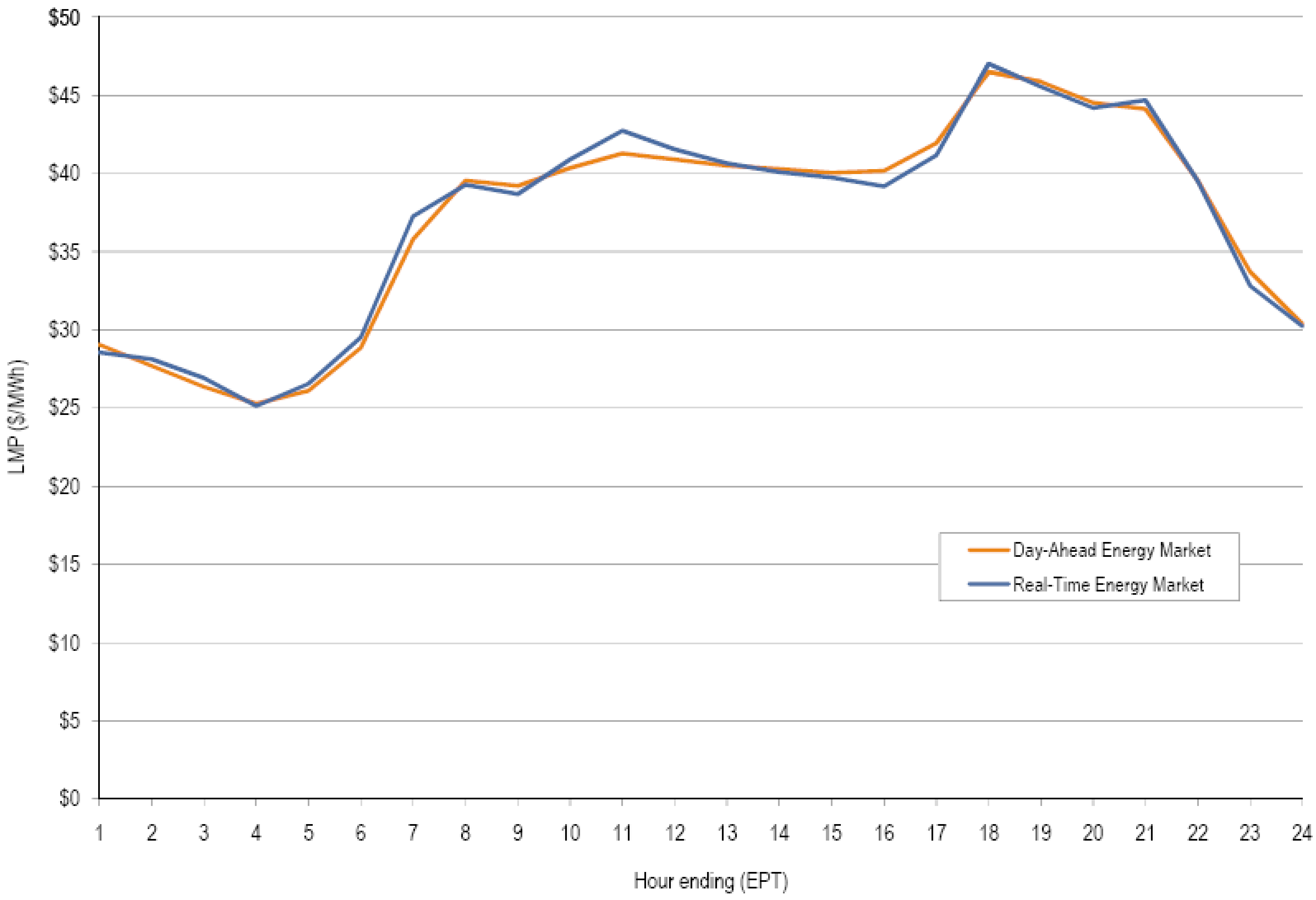
eSchedules- Contracts, Schedules

EES - Physical Schedules

Day-Ahead Market Timeline



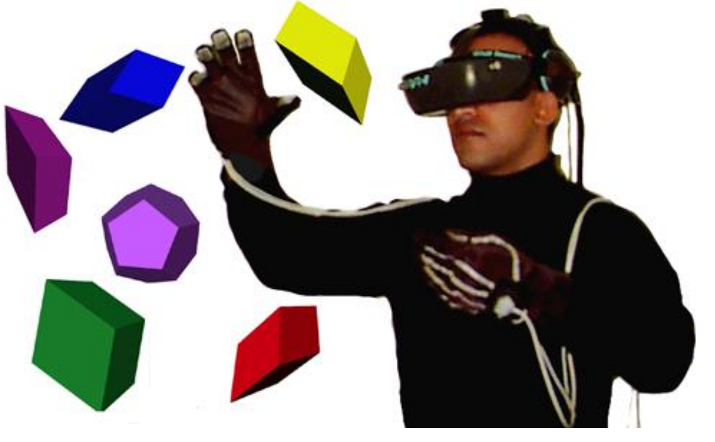
Day-Ahead vs. Real-Time LMP - 2009



Virtual Bids

Virtual Bids

- Financial product existing in the Day-Ahead market only
- Created to foster price convergence between Day-Ahead and Real-Time and add liquidity to markets
- Settlements based on the difference between Day-Ahead and Real-Time prices



INCS	DECS
• Look like a generator (injects MW) • Specifies a price and quantity • *Turns on* when the price gets **high** enough	• Look like a load (withdrawals MW) • Specifies a price and quantity • *Turns on* when the price gets **low** enough

How do virtual bids make money?

INCs

- Sells MW into Day Ahead Market at High Price
- Buys replacement MW from Real-Time Market at Lower Price
- Hopes that Day-Ahead Prices are Higher than Real-Time Prices

DECs

- Buys MW from Day Ahead Market at Low Price
- Sells those MW in Real-Time Market at Higher Price
- Hopes that Day-Ahead Prices are Lower than Real-Time Prices

Ancillary Services

Ancillary Services

- Regulation Market
- Synchronized Reserve Market
- Black Start Service
- Reactive Services
- Scheduling, System Control & Dispatch

Regulation Market

Purpose: To provide for the continuous balancing of generation and load

- Generation and Demand Response resources
- Transmission customer must provide or purchase
- RMCP = Regulation Market Clearing Price
- Regulation Price = Higher of RMCP or offer price plus opportunity cost

Synchronized Reserves Market

Purpose: To bring generation and load back in balance after the loss of generation

- LSE's have obligation to purchase based on Load Ratio Share
  - Bilateral
  - Scheduling owned resources
  - Purchase from Synchronized Reserve Market
- Co-optimized with Regulation Market
- Allows for participation by Demand Side Response resources

Purpose: To provide for the continuous balancing of generation and load

- Transmission Owners, with PJM identify critical Blackstart units
- Generator annual revenue requirements - Cost-based service
- Charges go to Transmission Customers
- Annual Blackstart testing requirements

Reactive Supply & Voltage Control

Purpose: To maintain transmission voltages within acceptable limits.

- FERC approves reactive revenue requirements
- PJM calculates zonal rate
- Paid by transmission customers
- Credits go to generation resources and transmission owners

Scheduling, System Control & Dispatch

Purpose: To provide transmission service and operate the energy market.

- Schedule 9 of PJM Tariff
  - Control Area Administrative Service
  - FTR Administrative Service
  - Market Support Service
  - Regulation Administrative Service
  - Capacity Resource and Obligation Service

Capacity Market
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) = 15.3% satisfies the reliability criterion for the 2013/14 Delivery Year.

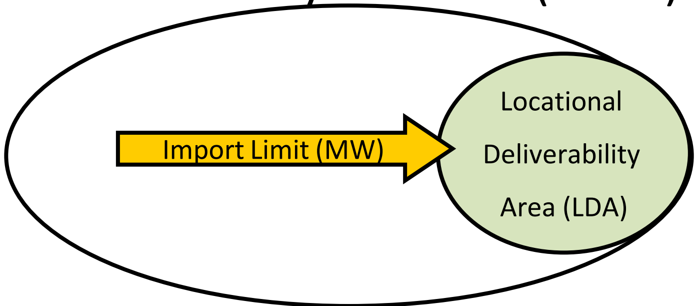
Resource Adequacy ICAP Requirement = Forecast Peak Load * (1+ IRM)

What are Locational Constraints?

- Locational Constraints are capacity **<u>import capability limitations</u>** 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

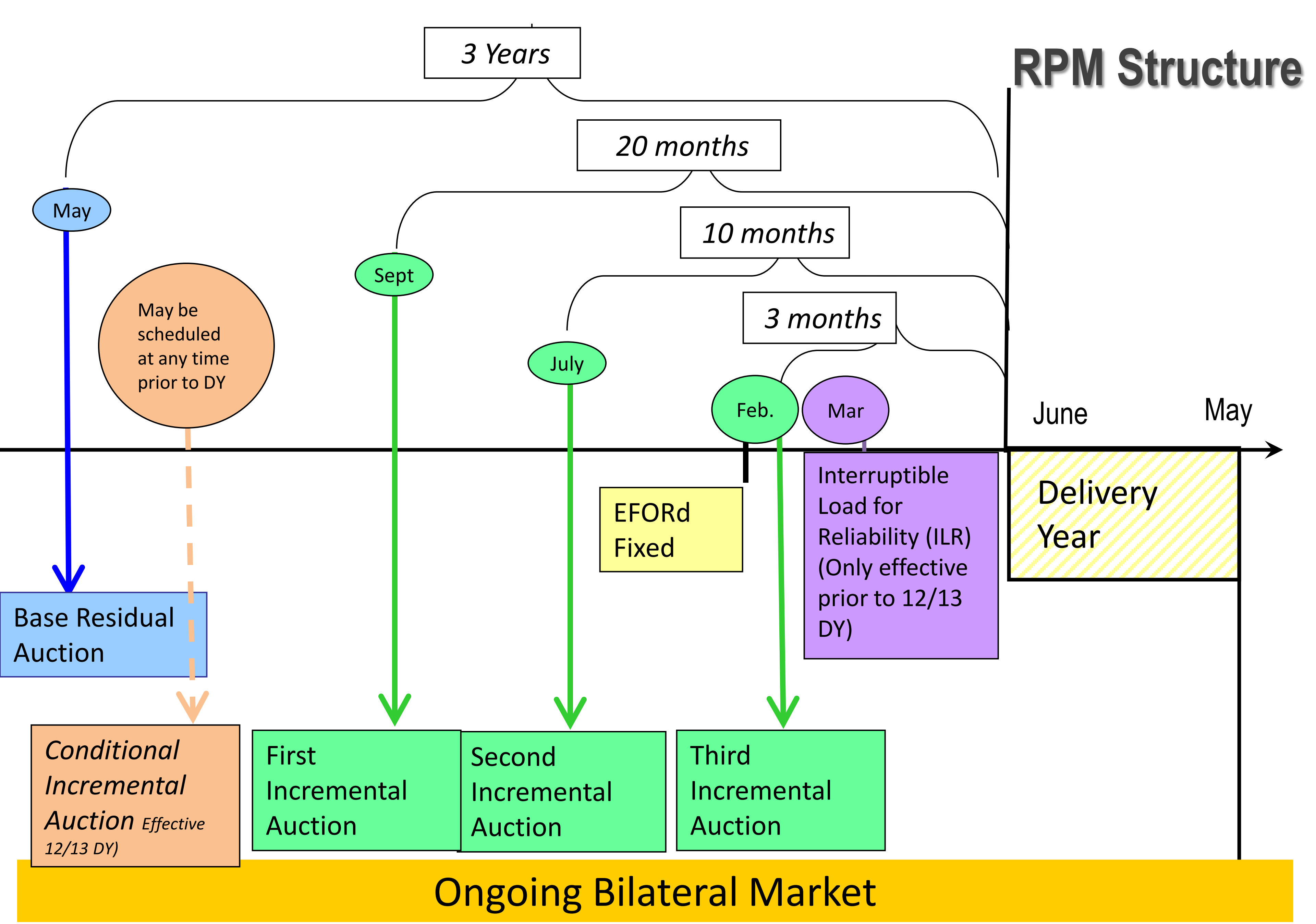
Locational Deliverability Areas

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)

**Includes ATSI effective with 13/14 DY and Duke effective with 14/15 DY.*

PJM required to make a filing with FERC before adding a new LDA.


RPM Structure
3 Years
20 months
10 months
3 months
May
Sept
July
Feb.
Mar
June
May
May be scheduled at any time prior to DY
EFORd Fixed
Interruptible Load for Reliability (ILR) (Only effective prior to 12/13 DY)
Delivery Year
Base Residual Auction
Conditional Incremental Auction Effective 12/13 DY)
First Incremental Auction
Second Incremental Auction
Third Incremental Auction
Ongoing Bilateral Market

RPM Auctions (Starting with 12/13 DY)

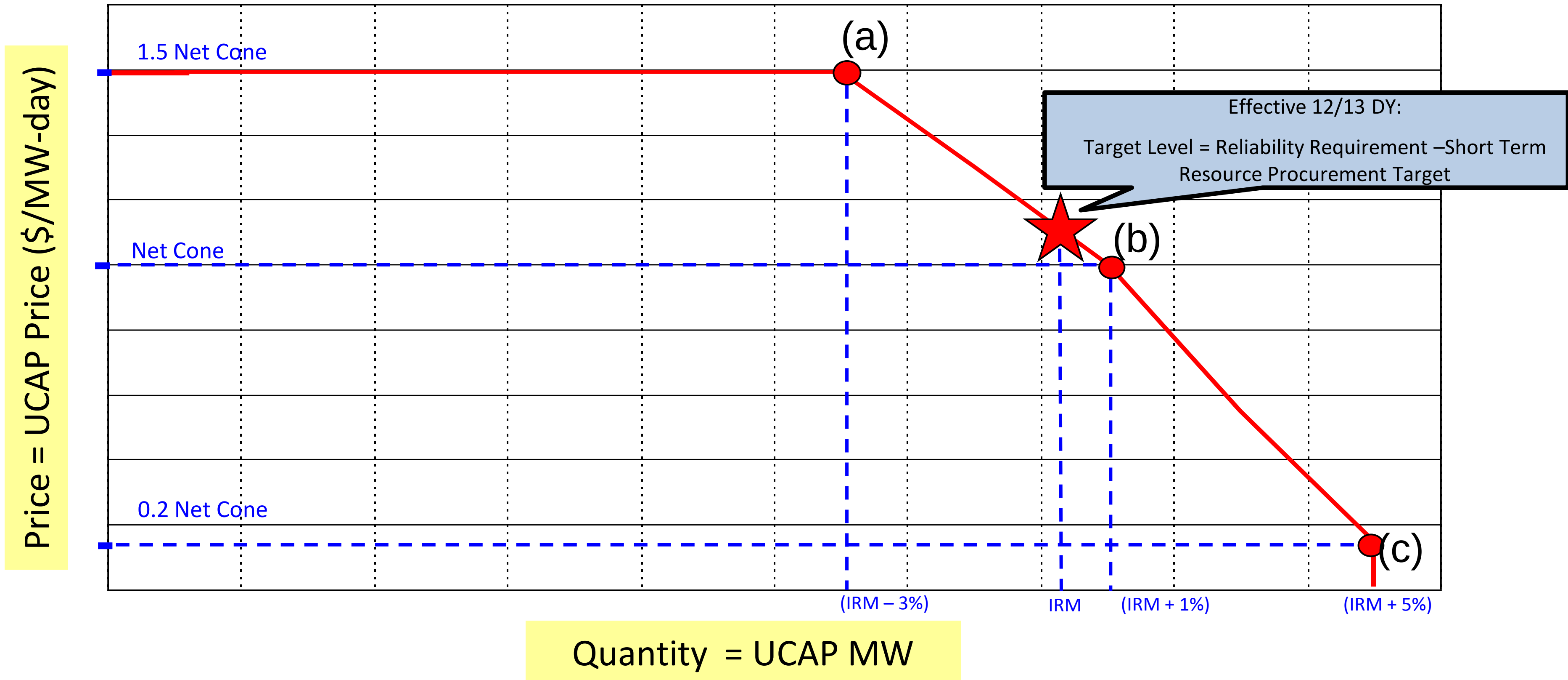
Activity	Purpose	Cost of Procurement
Base Residual Auction	Procurement of RTO Obligation less an amount reserved for short lead time resources, less FRR Obligation	Allocated to LSEs through Locational Reliability Charge
1st Incremental Auction	Allows for: (1) replacement resource procurement (2) increases 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
Interruptible Load for Reliability (ILR)	ILR Option eliminated starting with 12/13 DY	

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.

What is a Supply Resource in RPM?

In RPM, **<u>Resources</u>** are =

Generation Resources

Demand Resources

(DR)

Energy Efficiency Resources

(EE)

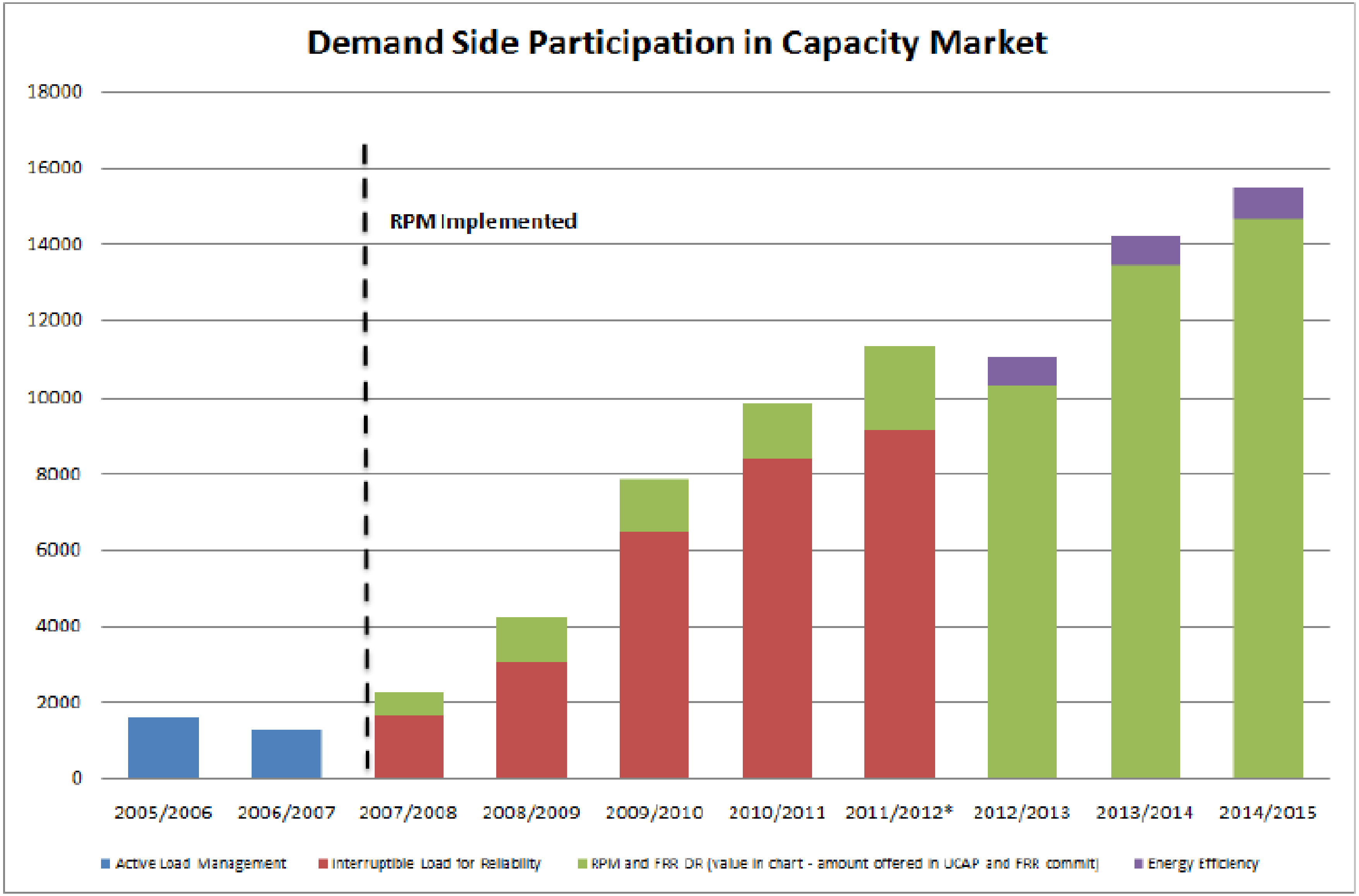
(Effective with 11/12 DY)

Qualifying Transmission Upgrades

(QTU)

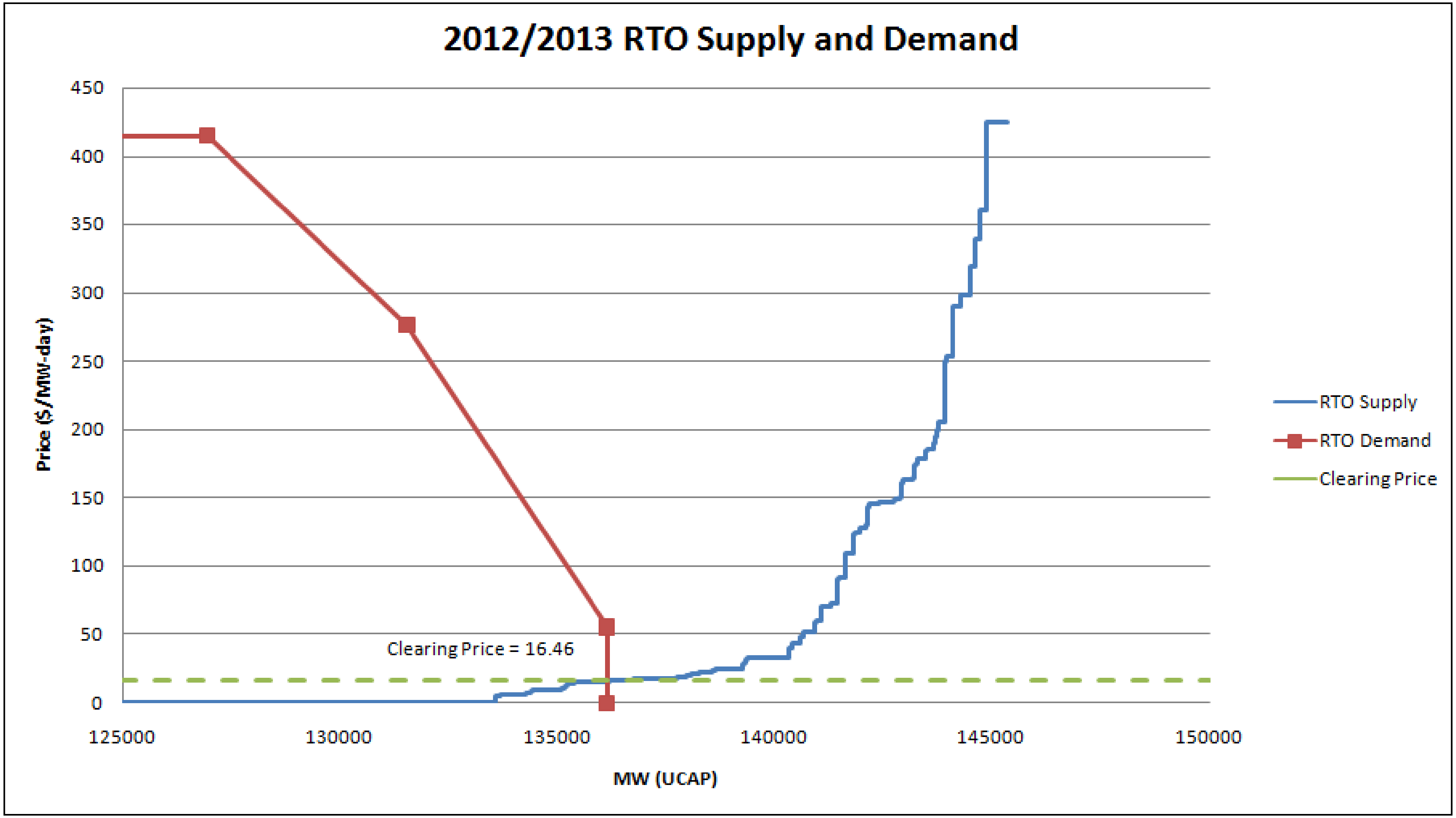
Interruptible Load for Reliability Resources (ILR)

(Prior to 12/13 DY)



Source: PJM 2014/15 Base Residual Auction Report

Clearing 2012/2013 Base Residual Auction



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