PJM Overview and Wholesale Power Markets

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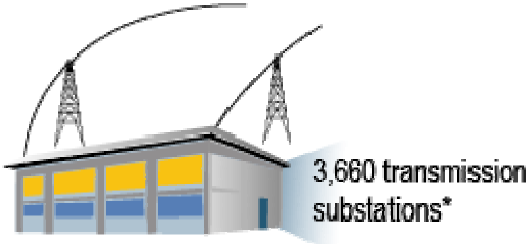
PJM Member Relations

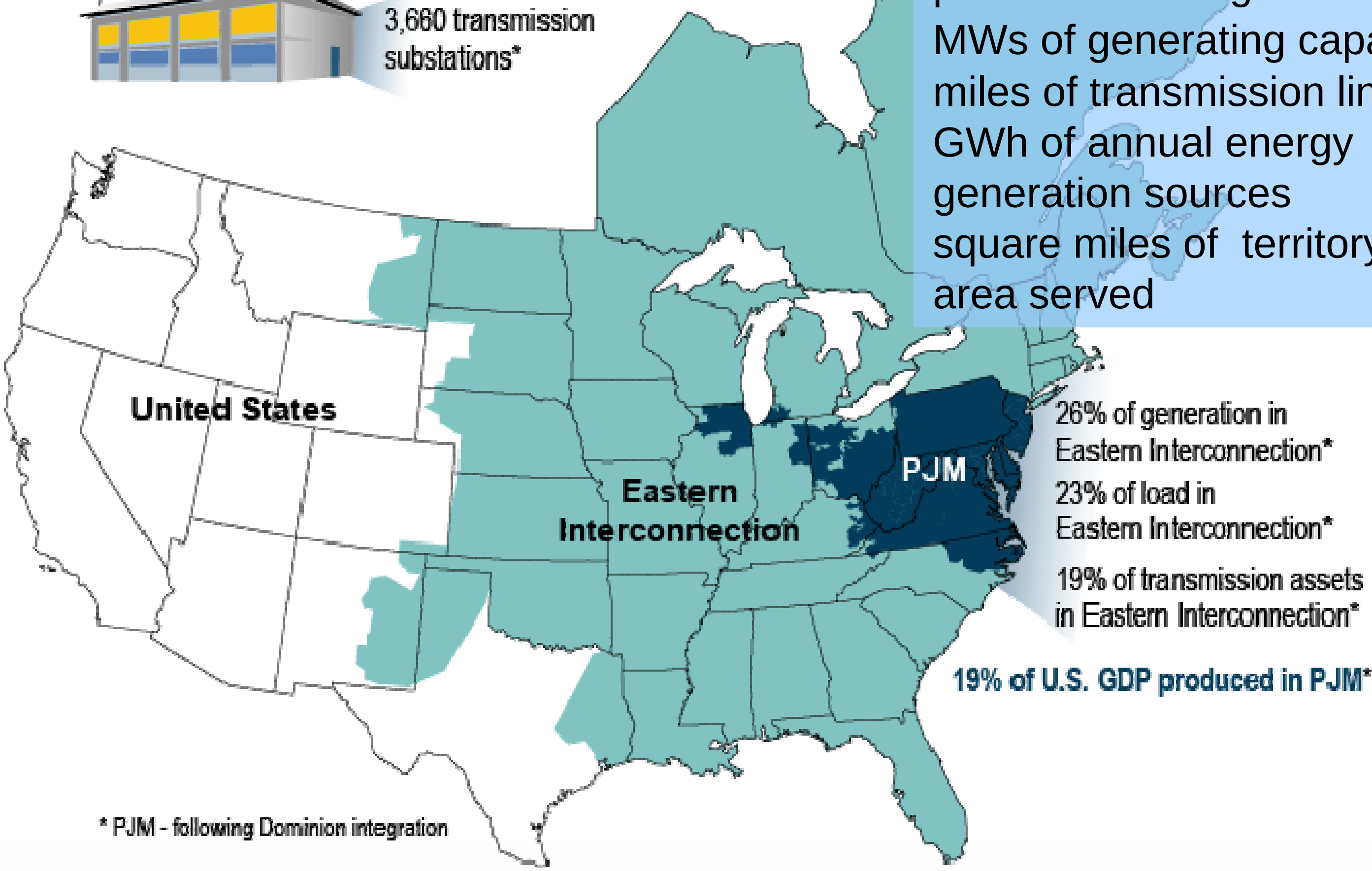
PJM's Role

- *Ensures the reliability of the high-voltage electric power system*
- *Coordinates and directs the operation of the region's transmission grid;*
- *Administers a competitive wholesale electricity market, the world's largest;*
- *Plans regional transmission expansion improvements to maintain grid reliability and relieve congestion.*

PJM as Part of the Eastern Interconnection

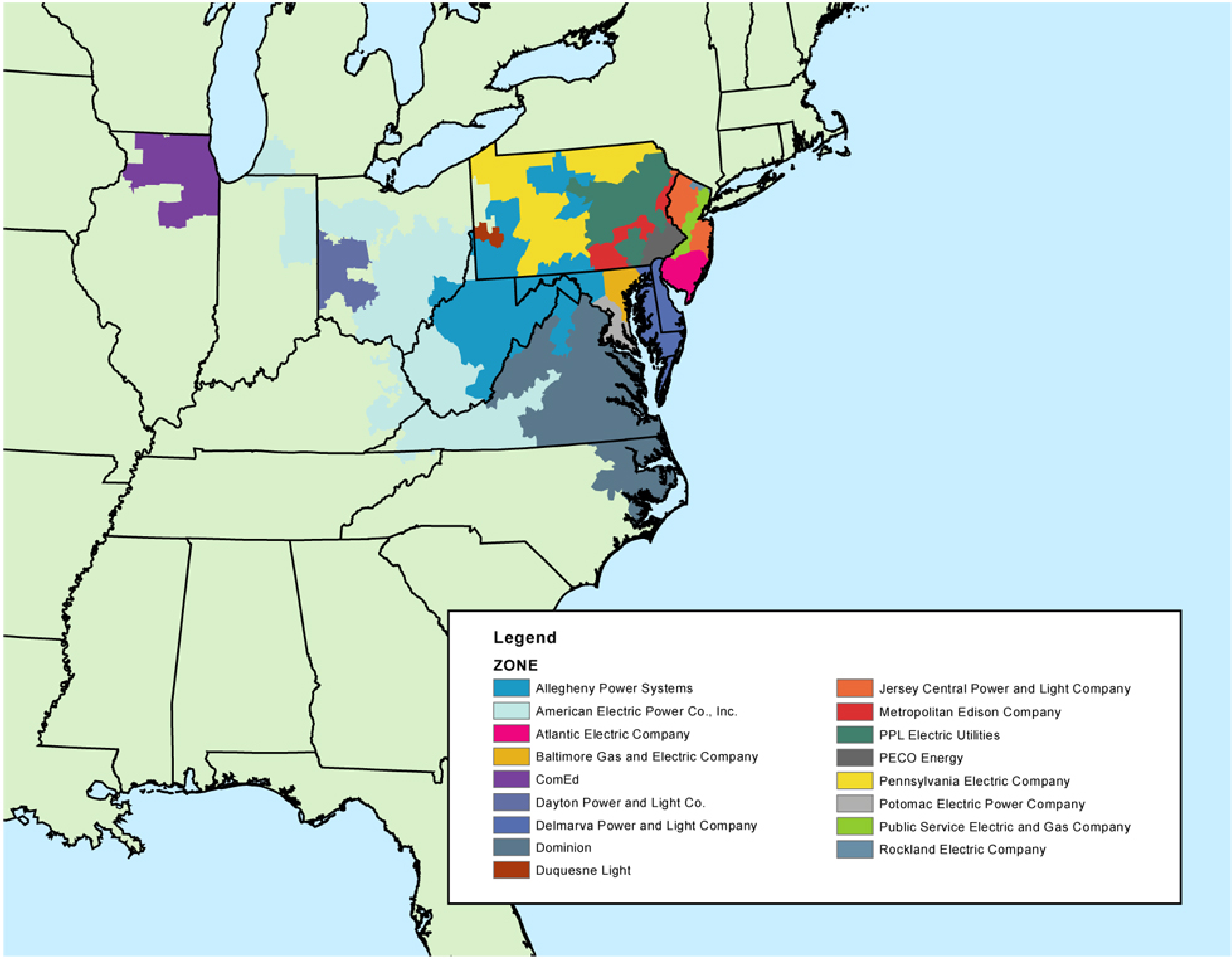
KEY STATISTICS	
PJM member companies	390+
millions of people served	51
peak load in megawatts	135,000
MWs of generating capacity	163,806
miles of transmission lines	56,070
GWh of annual energy	700,000
generation sources	1,200
square miles of territory	164,260
area served	13 states + DC





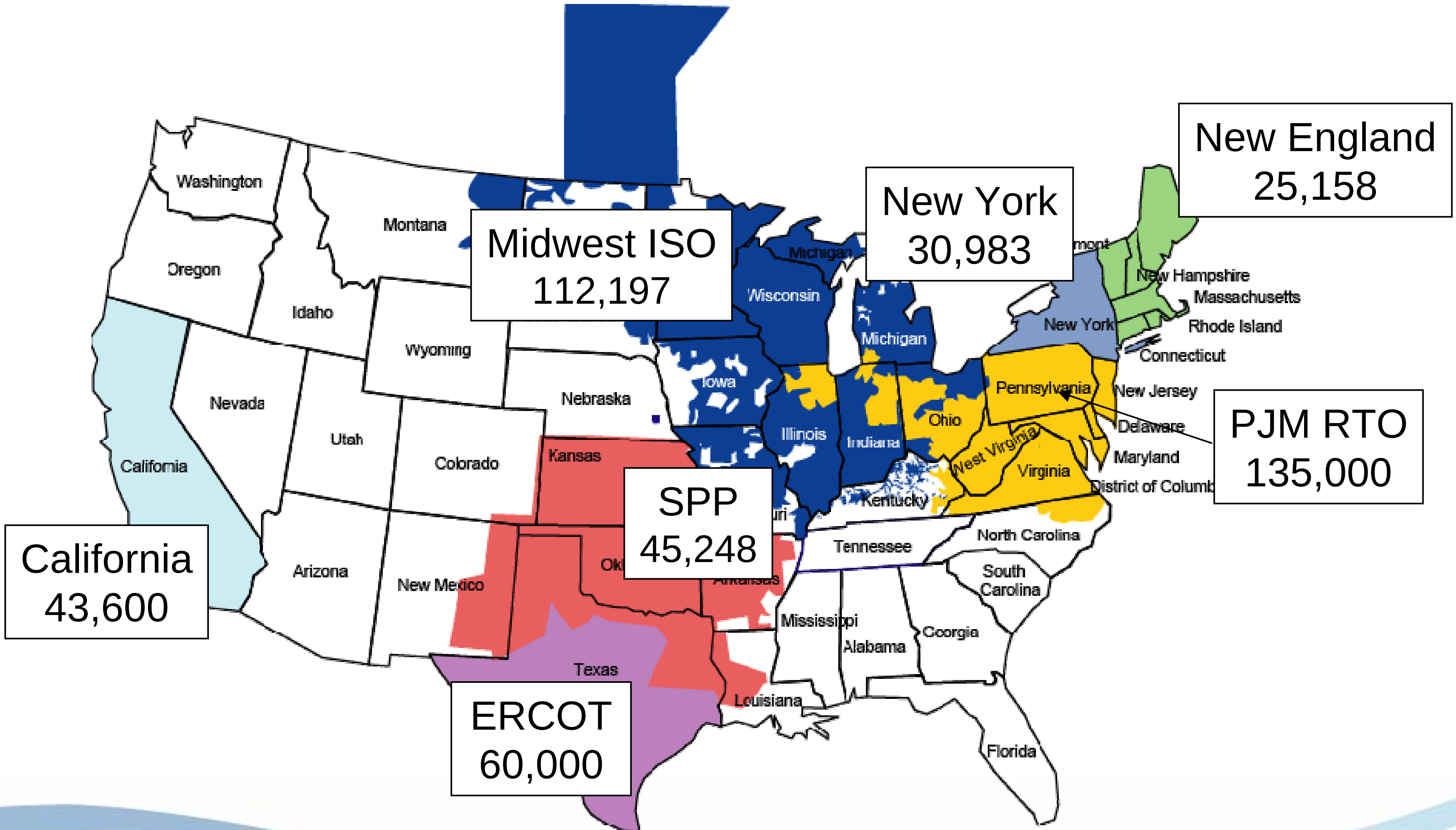
* PJM - following Dominion integration

PJM Transmission Zones

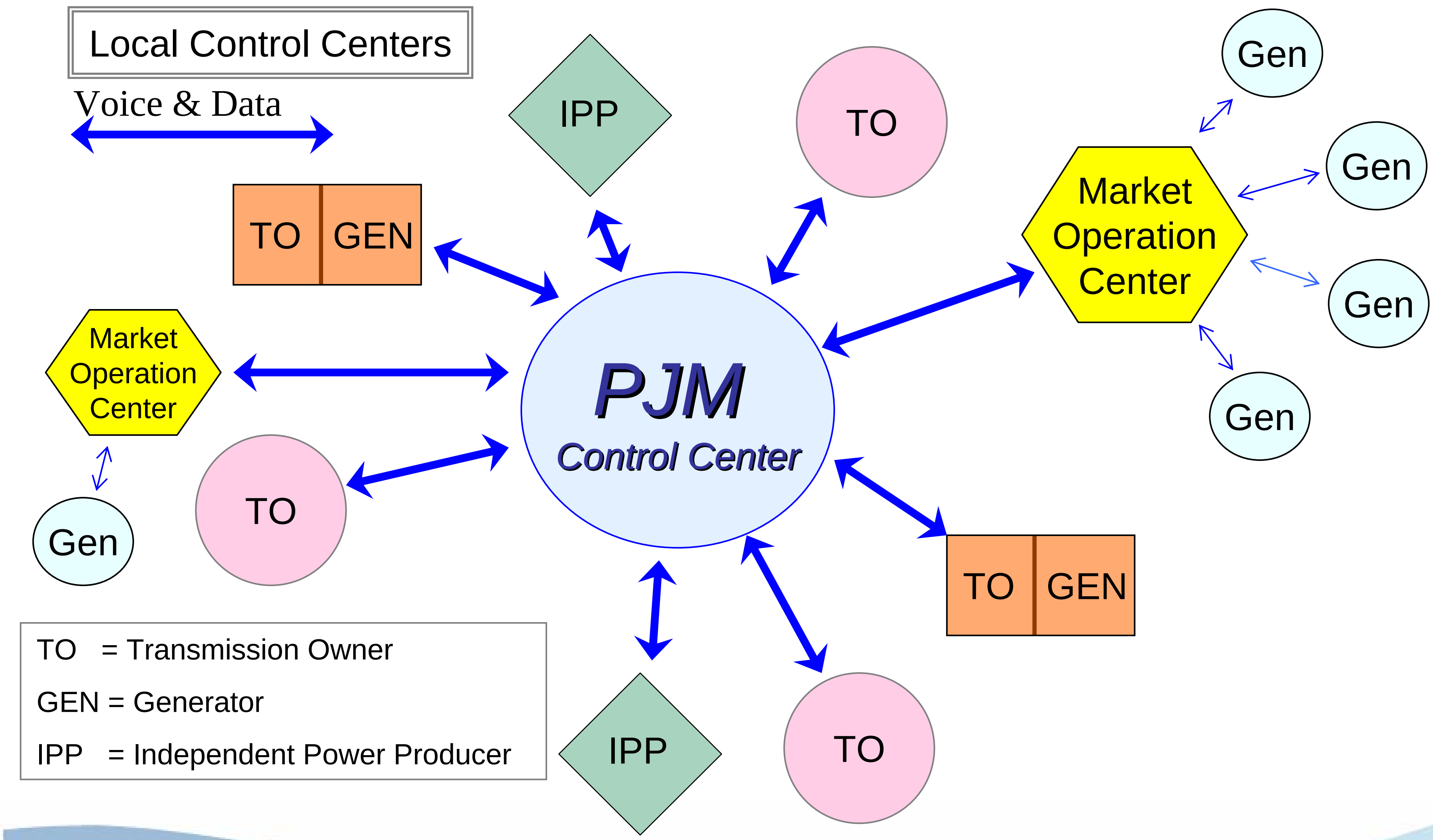


RTO/ISOs

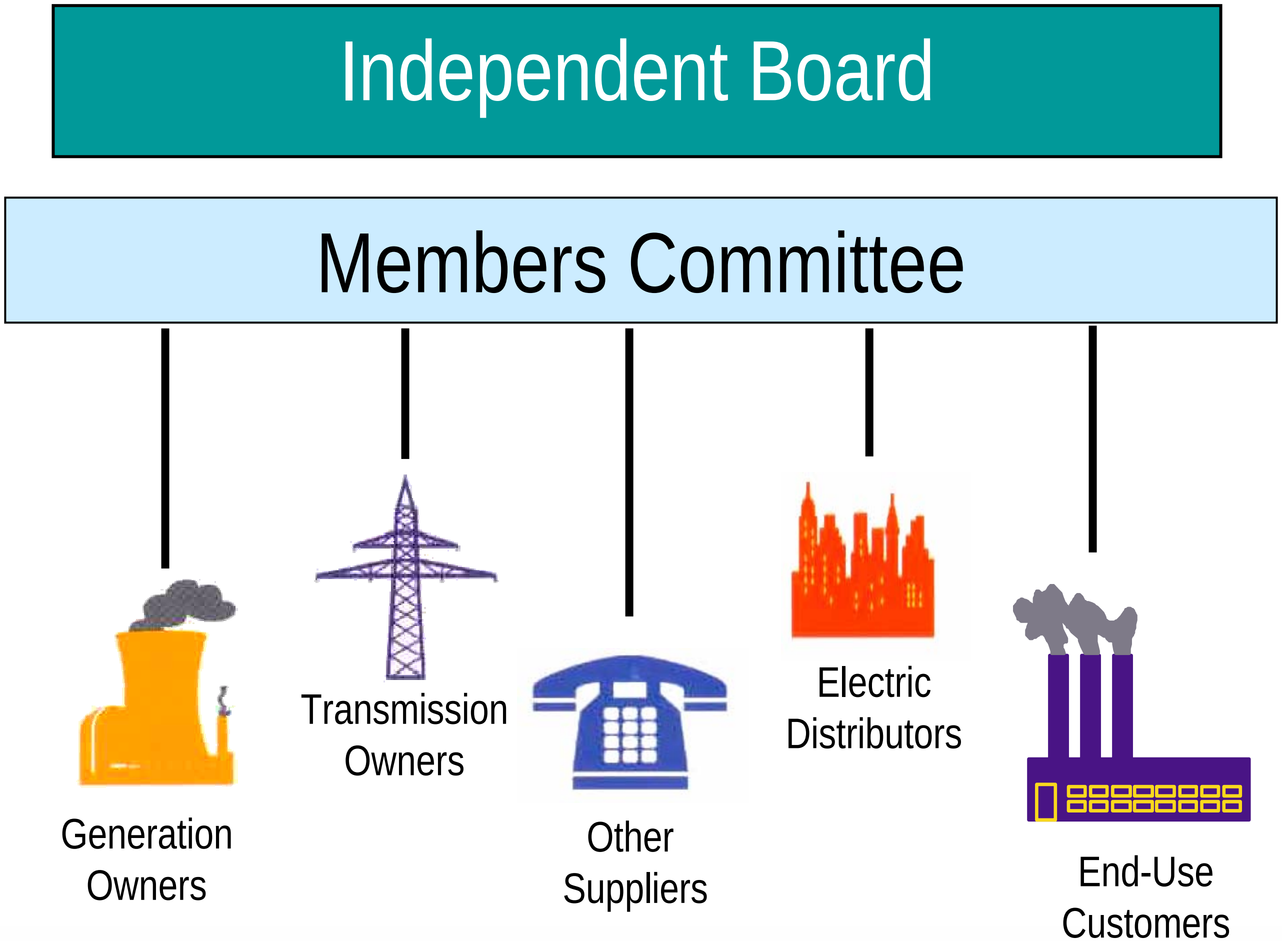
PJM is the largest centrally dispatched entity in the world



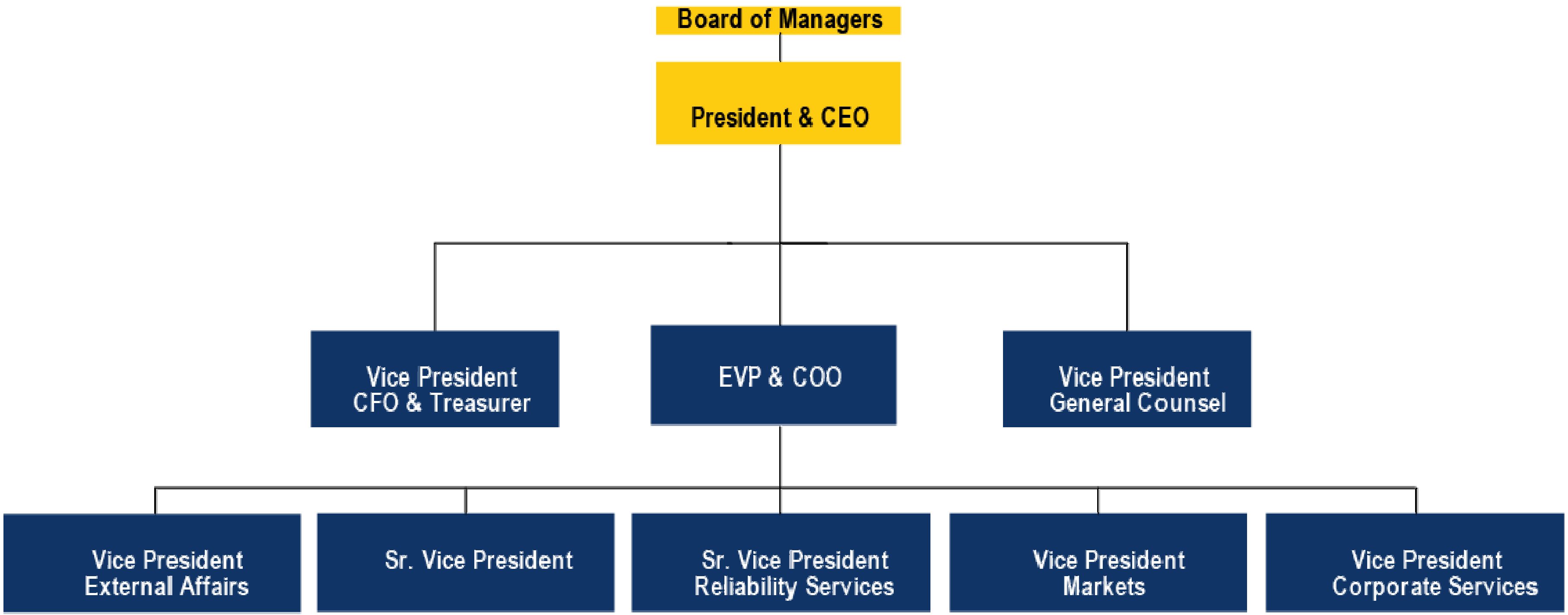
Communication of Information - Giving Direction



PJM Governance



PJM Organizational Chart

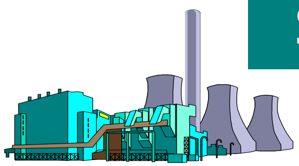


Market Design Details

- Futures
  - i.e. NYMEX PJM West Hub Contract
- Forward Market
  - Energy Brokers
  - RTO Day-ahead Energy Market
- Real-time Balancing Market
  - RTO Security–constrained economic dispatch
- Additional hedging alternatives
  - Financial Transmission Rights
  - Financial Bilateral Contracts

PJM Member Options in Time for Energy Supply

Forward Contracts



Self-scheduled own resources

Bilateral Transactions

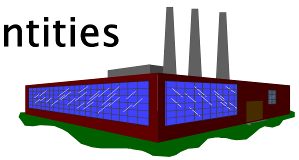
PJM Day Ahead Market

PJM Real-Time Energy Market

Retail Load Profile True-up

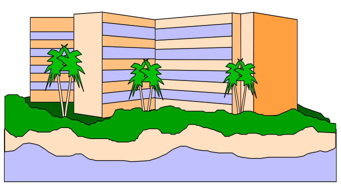
Customers

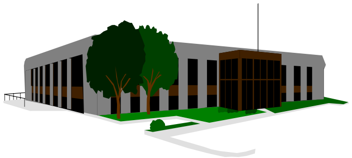
Industrial Load Serving Entities



Residential **LSEs**

Commercial LSEs





Other Buyers, Load Aggregators

Different Types of Markets in Wholesale Electricity

- Generation Capacity Markets
  - Daily
  - Long-Term
- Energy Markets
  - Forward (i.e. Day-Ahead)
  - Real Time
- Financial Transmission Rights Market
- Ancillary Services Markets
  - Regulation
  - Spinning Reserve

- Economic theory indicates no need for separate market for generation capacity.
- Energy supply and demand dynamic will encourage investment, but will also result in price volatility.
- The view of electricity as a necessity by stakeholders coupled with the lack of storage capability pushes regulators to require mechanism to ensure long term adequacy of supply.

What is the Day-Ahead Energy Market?

- A day-ahead hourly forward market for energy
- It provides the option to ‘lock in’:
  - scheduled MW quantities at day-ahead prices
  - scheduled energy deliveries at day-ahead congestion prices
- Provides additional price certainty to Market Participants by allowing them to commit to prices in advance of real-time dispatch

- Day-Ahead Energy Market
  - – develop day-ahead schedule using least-cost security constrained unit commitment and dispatch
  - – calculate hourly LMPs for next operating day using generation offers, demand bids and bilateral transaction schedules
- Real-Time Energy Market
  - – calculate hourly LMPs based on actual system operating conditions

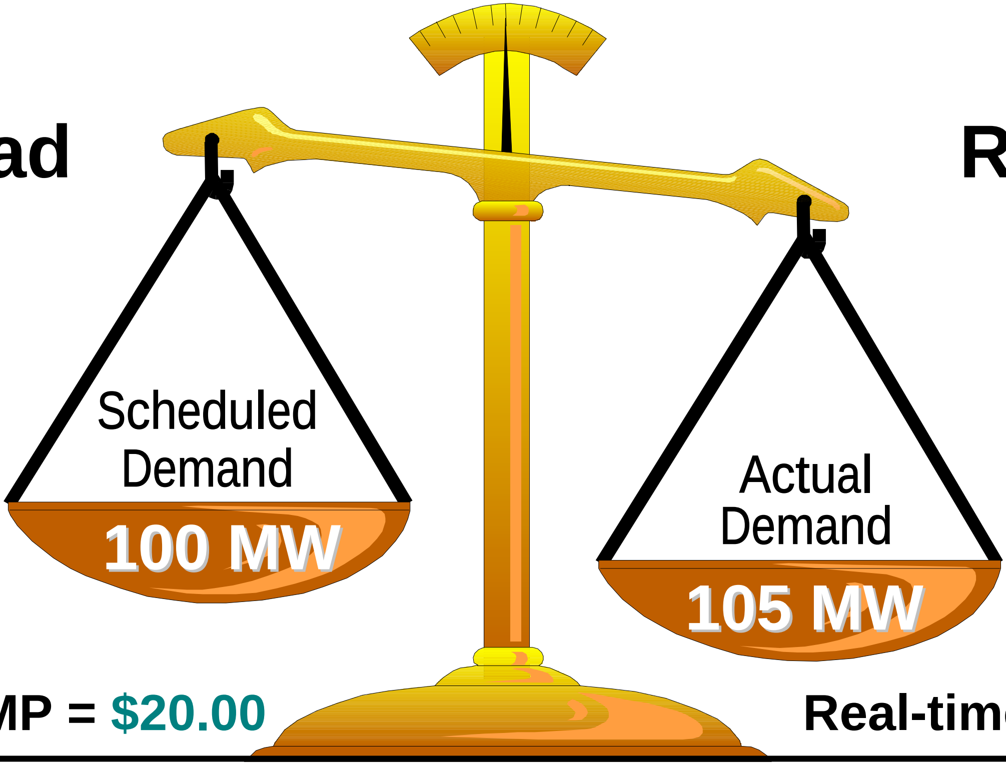
Two Energy Market Settlements

- Day-Ahead Market Settlement
  - based on scheduled hourly MW quantities and day-ahead LMPs
- Balancing Market Settlement
  - based on hourly MW quantity deviations between real-time and day-ahead
  - MW quantity deviations settled at real-time LMPs

Liquidating Day-Ahead Position

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

if Day-ahead Demand is 105MW = $2100.00

as bid = $2115.00

- Objective is to develop a set of financial schedules that are physically feasible
  - full transmission system model
  - unit commitment constraints
  - reserve requirement model
- Day-Ahead Market results based on participant demand bids and supply offers
  - PJM facilitates market but does not drive results

- Generation Resources
  - submit offers (required for designate resources)
  - can self-schedule
- Demand
  - submit quantity, price and location
- External Transactions
  - submit schedules into day-ahead market
- Financial
  - virtual supply offers and demand bids

- Fixed Quantity
  - hourly MW demand quantities
  - location (transmission zone or aggregate)
- Price Sensitive
  - hourly MW demand quantities
  - location (transmission zone or aggregate)
  - price at which demand is curtailed rather than pay clearing price
- Load Response

- Into, out of or thru Market
- Fixed hourly MW quantity
- Dispatchable (price-based)
  - into market (looks like dispatchable resource)
  - out of market (looks like price-sensitive demand)
- May specify maximum amount of congestion willing to pay
  - can act as an hourly ‘FTR equivalent’ in real-time market

- Virtual supply offers and demand bids
  - offer/bid to sell/buy block of energy at a price
  - do not require physical generation or load
  - submitted at any location for which PJM calculates an LMP
- Virtual supply offer looks like a spot sale or dispatchable resource
- Virtual demand bid looks like a spot purchase or price-sensitive demand

Real-time Spot Market

- Voluntary Bid Based Market
  - Unit Specific (start-up, no-load and energy bids)
  - External Transactions: Unit specific or Slice of System (energy only)
  - generation may offer or self-schedule
  - Bids “locked in” by noon day before with rebid period for generation not selected day-ahead
- Generation status and self-scheduled quantities can change in-day with 20 minute notice
- Voluntary nature of spot market is a critical design feature to provide maximum number of options for participant

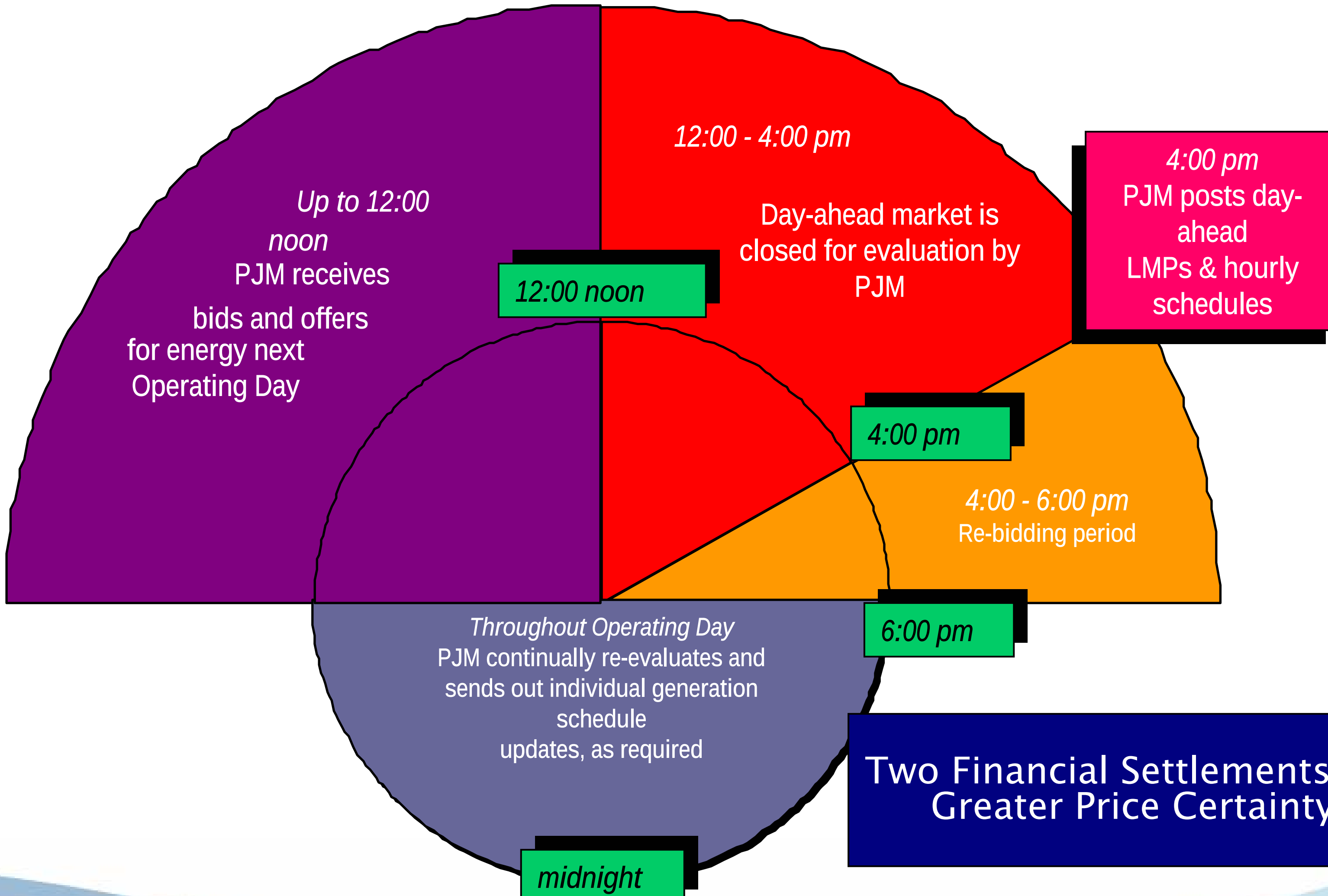
- Least-cost security-constrained dispatch optimizes energy and reserves and calculates unit specific dispatch instructions for the next five-minute period. (ex-ante dispatch)
- LMP values calculated every five minutes based on actual generation response to dispatch instructions that were sent in the previous five minute period (ex-post pricing)
- Real-time performance monitoring software determines if generator is following dispatch instructions.

- LMP pricing, pricing based on actual system operating conditions
- State estimator updated continuously (every minute)
- Same model for day-ahead market, system scheduling, dispatch, and settlements
- High degree of consistency between generator LMP values and dispatch instructions
- Consistency results in market confidence

- Regulation - a service that generators offer to provide fine tuning that is necessary for effective system frequency control requirement
- Spinning Reserve – quick response service that generators provides support when other generators trip.

- Simultaneous procurement of energy and ancillary services
- Product Substitution effects
- Ancillary Service prices should include opportunity costs
- Demand side for Ancillary services is obligation for LSEs

PJM Market Timeline



Two Financial Settlements = Greater Price Certainty

LMP and FTRs

- Locational Marginal Pricing (LMP)
  - LMP is not a new concept to power system operators, For many years, system operators have managed congestion using least-cost security constrained dispatch which is the same program that calculates LMP values
  - An LMP-based market provides an open, transparent and non-discriminatory mechanism to manage transmission congestion under open transmission access

- Pricing method based on actual grid conditions … used to:
  - – price energy purchases and sales in the energy market
  - – prices transmission congestion costs to move energy within the markets
- Physical, flow-based pricing system
  - – how energy actually flows,
  - – NOT contract paths

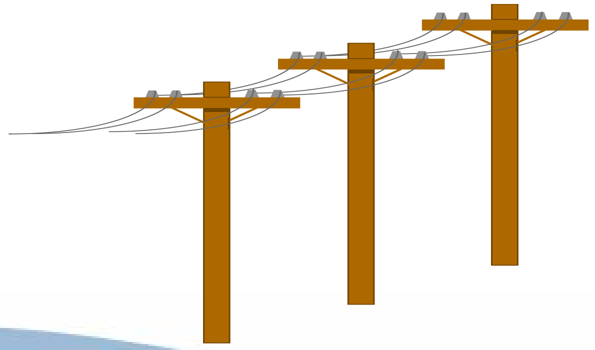
Definition:
Locational Marginal Pricing

Cost of supplying next MW of load at a specific location , considering generation marginal cost, cost of transmission congestion, and losses.

LMP = Generation Marginal Cost + Transmission Congestion Cost + Cost of Marginal Losses

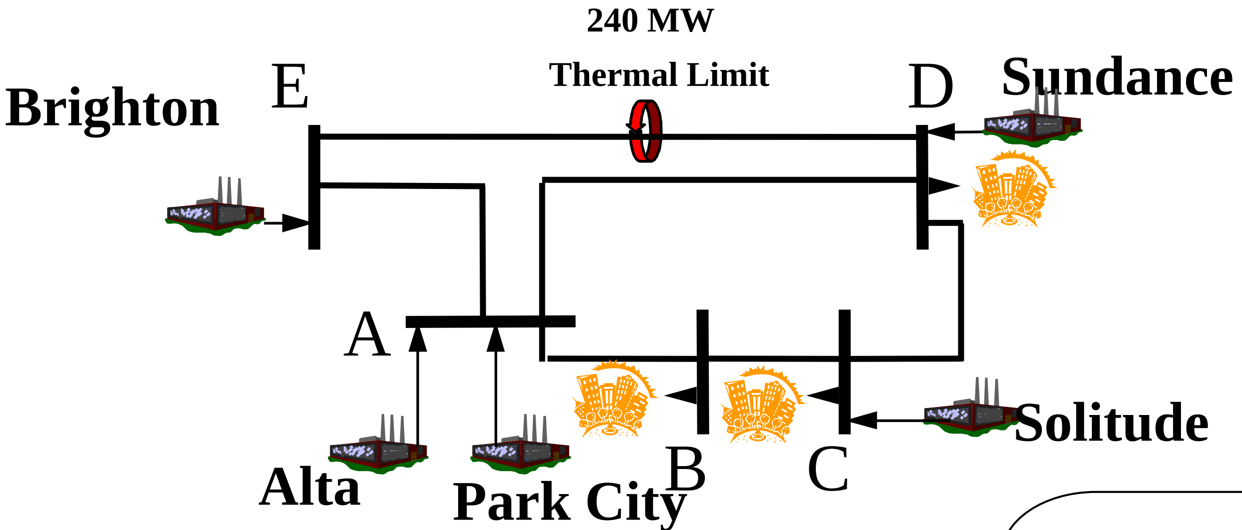
Cost of Marginal Losses = Not currently implemented in PJM

- Transmission system congestion occurs when available, low cost supply cannot be delivered to the demand location due to transmission limitations
- As Market Participants compete to utilize the scarce transmission resource, the RTO needs an efficient, non-discriminatory mechanism to deal with the congestion problem



Thermal Limits
Voltage Limits
Stability Limits

Control Actions



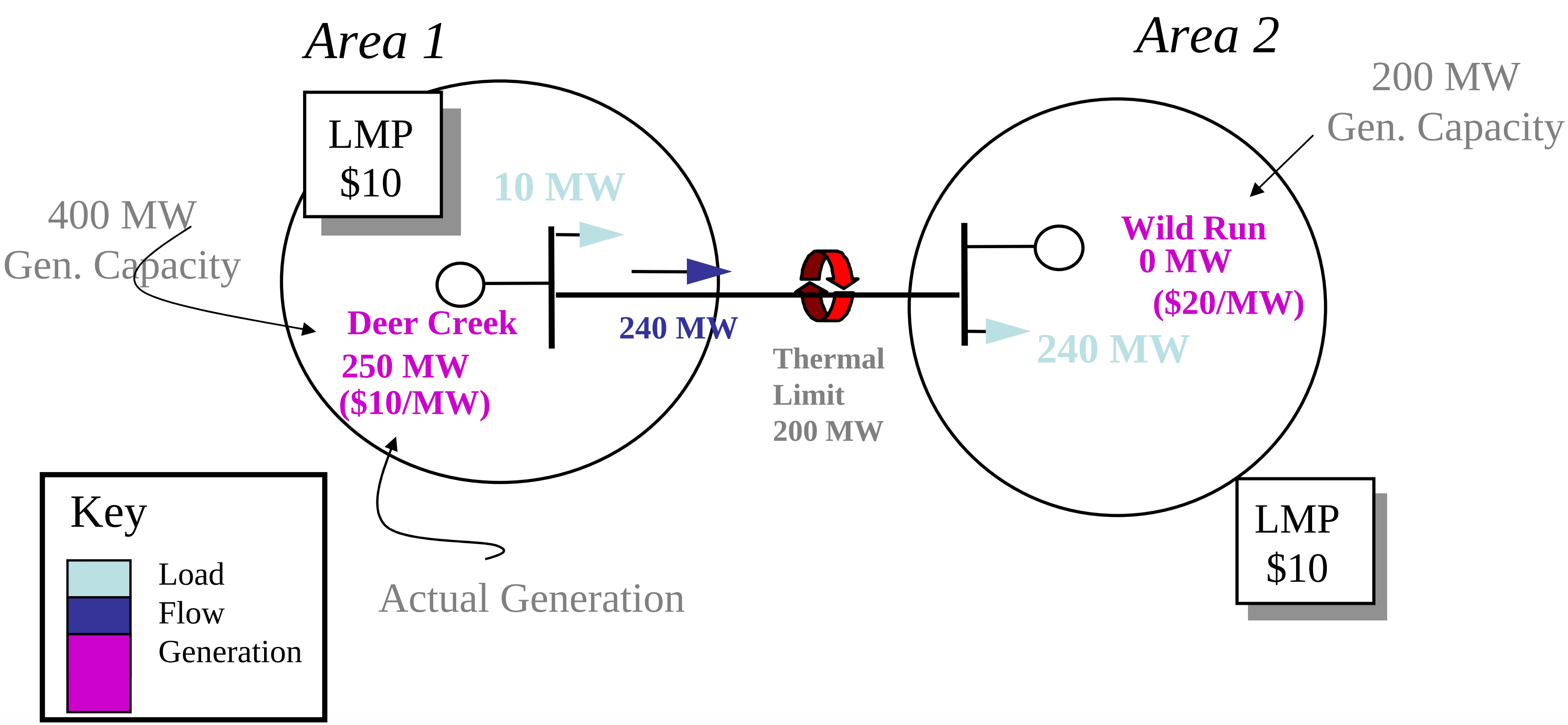
System Reconfiguration

Transaction Curtailments

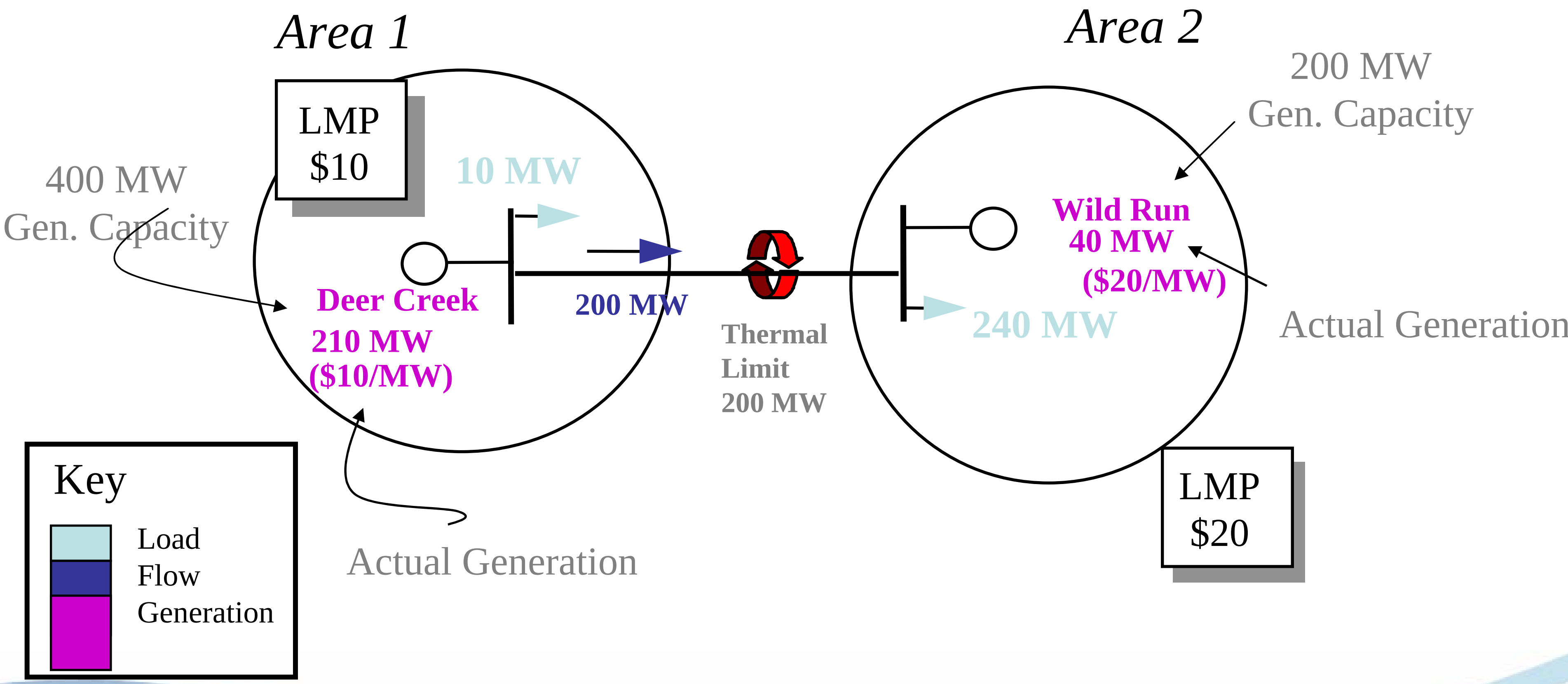
Re-dispatch Generation

- The following examples demonstrate how LMP values are determined at all locations
- The LMP values are a result of security-constrained economic dispatch actions
- LMP values are calculated based on generation offer data and the power flow characteristics of the Transmission system.

Economic Dispatch Ignoring Transmission Limitation



Security-Constrained Economic Dispatch



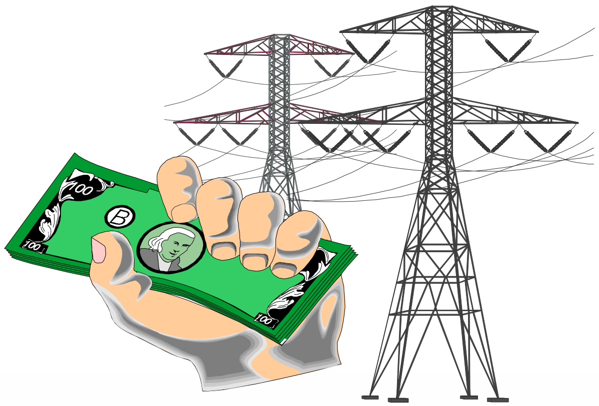
LMP Example - Wholesale Market Settlements

Customer	MW	LMP	Energy[1] Settlement	Congestion Credit
Area 1 Demand	10	$10	$100	-
Area 2 Demand	240	$20	$4800	$2000[2]
Deer Creek	210	$10	($2100)	-
Wild Run	40	$20	($800)	-
Totals	0		$2000	$2000

1. **Positive indicates charge, negative indicates credit**
2. **Congestion Credit is due to ownership of 200 MW Financial Transmission Right from Area 1 to Area 2, FTR Settlement = 200 MW ($20 - $10)**

Financial Transmission Rights are …

a financial contract that entitles holder to a stream of revenues (or charges) based on the hourly energy price differences across the path



- To protect firm transmission customers from increased cost due to transmission congestion, when energy deliveries are consistent firm reservations*
- To facilitate a forward energy market by providing a mechanism to manage basis risk caused by LMP differences during periods of transmission congestion

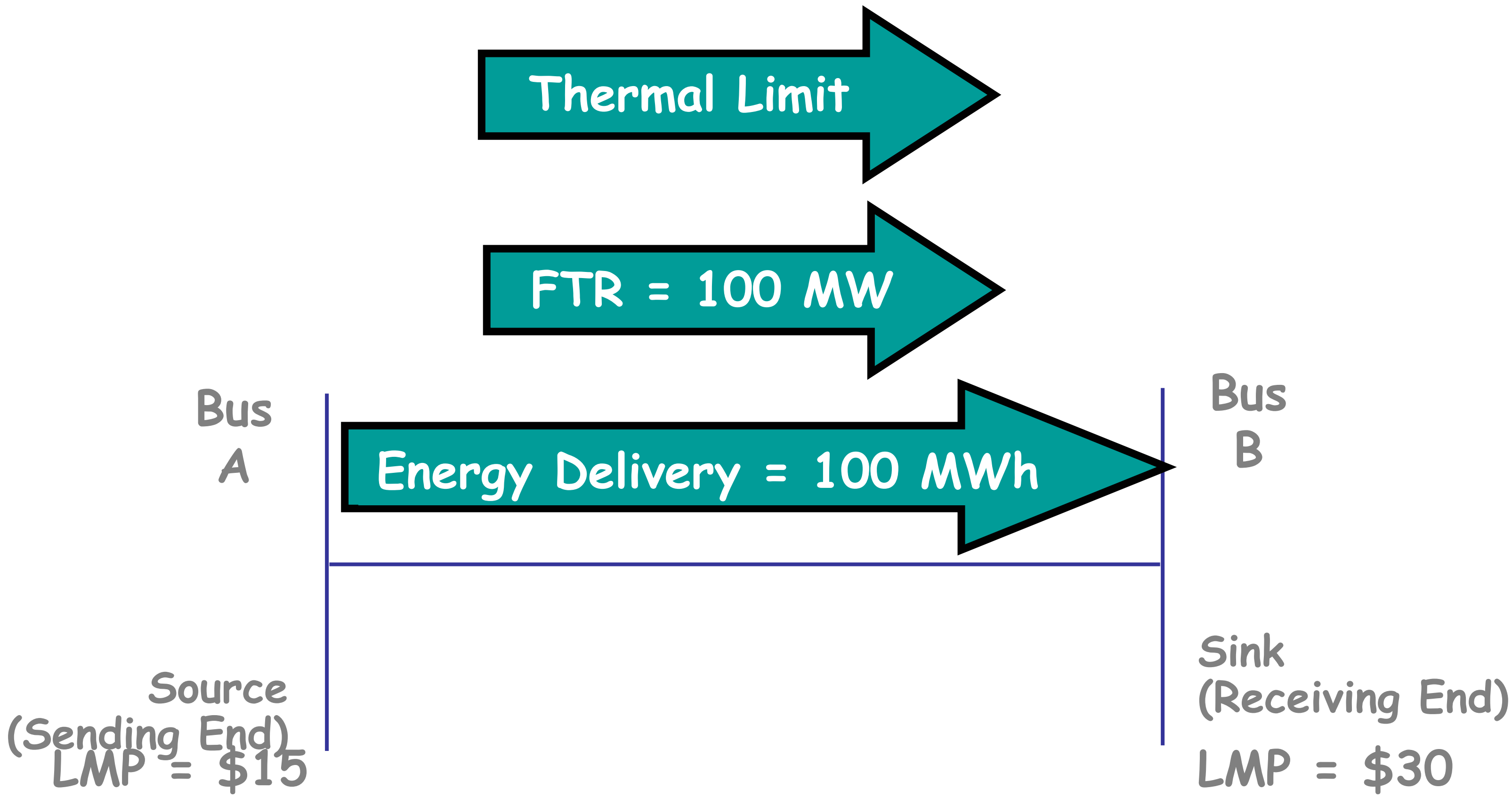
* Note: Customers can enter into long-term supply contracts and purchase FTRs to become indifferent to the hourly LMP values

- Defined from source to sink (point to point*)
- MW level based on transmission reservation
- Financially binding - an Obligation
- Financial entitlement, *not* physical right
- Independent of energy delivery

*** Note: FTR Sources and Sinks can be single nodes or aggregated points such as Trading Hubs, Zones or Aggregates**

- Native Load Customers
  - FTRs allocated to native load customers to protect them against congestion costs
- Firm Transmission Customers
  - Receive FTR allocation in return for paying embedded cost rate
- Secondary market -- bilateral trading
  - FTRs that exist are bought or sold
- FTR Auction -- centralized market
  - purchase “left over” capability

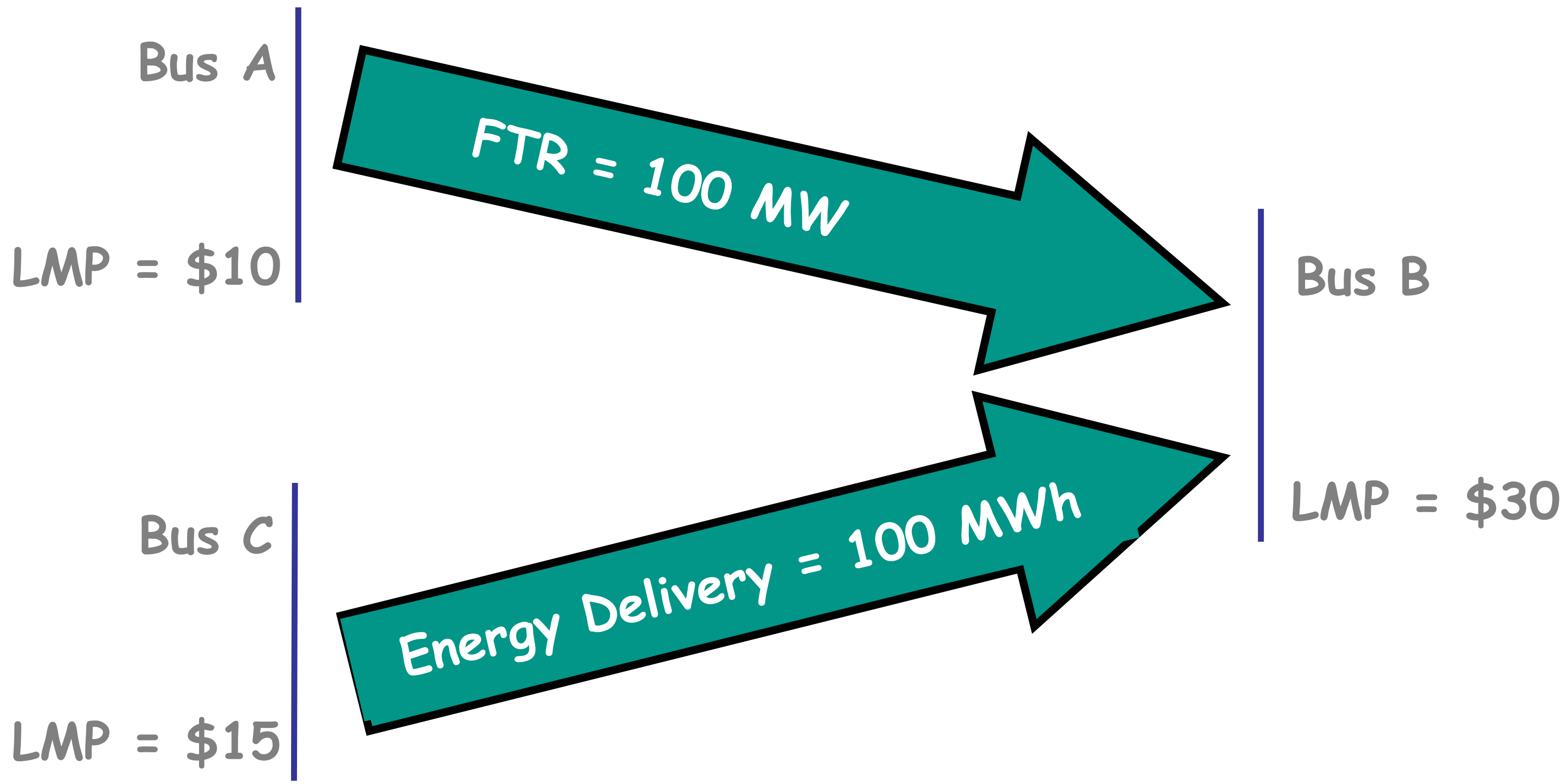
Energy Delivery Consistent with FTR



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

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

Energy Delivery
Not Consistent with FTR



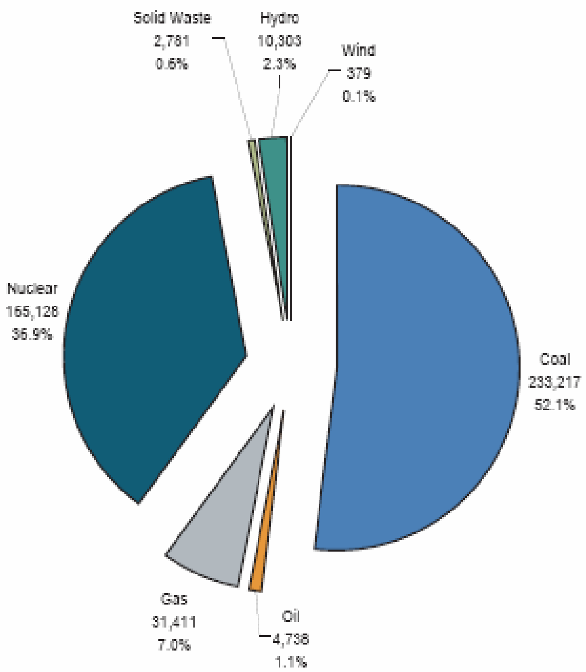
Congestion Charge = 100 MWh * ($30-$15) = $1500

FTR Credit = 100 MW * ($30-$10) = $2000

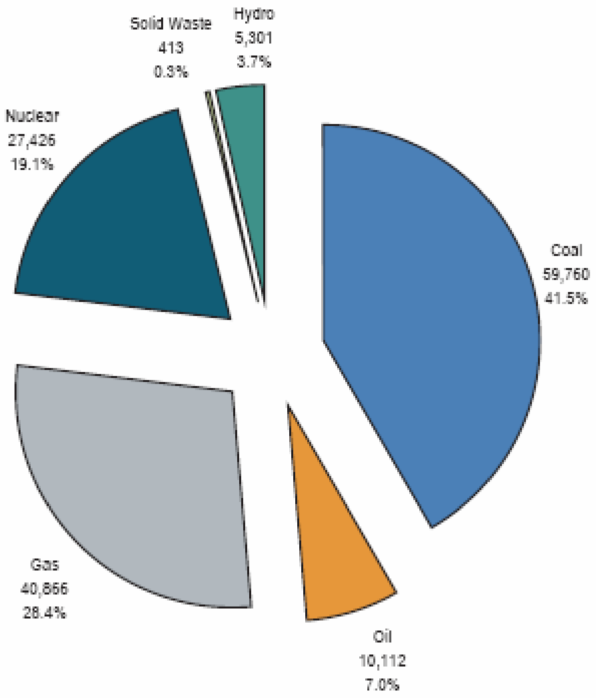
PJM Market Results

PJM Capacity / Energy

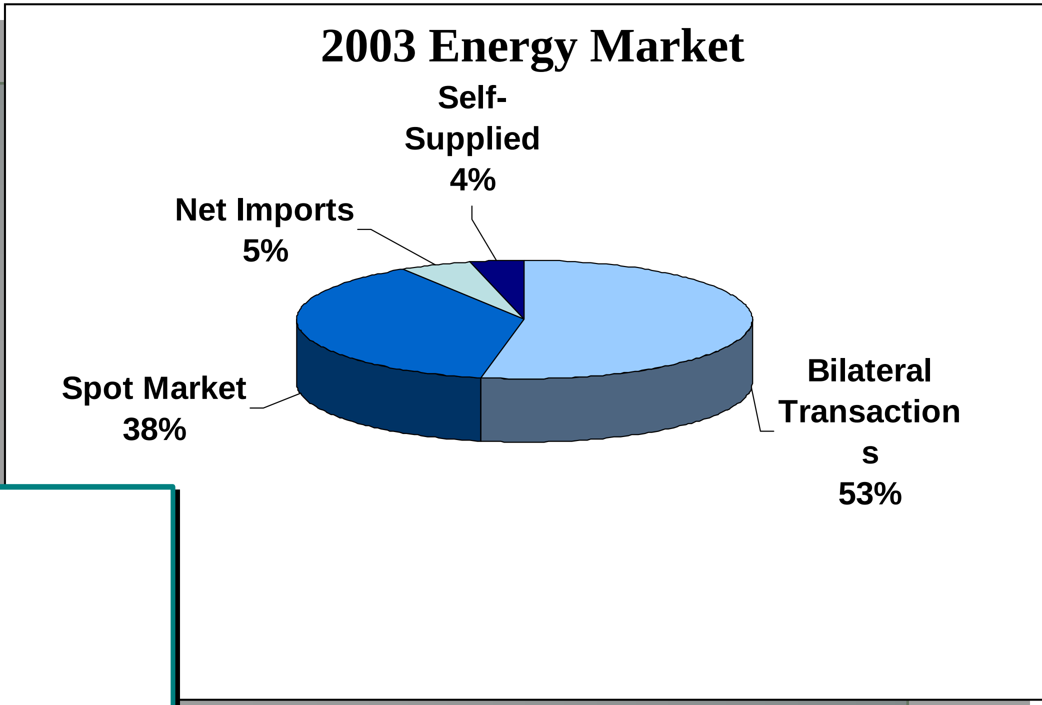
PJM generation by fuel source (GWh): Calendar year 2004

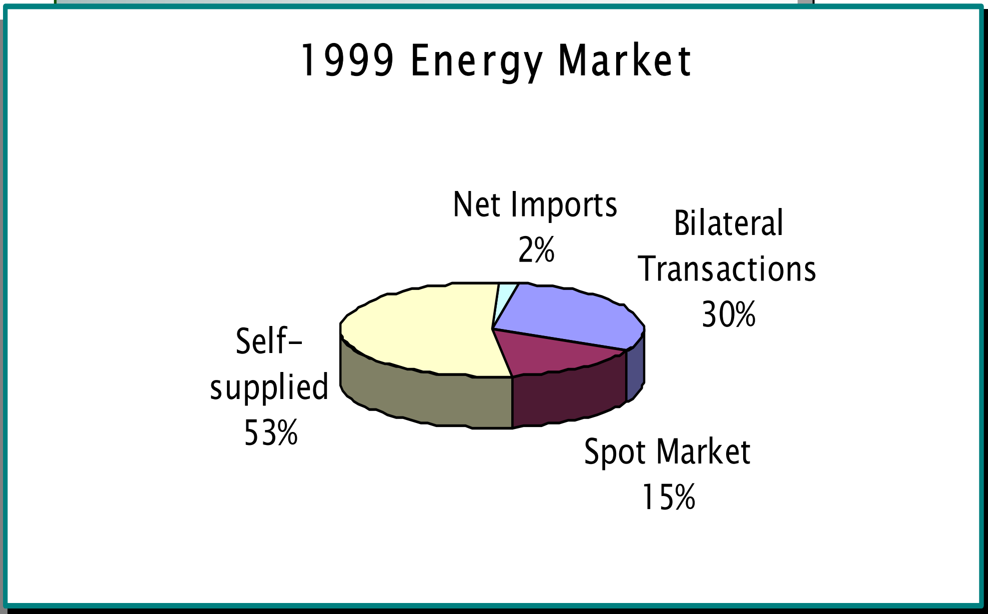


PJM capacity by fuel source: At December 31, 2004

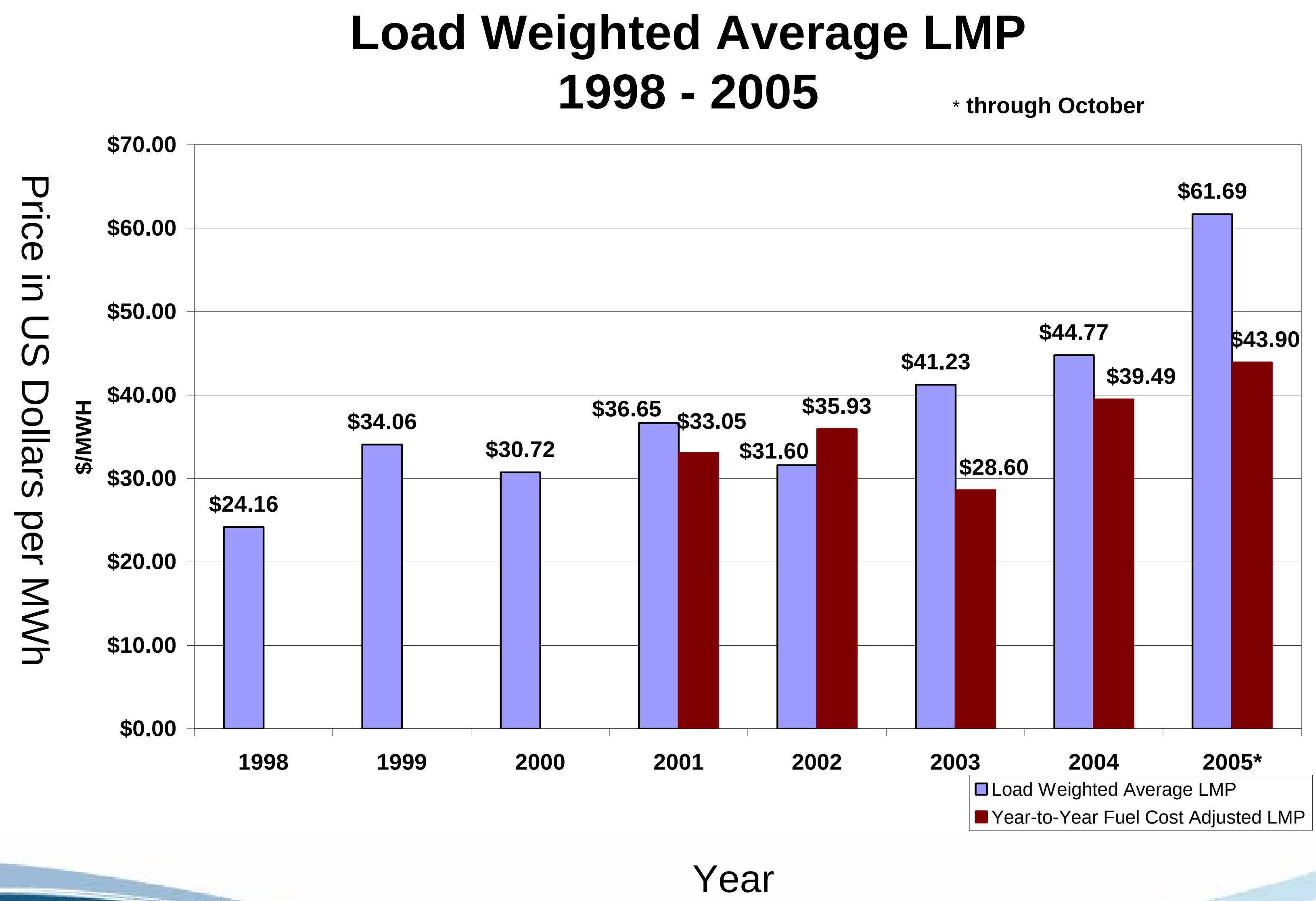


Competitive Market = More Customer Alternatives





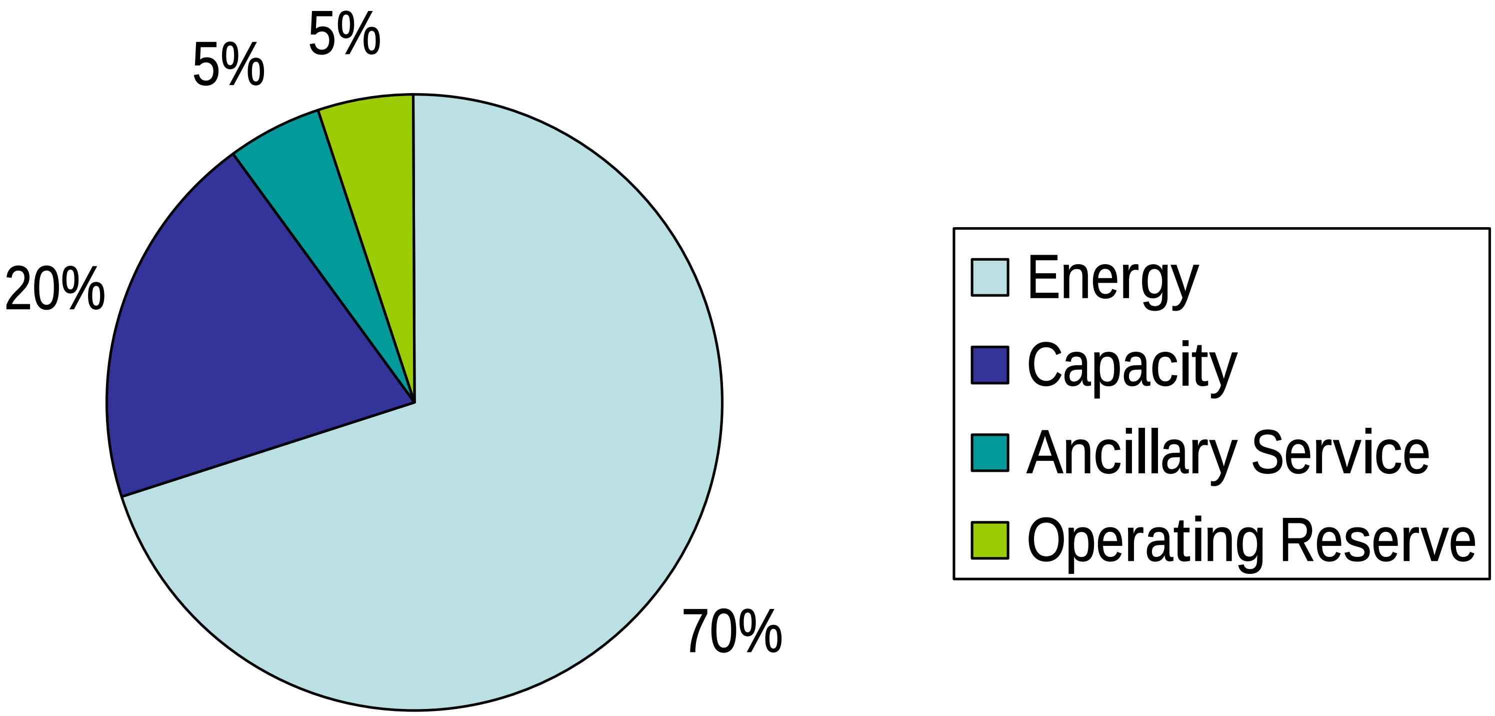
Annual Average Spot Market Prices



PJM Costs in Perspective

- Average residential cost for PJM equates to 24 cents per month
- Stated benefit of $3 billion in 2002 to retail load in original PJM area
- On fuel adjusted basis, prices in PJM fell 4.6%, according to the 2004 State of the Market
  - Assuming similar savings in the bi-lateral market, on a fuel adjusted basis, equivalent to $1 Billion

Generation Revenue by Category of Service



- Prior to implementation of regulation market, PJM operations was regularly short of regulation supply.
- After Regulation market implementation, Regulation offered into the market has exceeded requirement by a factor of 200 to 400 percent.
- Spinning Reserve availability under the market has also increased verses pre-market levels

What Has Not Worked ?

- **Generation Capacity Market**
  - Current Design is flawed, not integrated with transmission requirement, no long-term investment signal
- **Economic Transmission Planning**
  - No competitive transmission investment model
- **Lack of Coordination Between Wholesale Market and State Retail Rate Designs**
  - Conflicting incentives have inhibited demand response development

Market Implementation – Lessons Learned

- Incremental Implementation Approach
  - Market Matures through evolutionary process
- Market Flexibility
  - Support bilateral transactions
  - Self scheduling of supply
  - Spot Market access
- Market Information
  - Internet posting system
  - Participant Training
- Market Incentives
- Market Adaptation

- Implement a fundamentally sound Real-time Energy Market
- Incrementally add functionality based on the needs of Market Participants
- Develop system operating tools and participation information systems to support efficient market operations
- Integrate stringent audit processes into system as they are implemented to ensure customer confidence

- Participant Choice
  - Support bilateral transactions
  - Self scheduling of supply
  - Spot Market access
  - Provide choice in all markets
  - Virtual Bidding
  - Financial Bilateral settlements
- Voluntary Market Participation
- Flexible scheduling rules

- Ease of access via internet posting
- Transparent Market through real-time information posting
  - Energy Prices
  - Load Forecast
  - Transmission system information
  - System conditions
  - Interregional power transfers
  - Settlement information
  - Dispatch instructions
- Market Participant Training, Market Trials
- Stakeholder Process

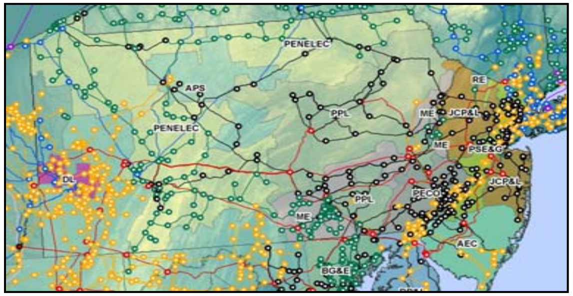
- Locational Pricing - consistency with generation dispatch instructions
- Day-ahead Market design
- Real-time Market design
- Revenue guarantee for flexible generators
- Ancillary Markets
  - Includes product-substitution cost

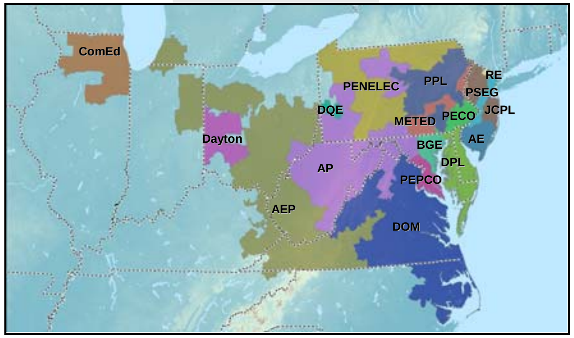
Organized Competitive Wholesale Markets
Regional Planning Process

The RTEP process identifies upgrades to meet customers' requirements:

- operational
- economic
- reliability requirements

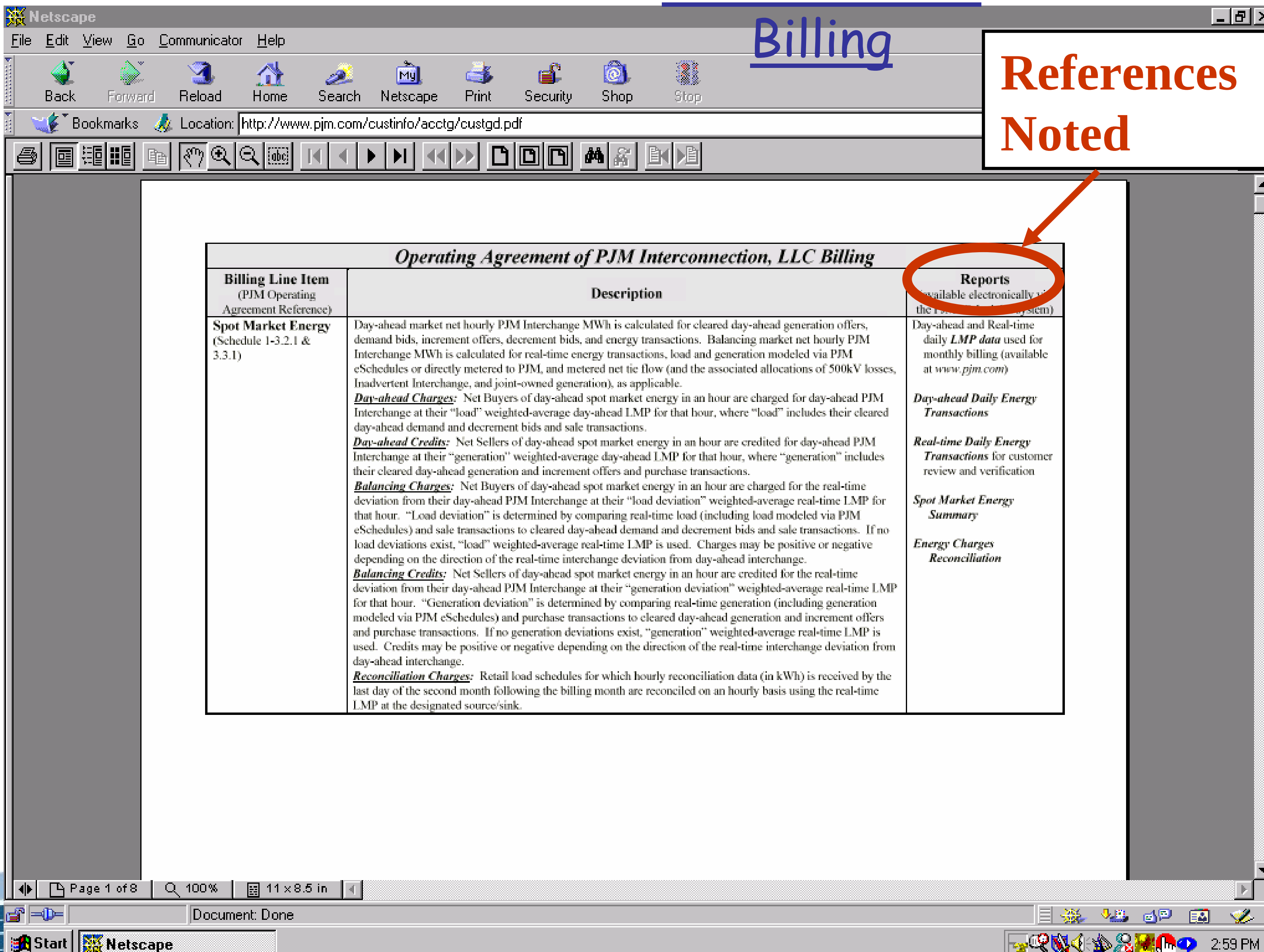
Broad system view that looks out 15 year over the entire geographic area





Guide to PJM Billing

References Noted



Operating Agreement of PJM Interconnection, LLC Billing

Billing Line Item (PJM Operating Agreement Reference)	**Description**	**Reports** (available electronically via the [illegible] system)
Spot Market Energy (Schedule 1-3.2.1 & 3.3.1)	Day-ahead market net hourly PJM Interchange MWh is calculated for cleared day-ahead generation offers, demand bids, increment offers, decrement bids, and energy transactions. Balancing market net hourly PJM Interchange MWh is calculated for real-time energy transactions, load and generation modeled via PJM eSchedules or directly metered to PJM, and metered net tie flow (and the associated allocations of 500kV losses, Inadvertent Interchange, and joint-owned generation), as applicable. ***Day-ahead Charges:*** Net Buyers of day-ahead spot market energy in an hour are charged for day-ahead PJM Interchange at their "load" weighted-average day-ahead LMP for that hour, where "load" includes their cleared day-ahead demand and decrement bids and sale transactions. ***Day-ahead Credits:*** Net Sellers of day-ahead spot market energy in an hour are credited for day-ahead PJM Interchange at their "generation" weighted-average day-ahead LMP for that hour, where "generation" includes their cleared day-ahead generation and increment offers and purchase transactions. ***Balancing Charges:*** Net Buyers of day-ahead spot market energy in an hour are charged for the real-time deviation from their day-ahead PJM Interchange at their "load deviation" weighted-average real-time LMP for that hour. "Load deviation" is determined by comparing real-time load (including load modeled via PJM eSchedules) and sale transactions to cleared day-ahead demand and decrement bids and sale transactions. If no load deviations exist, "load" weighted-average real-time LMP is used. Charges may be positive or negative depending on the direction of the real-time interchange deviation from day-ahead interchange. ***Balancing Credits:*** Net Sellers of day-ahead spot market energy in an hour are credited for the real-time deviation from their day-ahead PJM Interchange at their "generation deviation" weighted-average real-time LMP for that hour. "Generation deviation" is determined by comparing real-time generation (including generation modeled via PJM eSchedules) and purchase transactions to cleared day-ahead generation and increment offers and purchase transactions. If no generation deviations exist, "generation" weighted-average real-time LMP is used. Credits may be positive or negative depending on the direction of the real-time interchange deviation from day-ahead interchange. ***Reconciliation Charges:*** Retail load schedules for which hourly reconciliation data (in kWh) is received by the last day of the second month following the billing month are reconciled on an hourly basis using the real-time LMP at the designated source/sink.	Day-ahead and Real-time daily *LMP data* used for monthly billing (available at *www.pjm.com*) *Day-ahead Daily Energy Transactions* *Real-time Daily Energy Transactions* for customer review and verification *Spot Market Energy Summary* *Energy Charges Reconciliation*

Billing Cycle

S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	22	23	24	25	26
27	28	29	30			

Net Billing Statements for previous month issued on 5th business day

Financial Settlements via electronic funds transfer (EFT) on first business day after the 19th

Overdue Balances accrue interest charges

Detailed Billing Reports (including monthly statement) provided electronically via PJM eSchedules system

Preliminary Billing Results electronically available during the month