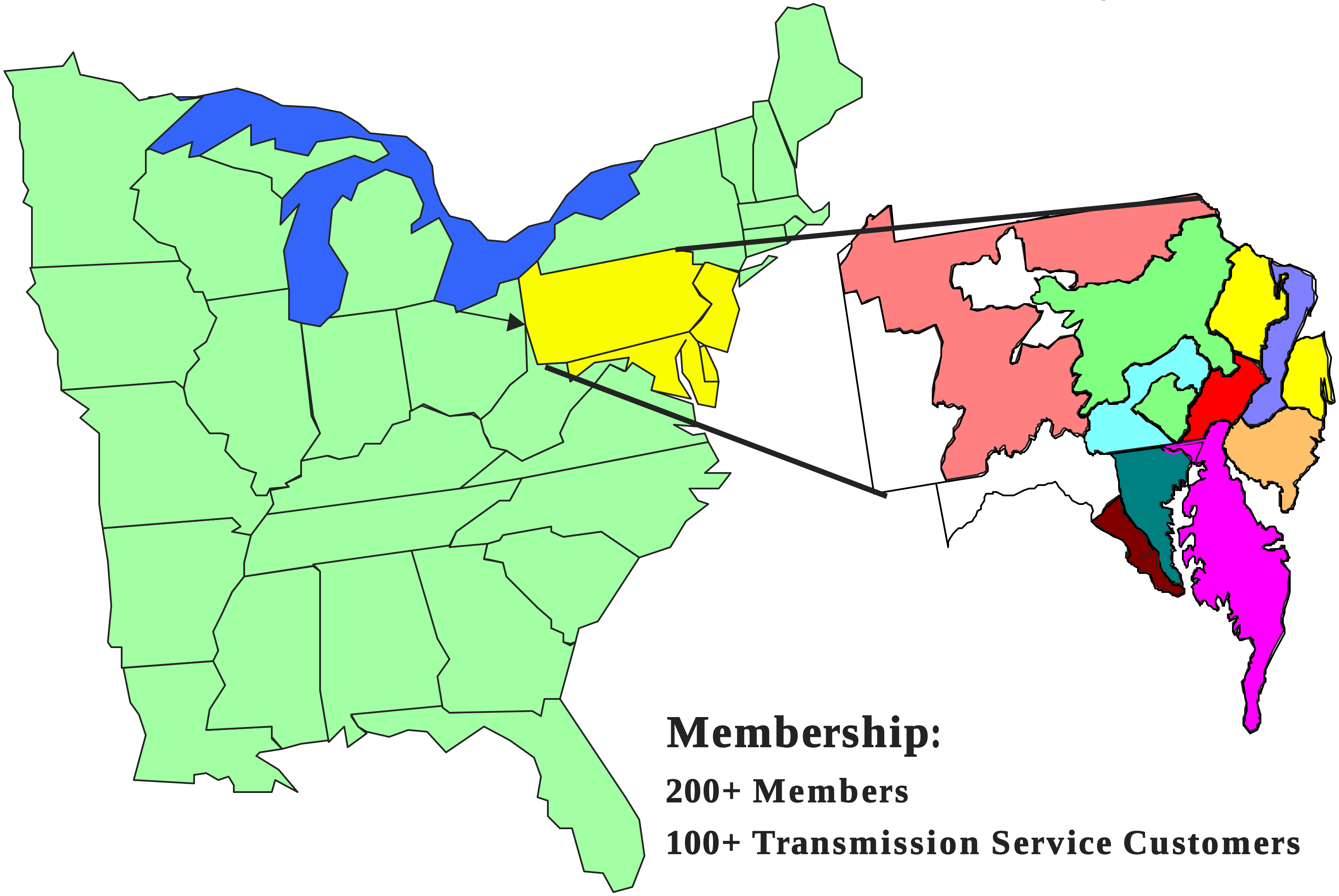
Overview of PJM Market Design

October 23rd, 2001

Background

PJM Area



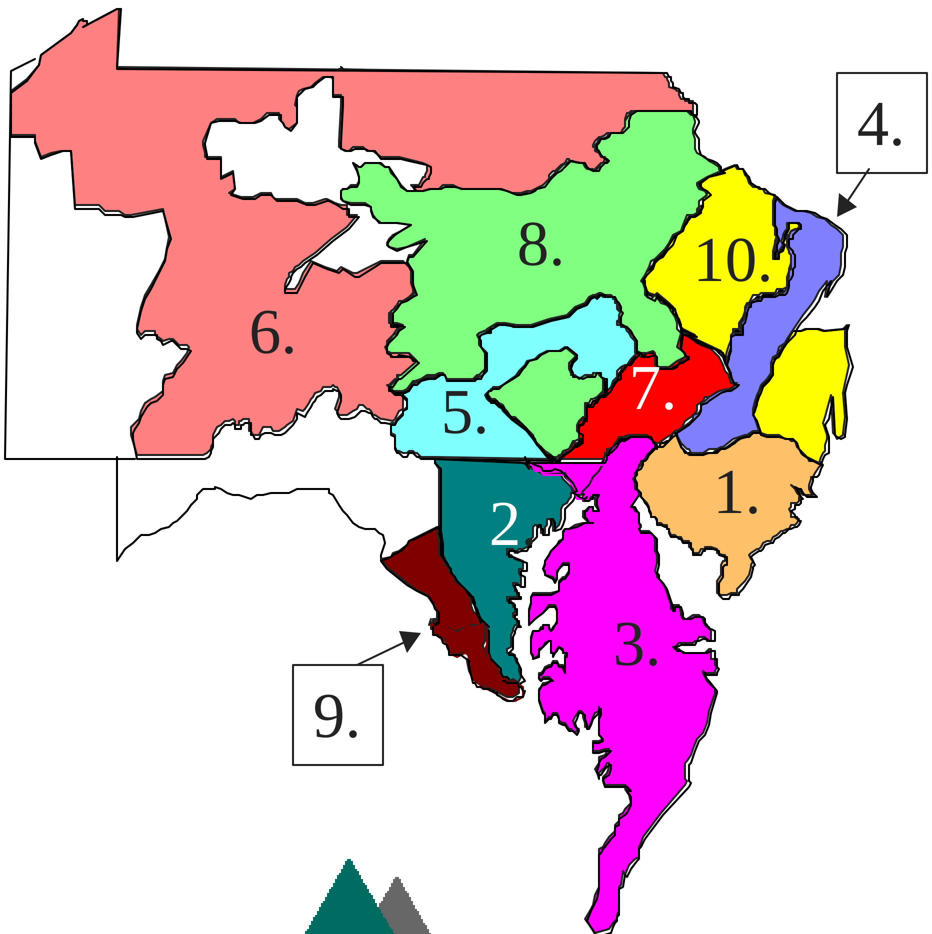
Membership:

200+ Members

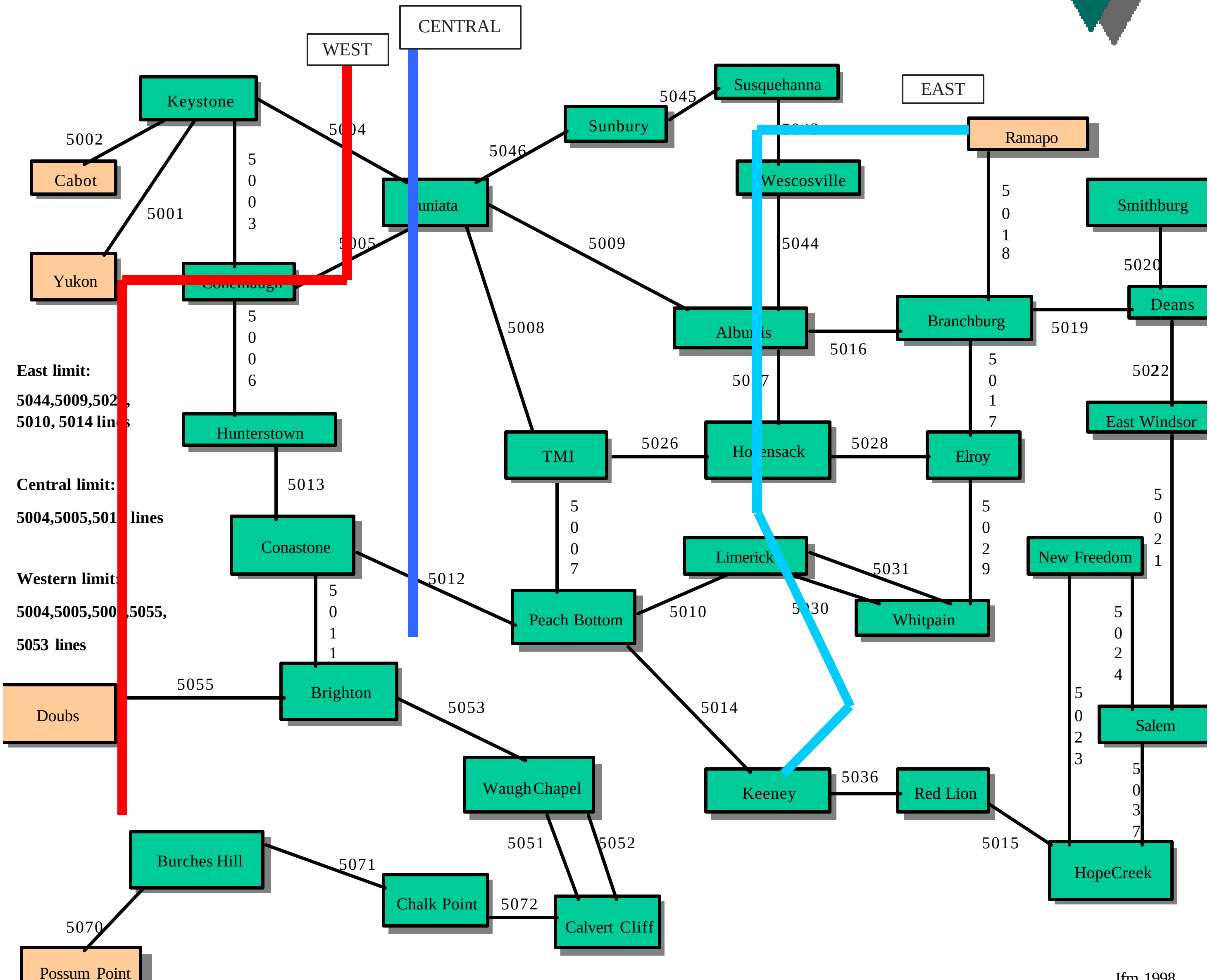
100+ Transmission Service Customers

Transmission Owners

Transmission Zones



Atlantic	H-1
Baltimore	H-2
Delmarva	H-3
Jersey Central	H-4
Met Ed	H-5
PenElec	H-6
PECO	H-7
PPL	H-8
PEPCO	H-9
PSEG	H-10


WEST
CENTRAL
EAST
Keystone
Cabot
Yukon
Susquehanna
Sunbury
Ramapo
Wescosville
uniata
Smithburg
Branchburg
Deans
Albur is
Hunterstown
TMI
Ho ensack
Elroy
East Windsor
Conastone
Limerick
New Freedom
Peach Bottom
Whitpain
Doubs
Brighton
Salem
Waugh Chapel
Keeney
Red Lion
HopeCreek
Burches Hill
Chalk Point
Calvert Cliff
Possum Point
5002
5001
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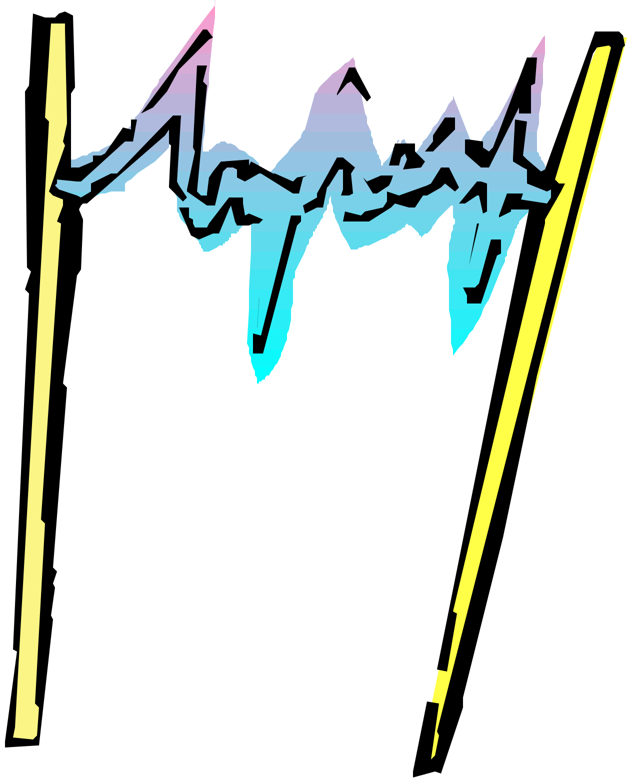
5072
5070
East limit:
5044,5009,502 ,
5010, 5014 lin s
Central limit:
5004,5005,501 lines
Western limit:
5004,5005,500 ,5055,
5053 lines

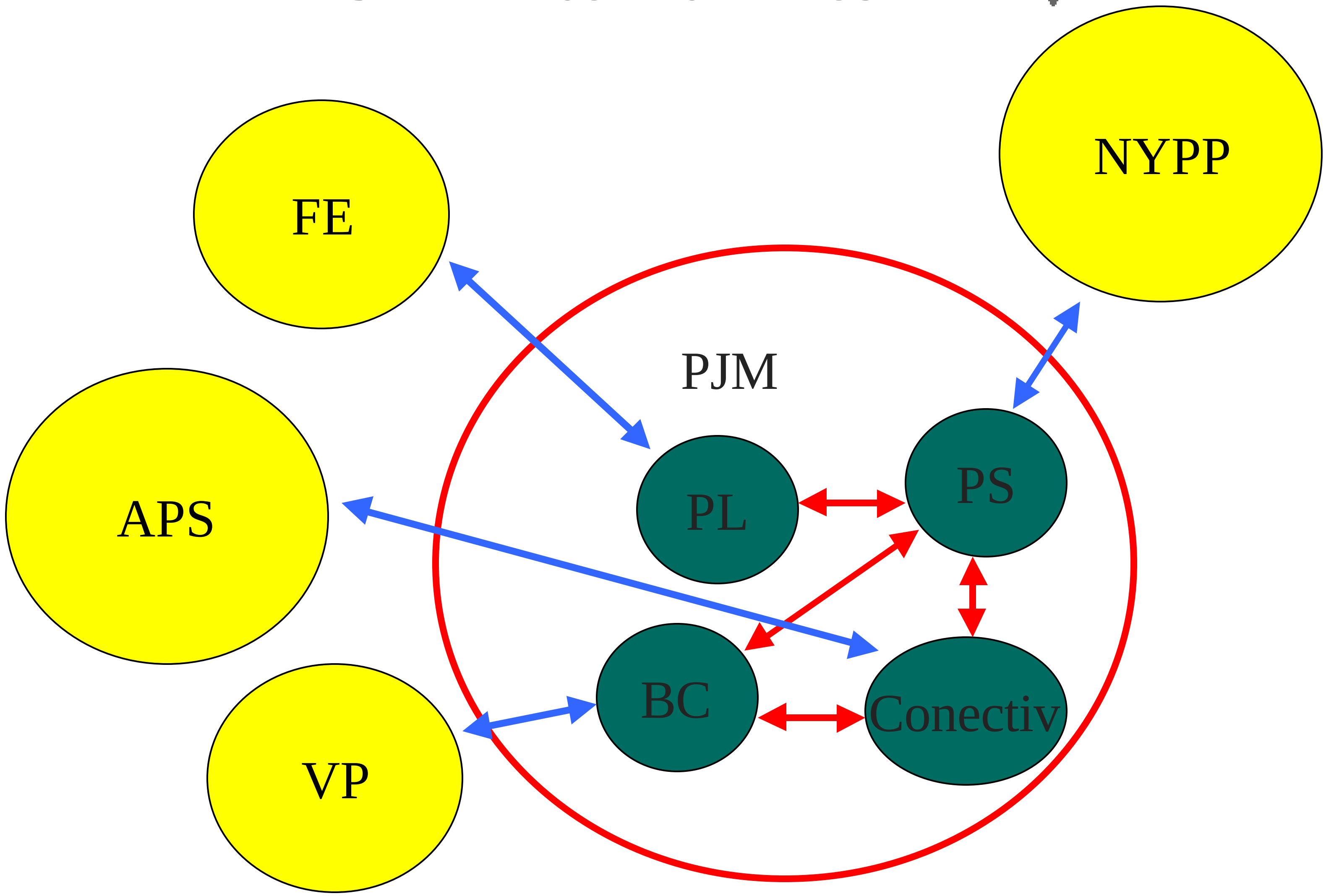
Jfm 1998

PJM External Ties

- 5 - 500 kV lines
- 8 - 345 kV lines
- 11 - 230 kV lines
- 3 - 138 kV lines
- 6 - 115 kV lines



PJM External Ties



System characteristics

- All data below includes PJM West (APS)
  - Installed capacity ~ 66,100 MW
  - Peak load ~ 59,900 MW
  - Transmission ~ 13,000 miles
  - Service area ~ 79,000 sq. miles
  - Customers ~ 11 million
  - Predominantly thermal system (nuclear, coal, gas and oil) of ~ 610 units

PJM History

- 1927: Three utilities form world's first power pool
- 1981: Membership grows to eight IOUs
- 1993: PJM formed as an independent entity
- 1997: PJM Interconnection, LLC formed
  - Memberships opens to non-utilities
  - Open Access Transmission Tariff implemented
  - First bid-based energy market opens

PJM History – Pt. 2

- 1998: PJM becomes an ISO
  - Locational marginal pricing implemented
  - Capacity market created
- 1999: Retail choice begins in Pennsylvania
  - Fixed Transmission Rights (FTRs) auction implemented
  - PJM sets all time operations record
- 2000: Day-ahead Market and Regulation Markets open
- 2001: PJM West approved to include Allegheny Power
  - PJM approved as a regional Transmission Organization (RTO)

Overview of PJM market design

Spot pricing

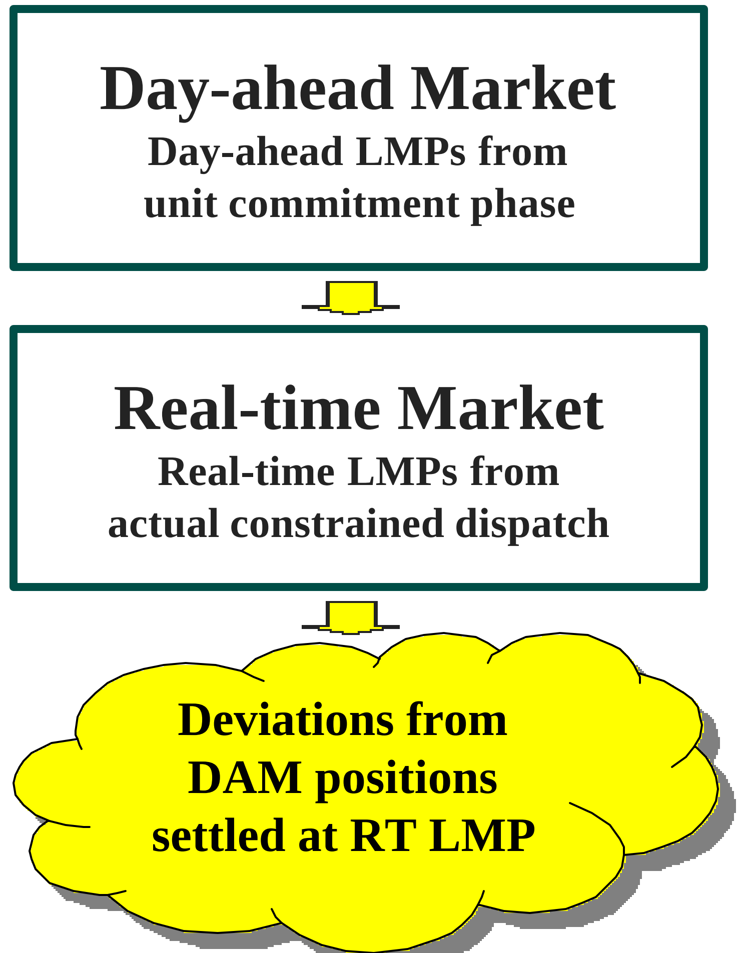
- PJM is based on the spot pricing framework
  - In a spot pricing model, all quantities can be settled financially at the prevailing spot price
  - Simplifies settlement as the very complex interactions between quantities can be settled easily as long as the spot prices are right
  - Similar to a cash-settled commodity contract

Locational spot prices

- How to calculate the “right” spot prices?
  - PJM relies on a locational marginal pricing (LMP) system
  - LMP is the cost to serve the next MW of load at a specific location, using the lowest production cost of all available generation, while observing all transmission limits
  - In simple terms, take all bids and calculate the cost of an additional MW given transmission and system constraints

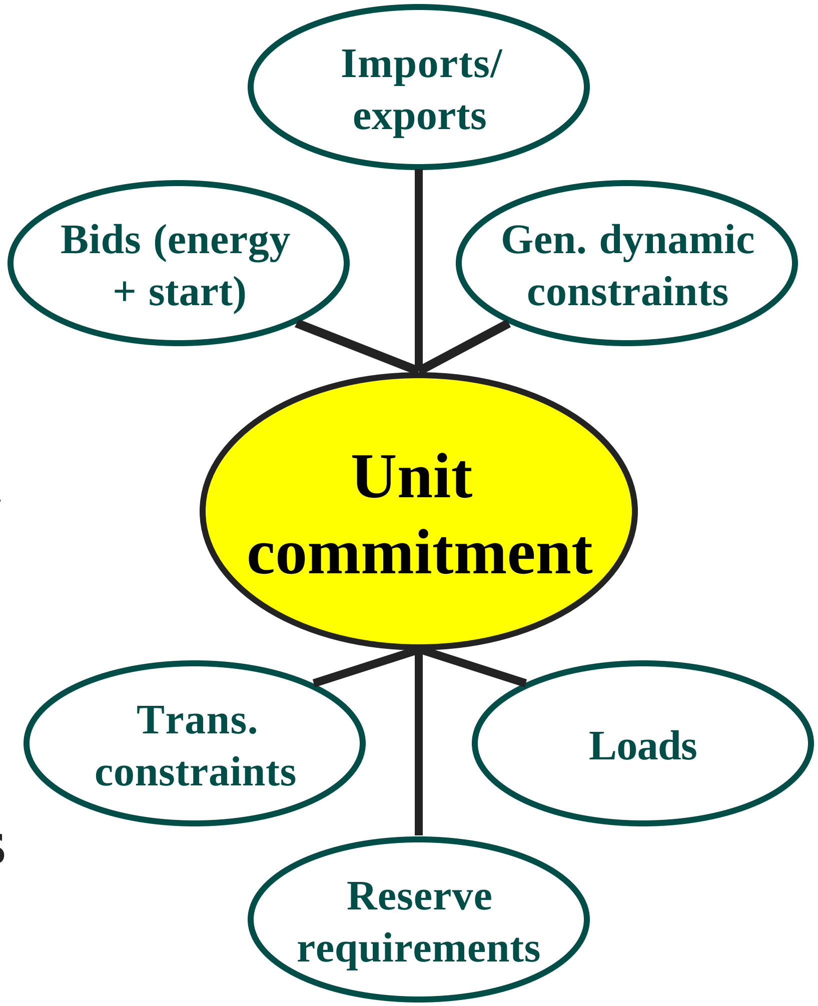
Multi-settlement – two sets of binding prices

- Two sets of LMPs
  - Day-ahead market linked to day-ahead bids and security-constrained unit commitment
  - Real-time LMPs calculated from actual operating conditions in the period – system dispatch



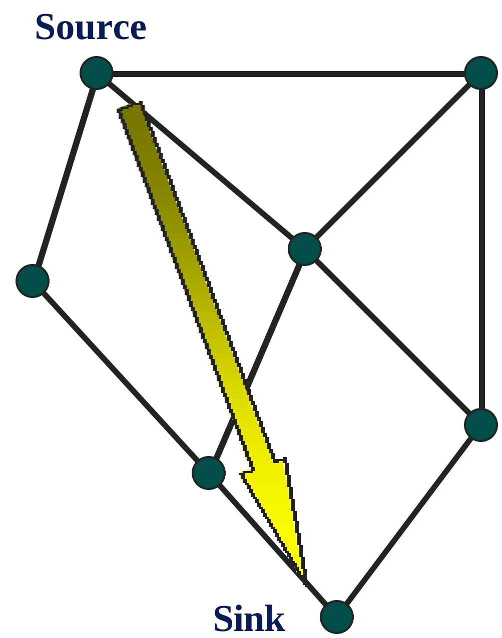
Unit commitment

- Need to get the right number of units on in the right places
  - Need to recognize expected transmission constraints to get technically feasible schedules
  - Also need to recognize dynamic constraints on a thermal system – ramp rates, on and off-times
  - Accomplished in PJM using a centralized unit commitment process – results in DAM LMPs
  - Self-scheduling also possible



Transmission rights are financial

- Transmission rights are financial instruments, unrelated to daily flows
  - Basically a financial derivative contract based on the difference in two local day-ahead LMPs
  - Two-way contract – you can be paid if LMP difference is positive or pay if LMP difference is negative



PJM Fixed Transmission Rights (FTRs) are struck against difference in two pre-determined LMPs – whether or not energy flows in the hour

Three Ways to Do Business

- Participate in spot market
  - congestion collected through interchange
  - difference between buyer's price and seller's price
  - Can self-schedule to run; take local LMP
- Use own generation to own load
  - congestion implicit in net bill
  - difference between load and generation price
- Bilateral transaction
  - congestion is explicit charge
  - difference between sink and source price

Market timing and multi-settlement

Energy Market Operations

- Day-ahead Market - create a set of financial schedules that are physically feasible
- Reliability Scheduling - performed after rebid period
  - Reserves adequacy
  - Transmission Security
- Regulation Market - Evaluate regulation adequacy and set regulation floor price
- Real-time Operations - Near-term scheduling and real-time security-constrained economic dispatch

Energy Markets

- Day-ahead Market
  - develop day-ahead schedule using least-cost security constrained unit commitment and security constrained economic dispatch programs
  - 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 operating conditions

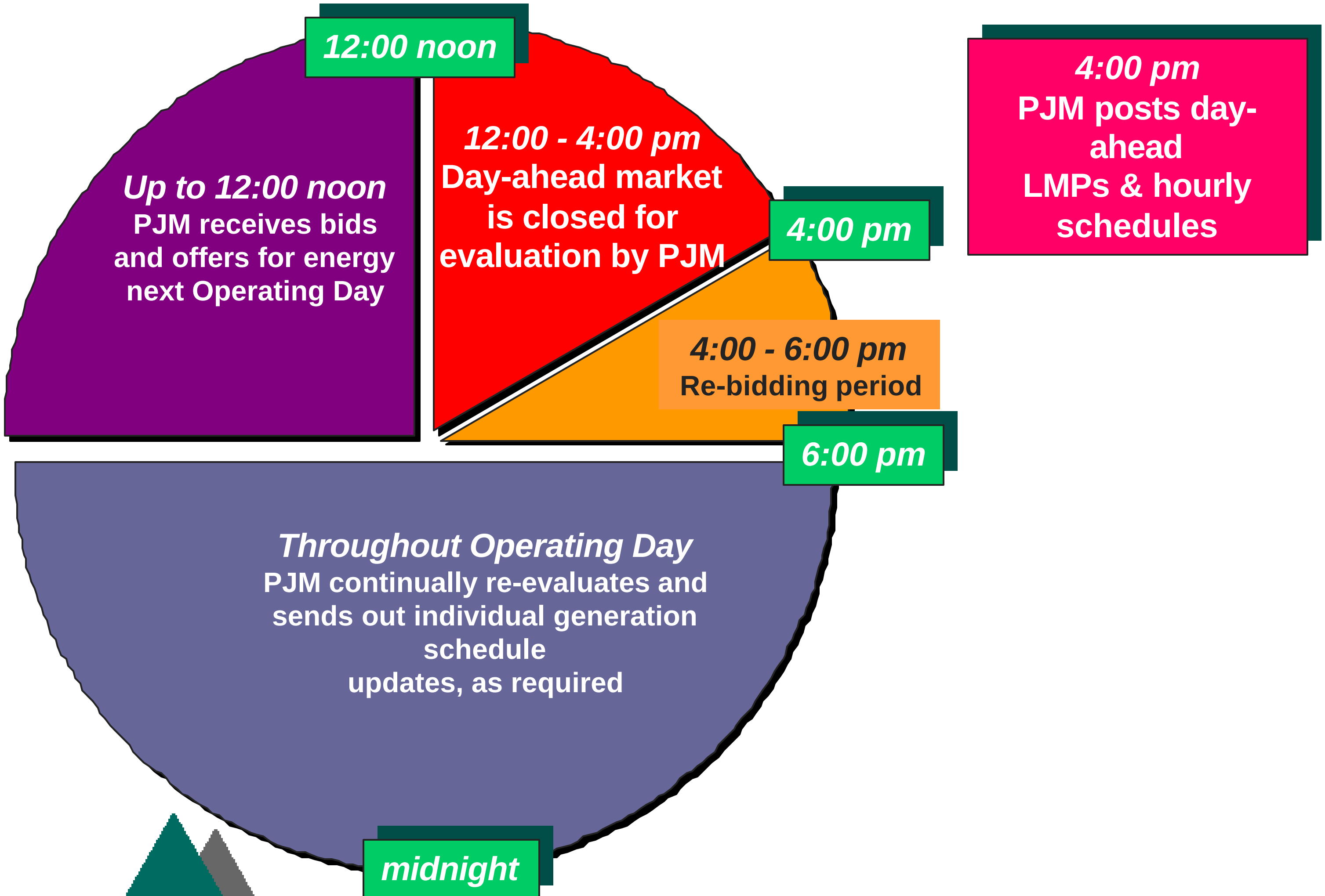
Day-ahead Market Mechanisms

- Provides Market Participants with the option to ‘lock in’ day-ahead scheduled quantities at day-ahead prices
- Provides additional price certainty to Market Participants by allowing them to ...
  - commit & obtain commitments to energy prices & transmission congestion charges in advance of real-time dispatch (forward energy prices)
  - submit price sensitive demand bids
  - inform PJM of maximum congestion charges it is willing to pay
  - submit increment offers & decrement bids (virtual demand and supply positions)

Day-ahead Market Participation

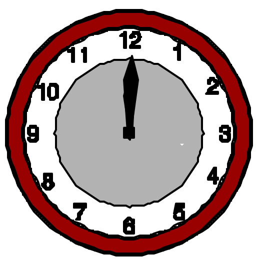
- Generation Resources
  - submit offers (Required for Designated Resources)
  - self-schedule
- Demand
  - submit fixed quantity & location
  - submit bids for price responsive load
- Transactions
  - submit schedules into the day-ahead market
  - may specify maximum amount of congestion they are willing to pay
- Financial
  - submit increment offer
  - submit decrement bid

Day-ahead Market Time Line



Unit Commitment Analyses

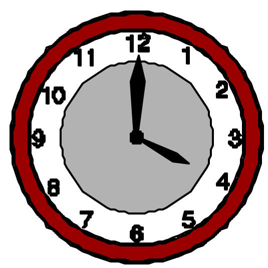
Day-Ahead Market closes



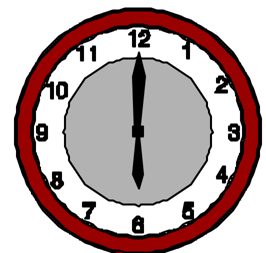
First Commitment

- determines commitment profile that satisfies fixed demand, demand bids, and PJM Operating Reserve Objectives
- minimizes total production cost

Day-ahead Results Posted & Balancing Market Bid period opens



Balancing Market Bid period closes



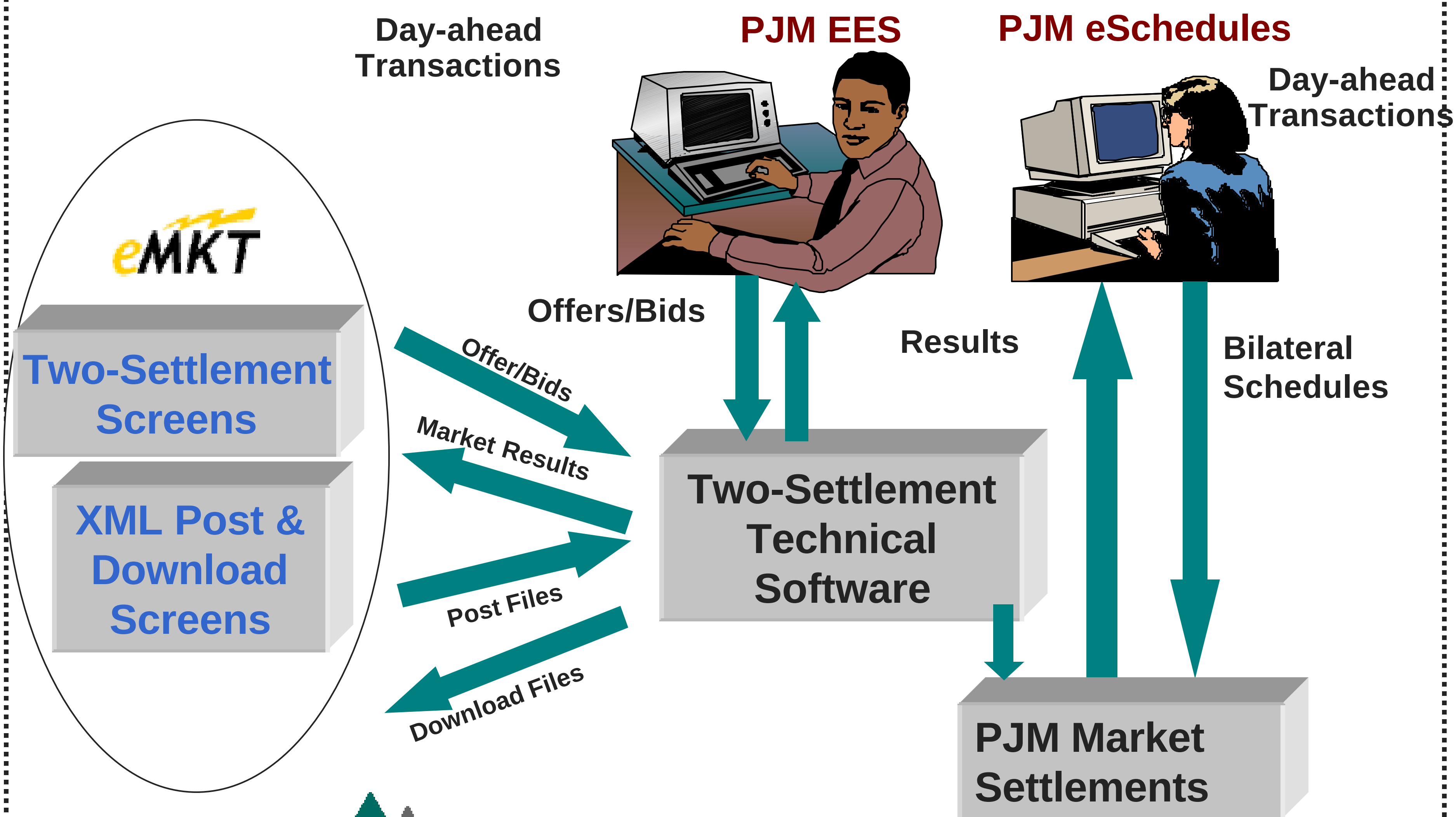
Second Commitment

- focus is reliability
- analysis includes updated bids, unit availabilities, and PJM load forecast information
- minimizes startup and cost to run units at minimum

Supplemental Commitments

- focus is reliability
- performed as necessary
- minimize start-up and cost to run at minimum for additional units committed

Day-ahead Market External Interfaces



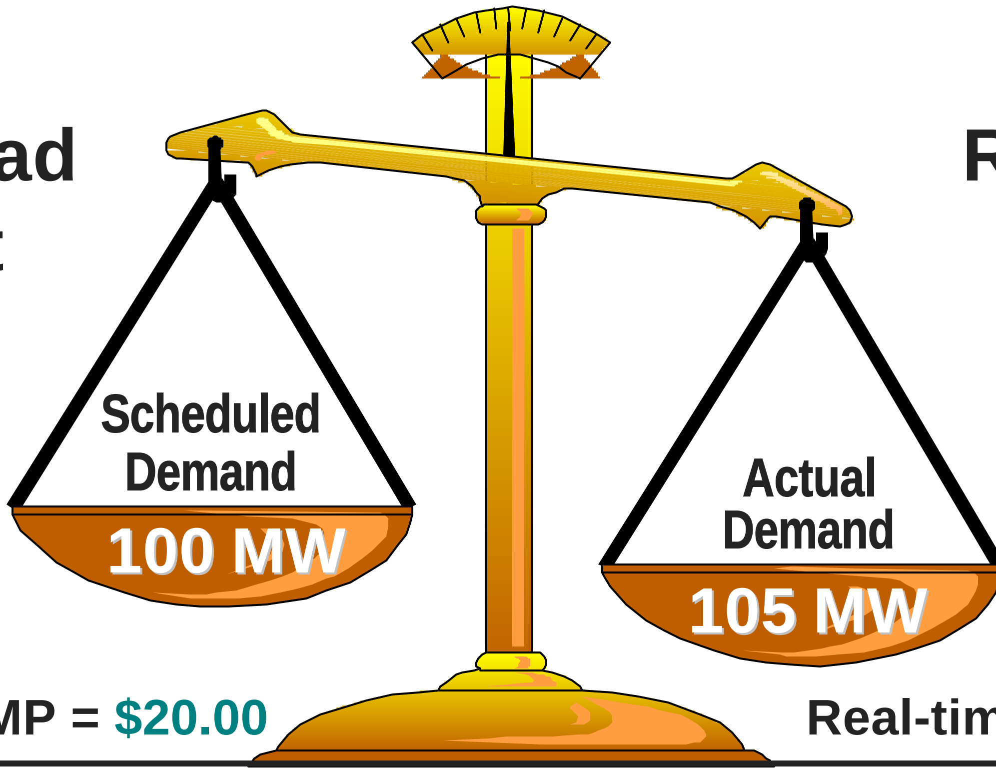
Energy Settlements

- Day-ahead Market Settlement
  - based on scheduled hourly quantities and day-ahead hourly prices
- Real-time Market Settlement
  - based on actual hourly quantity deviations from day-ahead schedule hourly quantities and on real-time prices

Example: LSE with Day-ahead Demand < Actual Demand

Day Ahead Market

Real-time Market



Day Ahead LMP = $20.00

Real-time LMP = $23.00

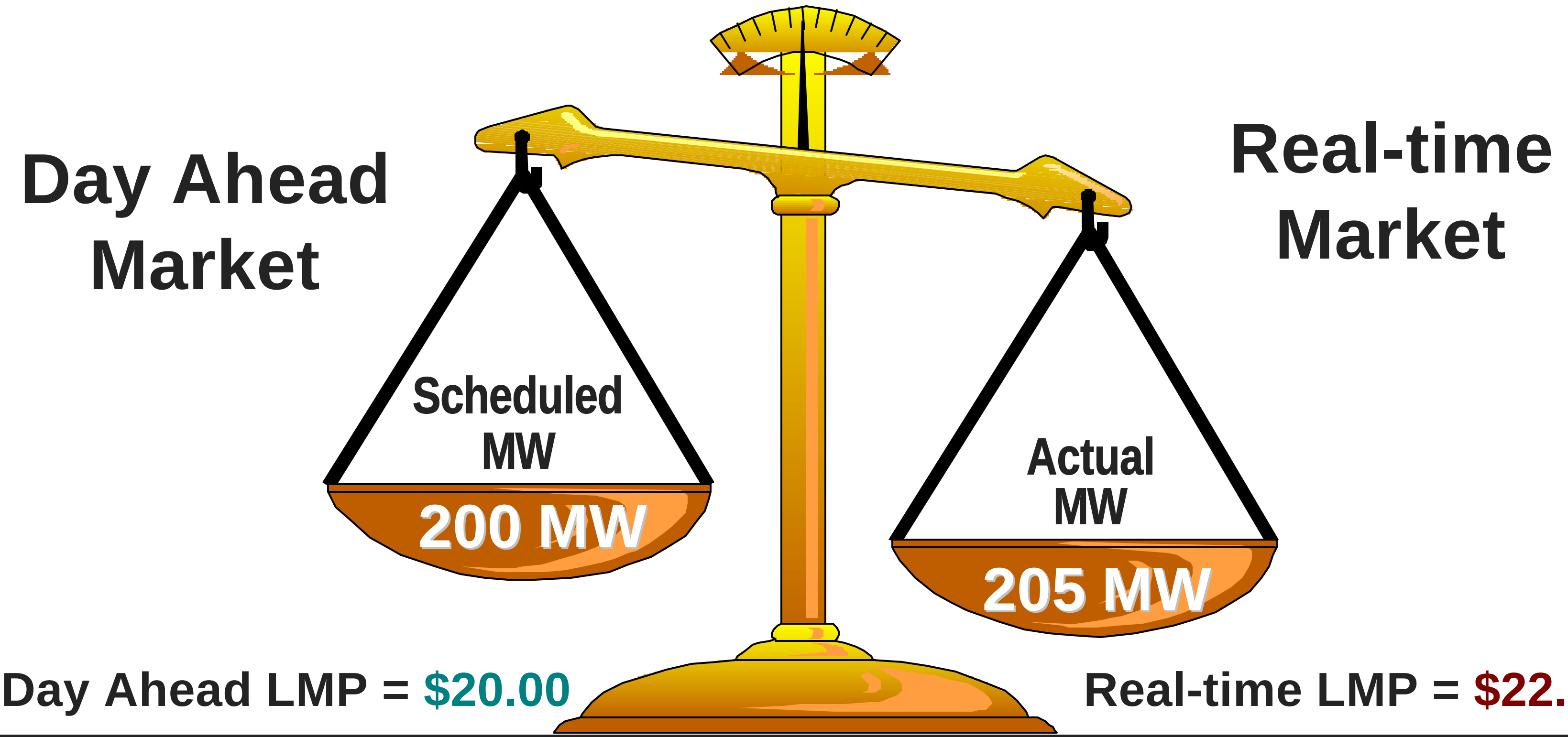
*= 100 * 20.00 = $2000.00*

= (105 - 100) 23.00 = $115.00*

if Day-ahead Demand is 105MW = $2100.00

as bid = $2115.00

Example: Generator with Day-ahead MW < Actual MW



Day Ahead LMP = $20.00 Real-time LMP = $22.00

$ = 200 * 20.00 = $4000.00 $ = (205 - 200) * 22.00 = $110.00

Calculating locational marginal prices

Locational Marginal Price

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

Cost to serve the next MW of load at a specific location, using the lowest production cost of all available generation, while observing all transmission limits

Factors Affecting LMPs

- Energy Demand
- Available Dispatchable Units
- Economic Dispatch
- Transmission Network Configuration
- Transmission Constraints

Characteristics of LMPs

- When the transmission system is unconstrained, there is a single clearing price for energy, which is equal to the marginal cost of meeting the last increment of demand.
- Under constrained conditions, the marginal cost of energy varies by location because the available low cost supply cannot be delivered to the demand location.
- Since the redispatch costs are reflected in the LMP at each location, all buyers and sellers at that location share in these costs in proportion to their energy receipts and deliveries.

PJM LMP Model

- The price of energy is based on actual PJM operating conditions, as described by the PJM state estimator.
- The price of energy at each location is calculated and posted on the PJM website at five minute intervals.
- The five-minute LMP values are integrated at the end of each hour; the hourly value is posted on the PJM website.
- Accounting settlements are performed based on hourly integrated LMPs (after LMP verification procedure).

Posting PJM LMP Information

Operational Data Page

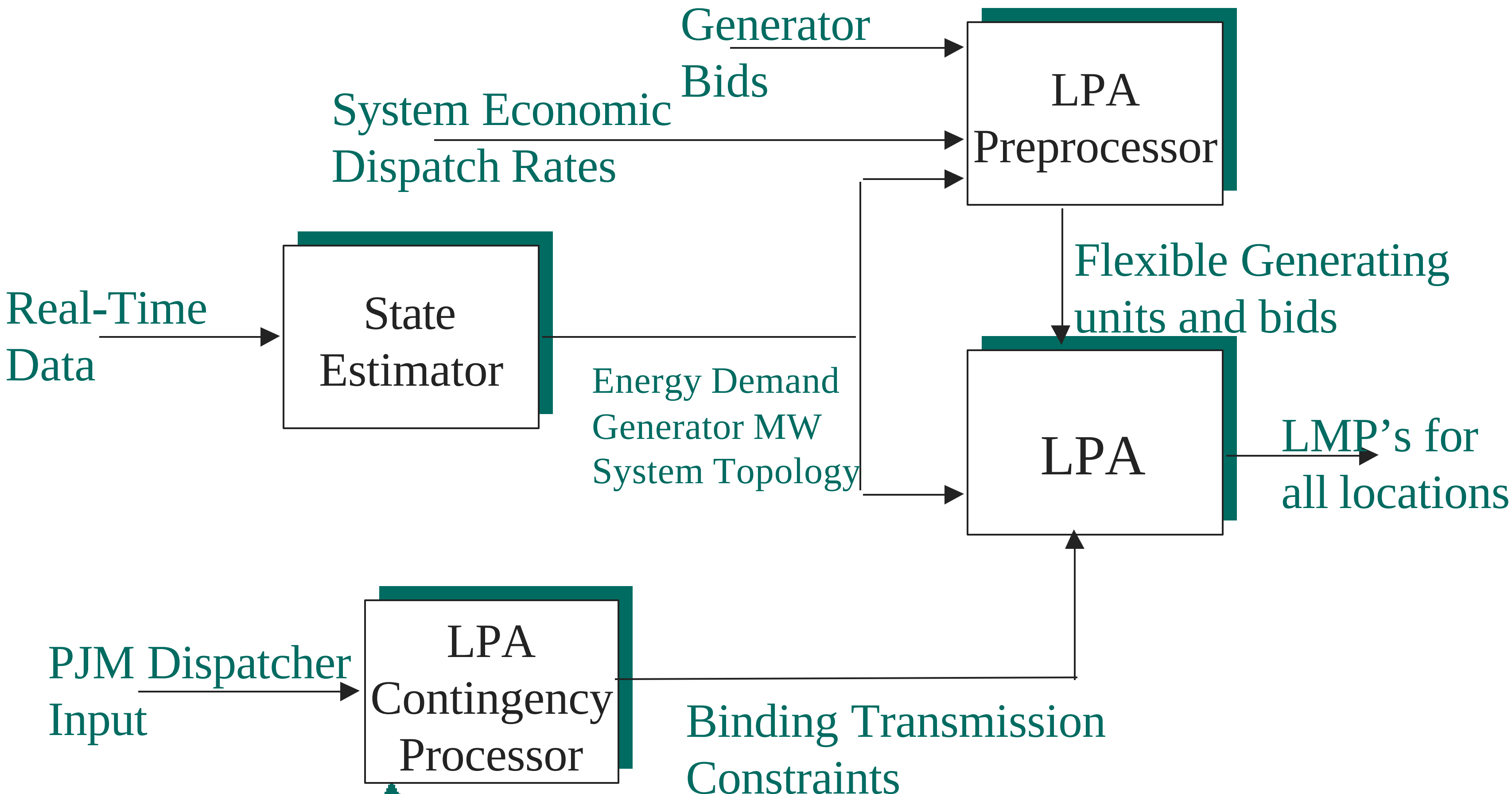
- **Purpose**: Provide the current five-minute and hourly integrated LMP values for selected points and provide other real-time market information.
- **LMP Values Posted:**
  - PJM and 11 Transmission Zones (Load-weighted average LMPs)
  - 3 PJM Trading Hubs
  - Various Aggregates
  - 5 Interfaces into PJM
  - Twenty-nine 500 kV Busses

PJM LMP Model

Daily LMP Verification Procedure

- **Purpose:** Ensure that LMP values are accurately and completely calculated for each of the 288 five-minute intervals of the previous operating day.
- **Procedure:**
  - Market Services Division Engineers review dispatcher logs, program error logs, and LMP results for each interval
  - Recalculate or replace LMP values, as required
  - Notify PJM Grid Accounting the LMP results are verified and ready to use in PJM accounting
  - Post daily LMP file
- The current LMP replacement rate is about 3.5 % .

Locational Marginal Pricing Model

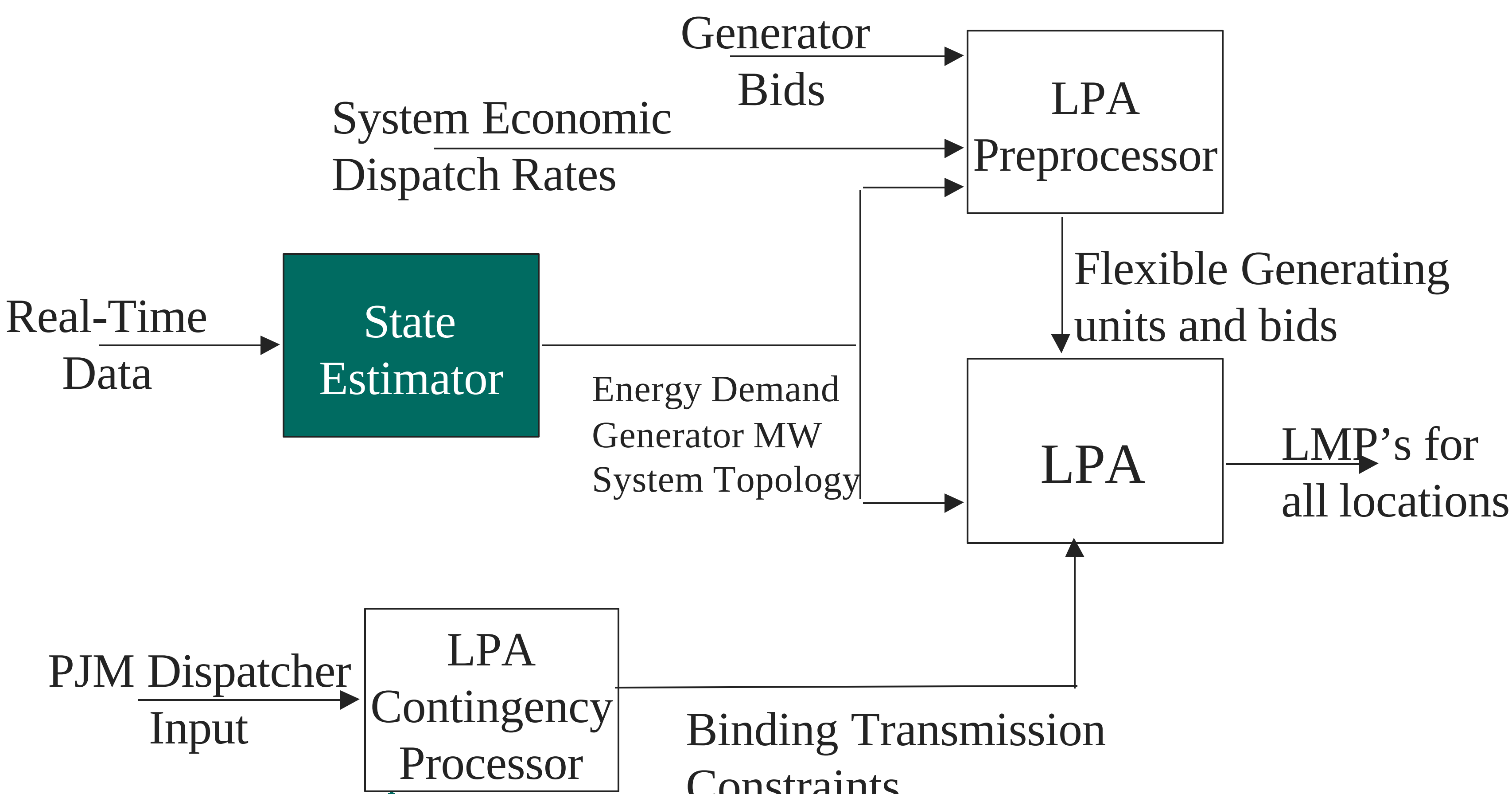


PJM LMP Model

LMP Audit

- The PJM LMP calculation is repeatable and can be audited.
- All input and output data is retained for each five-minute interval. Therefore, the LMP calculation for any five-minute interval can be recalculated in off-line mode.
  - 11 input files
  - 7 output or diagnostic files
  - 8 real-time error logs

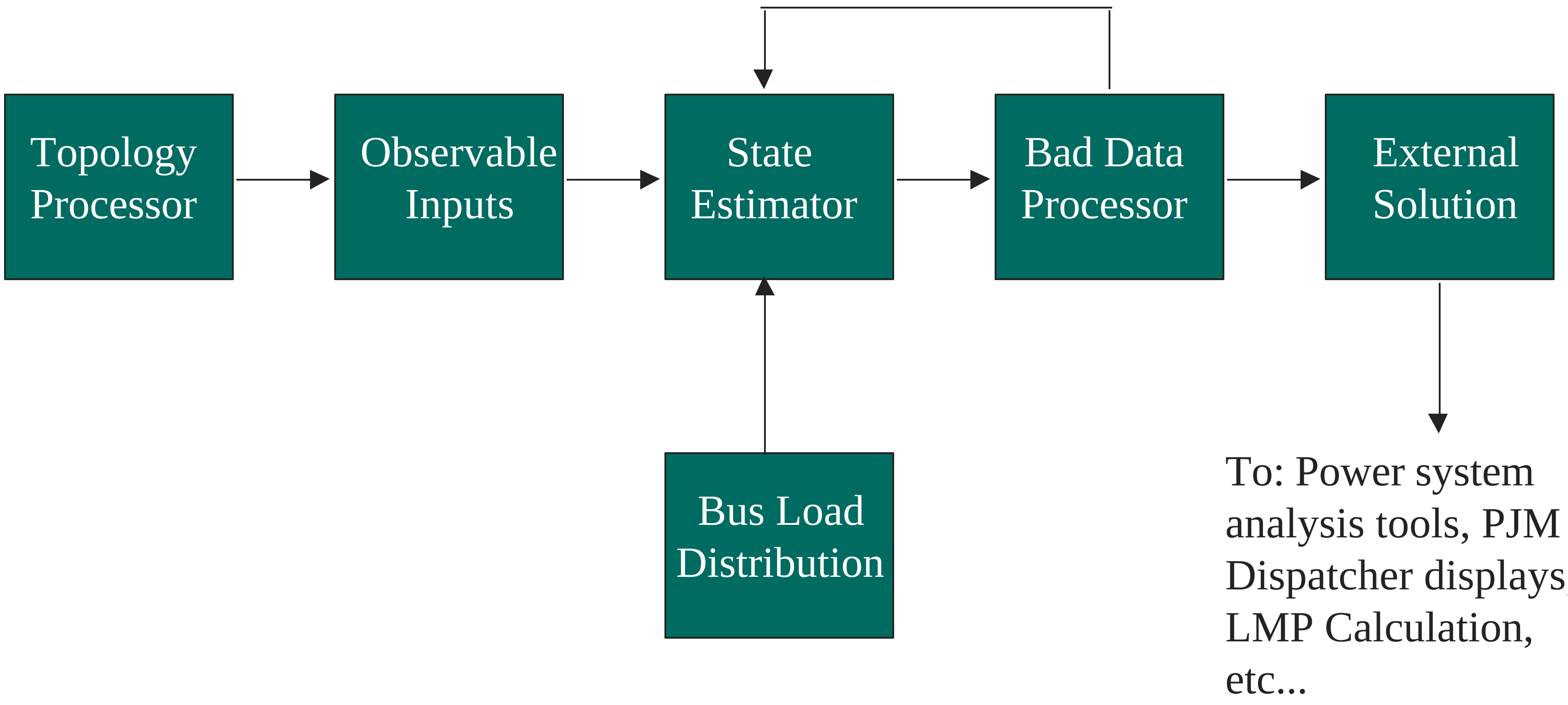
Locational Marginal Pricing Model



PJM State Estimator

The PJM state estimator is a standard power system operations tool that is designed to provide a complete and consistent model of the conditions that currently exist on the PJM power system based upon metered input and an underlying mathematical model.

PJM State Estimator Functional Overview



PJM State Estimator

Purpose: To provide a complete and consistent solution for both the observable and unobservable portions of the electrical network.

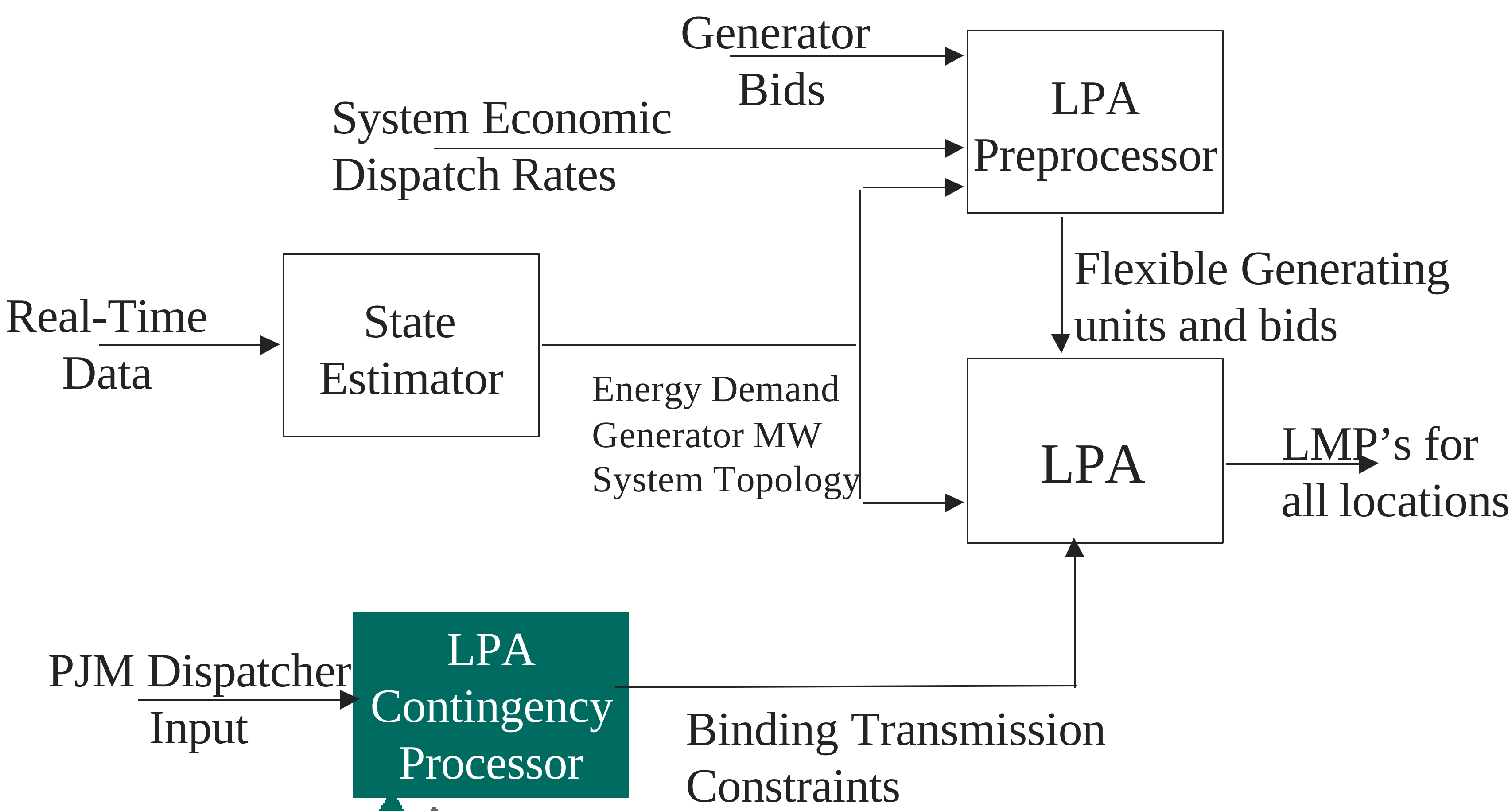
Use available real-time measurements which are imperfect but redundant.

- Data redundancy and the underlying physical and mathematical relationships provide a solution with less error than the original measurements.
- State estimator can correct "bad data" and calculate missing data in the model.

PJM State Estimator Characteristics

Statistics	Additional Details
◆ Analog telemetry (measurements) = 10449 ◆ Equipment Status Telemetry = 7352 ◆ Total busses in Network model = 2678 ◆ Total Observable busses = 1735 ◆ Number of PJM busses = 1775 ◆ Observable PJM busses = 1317	◆ System measurements are transmitted every 14 seconds ◆ Observable busses are those whose conditions can be completely described with available measurements ◆ PJM state estimator accurately models the PJM control area, 74 % of PJM busses are observable ◆ Since only a few external busses are observable, the PJM energy prices do not reflect external transmission limits

Locational Marginal Pricing Model



LPA Contingency Processor

Purpose: To provide mechanism for PJM dispatchers to enter binding transmission constraints and controlling actions into the Locational Marginal Price Calculation process.

Secondary purpose: To provide a tool for PJM dispatchers to evaluate upcoming transmission constraints (Study Mode) and suggest appropriate curtailment and re-dispatch actions.

LPA Contingency Processor

Study Mode Options

- Contract Curtailments Mode

  Provides list of transmission contracts with their effect on the transmission constraint, expressed as a flow percentage. The list is sorted by curtailment priority.

- Re-dispatch Mode

  Provides several lists of generation re-dispatch options, sorted by their dollar per MW effect on the transmission constraint. This list provides dispatchers with information to determine the most economic (least costly) means of mitigating the constraint(s).

LPA Contingency Processor

Types of transmission constraints:

- Actual Thermal Limit
- Contingency Thermal Limit
- Interface Flow Limit
- Local Voltage Limit
- Stability Limit

Types of controlling actions:

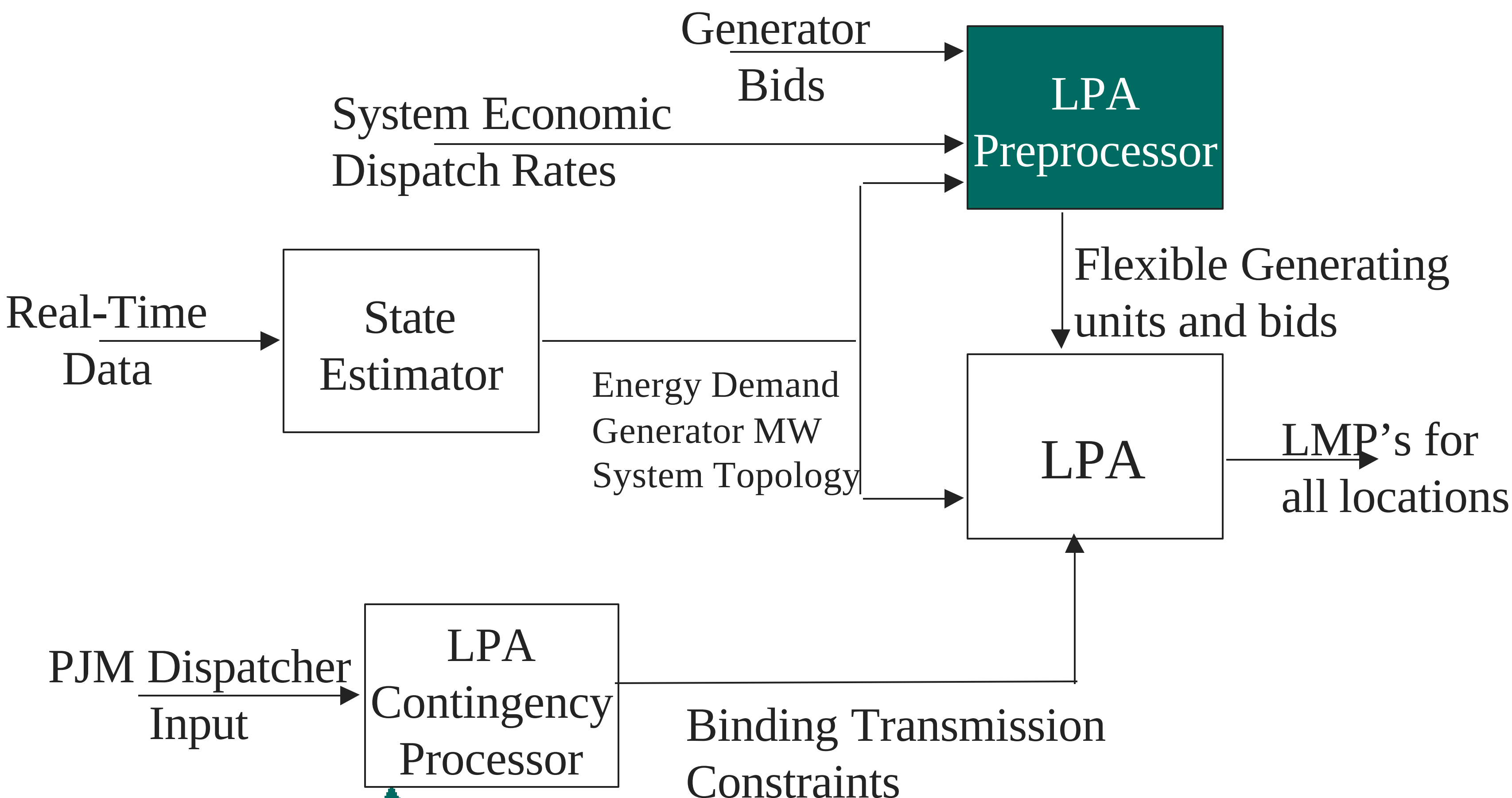
- System Reconfiguration
- Contract Curtailment
- Re-dispatch

PJM Economic Dispatch

PJM dispatchers balance load and generation within system reliability limitations by performing real-time security constrained economic dispatch using various dispatching tools.

- Electronic dispatch signals are sent to flexible generators to control their output.
- Under transmission constrained conditions:
  - Capability exists to send up to 13 different electronic dispatch signals
  - Individual generators are instructed via telephone

Locational Marginal Pricing Model



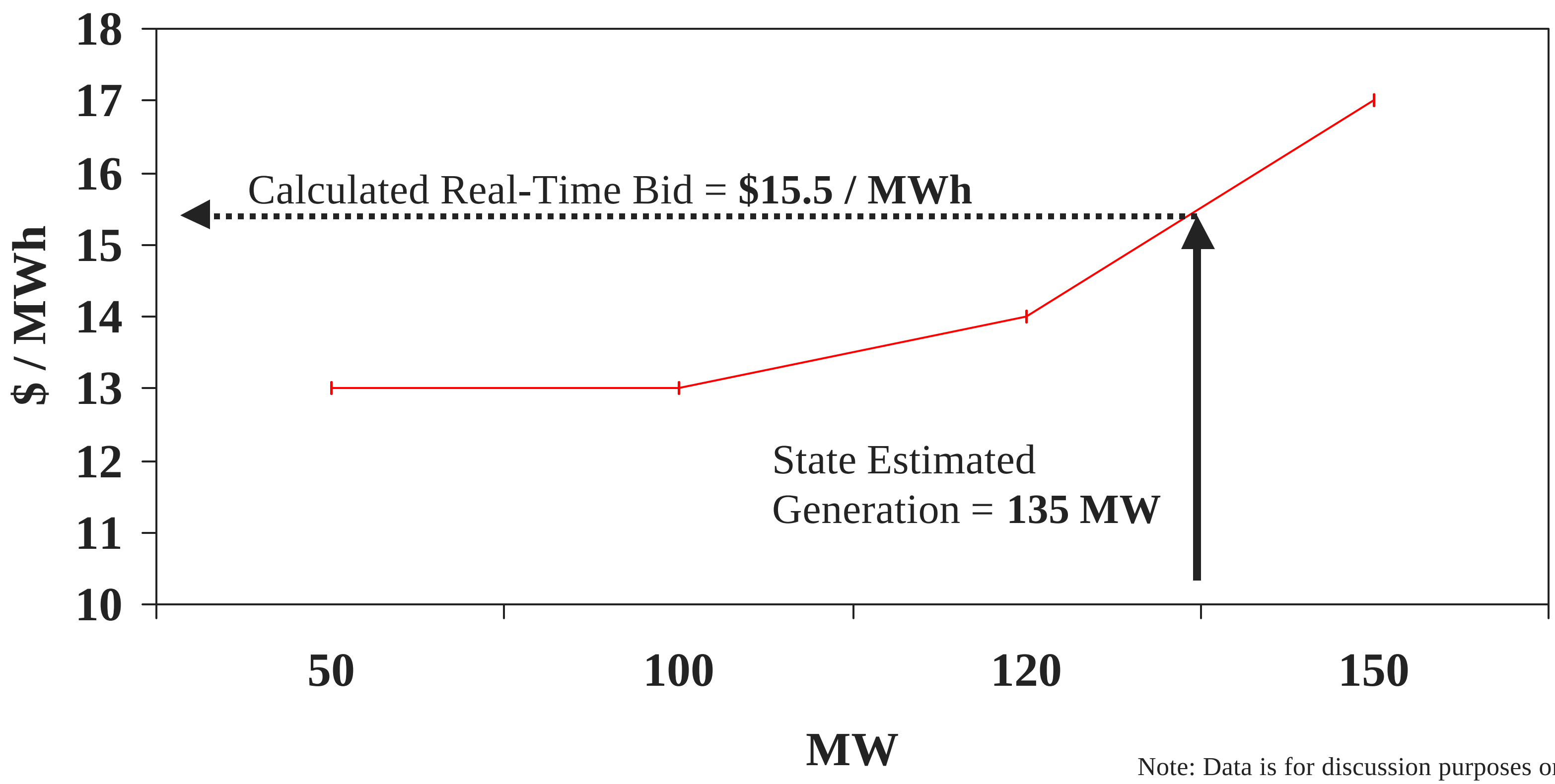
LPA Preprocessor

Purpose: Determine which generating units are eligible to participate in the LMP calculations

- Calculate real-time generator bid by comparing State Estimator MW output to day-ahead bid information
- Compare real-time bid to economic dispatch rate
- Process generation that is designated as under control for transmission constraints

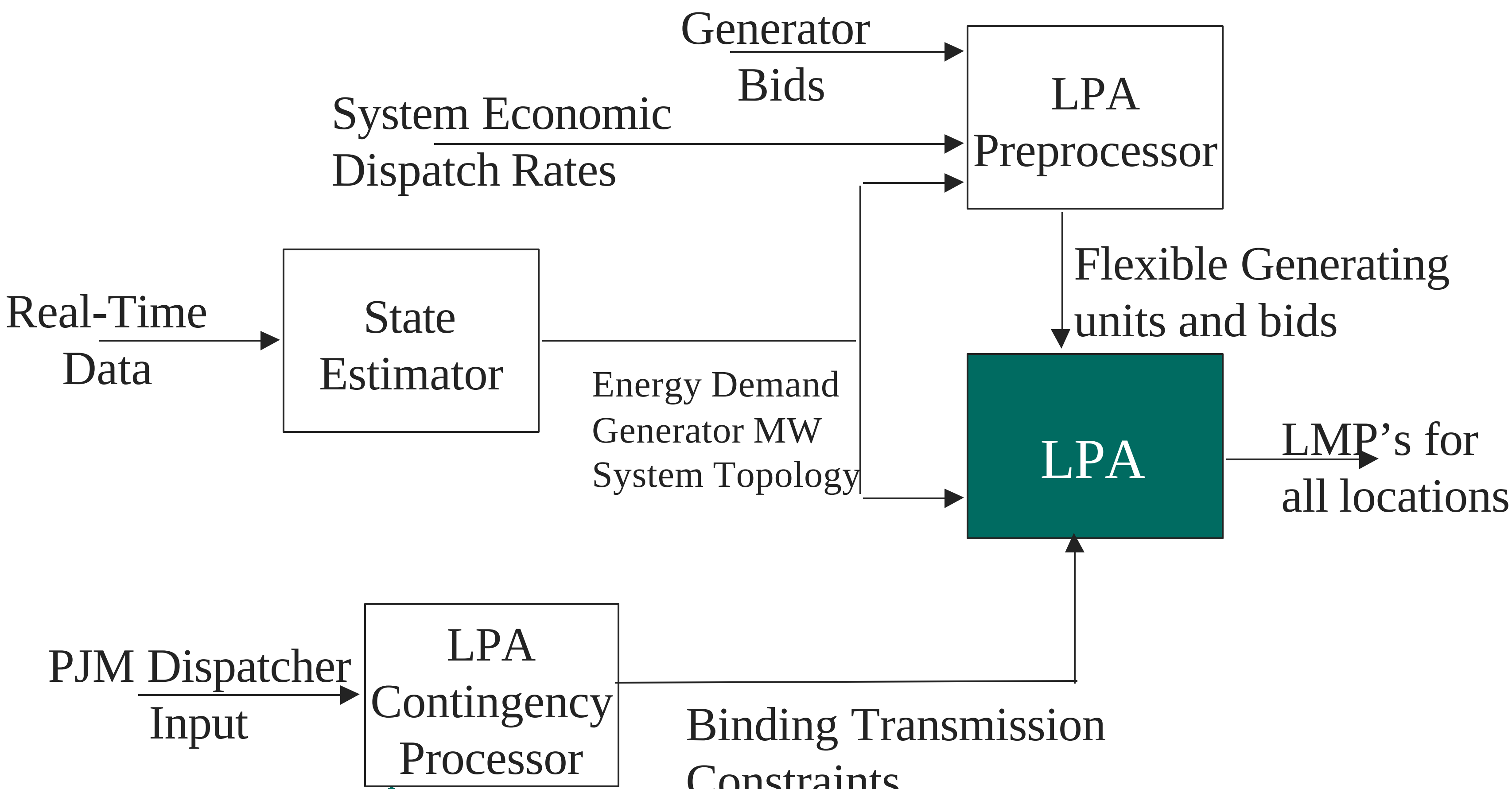
LPA Preprocessor

Generic Generator Real-time Bid Calculation



Note: Data is for discussion purposes only.
It does not represent actual PJM Generation
Information

Locational Marginal Pricing Model



Locational Price Algorithm

Purpose: Calculate locational marginal prices based on actual system conditions at five minute intervals

- Incremental Linear Programming formulation around the current operating point
- Real-time generation bids are entered with a constant slope
- The LP is formulated such that the optimal solution will be very close to the current system operating condition

Locational Price Algorithm

Formulation:

Minimize : $Z = \Sigma\, C_i(\Delta P_i) - \Sigma\, C_j(\Delta L_j)$

– ***subject to:***

$$\Sigma\, \Delta P_i - \Sigma\, \Delta L_j = 0$$

$$\Delta Pmin_i \le \Delta P_i \le \Delta Pmax_i$$

$$\Delta Lmin_j \le \Delta L_j \le \Delta Lmax_j$$

$$A_{ik} \Delta P_i + D_{jk} \Delta L_j \le 0$$

– ***where:***

ΔP_i - the change in power output for generator i

$\Delta Pmax_i$ – the upper MW bound for generator i

$\Delta Pmin_i$ – the lower MW bound for generator i

C_i - the calculated real-time offer for generator i

C_j - the calculated real-time bid for load (transaction) j

ΔL_j - the change in power consumption for load j (note in practice the only dispatchable loads that currently exist are external purchase transactions)

$\Delta Lmax_j$ - the upper MW bound for load j

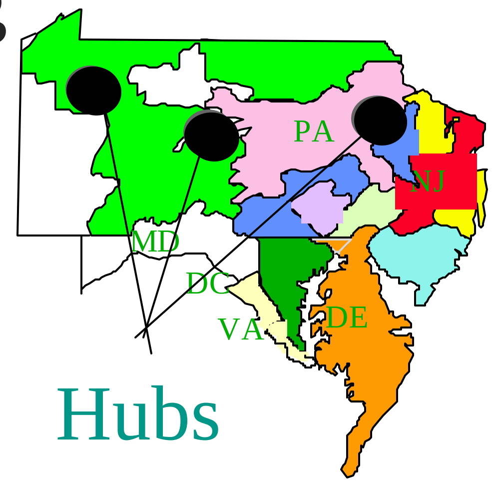
$\Delta Lmin_j$ - the lower MW bound for load j

A_{ik}, - the matrix of shift factors for generation bus i (with respect to the reference bus) on the binding transmission constraints (k)

D_{jk}, - the matrix of shift factors for load bus j (with respect to the reference bus) on the binding transmission constraints (k)

Hubs

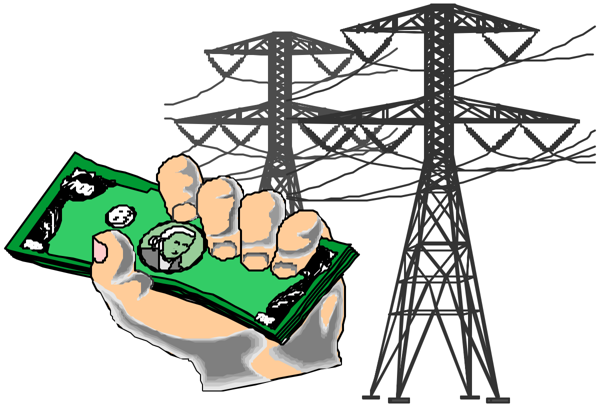
- Cross section of representative buses
- Price less volatile than a single point
- Common point for commercial trading
- Three Hubs
  - Western (111 Buses)
  - Eastern (237 Buses)
  - Interface (3 Buses)
- Weighted average price, based on fixed, equal weights at each bus



Fixed Transmission Rights and Transmission Service

Fixed 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



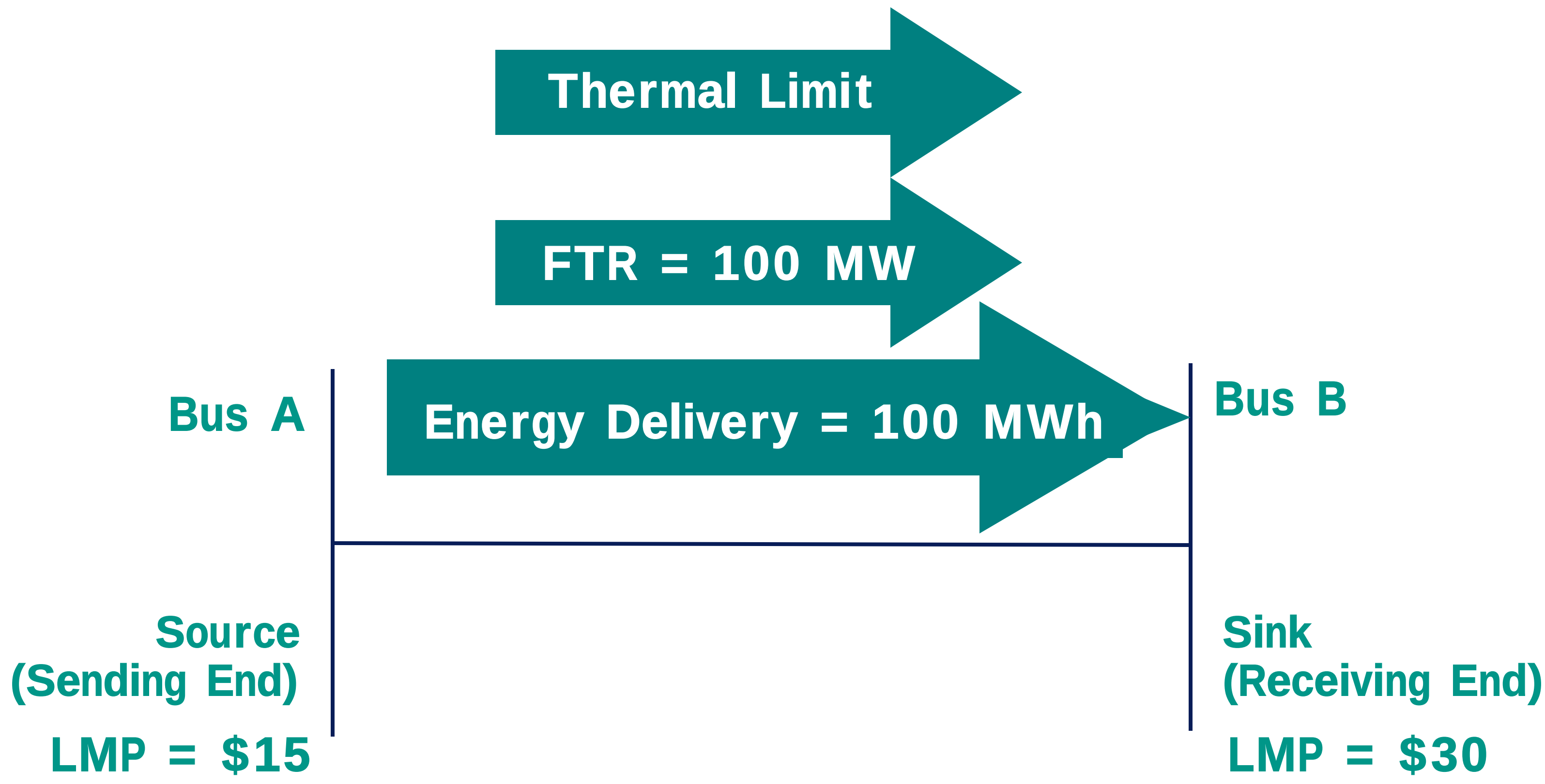
Characteristics of FTRs

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

What are FTRs Worth?

- Economic value determined by hourly Day-ahead LMPs
- Benefit (Credit)
  - same direction as congested flow
- Liability (Charge)
  - opposite direction as congested flow

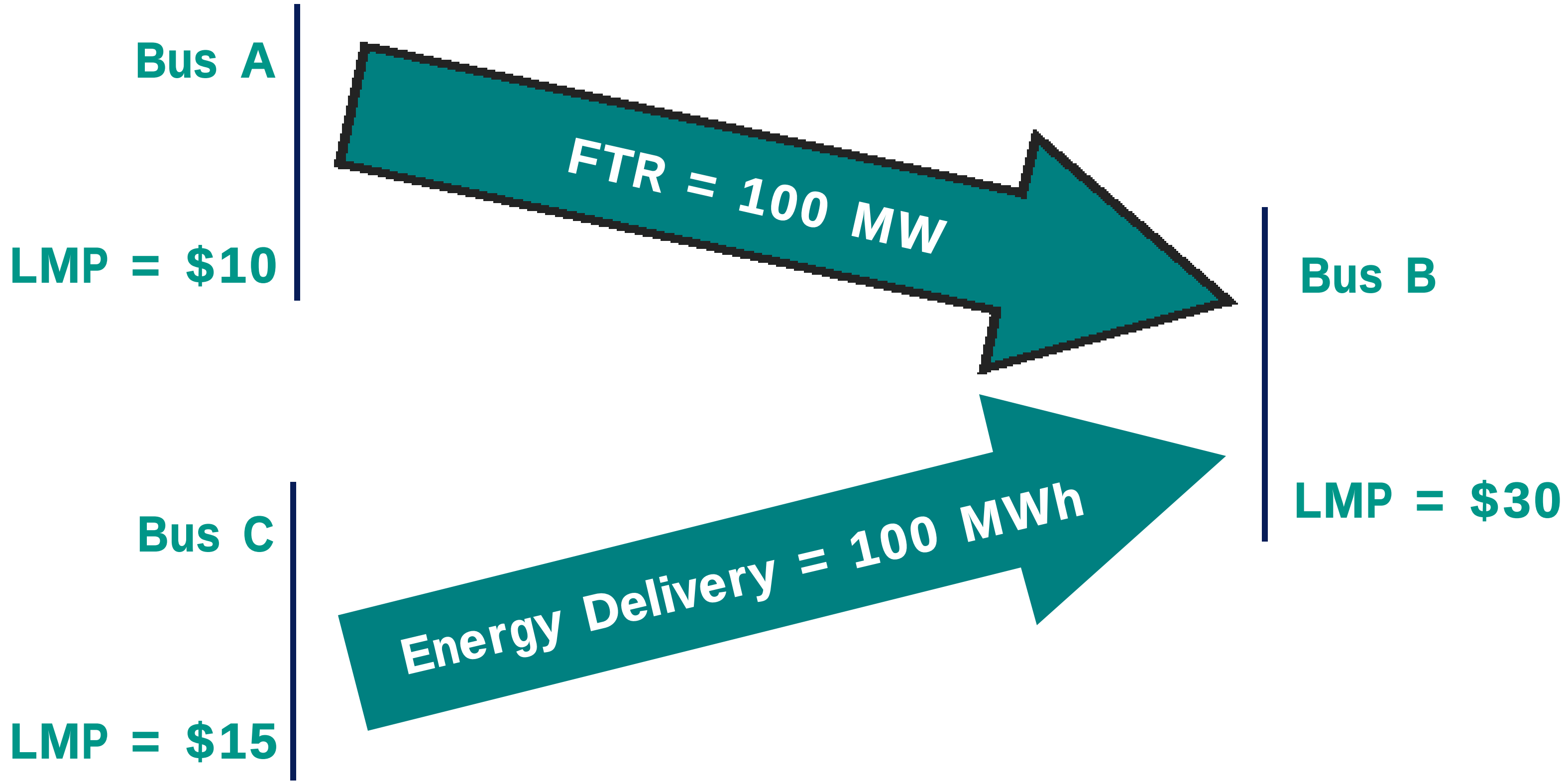
Energy Delivery Consistent with FTR



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

Obtaining FTRs

- Network service
  - based on annual peak load
  - designated from resources to aggregate loads
- Firm point-to-point service
  - may be requested with transmission reservation
  - designated from source to sink
- Secondary market -- bilateral trading
  - FTRs that exist are bought or sold
- FTR Auction -- centralized market
  - purchase “left over” capability

Types of Transmission Service

Point to Point

- Firm
  - Long Term - one year or longer
  - Short term - daily, weekly, monthly
- Non-Firm
  - Short term - hourly, daily, weekly, monthly

Network Integration

- Firm - designated resources
- Non-Firm - non-designated resources

Priority of Service

1. Network and Firm Point to Point
2. Network import willing to pay congestion
3. Non-Firm willing to pay congestion
4. Non-Firm over Secondary Points willing to pay congestion
5. Spot Market Import
6. Network not willing to pay congestion
7. Non-firm not willing to pay congestion

Simultaneous Feasibility Test

What is an SFT?

- Test to ensure that all subscribed transmission entitlements (FTRs) are within the capability of the existing transmission system
- Test to ensure the PJM Energy Market is revenue adequate under normal system conditions
- <u>NOT</u> a system reliability test
- <u>NOT</u> intended to model actual system conditions

Test Conditions

- Model all requested FTRs for study period in a DC powerflow analysis
- FTRs for point-to-point service are modeled as generation at receipt (source) point(s) and load at delivery (sink) point(s)
- FTRs for network service are modeled as a set of generators at receipt (source) point and network load at delivery (sink) point

SFT Data Inputs

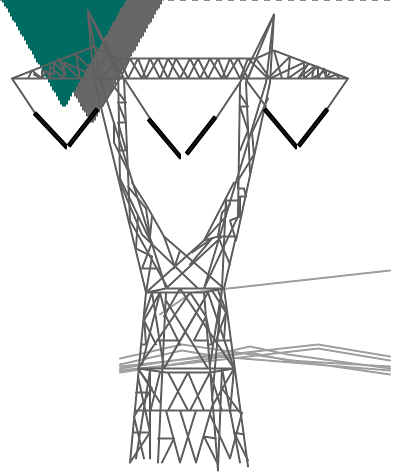
- *Uncompensated Parallel Flow Injections*
- *Transmission Outages*
- *Existing FTRs*
- *Facility Ratings*
- *PJM Network Model*
- *List of Contingencies*
- *Interface Ratings*

FTR SFT (DC Powerflow)

Network Topology Assumptions

- SFT uses power flow model that accurately as possible models expected network topology (facilities status) during time period being analyzed
- Annual case assumes all bulk facilities in service unless there is a known long-term equipment outage
- Monthly cases assume worst-case bulk facilities outage scenario (i.e, scheduled facilities will be modeled as out-of service)
- Near-term cases incorporate more definitive bulk facilities outages

Testing Criteria



- Single contingency test criteria
- Perform DC powerflow analysis to
  - evaluate ability of all system facilities to remain within normal thermal ratings
  - evaluate ability to sustain the loss of any single contingency event with all system facilities remaining within applicable short-term, emergency ratings
  - evaluate ability to maintain acceptable bulk system voltage performance by imposing 500 kV reactive interface limits

FTR Auction

What is the FTR Auction?

- FTR Auction provides a method of auctioning the residual FTR capability that remains on the PJM transmission system at the time of the close of the auction quoting period
- Allows rights to be purchased without firm service
- Allows market participants to bid for FTRs and offer to sell existing entitlements

Why have an FTR Auction?

- Facilitates a more robust and liquid market for transmission entitlements
- Allows PJM Market Participants to submit bids to purchase residual entitlements and to submit offers to sell existing entitlements
- Maximizes efficiency of FTR trading by providing automatic reconfiguration of FTRs

Auctions

- Scope
  - any holder can offer FTR for sale
  - any transmission customer or PJM member can bid for & acquire any number of FTRs
- Frequency
  - single round monthly auction
  - separate auctions
    - on peak -- hours ending 0800 to 2300
    - off peak -- hours ending 2400 to 0700, weekends, and holidays

FTR Auction Process & Time Line

PJM determines and posts expected non-simultaneous estimates of Available FTR Capability for each interface (5)

Fifteen days prior to start of auction month, participants may submit bids to purchase or offers to sell FTRs

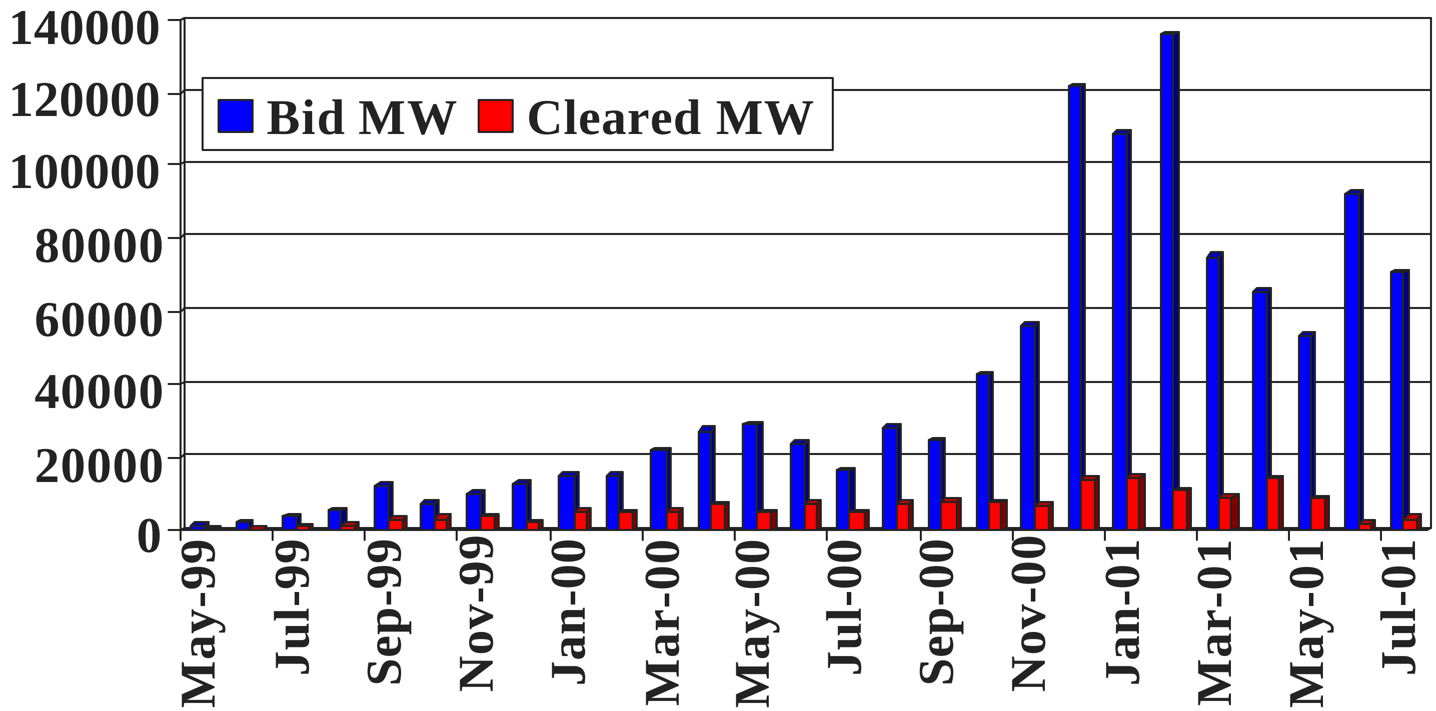
Ten days prior to start of auction month, auction closes

PJM performs FTR auction clearing analysis

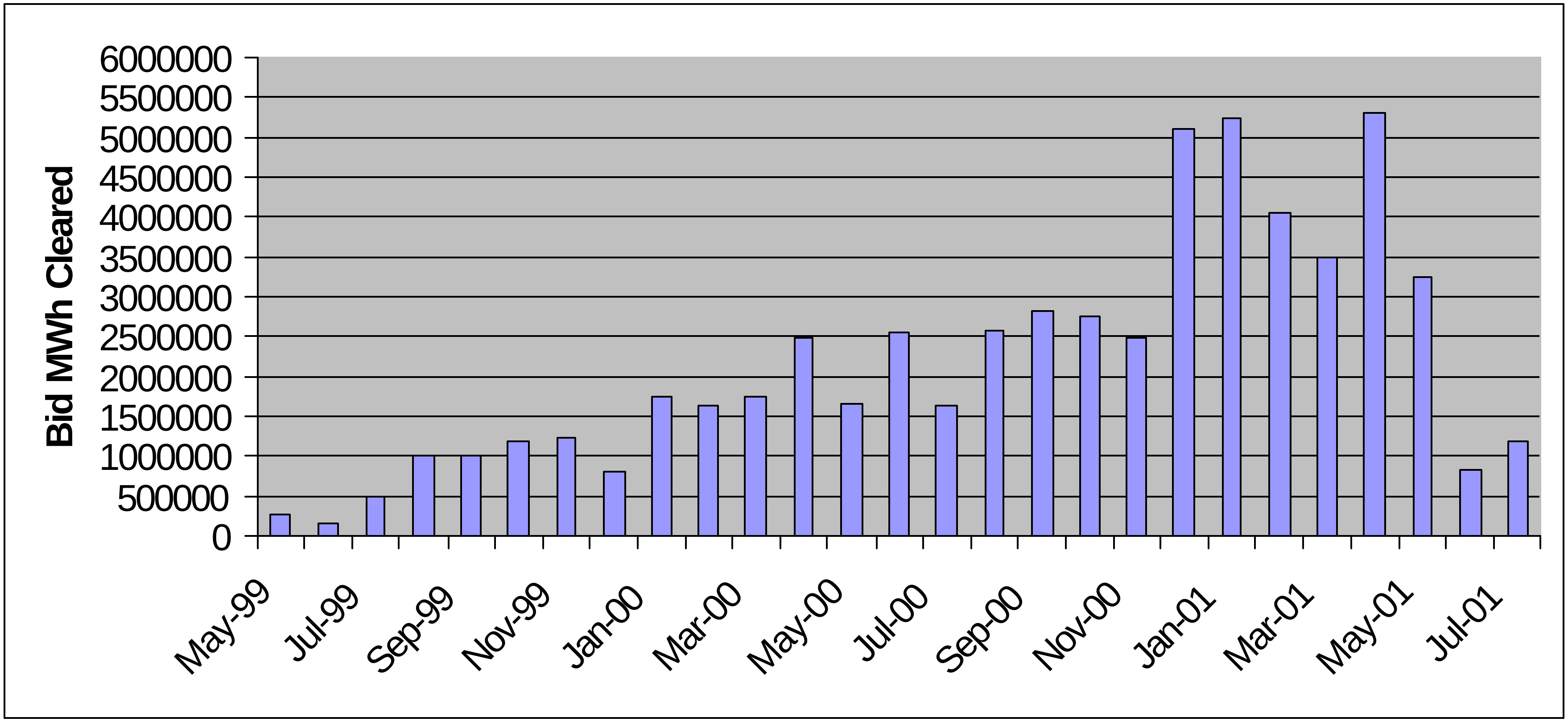
PJM posts FTR auction results *within 2 business days of quoting period closing*

PJM FTR Auction

Monthly Activity

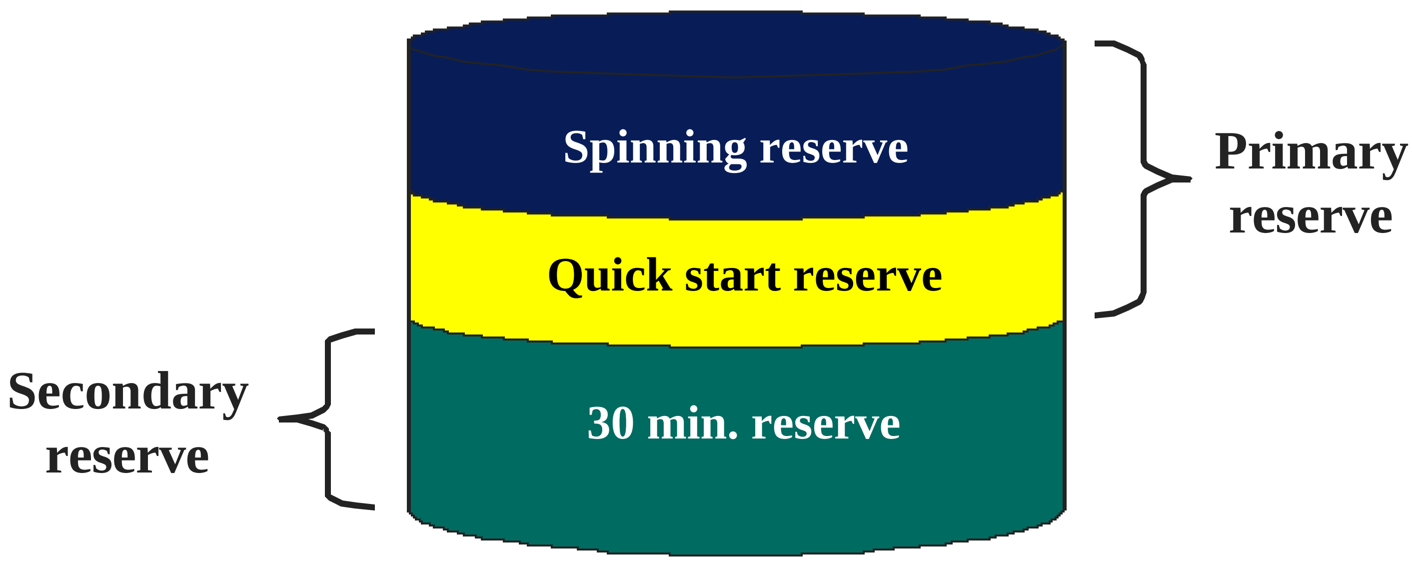


FTR Auction Trading Volume



Ancillary Services and Losses

Operating reserves



Scheduling and paying for operating reserves

- All reserves are scheduled in centralized unit commitment
- Generators provided with “make whole payments” for units started for reserves
- Costs are spread over loads and exports as an uplift
- Reserve quantities:
  - Spinning reserve: ~ 900 MW or largest unit
  - 10-minute non-synch. ~ 1700 MW
  - 30-minute secondary ~ 2500-4500 MW, depending on system conditions

Regulation service

- Transmission customer must provide or purchase
- Regulation market opened June 2000
- Regulation price = higher of RMCP (Regulation Market Clearing Price) or offer price plus opportunity cost

Paying for losses

- Calculating the true marginal cost of losses in LMP is difficult in practice
- PJM effectively charges for average losses:
  - 3% on-peak/2.5% off-peak
- Prices based on load-weighted average LMPs (day-ahead and real-time LMPs)