Smart Markets for a Smart Grid: The US Standard Market Design

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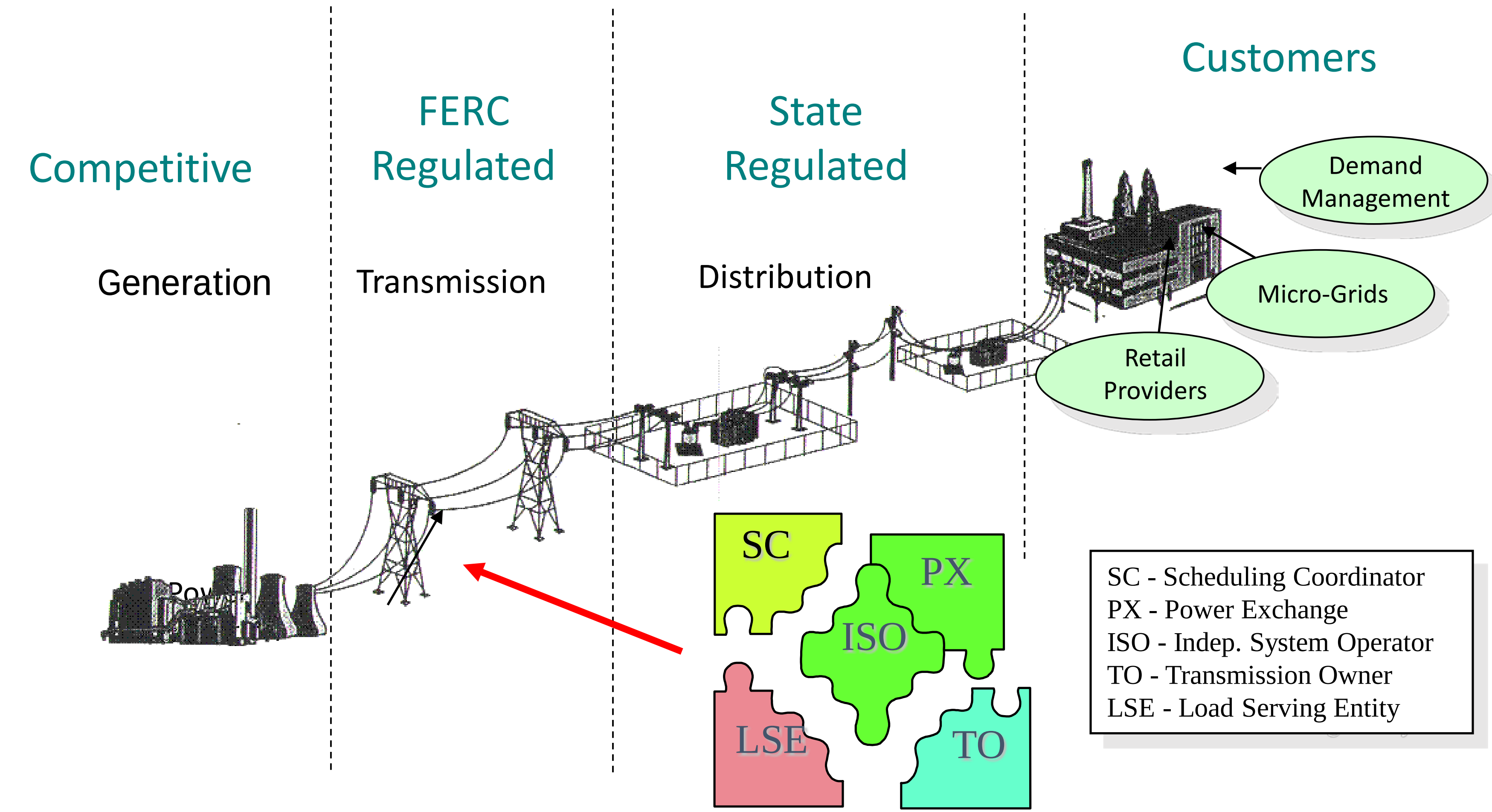
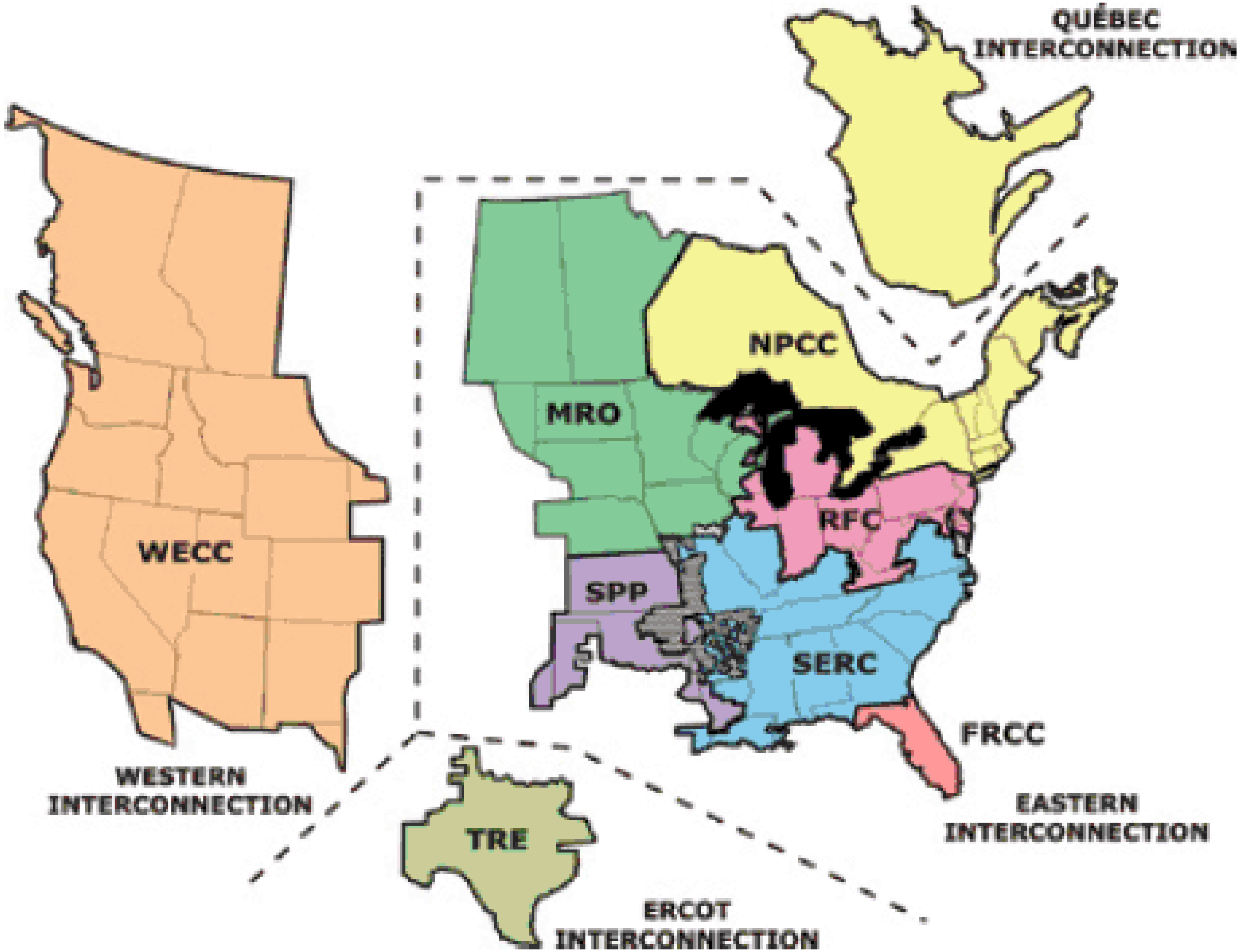
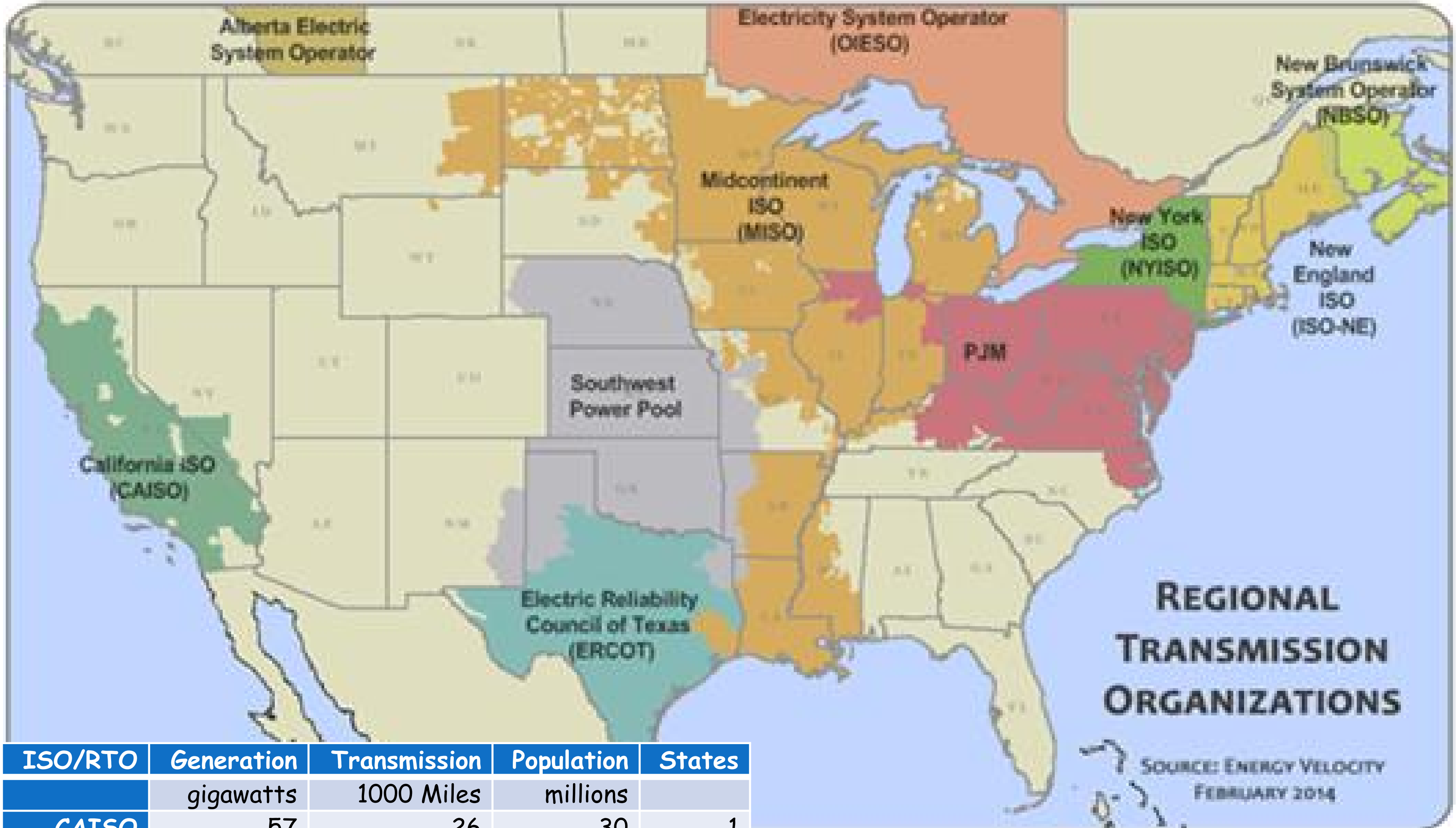
POWER INDUSTRY RESTRUCTURING



Interconnection Regions



Source: NERC, 2009



ISO/RTO	Generation	Transmission	Population	States
	gigawatts	1000 Miles	millions	
CAISO	57	26	30	1
ISO-NE	34	8	14	6
MISO	201	66	53	15
NYISO	41	11	19	1
PJM	165	56	51	13
SPP	66	51	15	6
ERCOT	70	40	23	1
TOTAL	634	256	205	43

Cover 70% of US load

ISO Principles

(for control area operators)

- Non-discriminatory governance
- No financial interest in market
- Open-access transmission with single tariff
- Rates promote efficient use of grid
- Short-term reliability/relieve constraints
- Control of transmission facilities
- Incentives to be efficient

  (Uniform price auction and marginal cost pricing)
- Open information system
- Coordinate with neighbors

Market Design

Market Designs Vary among RTOs

Table 7: Wholesale Electric Markets in 2006

■ Existing   □ Projected

	Real-time market (RTO/ISO)	Real-time market Bilateral	Day-ahead market (RTO/ISO)	Day-ahead market Bilateral	Virtual Bidding (RTO/ISO)	Ancillary services markets (RTO/ISO)	Financial transmission rights (RTO/ISO)	Capacity (UCAP) markets (RTO/ISO)	Associated financial markets
New England	■	■	■	■	■	■	■	■ [1]	■
New York	■	■	■	■	■	■	■	■ [2]	■
PJM	■	■	■	■	■	■	■	■ [3]	■
Midwest	■	■	■	■	■	□ 08	■		■
Southeast		■		■					■
SPP	■	■		■					
ERCOT	■	■	□ 09	■		■	■		
Northwest		■		■					■
Southwest		■		■					■
California	■	■	□ 08	■	□ 09	■	■	[4]	■

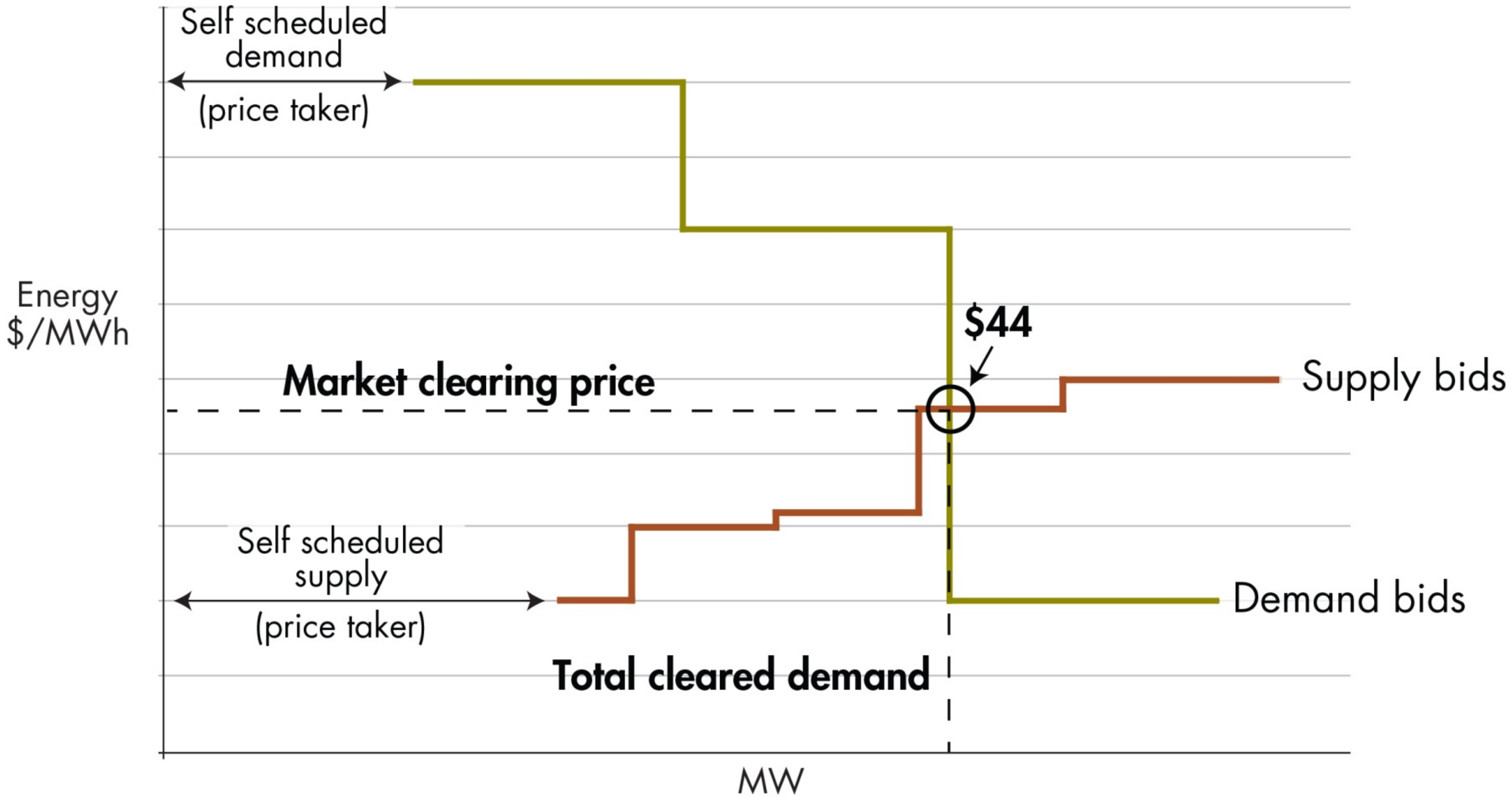
[1] Transitioning to a formal capacity market. ISO-NE's installed capacity market was replaced on December 1, 2006, with the transition period for its new Forward Capacity Market.
[2] Locational
[3] Systemwide
[4] California is considering a formal capacity market.

Economic Dispatch

Multiple Products and Markets

- ❑Day-ahead energy market
- ❑Real-time energy market
- ❑Forward capacity market
- ❑Financial transmission rights (FTR, CRR) auction market
- ❑Regulation market (capacity and mileage)
- ❑[Flexible Ramping Product]
- ❑Operating reserves markets
  - Spinning
  - Non-spinning
  - Replacement

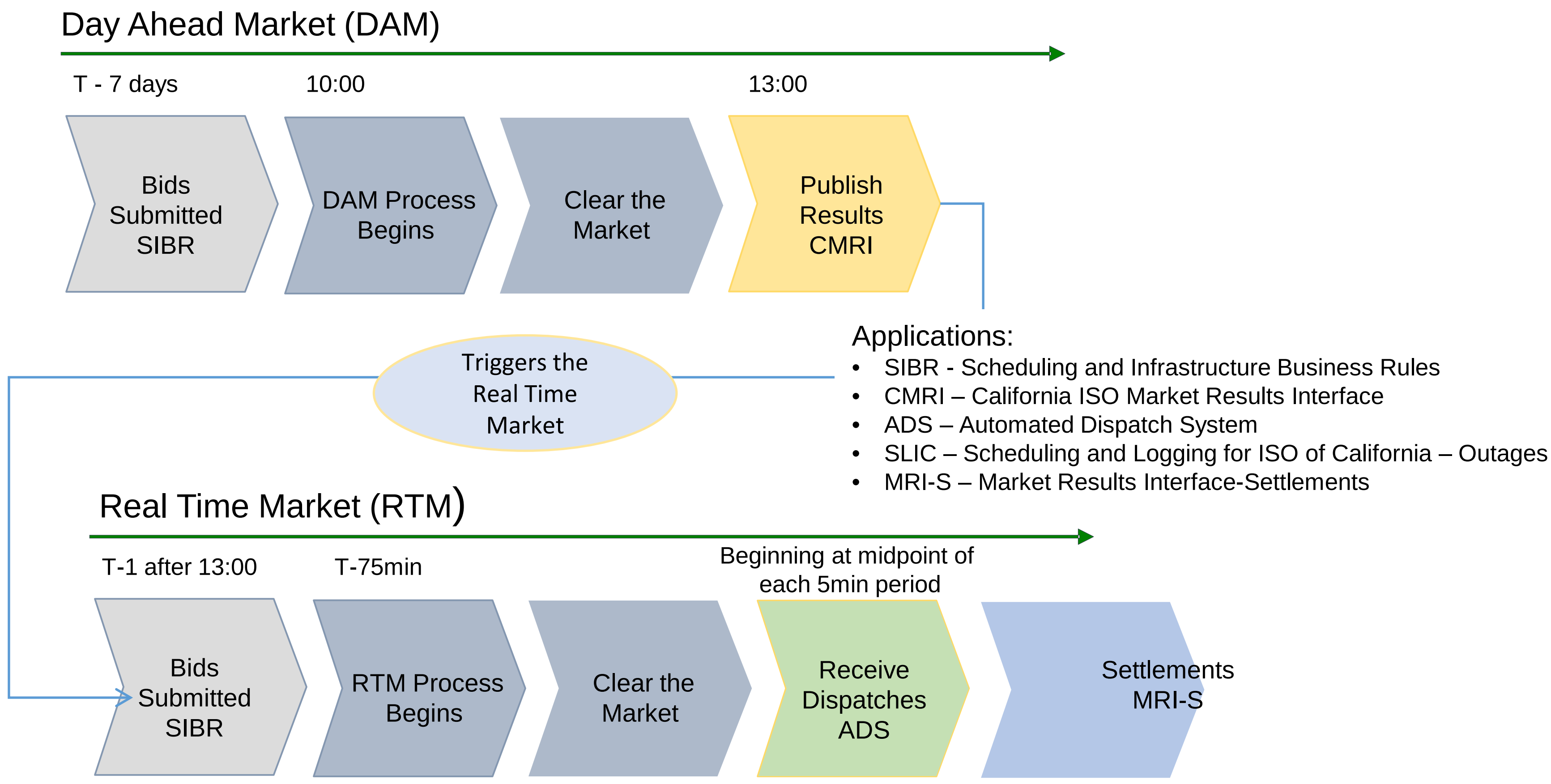
Uniform Marginal Cost Pricing



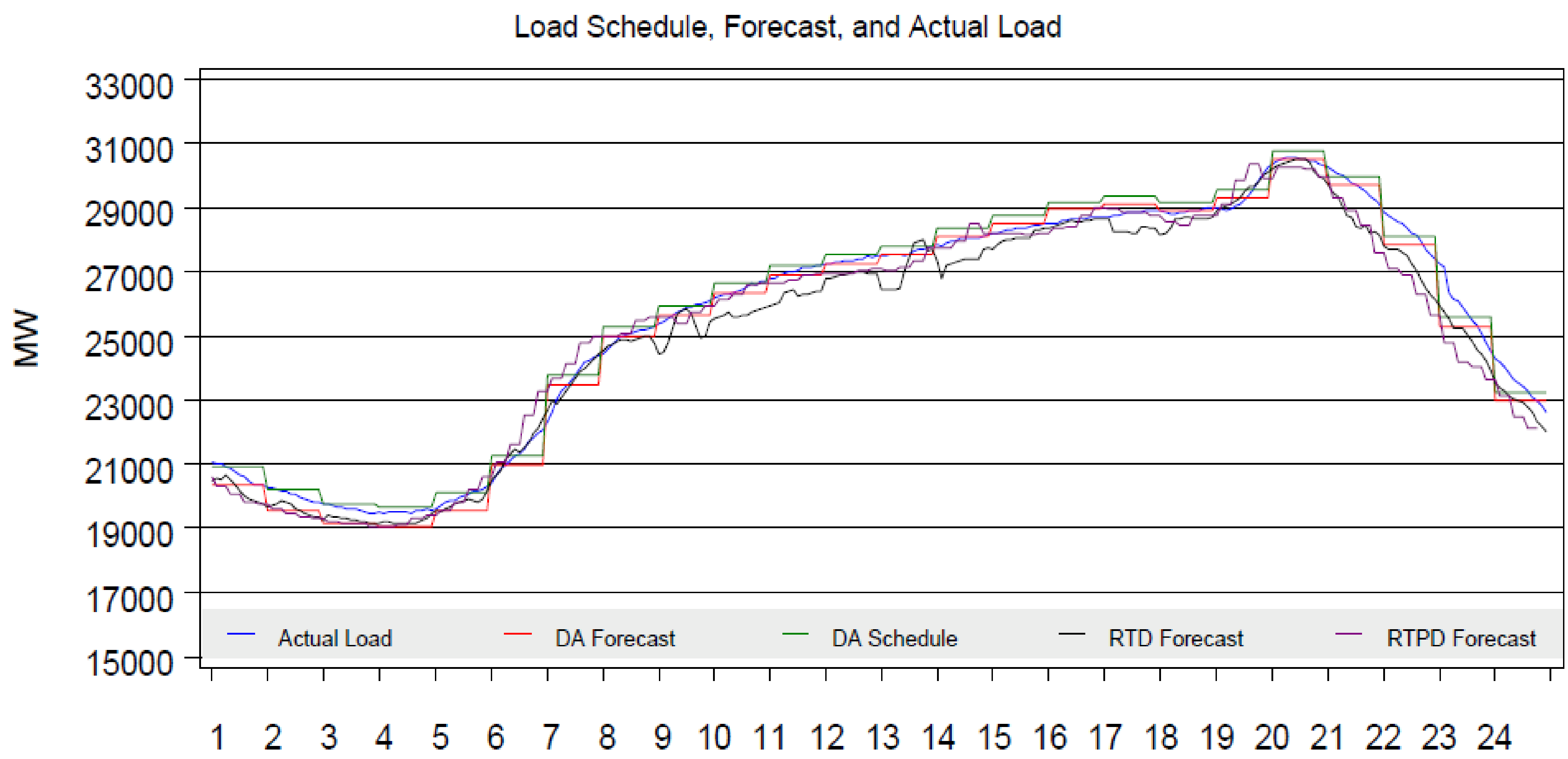
Two-settlements Energy Markets

- The two-settlement electricity markets consist of two interrelated markets: day-ahead (DA) market, and real-time (RT) market.
- DA LMPs are generally considered more stable than RT LMPs.
- The DA market includes three sequential processes: market power mitigation and reliability requirement determination (MPM-RRD), integrated forward market (IFM), and residual unit commitment (RUC).
- In the RT market, the ISO runs the economic dispatch process every 5 minutes to rebalance the residual demand.
- If a resource does not cover its total cost including start-up and minimum load cost through its energy revenue at DA and RT LMPs, its shortfall is covered by an uplift payment which is allocated to market participants.

California ISO Market Timeline

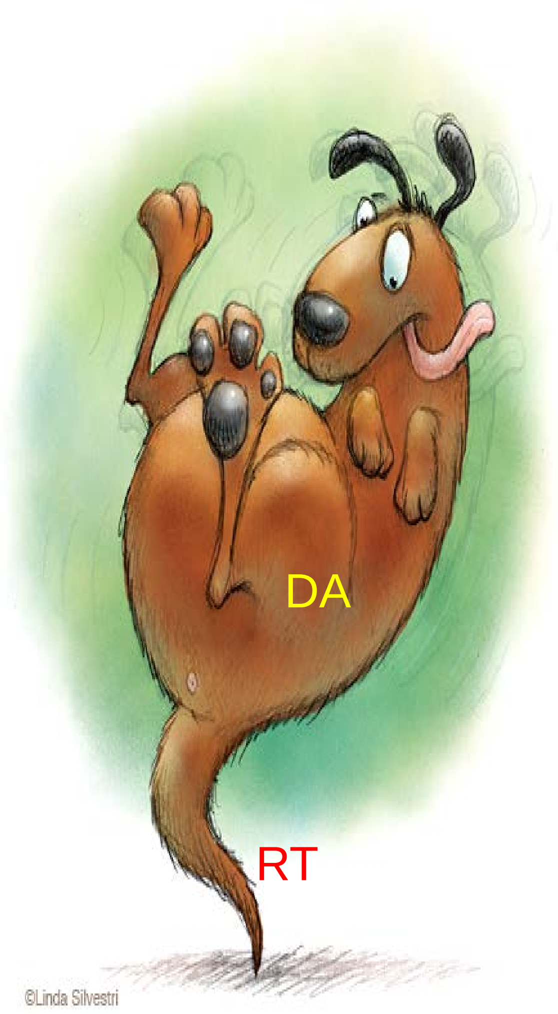


Typical Daily Scheduling

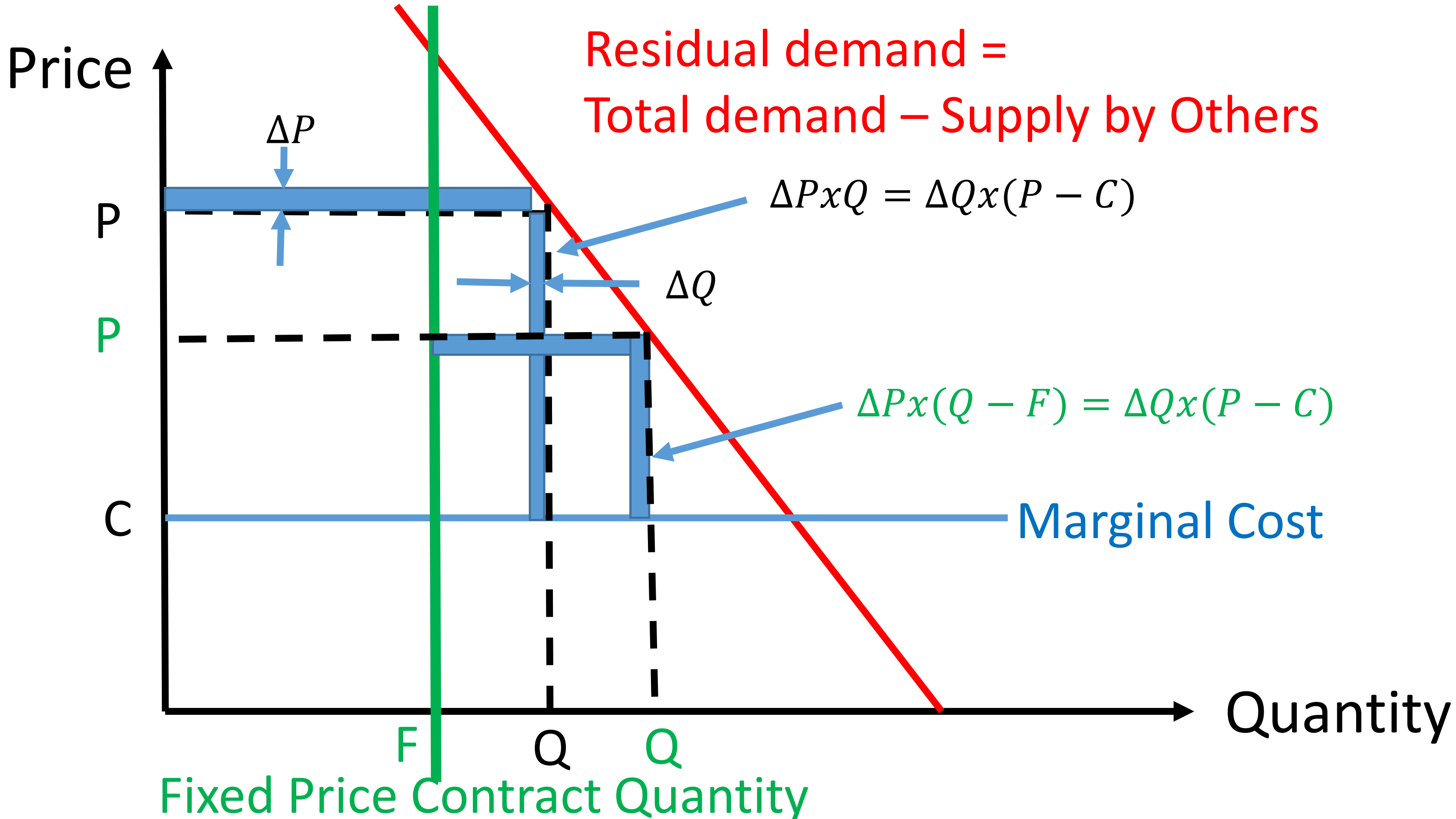


Why Two Settlements

- Reduces incentive for real time price manipulation through physical withholding and deviation from schedule (forward markets mitigate market power)
- Provides ex-ante price signals for demand response
- Provides a stable spot price for settlement of long term bilateral contract
- Improves reliability through economic deviation penalty (day ahead dispatch is financially binding with RT prices setting deviation penalties)



Two Settlements Mitigate Market Power



Unit Commitment Optimization - MIP
(Solved for 24 hours in Day Ahead market)

Decisions (financially binding):

on/off , output level and compensated reserves for each unit in each of 24 hours + locational marginal energy prices and reserve prices for each node and hour

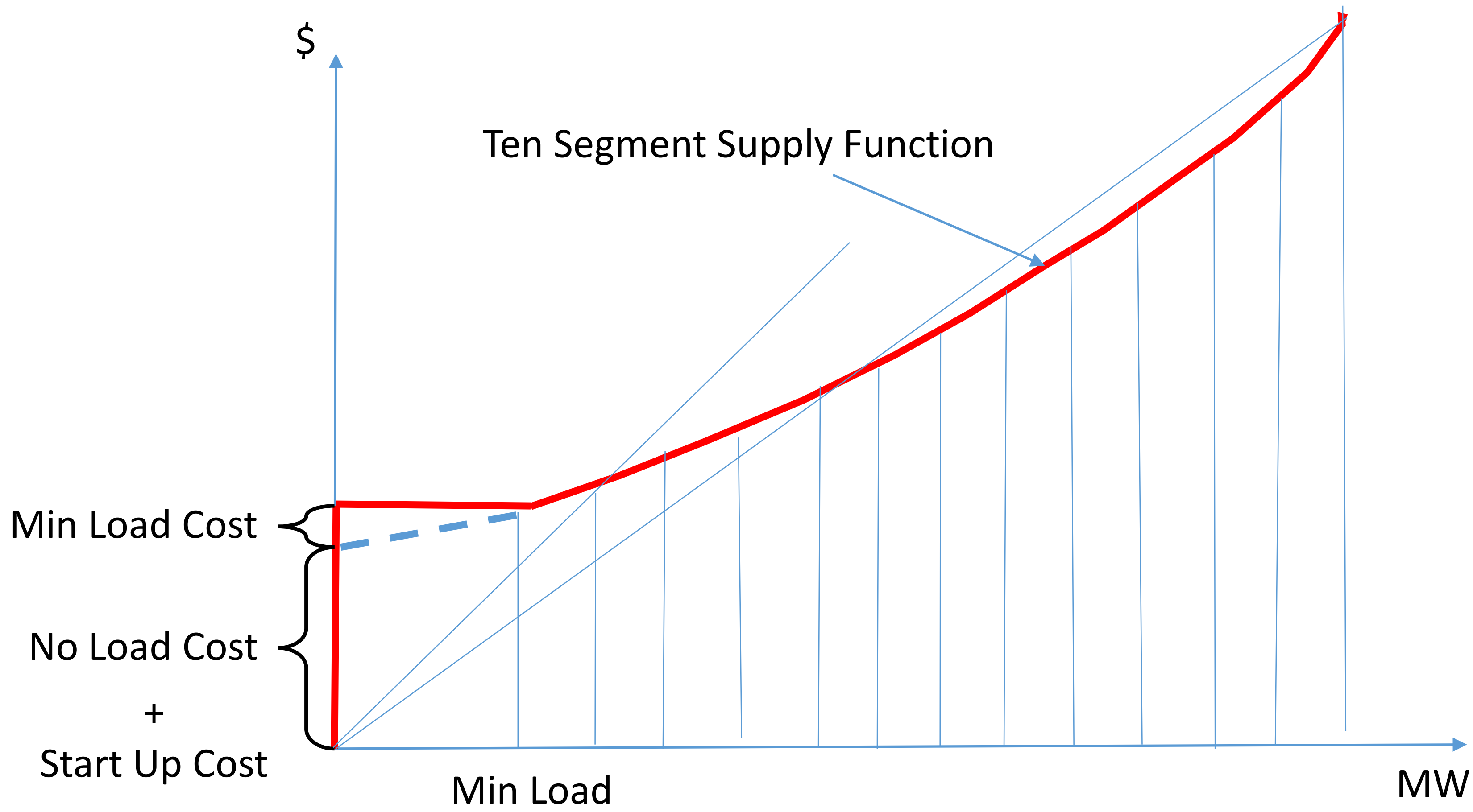
- *Minimize* Σ ***(fuel cost + no-load cost + startup cost)***

  s.t.

  - **Load balance constraint at each node**
  - **Unit output constrain for each generator**
  - **Unit ramping limits for each gen**
  - **Unit min up time and min down time for each gen**
  - **Transmission constraints (DC approximation with thermal proxy limits)**
  - **Reserves margin requirements**
  - **Contingencies (n-1)**

(Cost and constraints data provided as offers in day ahead auction)

Offer Structure in DA Market



Scale of Day Ahead Market Clearing

pjm

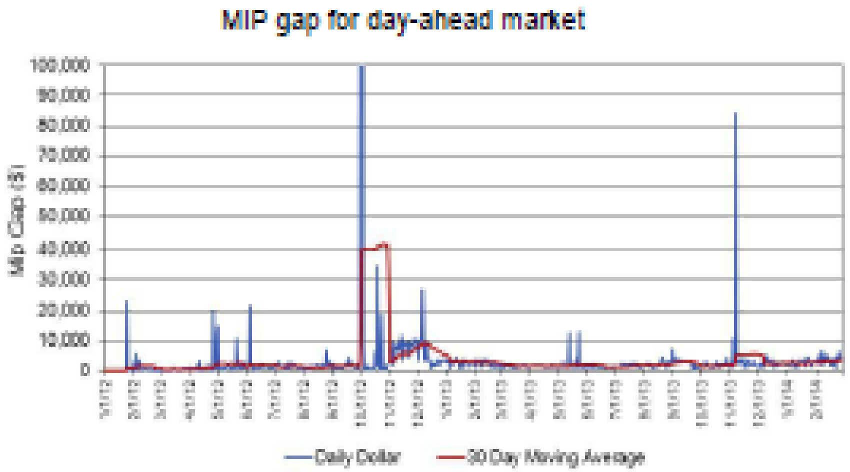
Day Ahead Market – Average Daily Volumes

- 1,600 generators, 3 part offers (startup, no load, 10 segment incremental energy offer curve)
- 20,000 - Demand bids – fixed or price sensitive
- 60,000 - Virtual bids / offers
- 9,500 - eligible bid/offer nodes (pricing nodes)
- 20,000 - monitored transmission elements
- 6,000 - transmission contingencies modeled

CAISO Markets -Core Engine

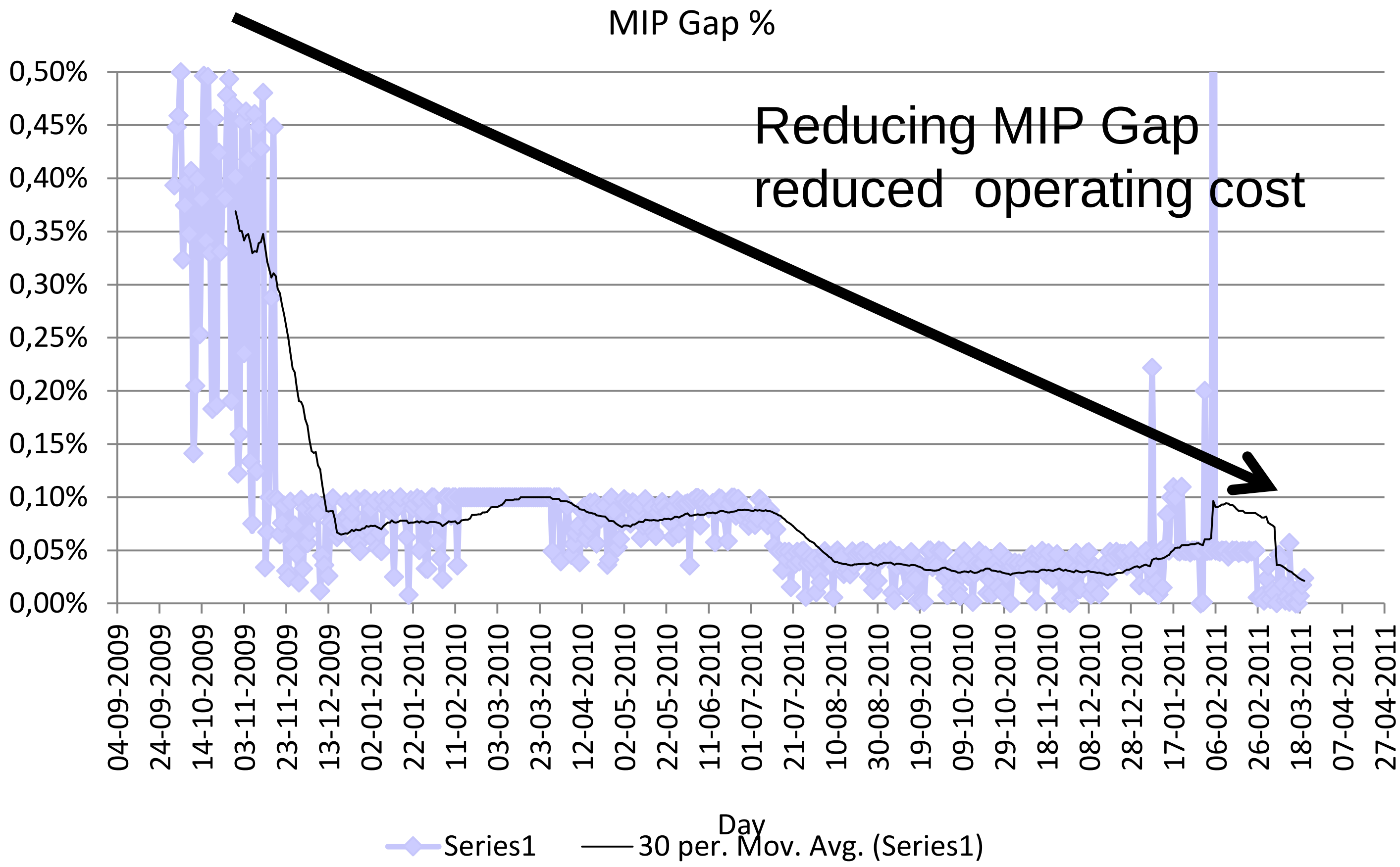
- Mixed Integer Programming: Linearized Formulation
- Solution within MIP gap, absolute or relative

- MIP Gap: At any given iteration, difference between current best MIP solution and best LP solution.
-Best MIP solution enforces {0,1} constraints.
-Best LP solution relaxes {0,1} constraints.



- Constraint violations modeled with penalty prices.
  - One-segment penalty for all transmission constraints.
  - Constraint relaxation to attain a feasible solution.

Improving accuracy of Mixed Integer Programming reduced annual operating costs by estimated $23 million



Bid Cost Recovery (BCR) Uplift

- Generation units submitting bids (startup, no-load and variable energy cost) in the day ahead market, are paid only for market clearing energy awards according to the hourly LMP at their location but are guaranteed not to loose money over the 24 hour period.
- If a unit committed by the ISO in the day ahead market does not cover its total (as bid) commitment cost with its energy revenues, then the ISO will make up the shortfall as a BCR payment which is uplifted to load.
- In 2013 the California ISO paid $33 million BCR payments out of a total $10.7 billion total annual cost (0.3%)

Power Flow Optimization (every five minutes) and Locational Marginal Pricing (LMP) For Generators that are Running and Synchronized

Decisions:

Price of energy (LMP) at node i = Marginal cost of energy at the node Calculated as the dual variable to energy balance constraint for the node in a linearized Optimal Power Flow approximation (DCOPF)

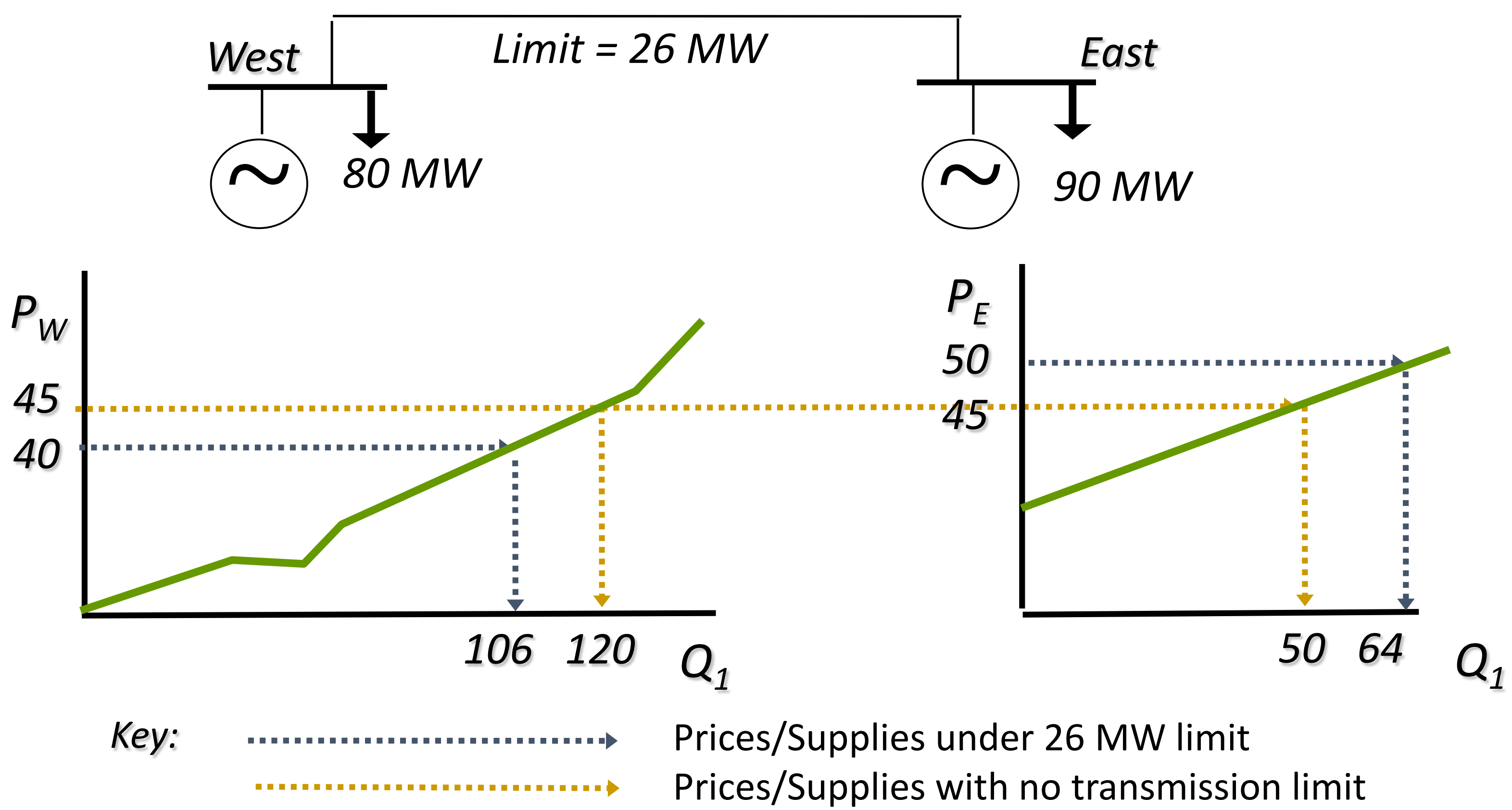
- ***Minimize Σ(Generator Fuel Cost)***

s.t.

- ***Energy balance (net supply = load at each node)***
- ***Generator limits (including dynamic limits such as ramp rates)***
- ***Transmission Constraints (AC model with voltage and thermal limits)***
- ***Reserve requirements***

(Cost curves and generator limits data provided as offers in real time auction every 15 minutes)

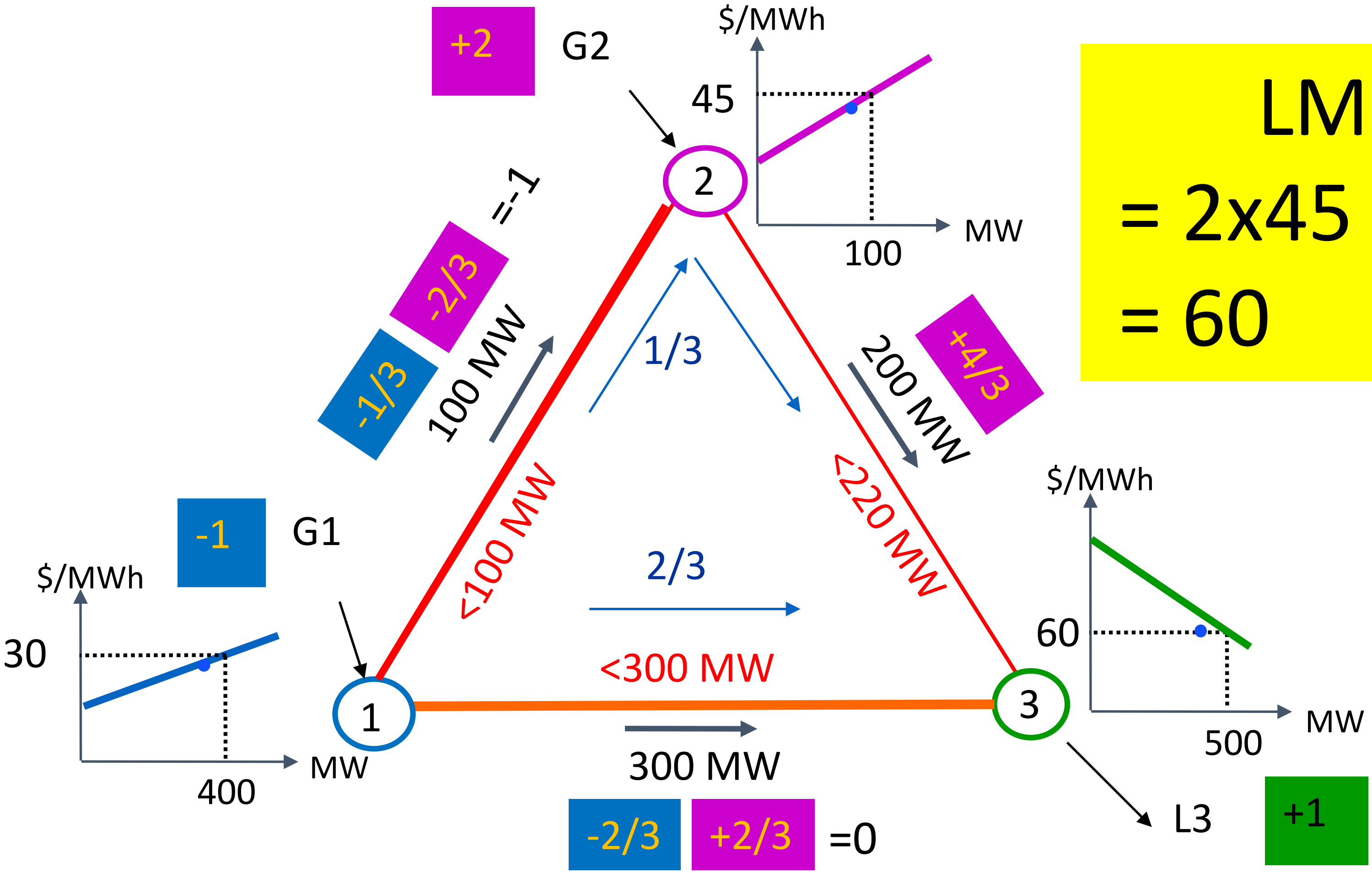
LMP / Congestion Example



- ***Marginal value of transmission = \$10/MWh (=\$50 – \$40)***
- ***Total congestion revenue = \$10*26 = \$260/hr***
- ***Total redispatch cost = \$130/hr***
- ***Congestion cost to consumers: (40*106+50*64) – (45*170) = 7440 – 7650 = –\$210/hr***

Locational Marginal Prices with Loop flow

LMP is the price of serving one more MW at a location without violating flow limits



LMP3

= 2x45 - 1x30

= 60

Electric Power Network

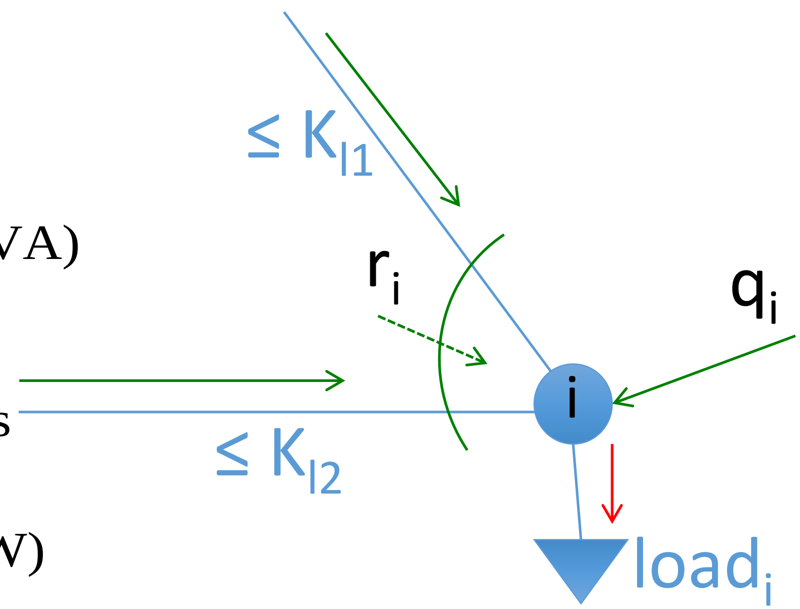
N = the set of buses
L = the set of transmission lines

(MW = Megawatt)

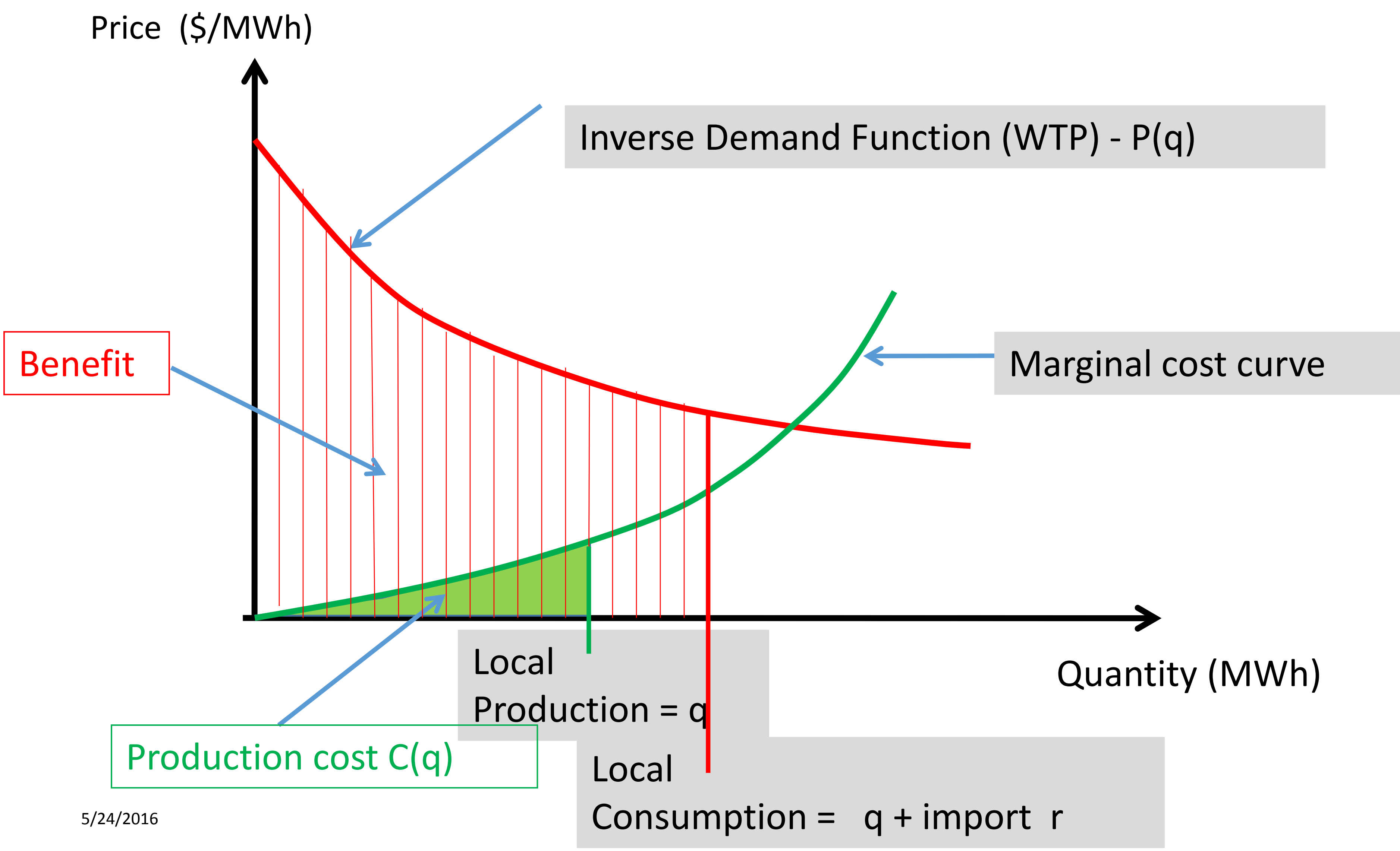
$$q_i + r_i = load_i, \quad \forall i \in N$$
$$\sum_{i \in N} r_i + Losses = 0$$
$$-K_l \le \sum_{i \in N} D_{l,i} r_i \le K_l, \ \forall l \in L$$
$$\underline{q}_i \le q_i \le \bar{q}_i, \quad \forall i \in N$$

q_i MW output of the plant at bus i
r_i MW import/export at bus i (import = +)

$load_i$ MW fixed load at bus i
K_l Rating of transmission line l (MVA)
$D_{l,i}$ $\text{PTDF}_{l,i}$ of line l with respect to a unit injection at bus i and a unit withdrawal at the slack bus
$\underline{q}_i$ Plant i's must-run limit (MW)
$\bar{q}_i$ Plant i's maximum capacity (MW)



Measuring Social Welfare



DC- Approx. Optimal Power Flow (DCOPF)

Maximizes Net Benefit (or minimizes as bid cost)

Import/Export quantity

Local production

$$\max_{r_i\ ,i\in N} \sum_{i\in N}\left(\int_0^{r_i\ +q_i} P_i(\tau_i)d\tau_i - C_i(q_i\ )\right)$$

Inverse demand function

subject to:

$$\sum_{i\in N} r_i\ + losses = 0$$

Balancing constraint

$$-K_l\ \le \sum_{i\in N} D_{l,i} r_i\ \le K_l\ ,\ l \in L$$

Flows constraints

KKT conditions for the DCOPF problem

LMP

$$\boxed{P_i(q_i + r_i) = p + \varphi_i \quad i \in N}$$

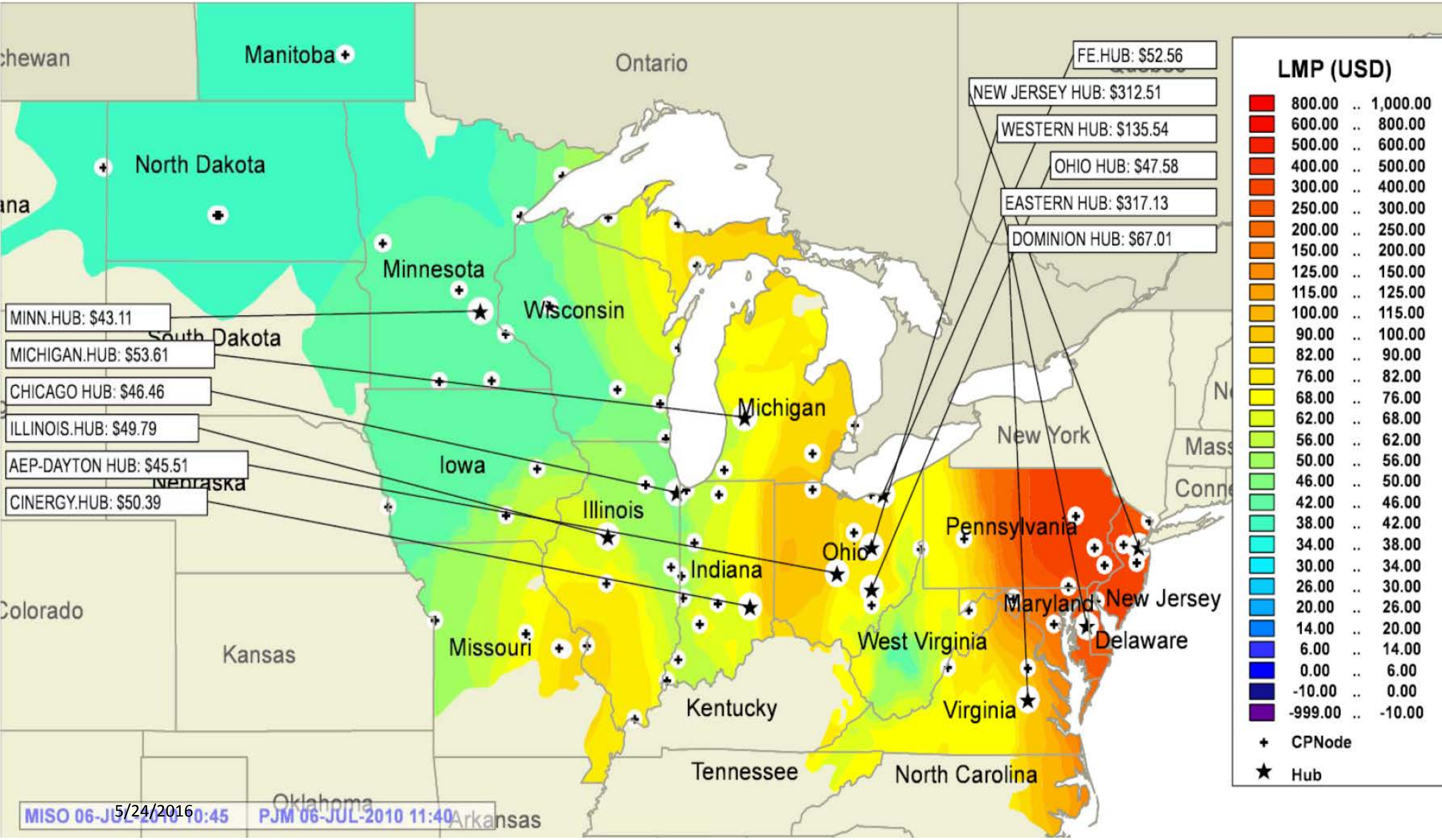
Nodal Markup

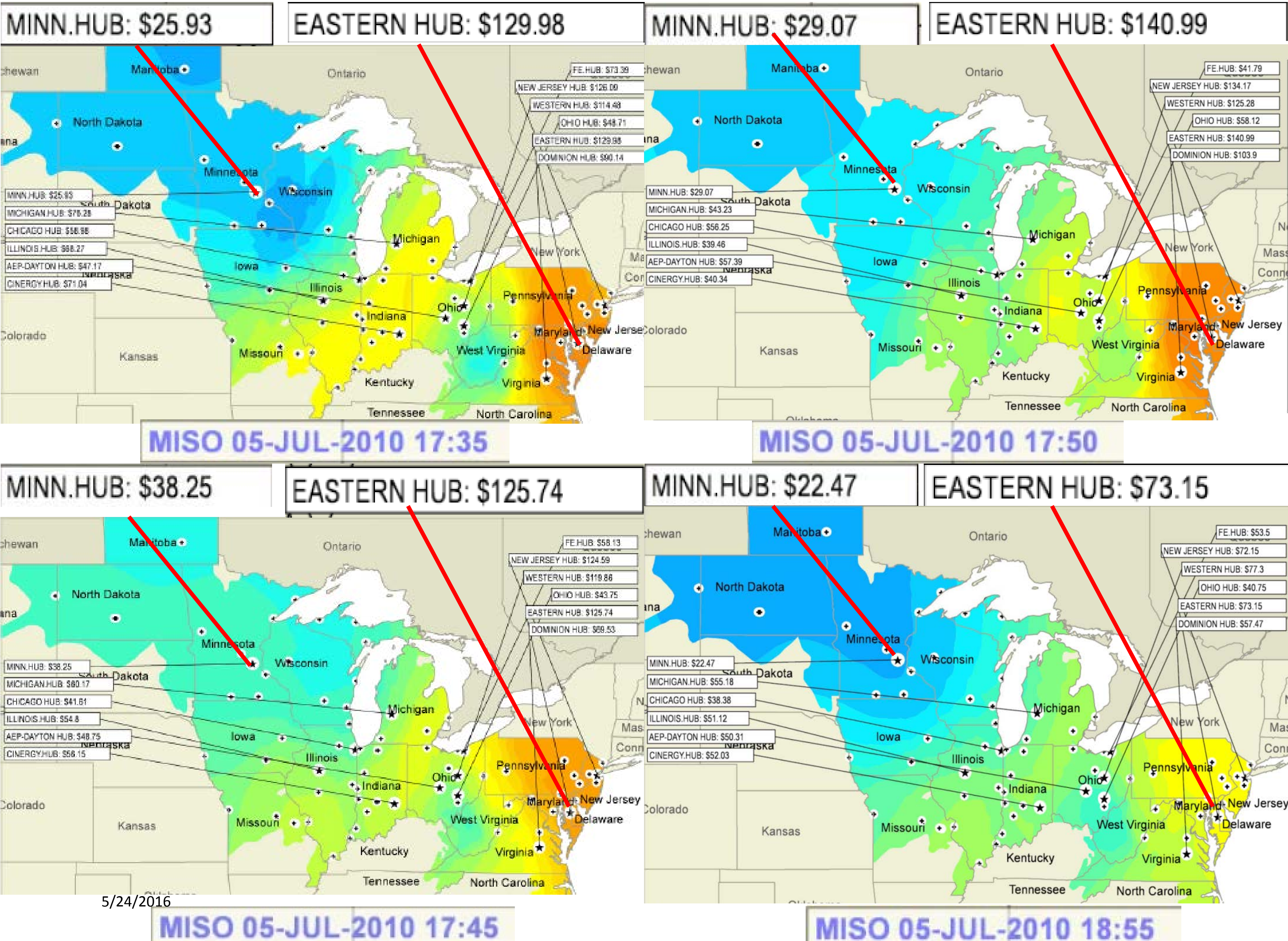
$$\varphi_i = \sum_{m \in L} (\lambda_m^+ - \lambda_m^-) D_{m,i}$$

$$\sum_{j \in N} r_j + losses = 0$$

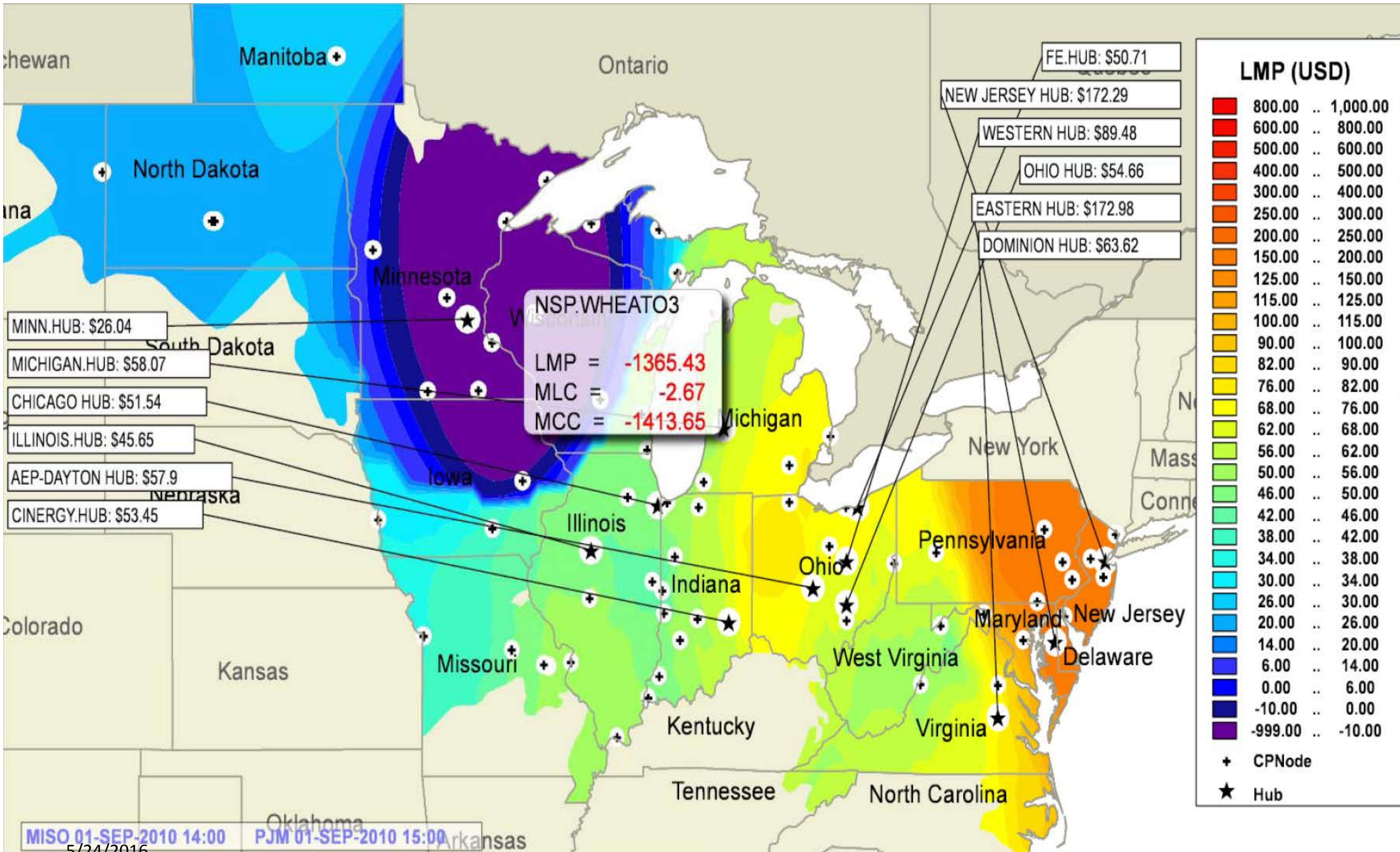
$$0 \le \lambda_l^- \perp \sum_{j \in N} D_{l,j} r_j + K_l \ge 0 \quad l \in L$$

$$0 \le \lambda_l^+ \perp K_l - \sum_{j \in N} D_{l,j} r_j \ge 0 \quad l \in L$$

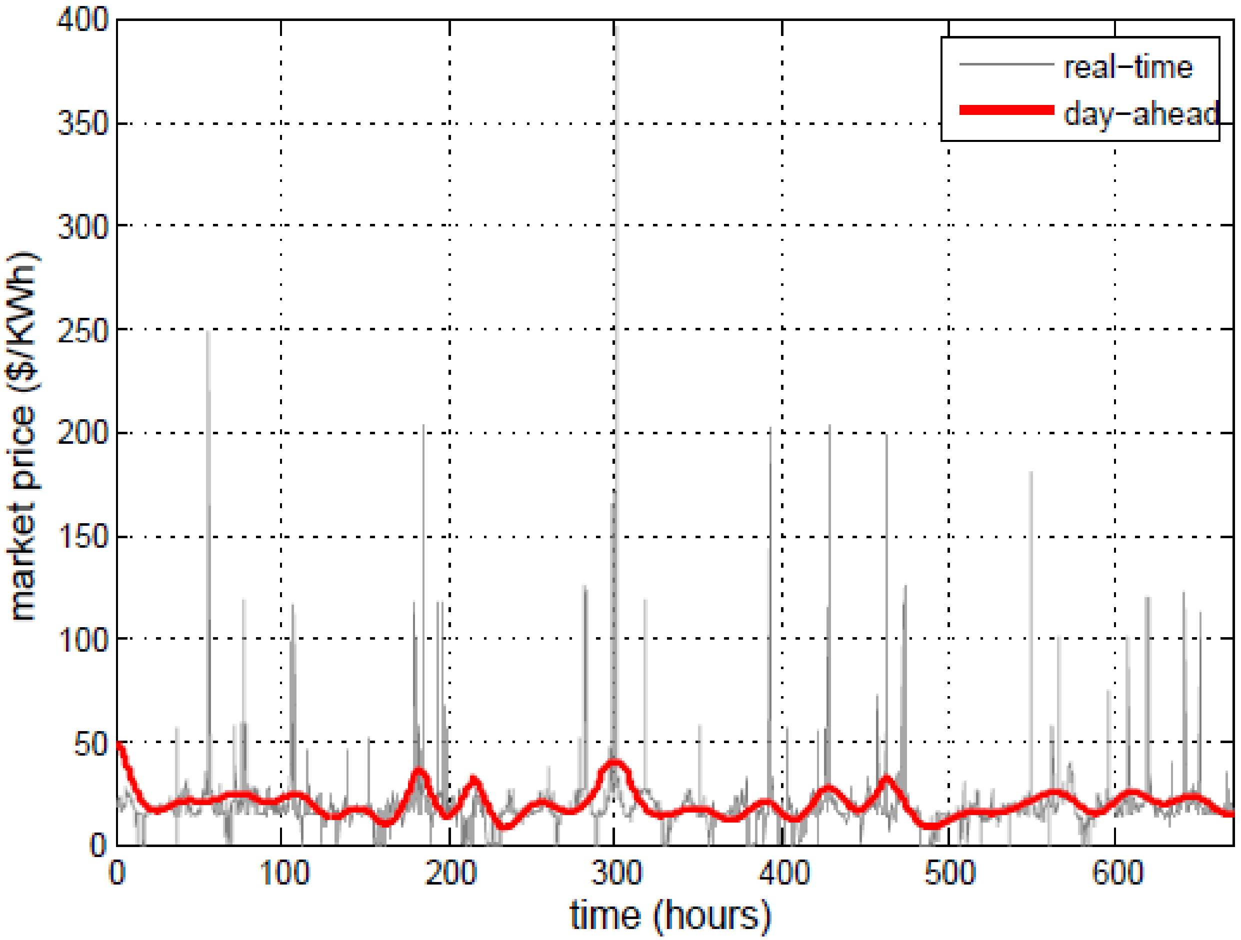

FE.HUB: $52.56
NEW JERSEY HUB: $312.51
WESTERN HUB: $135.54
OHIO HUB: $47.58
EASTERN HUB: $317.13
DOMINION HUB: $67.01
MINN.HUB: $43.11
MICHIGAN.HUB: $53.61
CHICAGO HUB: $46.46
ILLINOIS.HUB: $49.79
AEP-DAYTON HUB: $45.51
CINERGY.HUB: $50.39
LMP (USD)
800.00 .. 1,000.00
600.00 .. 800.00
500.00 .. 600.00
400.00 .. 500.00
300.00 .. 400.00
250.00 .. 300.00
200.00 .. 250.00
150.00 .. 200.00
125.00 .. 150.00
115.00 .. 125.00
100.00 .. 115.00
90.00 .. 100.00
82.00 .. 90.00
76.00 .. 82.00
68.00 .. 76.00
62.00 .. 68.00
56.00 .. 62.00
50.00 .. 56.00
46.00 .. 50.00
42.00 .. 46.00
38.00 .. 42.00
34.00 .. 38.00
30.00 .. 34.00
26.00 .. 30.00
20.00 .. 26.00
14.00 .. 20.00
6.00 .. 14.00
0.00 .. 6.00
-10.00 .. 0.00
-999.00 .. -10.00
CPNode
Hub
Manitoba
Ontario
North Dakota
Minnesota
Wisconsin
Michigan
Iowa
Illinois
Indiana
Ohio
Pennsylvania
New York
New Jersey
Maryland
Delaware
West Virginia
Virginia
Kentucky
Tennessee
North Carolina
Missouri
Kansas
Colorado
PJM 06-JUL-2010 11:40


MINN.HUB: $25.93
EASTERN HUB: $129.98
MISO 05-JUL-2010 17:35
MINN.HUB: $29.07
EASTERN HUB: $140.99
MISO 05-JUL-2010 17:50
MINN.HUB: $38.25
EASTERN HUB: $125.74
MISO 05-JUL-2010 17:45
MINN.HUB: $22.47
EASTERN HUB: $73.15
MISO 05-JUL-2010 18:55

Over-generation, congestion and no storage capability can lead to negative prices



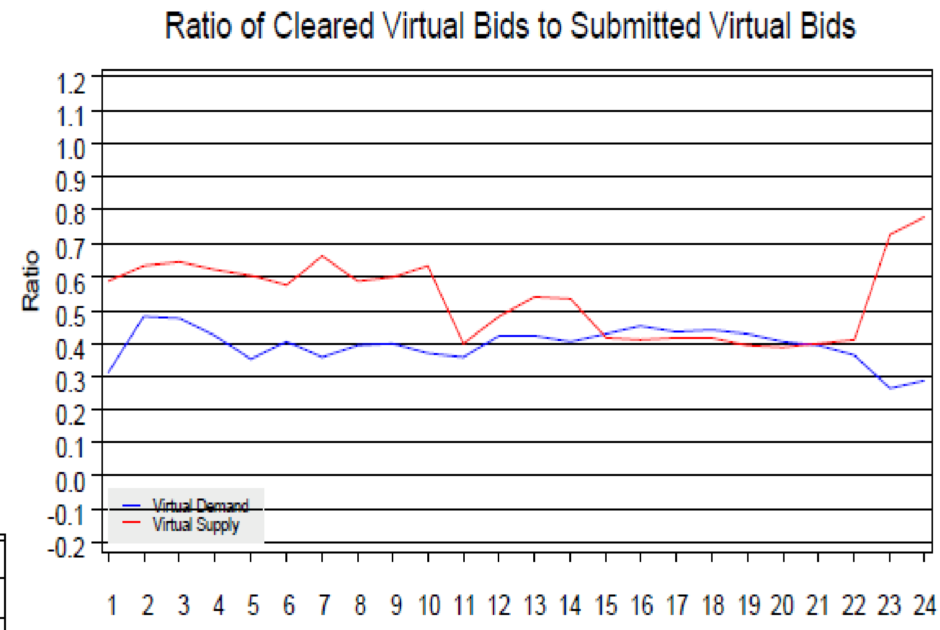
Example of DA-RT Price Spread

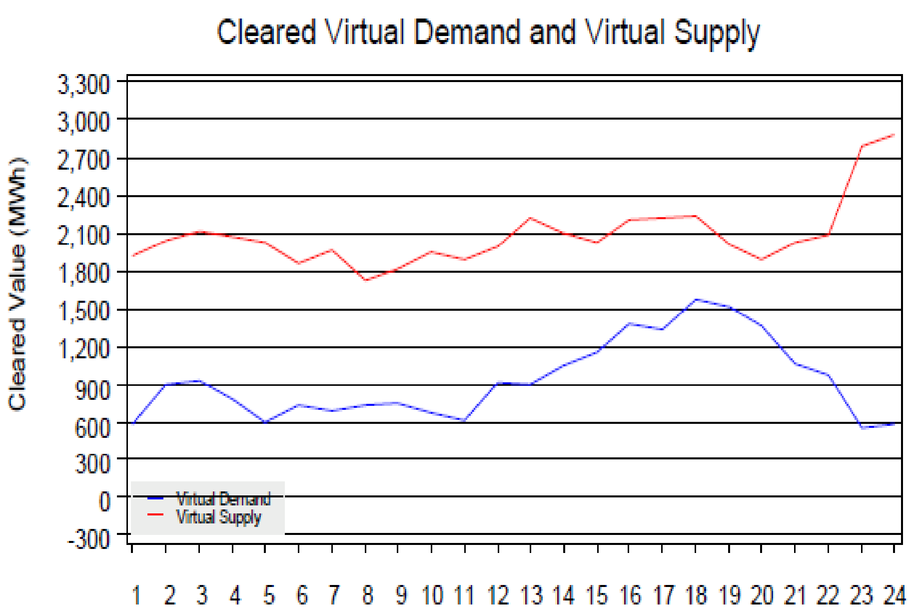


Convergence (Virtual) Bidding (CB)

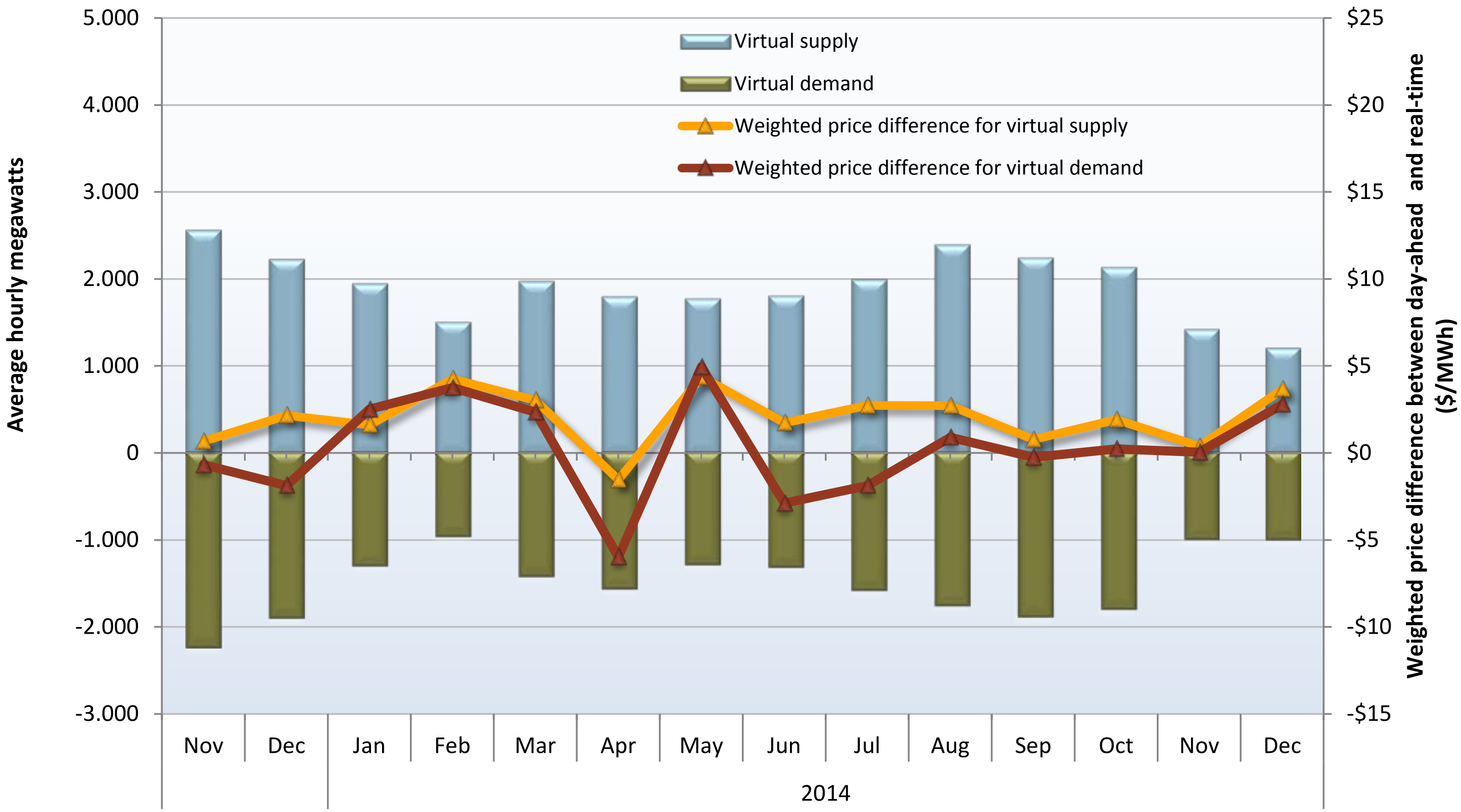
- The California Independent System Operator (CAISO) has implemented CB on February 1, 2011 under Federal Energy Regulatory Commission's (FERC) September 21, 2006 Market Redesign and Technology Upgrade (MRTU) Order.
- CB is a pure financial mechanism that allows market participants to arbitrage price differences between forward and spot electricity markets without physically obligation.
- CB enables market participants to opt for RT prices instead of DA prices. It Also increases market liquidity by enablein participants with no assests to take positions arbitraging the DA-RT spread

Typical Submitted and Cleared CB Volumes





Convergence bidding volumes and weighted price differences Q4 2014



Empirical Profitability of Arbitrage (Market Inefficiency) Before an After Instituting CB (CVaR constrained portfolio optimization)

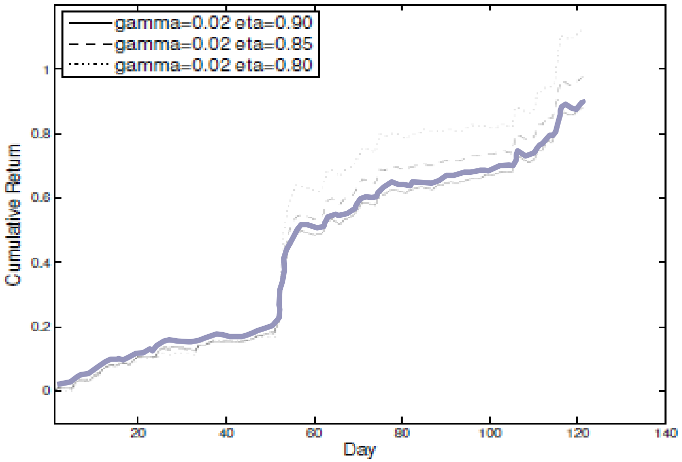


Fig. 10 Pre-CB In-Sample Performance under a CVaR constraint

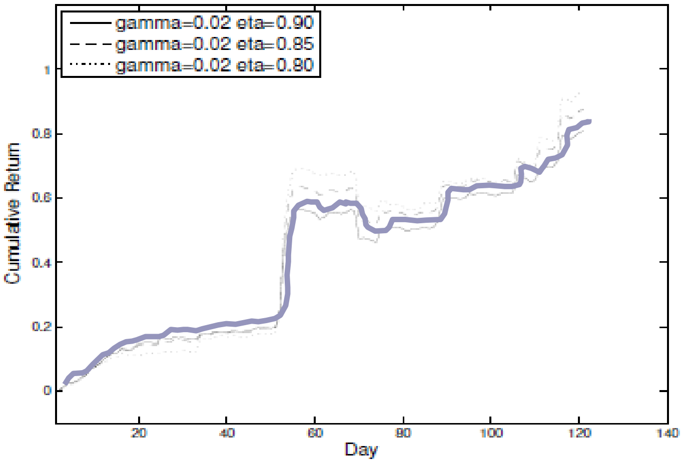


Fig. 11 Pre-CB Out-of-Sample Performance under a CVaR constraint

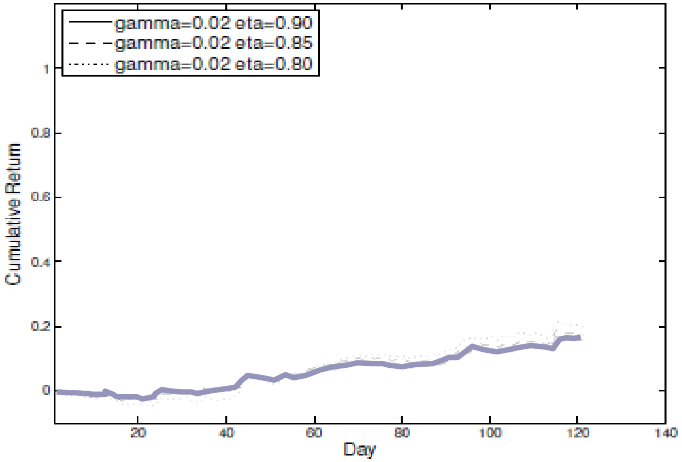


Fig. 12 Post-CB In-Sample Performance under a CVaR constraint

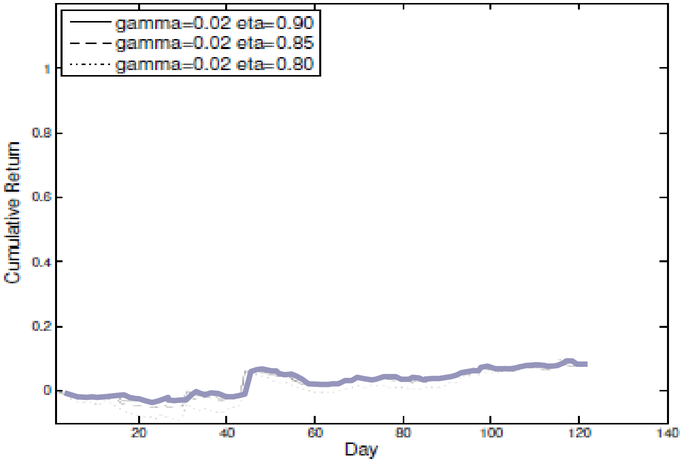


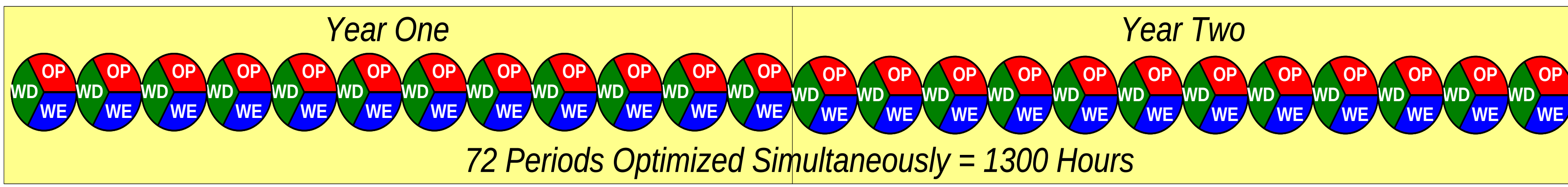
Fig. 13 Post-CB Out-of-Sample Performance under a CVaR constraint

Financial Transmission Rights (FTR) Market

- Under LMP Participants in wholesale spot market or bilateral contracts paying congestion charges are exposed to the LMP difference between the injection and withdrawal nodes
- FTRs were designed to hedge transmission service customers against congestion charge (nodal price differences) risks
- FTRs are defined as LMP swaps between each pair of nodes and are settled based on the realized nodal price difference (to offset congestion charges)
- FTRs are available as options or as two sided contracts which may become a liability when the path is opposite to the direction of the actually congested flow
- Auction conducted monthly for new FTRs and for trading of outstanding FTRs

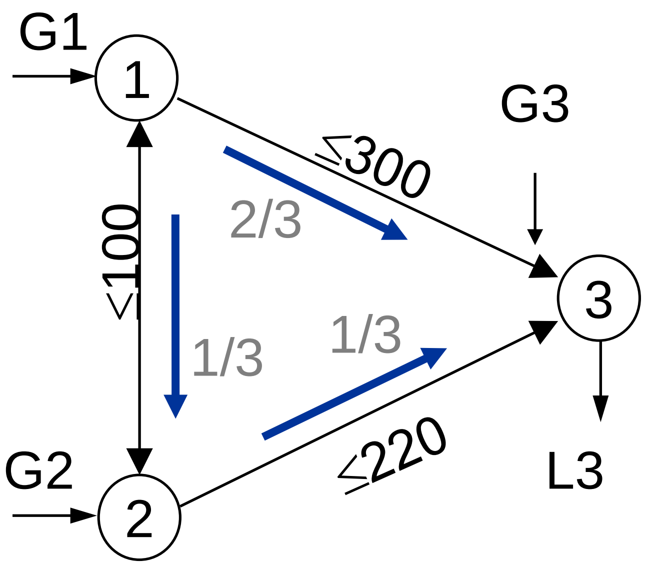
FTR Auction (ERCOT)

- Initial design had 72 time slices (24 monthly blocks divided into 3 time blocks
- Bids (and offers) can cover any subset of the 72 products



- Clearing mechanism maximizes auction revenue subject to simultaneous feasibility test (SFT) in every time slice
- SFT ensures that physical grid could support physical exercise of all outstanding FTRs

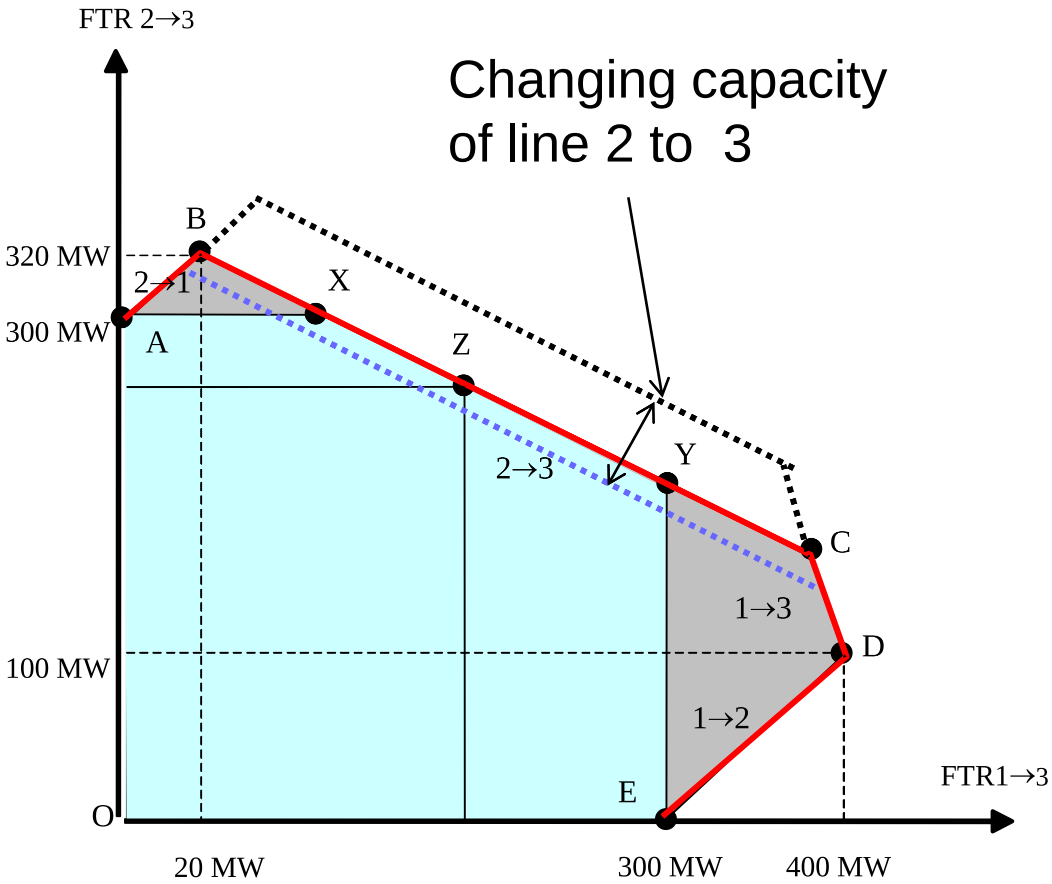
Simultaneous Feasibility Guarantees Revenue Adequacy (congestion revenues cover FTR settlements)



$$\tfrac{2}{3}G1+\tfrac{1}{3}G2\le 300$$

$$\tfrac{1}{3}G1+\tfrac{2}{3}G2\le 220$$

$$-100\le \tfrac{1}{3}(G1-G2)\le 100$$



- Two sided FTRs must stay within the outer nomogram
- One sided FTRs (options) must stay within the inner nomogram because we cannot rely on counter flows to alleviate congestion.

LMP + FTRs Supports Renewables Penetration and Sharing of Transmission

$5/MWh
when available

Thermal unit owns FTRs

LMP=$60/MWh

LMP set by marginal
MW produced

$30/MWh

Without wind, Thermal Gen earns 60-30=$30 per MWh exported over transmission lines and its FTRs offset congestion charges.

With wind, Thermal Gen has incentive to let wind maximize output and set LMP to $5/MWh and collect 60-5=$55 per MWh exported over the transmission line for its unused FTRs. Wind can be subsidized by “use it or loose it” FTR awards to offset congestion cost

Ancillary Services

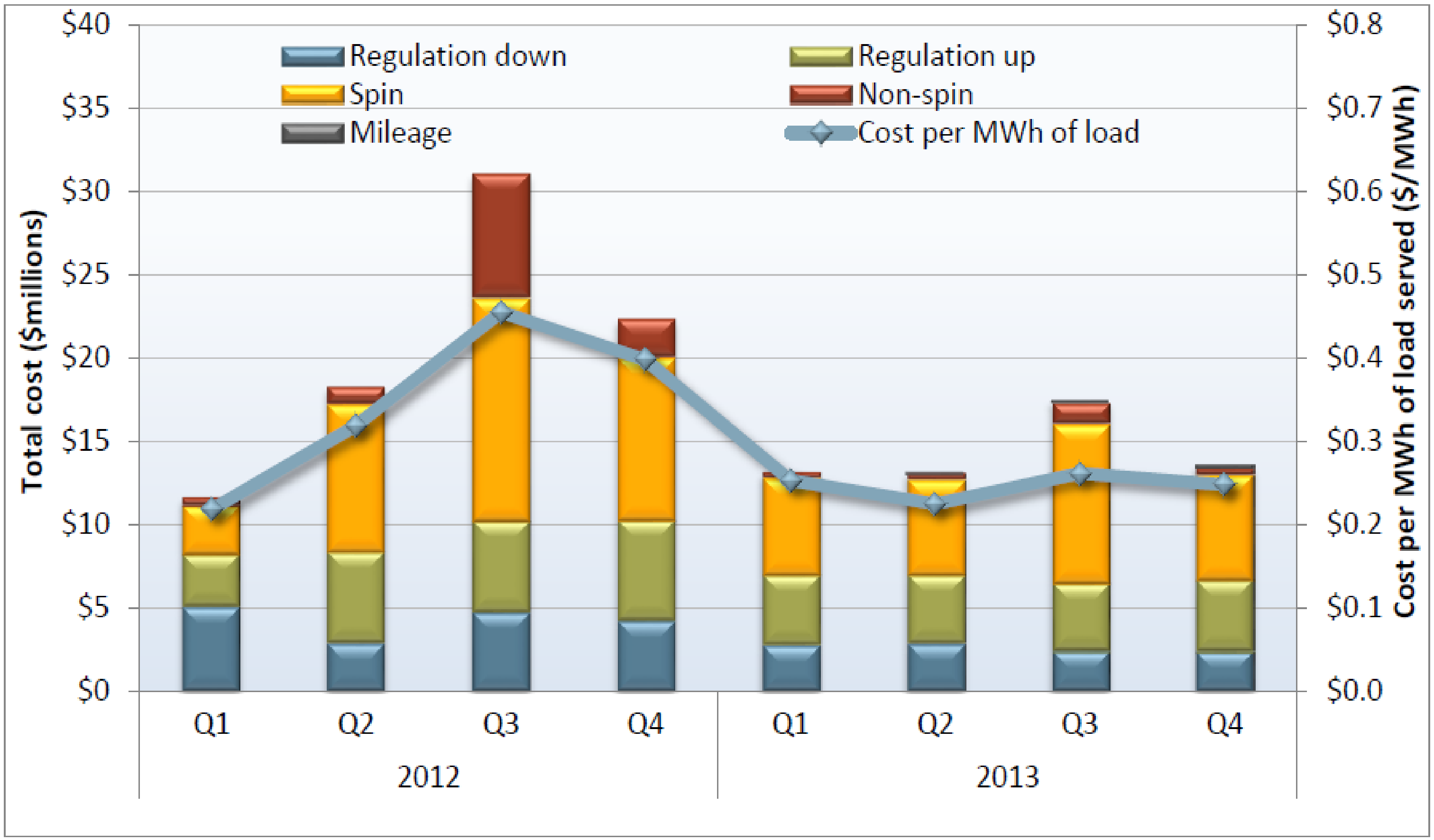
- Automatic Generation Control (AGC) – Regulation (Up/Down)
  - Payment for capacity and performance payment for “mileage” (FERC Order 755)
- Flexible Ramping
  - Opportunity cost payment based on energy bid
- Reserves with varying different response time
  - Spinning (synchronized) Reserves - Spin
  - Non-spinning (non-synchronized) Reserves
  - Replacement Reserves

  Payment for capacity
- Voltage Support
- Black Start Capability

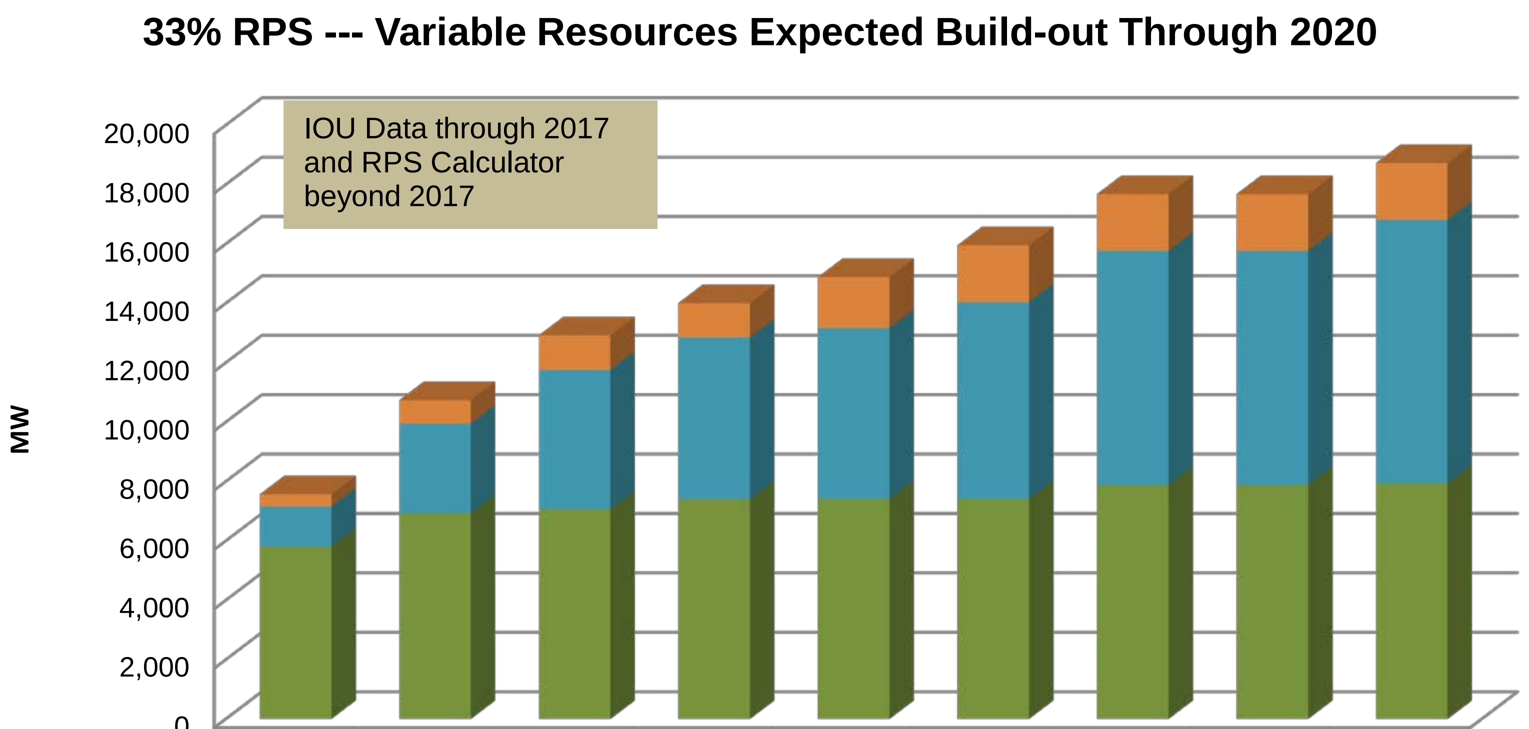
  Payment per contract

Cost Components (California)

Figure 6.7 Ancillary service cost by product



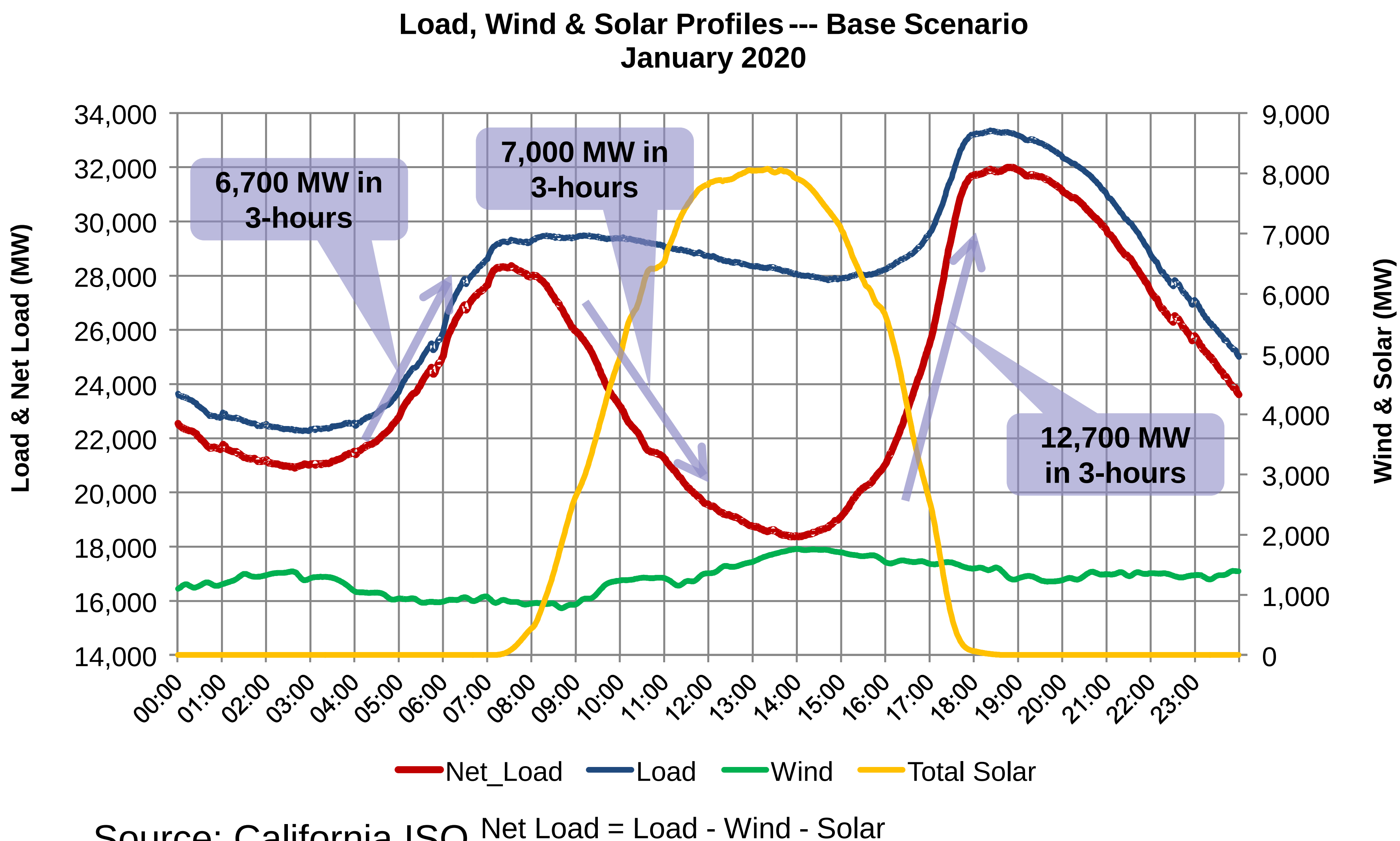
33% RPS --- Cumulative expected VERs build-out through 2020



	2012 Existing	2013	2014	2015	2016	2017	2018	2019	2020
Solar Thermal	419	792	1,167	1,167	1,717	1,917	1,917	1,917	1,917
Solar PV	1,345	3,022	4,693	5,445	5,756	6,628	7,881	7,881	8,872
Wind	5,800	6,922	7,058	7,396	7,406	7,406	7,877	7,877	7,934

Source: California ISO

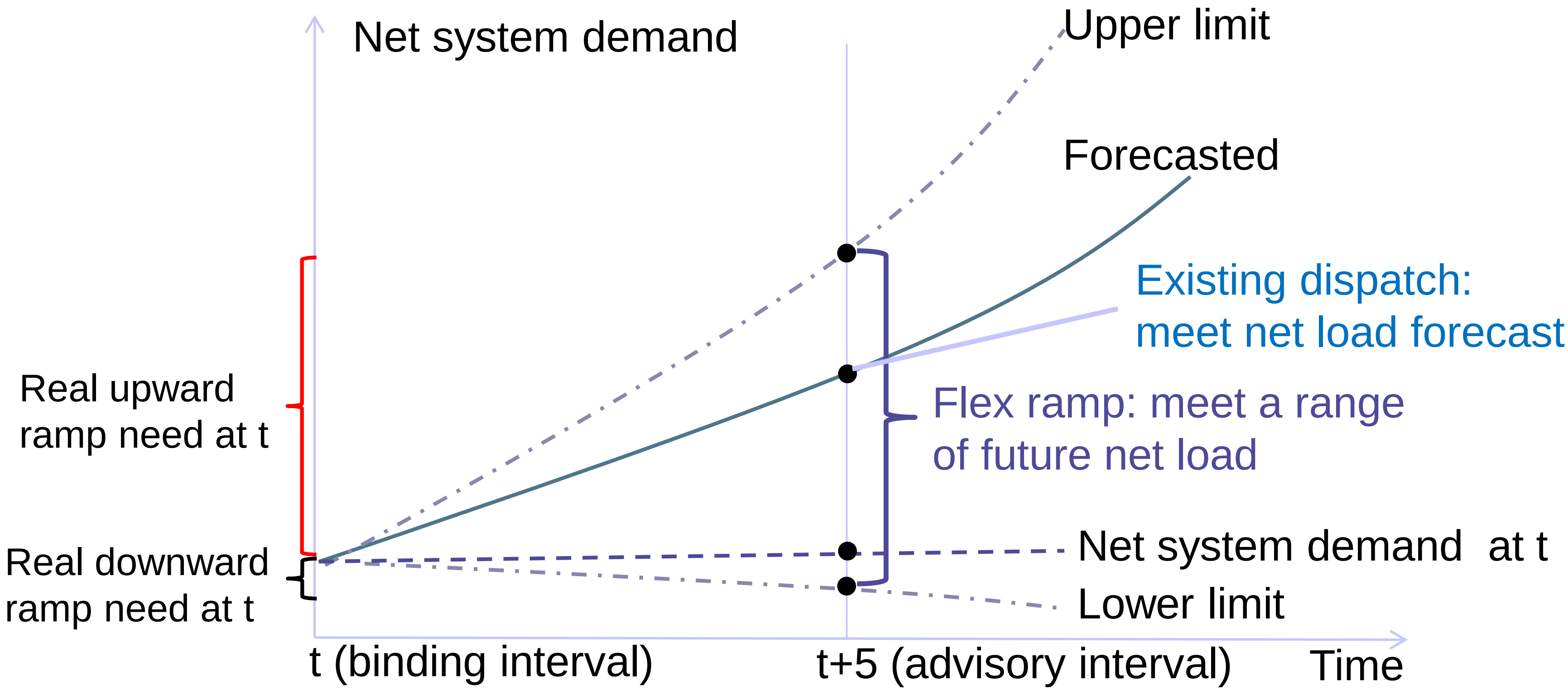
The Duck Chart



Source: California ISO

5/24/2016

Ramping need



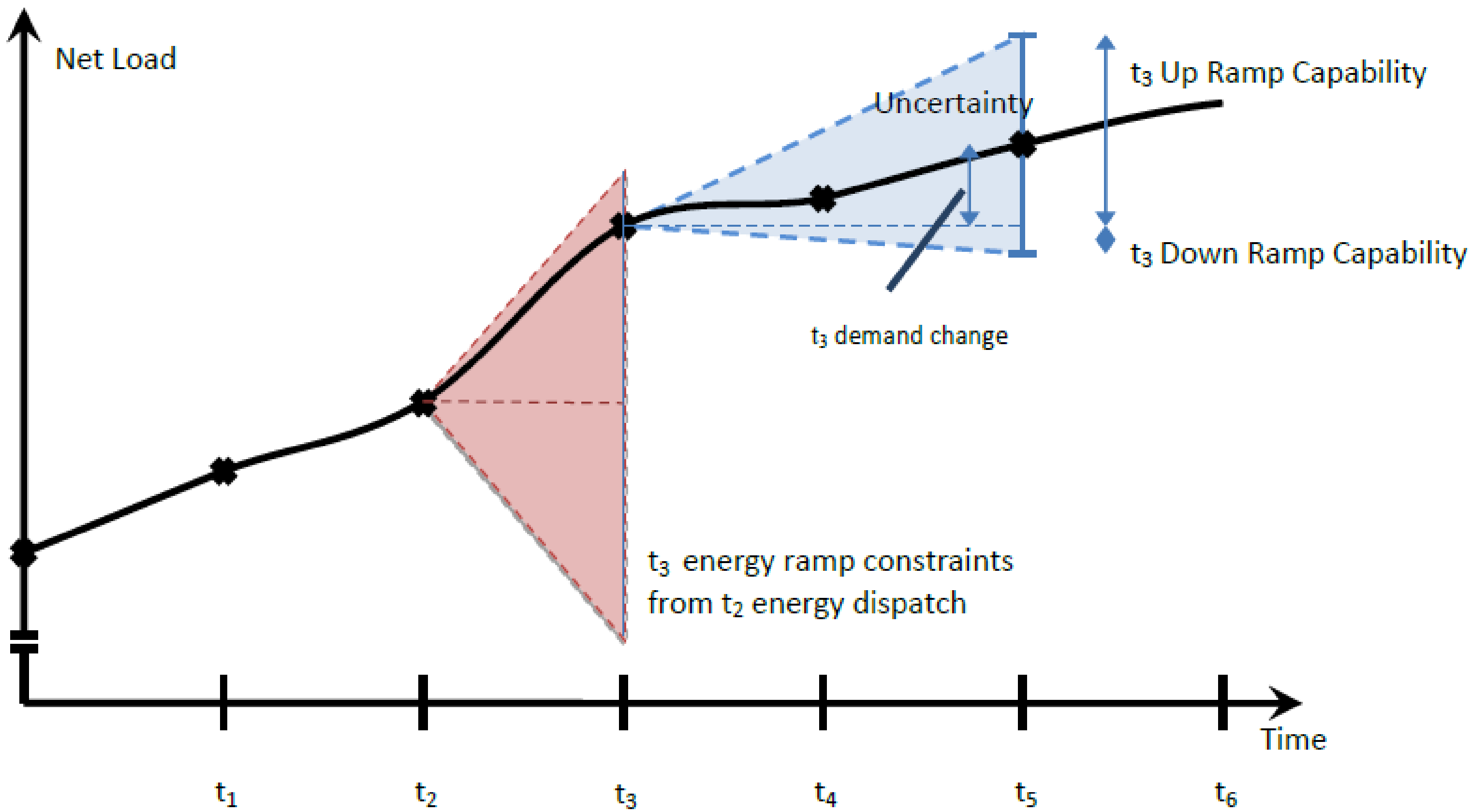
Ramping need:

Potential net load change from interval t to interval t+5

(net system demand t+5 – net system demand t)

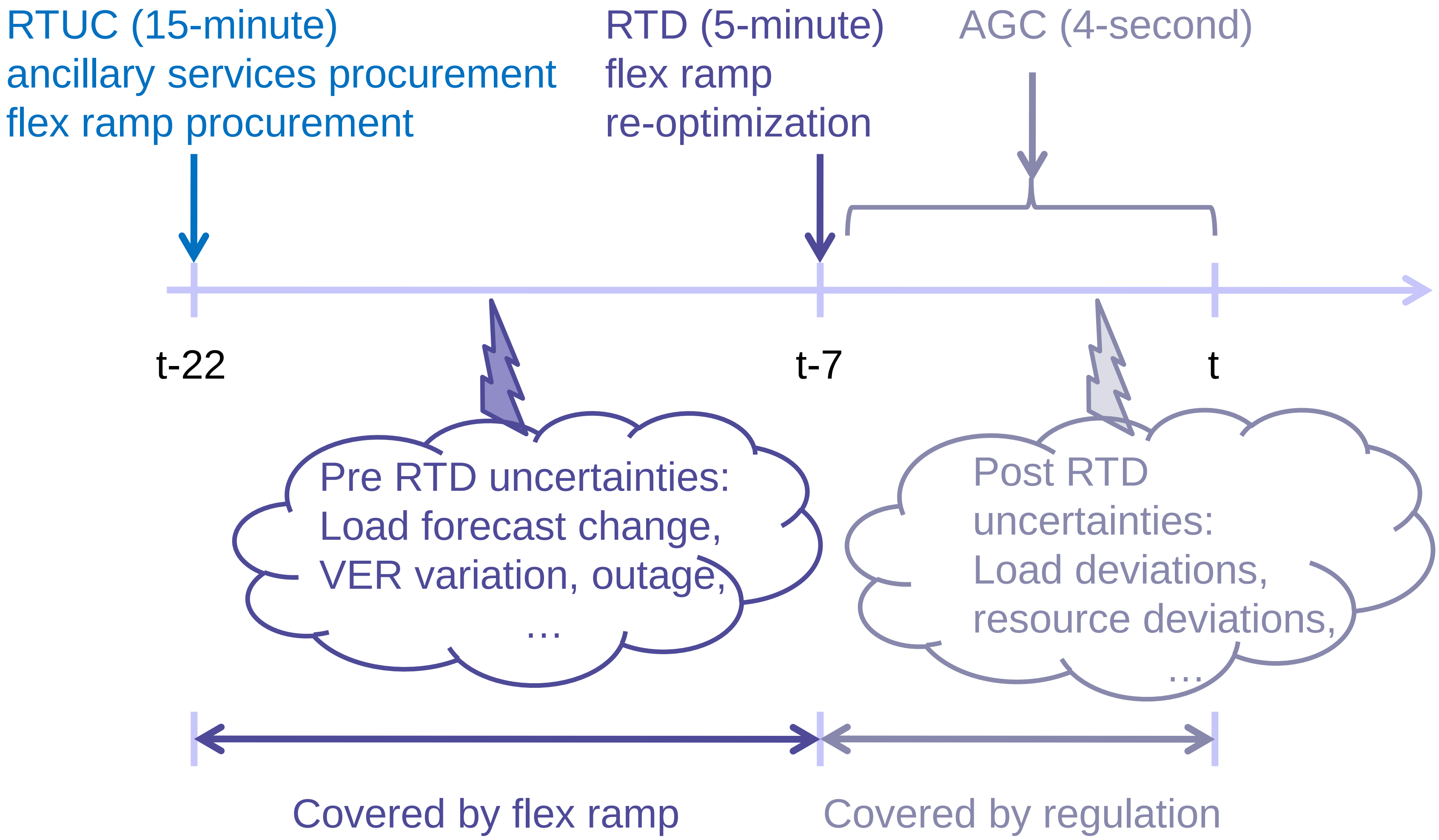
Source: California ISO

Ramp Reserves Captures Potential Future Interval Variation in Current Dispatch



Source: MISO White Paper

Flex ramp and regulation



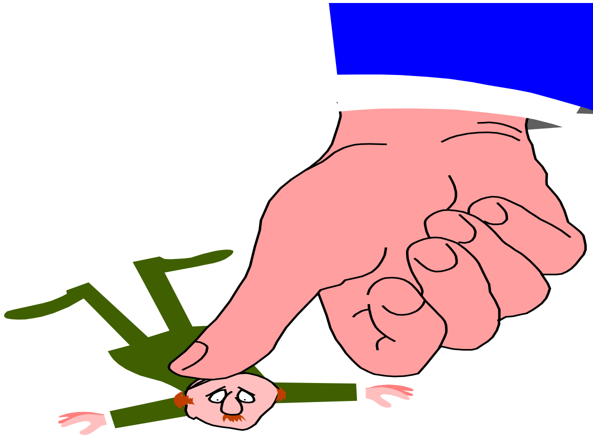
Flexible ramping product

- What is flexible ramping product?
  - Ramping capability between market clearing intervals
- Why ramping capacity is important?
  - The future load and renewable generation may change faster than the fleet ramping capability
- Benefits of flexible ramping product
  - Improve system reliability
    - Increase real-time ramping capability to meet net load movement between intervals
    - Reduce power balance violations due to ramping shortage
  - Improve market efficiency
    - Produce transparent energy and ramping prices
    - Reduce real-time price volatility
  - Accommodate increasing penetration of variable energy resources
  - Incentivizes and values flexible capability

Modeling flexible ramping

- Any resource that is 5-minute dispatchable by the ISO can provide flexible ramping
- Upward and downward ramping constraints
  - Ramping constraints in the same granularity as the market clearing interval: DA 60-minute, RTUC 15 minute, RTD 5-minute
- Co-optimized with ancillary services and energy
  - System wide flex ramp requirements in the up and down directions
  - Total upward awards including energy, regulation up, spin, non-spin, and flex ramp up for a resource should be less than or equal to its Pmax
  - Total downward awards including regulation down and flex ramp down for a resource should be greater than or equal to its Pmin
- Two settlement system for flex ramp
  - day-ahead flex ramp settled at day-ahead price
  - difference between RTD flex ramp and day-ahead flex ramp is settled at RTD flex ramp price
  - Flex ramp is paid lost opportunity cost (if any) for not producing energy while it is “in the money”

Market Power



Should we Worry About it?
Mitigation Approaches.

Market Power Mitigation Options

- Hear No Evil, See No Evil, Speak No Evil

- Let antitrust folks take care of it
- Punitive Ex-post enforcement (The Antitrust Approach)
- Watch, Report and ?
- Return to Cost-of-Service (Regression Therapy)
  - Price Caps and curtailments
  - Long-term contracts with price caps
  - Divestiture (the Big Stick)
- Must offer with bid caps and Default Energy Bids (DEB)
  - Structure based mitigation
  - Conduct and impact based mitigation

(Both approaches approved by FERC as consistent with the "just and reasonable "rates criteria)

Market Monitoring

- Each ISO has a Market Monitoring unit (either internal or external) which is paid for by the ISO but is independent and reports to FERC.
- Functions of the Market Monitoring unit
  - Conducts ongoing empirical analysis of market data
  - Publishes quarterly and annual report on the state of the market
  - Submits opinions to the ISO staff on market design modifications
  - Develops (subject to FERC approval) and implements market mitigation protocols including dynamic screening and mitigation of energy bids, and price caps on various bid components.
  - Monitors participants' behavior in all ISO markets and files complaints with FERC enforcement division if they detect price manipulation attempts. (in 2013 JPMorgan settled an electricity market manipulation case with FERC for $410 million penalty)

SMD – Standard (Successful) Market Design

- Pre-day-ahead markets
  - For transmission rights: CRT/TCC/TRCs/FGRs
  - For generation capacity/reserves (ICAP)
  - Market power mitigation via options contracts
- Day-ahead market for reliability
  - Centralized, bid based security constrained unit commitment
  - Reliability unit commitment
  - Bid cost recovery (make whole payments)
- Simultaneous nodal market-clearing auctions for energy, ancillary services and congestion
  - Allow multi-part bidding
  - Higher of market or bid cost recovery
  - Allow self scheduling
  - Allow price limit bids on ancillary and congestion
- Real-time balancing myopic market
- Markets are locational (nodal-based) marginal price (LMP)
- Market power mitigation (structure-based or conduct and Impact)

Questions?

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