ELECTRICITY MARKET DESIGN: PRICE FORMATION

William W. Hogan

Mossavar-Rahmani Center for Business and Government
John F. Kennedy School of Government
Harvard University
Cambridge, Massachusetts 02138

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A core challenge for all electricity systems is between monopoly provision and market operations. Electricity market design depends on critical choices. There is no escape from the fundamentals.

Integrated Monopoly	Competitive Markets
• Mandated	• Voluntary
• Closed Access	• Open Access
• Discrimination	• Non-discrimination
• Central Planning	• Independent Investment
• Few Choices	• Many Choices
• Spending Other People's Money	• Spending Your Own Money
• Average Cost Pricing	• Marginal Cost Pricing

A Key Market Design Objective

Supporting the Solution: Given the prices and settlement payments, individual optimal behavior is consistent with the aggregate optimal solution.

A passing reflection on history reinforces the view that there is great uncertainty about energy technology choices for the future. There are many examples of both bad and good surprises.

TVA's nuclear plant auction set for November

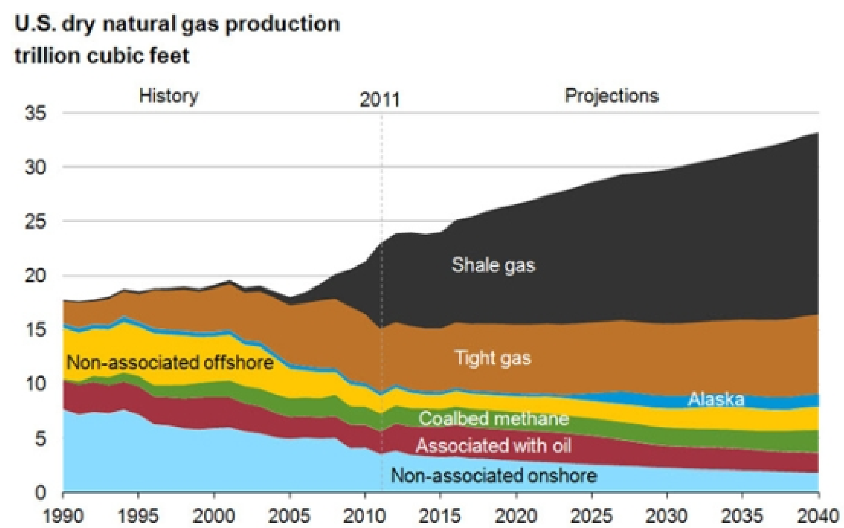
"The Tennessee Valley Authority, in apparently a first in the US power industry, plans to auction its unfinished Bellefonte nuclear plant in Alabama on November 14 in what amounts to a "fire sale" of epic proportions.

Over more than four decades, an estimated $6 billion was pumped into the project imagined at a time of far different economic and electricity projections and expectations. Bellefonte's minimum asking price — $36.4 million."

(Megawatt Daily, October 18, 2016, p. 3)

U.S. Shale Miracle:

Once the technology crossed the market threshold, deployment was both large and rapid.

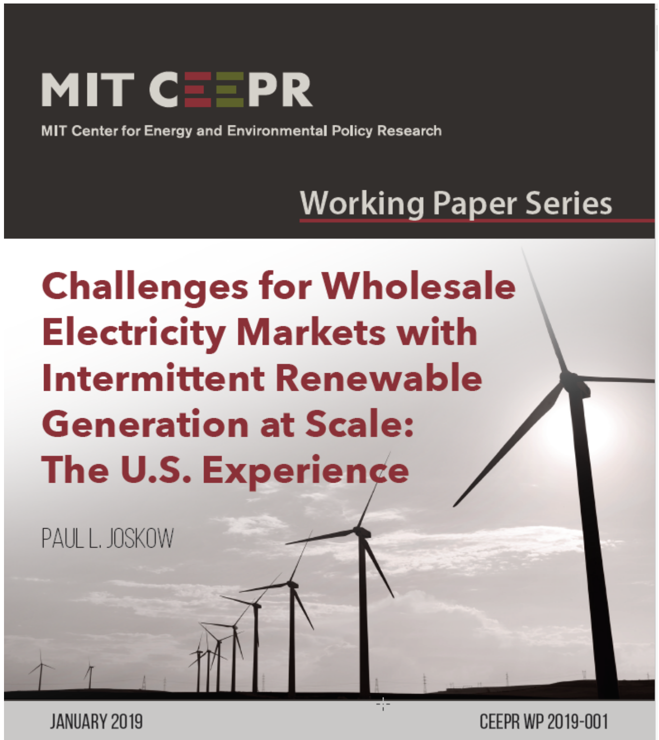


Source: U.S. Energy Information Administration, *Annual Energy Outlook 2013 Early Release*

Good wholesale electricity market design is necessary to provide open access with non-discrimination principles that encourage entry and innovation.

The expansion of intermittent sources and the rise in special subsidies is seen as a threat to efficient electricity market design.

"The supply of intermittent wind and solar generation with zero marginal operating cost is increasingly rapidly in the U.S. These changes are creating challenges for wholesale markets in two dimensions. Short term energy and ancillary services markets, built upon mid-20th century models of optimal pricing and investment, which now work reasonably well, must accommodate the supply variability and energy market price impacts associated with intermittent generation at scale. These developments raise more profound questions about whether the current market designs can be adapted to provide good long-term price signals to support investment in an efficient portfolio of generating capacity and storage consistent with public policy goals. … Reforms in capacity markets and ***scarcity pricing mechanisms*** are needed if policymakers seek to adapt the traditional wholesale market designs to accommodate intermittent generation at scale. However, if the rapid growth of integrated resource planning, subsidies for some technologies but not others, mandated long term contracts, and other expansions of state regulation continues, more fundamental changes are likely to be required in the institutions that determine generator and storage entry and exit decisions." (Joskow, 2019) (emphasis added)



The case of electricity restructuring presents examples of fundamental problems that challenge regulation of markets.

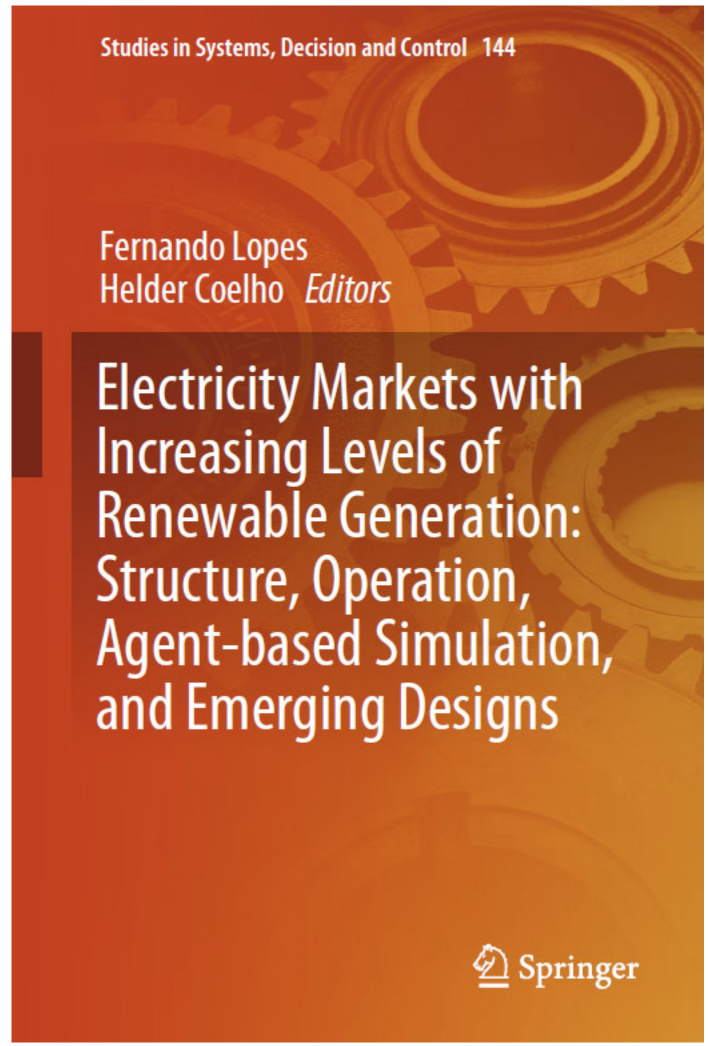
- **Marriage of Engineering and Economics.**
  - **Loop Flow.**
  - **Reliability Requirements.**
  - **Incentives and Equilibrium.**

- **Devilish Details.**
  - **Retail and Wholesale Electricity Systems.**
  - **Market Power Mitigation.**
  - **Coordination for Competition.**

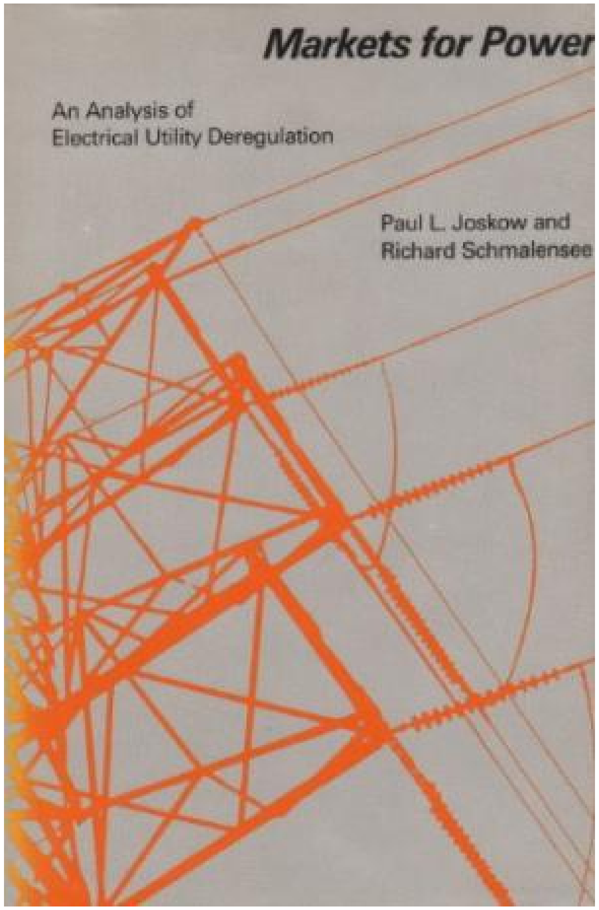
- **Jurisdictional Disputes.**
  - **US State vs. Federal Regulators.**
  - **European Subsidiarity Principle.**

A major challenge is the integration of increasing levels of renewables. There is a large and growing literature on the subject. (Lopes & Coelho, 2018) (Hogan & Pope, 2017)

- **Are renewables fundamentally different?**
  - Zero marginal cost, which affects the system economics.
  - Intermittency of supply, which affects system operations.
- **Will increasing levels of renewables require a fundamentally new approach to electricity market design?**
  - Green New Deal proposed mandates with effects both on investment and operations.
  - Expanded state subsidies (NY, IL), inconsistent carbon markets (CA and EIM), net energy metering (Belmont, MA), and ever-present rent seeking.
- **What is wrong with the existing market design fundamentals?**



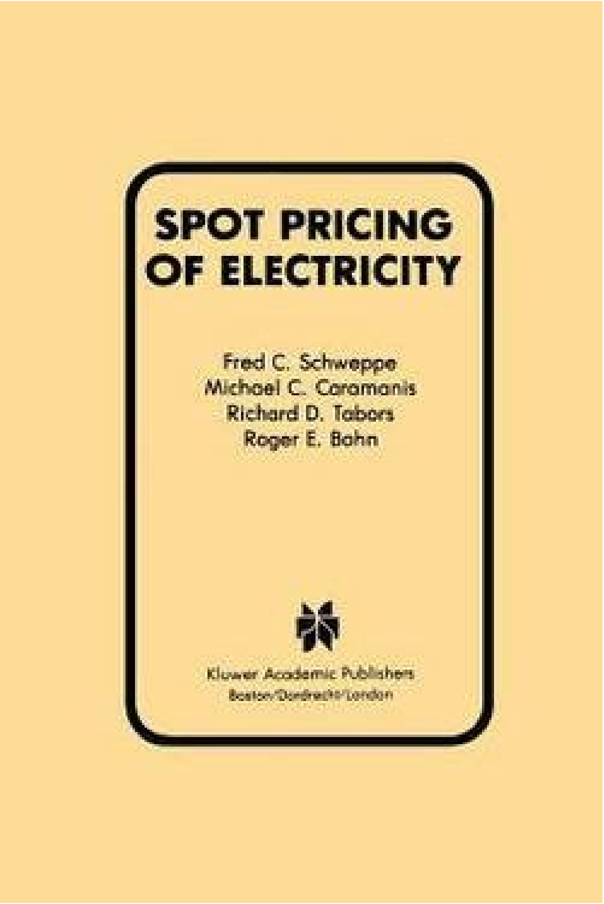
The evolution of electricity restructuring contains a thread of issues related to counterintuitive market design requirements requiring coordination for competition. MIT led the way.



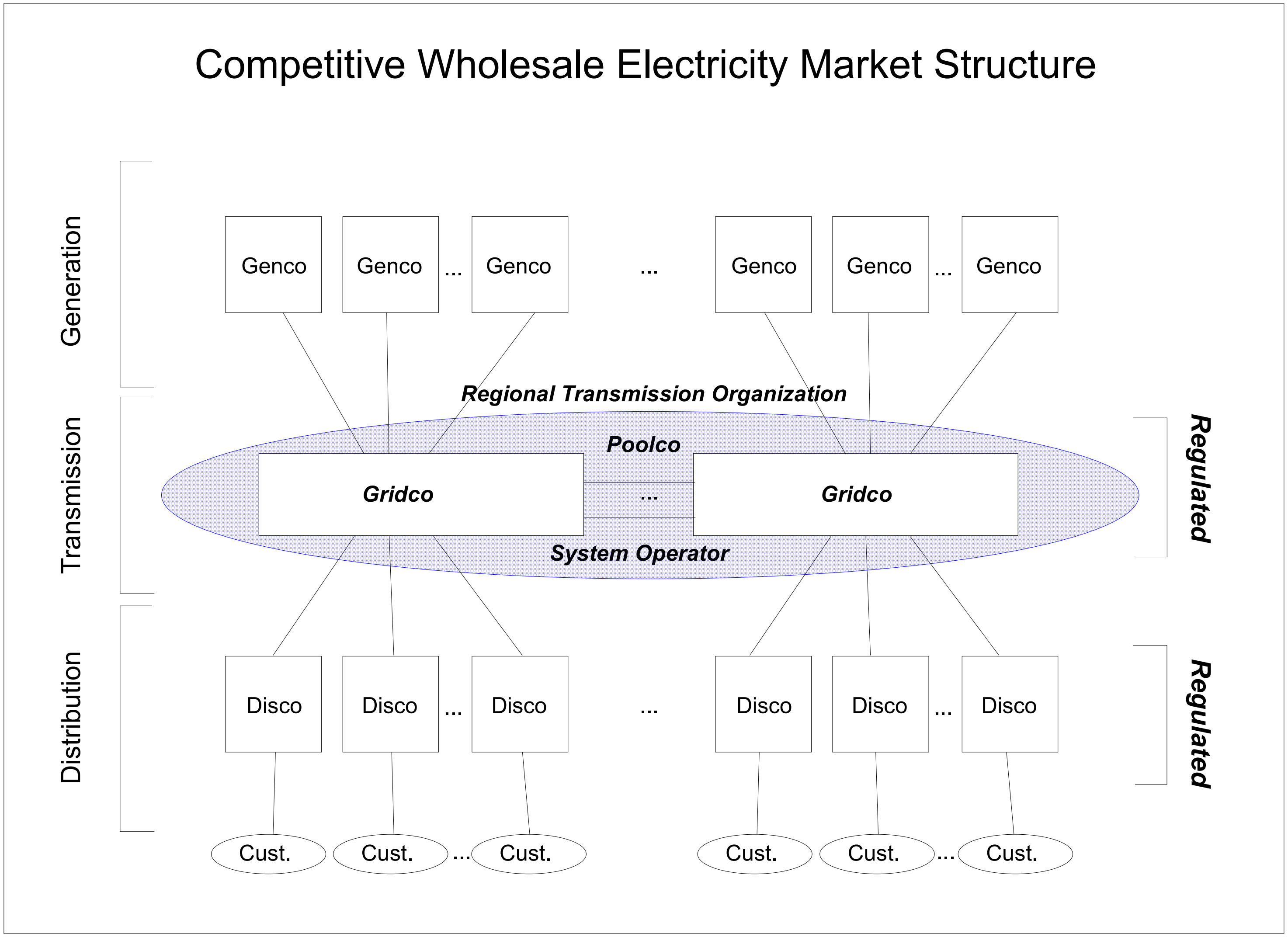
Markets for Power, 1983. Joskow and Schmalensee. Addressed the possibility and problems of introducing competition and markets in the power sector. (Joskow & Schmalensee, 1983)

"*The practice of ignoring the critical functions played by the transmission system in many discussions of deregulation almost certainly leads to incorrect conclusions about the optimal structure of an electric power system.*" (p.63)

Schweppe et al., 1988. Spot Pricing of Electricity, Kluwer. Using prices to direct the dispatch. (Schweppe, Caramanis, Tabors, & Bohn, 1988)



The original arguments for greater reliance on markets emphasized the effects of non-utility generators and the reduction or elimination of the conditions for natural monopoly in generation.



The U.S. experience illustrates successful market design and remaining challenges for both theory and implementation.

- **Design Principle: Integrate Market Design and System Operations**

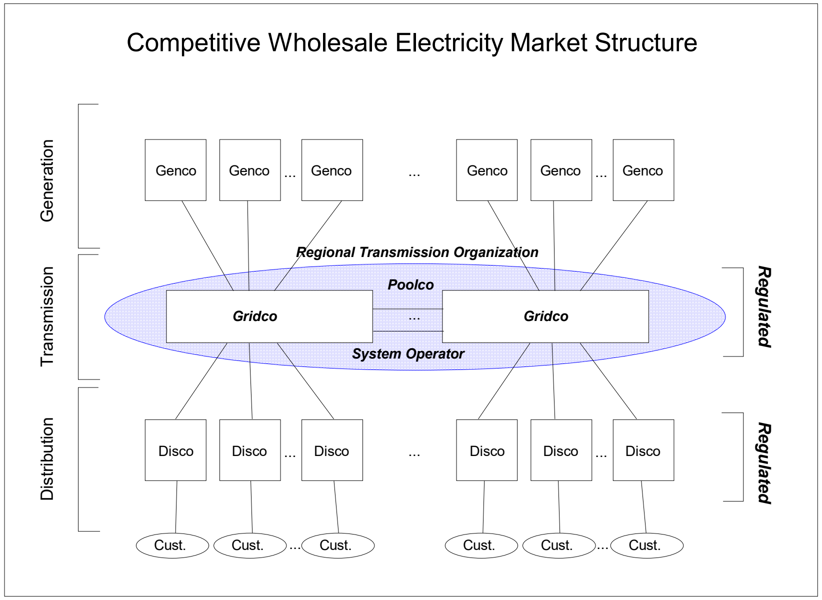
  Provide good short-run operating incentives.

  Support forward markets and long-run investments.

- **Design Framework: Bid-Based, Security Constrained Economic Dispatch**

  Locational Marginal Prices (LMP) with granularity to match system operations.

  Financial Transmission Rights (FTRs).



- **Design Implementation: Pricing Evolution**

  Better scarcity pricing to support resource adequacy.

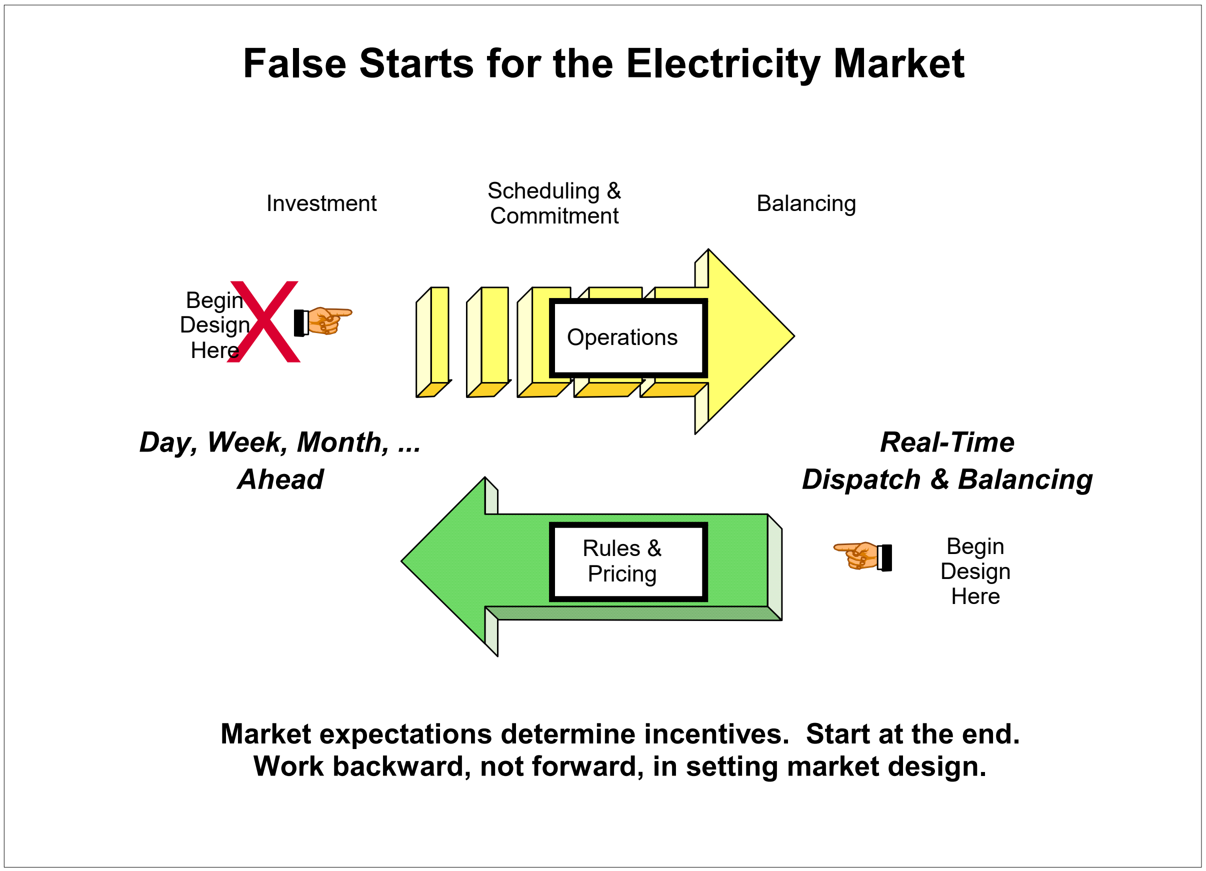
  Unit commitment and lumpy decisions with coordination, bid guarantees and uplift payments.

- **Design Challenge: Infrastructure Investment**

  Hybrid models to accommodate both market-based and regulated transmission investments.

  Beneficiary-pays principle to support integration with rest of the market design.

The solution to open access and non-discrimination inherently involves market design. Good design begins with the real-time market and works backward. A common failure mode starts with the forward market, without specifying the rules and prices that would apply in real time.



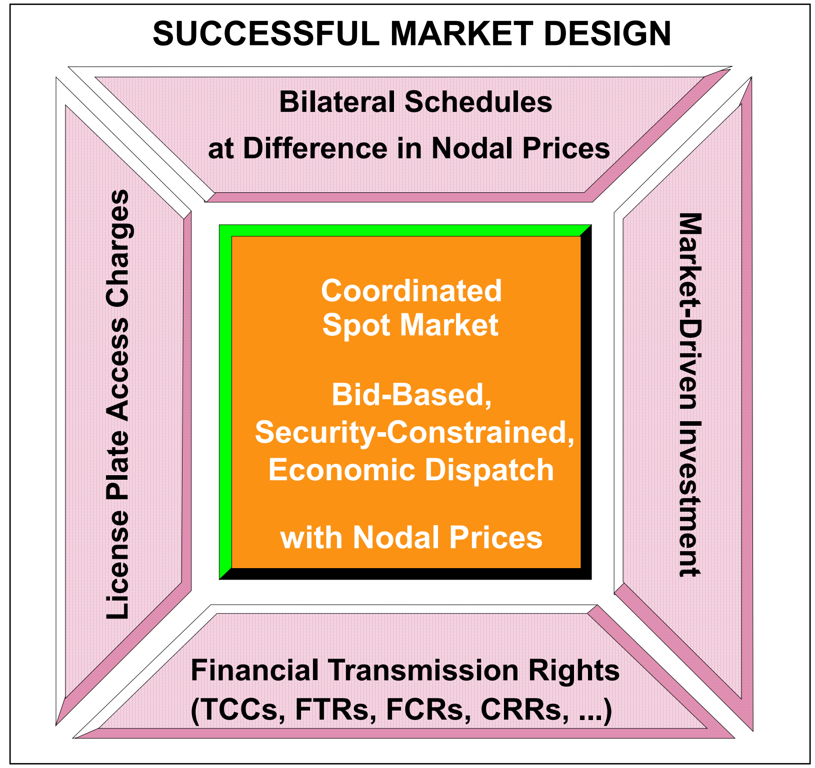
All energy delivery takes place in the real-time market. Market participants will anticipate and make forward decisions based on expectations about real-time prices.

- **Real-Time Prices:** In a market where participants have discretion, the most important prices are those in real-time. "Despite the fact that quantities traded in the balancing markets are generally small, the prevailing balancing prices, or real-time prices, may have a strong impact on prices in the wholesale electricity markets. … No generator would want to sell on the wholesale market at a price lower than the expected real-time price, and no consumer would want to buy on the wholesale market at a price higher than the expected real-time price. As a consequence, any distortions in the real-time prices may filter through to the wholesale electricity prices." (Cervigni & Perekhodtsev, 2013)
- **Day-Ahead Prices:** Commitment decisions made day-ahead will be affected by the design of day-ahead pricing rules, but the energy component of day-ahead prices will be dominated by expectations about real-time prices.
- **Forward Prices:** Forward prices will look ahead to the real-time and day-ahead markets. Although forward prices are developed in advance, the last prices in real-time will drive the system.
- **Getting the Prices Right:** The last should be first. The most important focus should be on the models for real-time prices. Only after everything that can be done has been done, would it make sense to focus on out-of-market payments and forward market rules.

The principles of open access and non-discrimination lead to the Successful Market Design (SMD). The pieces fit together to provide the components to support both short- and long-run efficiency.

How did we get to SMD?

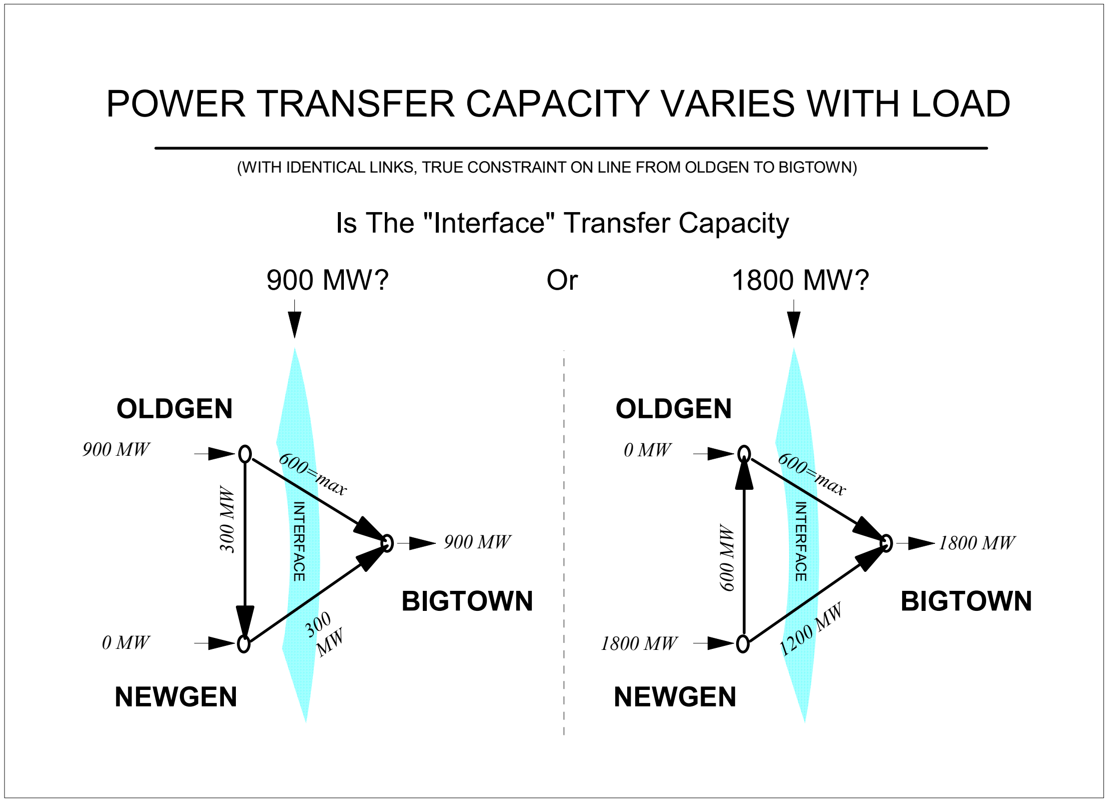
- **Why an Independent System Operator (ISO)?**
- **Why economic dispatch?**
- **Why Locational Marginal Prices (LMP)?**
- **Why Financial Transmission Rights (FTRs)?**
- **Why fund FTRs with congestion costs?**
- **Why include virtual bidding?**
- **Why is this important?**



Supporting the Solution: Given the prices and settlement payments, individual optimal behavior is consistent with the aggregate optimal solution.

Electric transmission network interactions can be large and important.

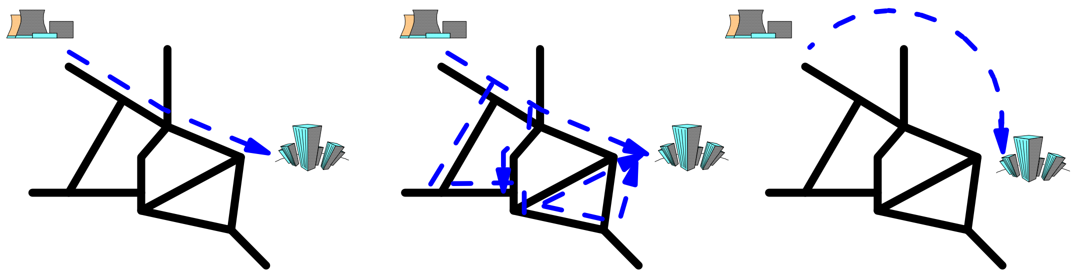
- Conventional definitions of network "Interface" transfer capacity depend on the assumed load conditions.
- Transfer capacity cannot be defined or guaranteed over any reasonable horizon.



Defining and managing transmission usage is a principal challenge in electricity markets.

Transmission Capacity Definitions

Contract Path → Flow-Based Paths → Point-to-Point



Contract Path Fiction	Parallel Flows	Flows Implicit
OASIS Schedules and TLR	Flowgate Rights FGRs	Financial Transmission Rights FTRs

The independent system operator provides a dispatch function. Three questions remain. Just say yes, and the market can decide on the split between bilateral and coordinated exchange.

- **Should the system operator be allowed to offer an economic dispatch service for some plants?**

The alternative would be to define a set of administrative procedures and rules for system balancing that purposely ignore the information about the costs of running particular plants. It seems more natural that the system operator considers customer bids and provides economic dispatch for some plants.

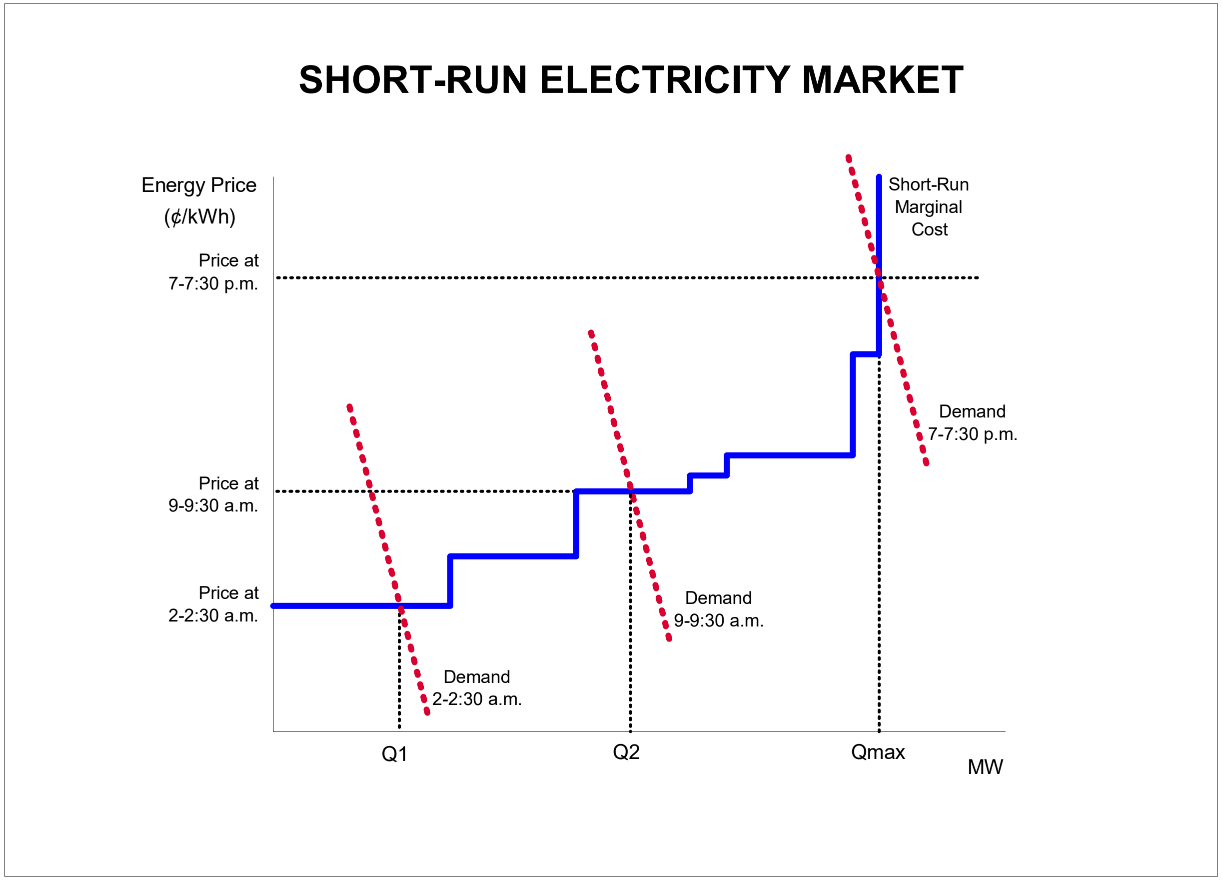
- **Should the system operator apply marginal cost prices for power provided through the dispatch?**

Under an economic dispatch for the flexible plants and loads, it is a straightforward matter to determine the locational marginal costs of additional power. These marginal costs are also the prices that would apply in the case of a perfect competitive market at equilibrium. In addition, these locational marginal cost prices provide the consistent foundation for the design of a comparable transmission tariff.

- **Should generators and customers be allowed to participate in the economic dispatch offered by the system operator?**

The natural extension of open access and the principles of choice would suggest that participation should be voluntary. Market participants can evaluate their own economic situation and make their own choice about participating in the operator's economic dispatch or finding similar services elsewhere.

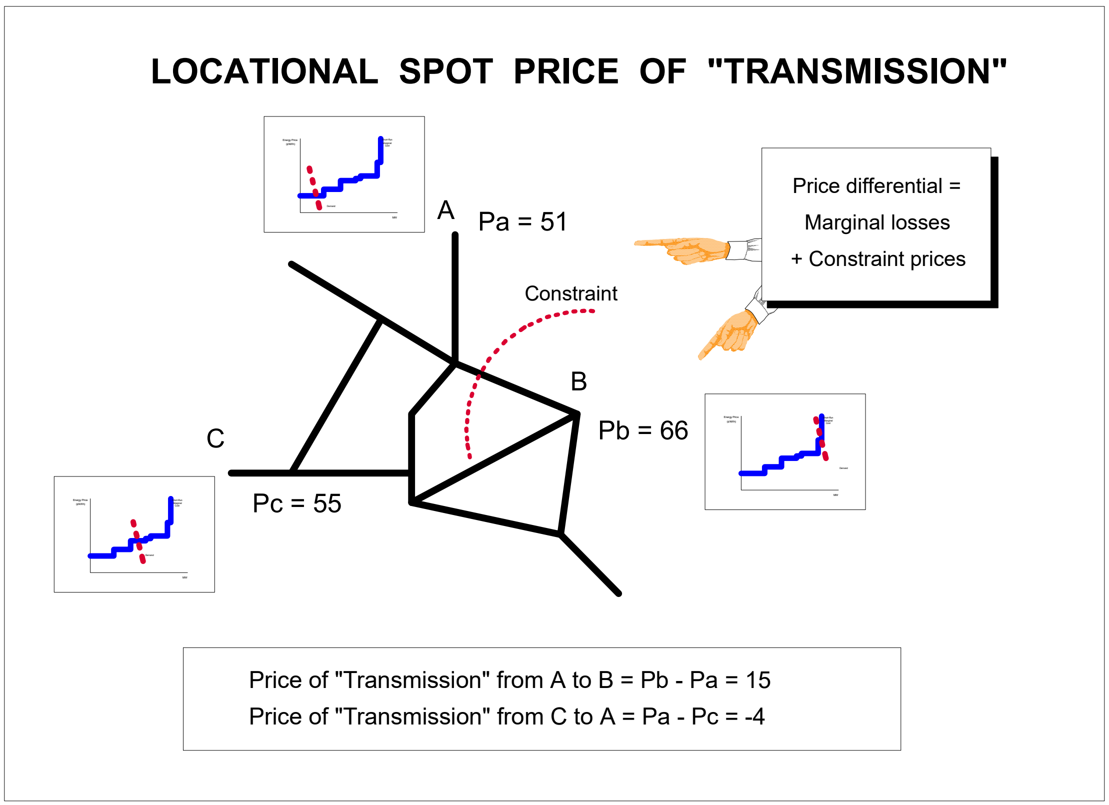
An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand balanced in an economic dispatch. Everyone pays or is paid the same price. The same principles apply in an electric network. (Schweppe et al., 1988)



NETWORK INTERACTIONS — Locational Spot Prices

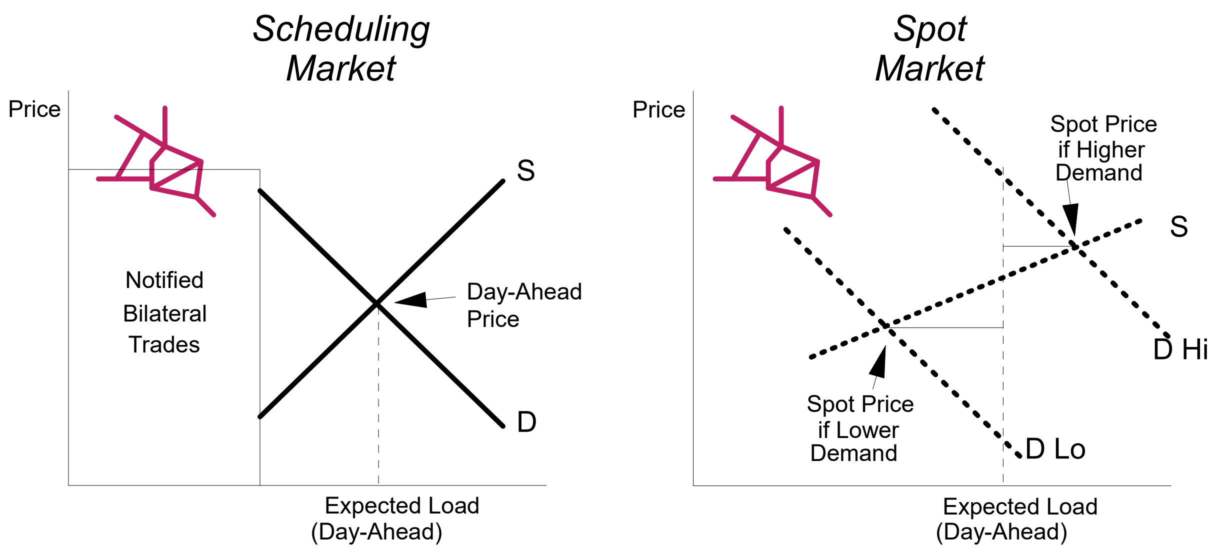
The natural extension of a single price electricity market is to operate a market with locational spot prices.

- It is a straightforward matter to compute "Schweppe" spot prices based on marginal costs at each location.
- Transmission spot prices arise as the difference in the locational prices.



The expected value of the real-time dispatch can differ from the day-ahead dispatch.

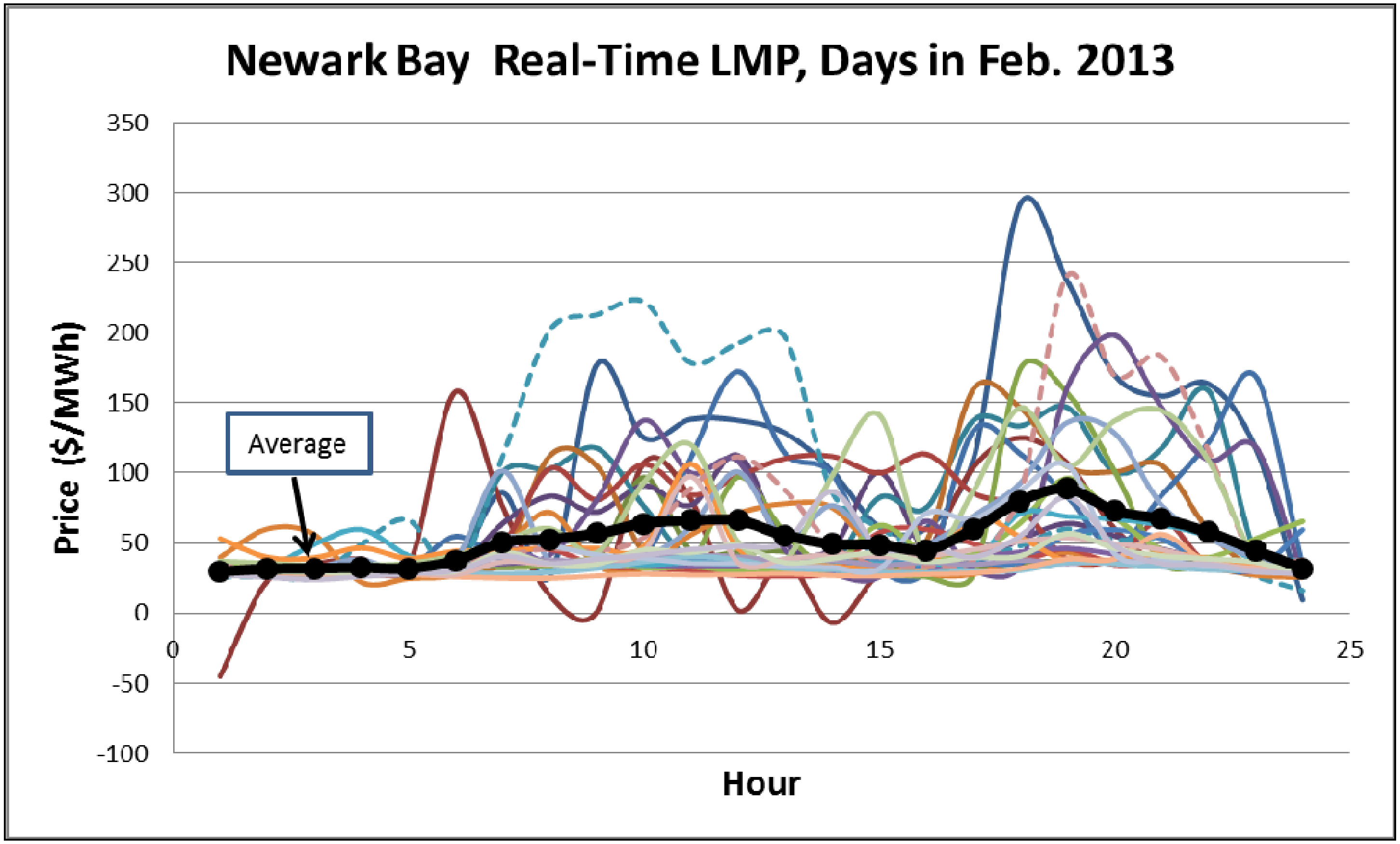
Spot Price Applies to Deviations from Scheduled Quantities



- Notified bilateral trades pay locational transmission charge but are settled outside pool
- Other trades settle at day-ahead price
- Locational congestion rents paid to transmission right holders along with excess congestion costs

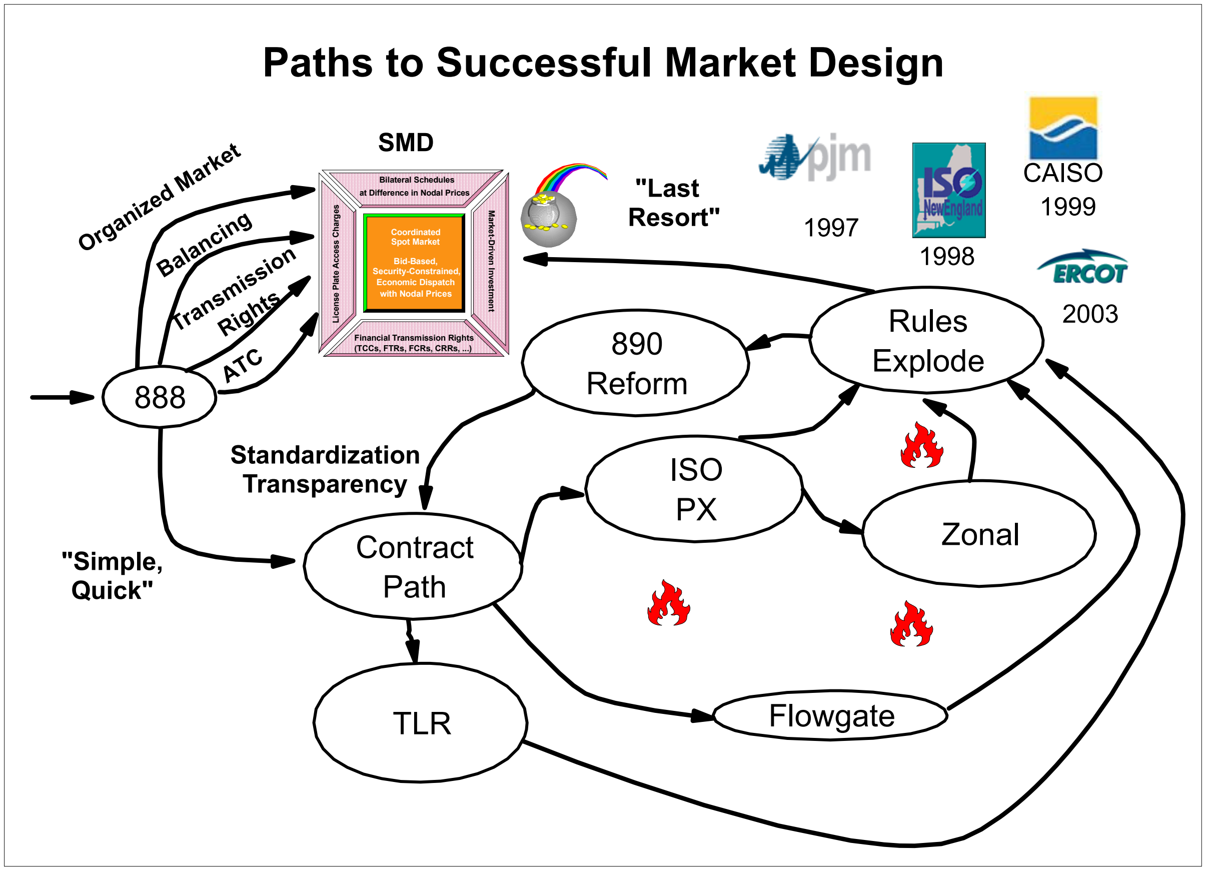
- Payments for deviations from day-ahead trades at spot price for all transactions
- Uplift covers ancillary services and other costs
- Excess congestion costs paid to holders of transmission rights

The hourly average prices capture very little of the total real-time price variation.

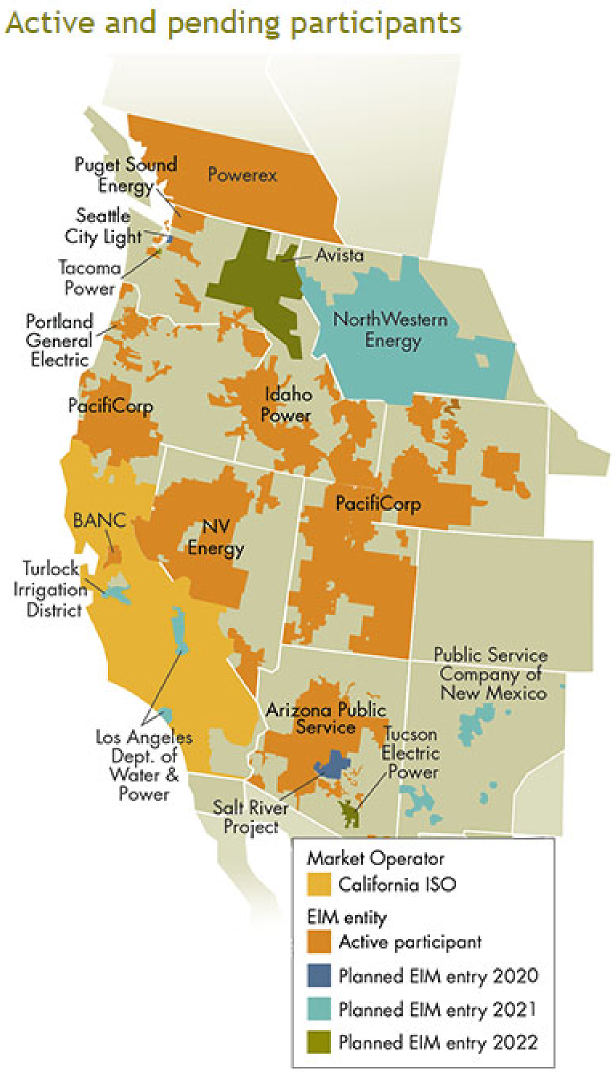


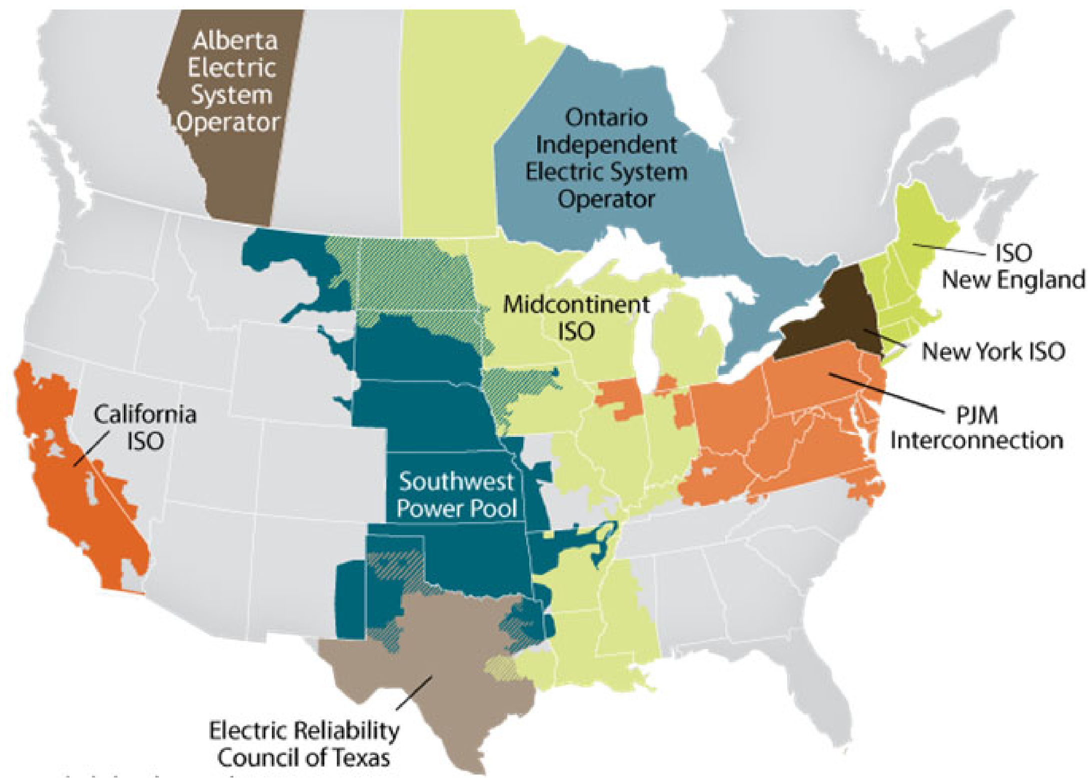
(Source: www.pjm.com) (W. Hogan, "Time-of-Use Rates and Real-Time Prices," August 23, 2014, www.whogan.com)

The path to successful market design can be circuitous and costly. The FERC "reforms" in Order 890 illustrate "path dependence," where the path chosen constrains the choices ahead. Early attempts with contract path, flowgate and zonal models led to design failures in PJM (\`97), New England (\`98), California (\`99), and Texas (\`03). Regional aggregation creates conflicts with system operations. Successful market design integrates the market with system operations.

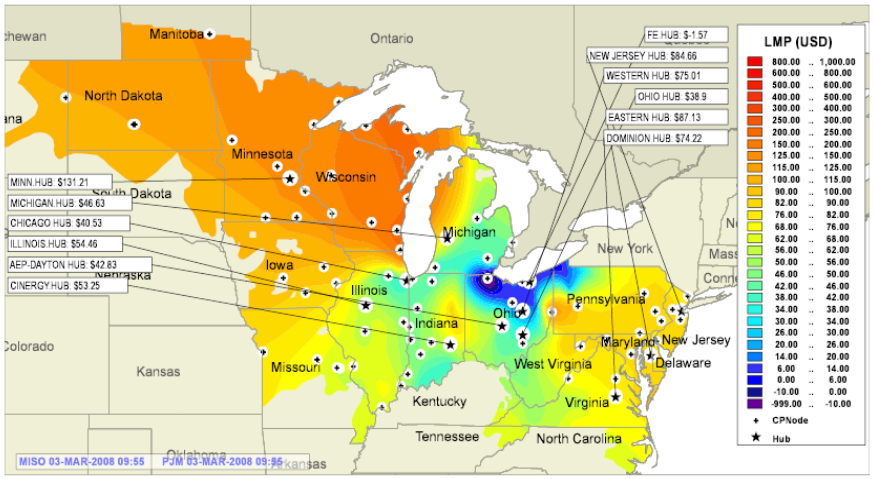


The basic model covers the existing Regional Transmission Organizations and is expanding through the Western Energy Imbalance Market. (www.westerneim.com)

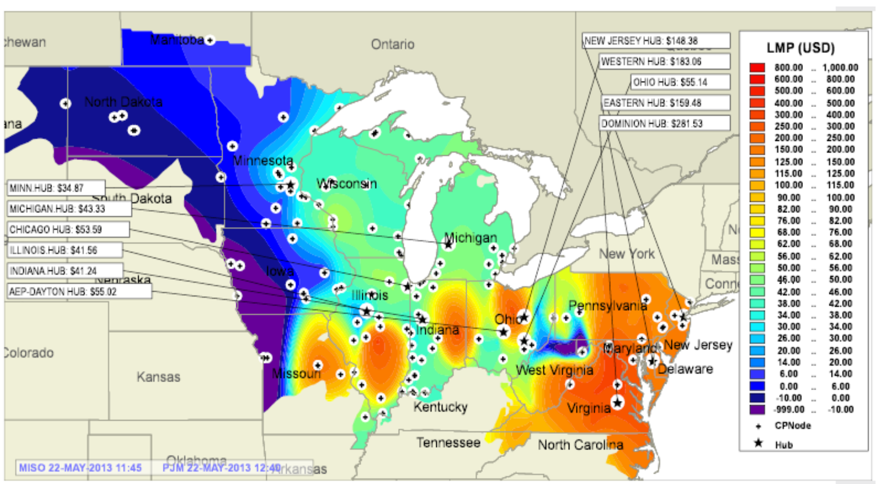




RTOs operate spot markets with locational prices. For example, PJM updates prices and dispatch every five minutes for over 12,000 locations. Locational spot prices for electricity exhibit substantial dynamic variability and persistent long-term average differences.



Minnesota Hub: $131.21/MWh. First Energy Hub: $-1.57/MWh. March 3, 2008, 9:55am



Missouri MPS -$71.25, Dominion Hub $281.53. May 22, 2013, 12:40pm.

From MISO-PJM Joint and Common Market, http://www.jointandcommon.com

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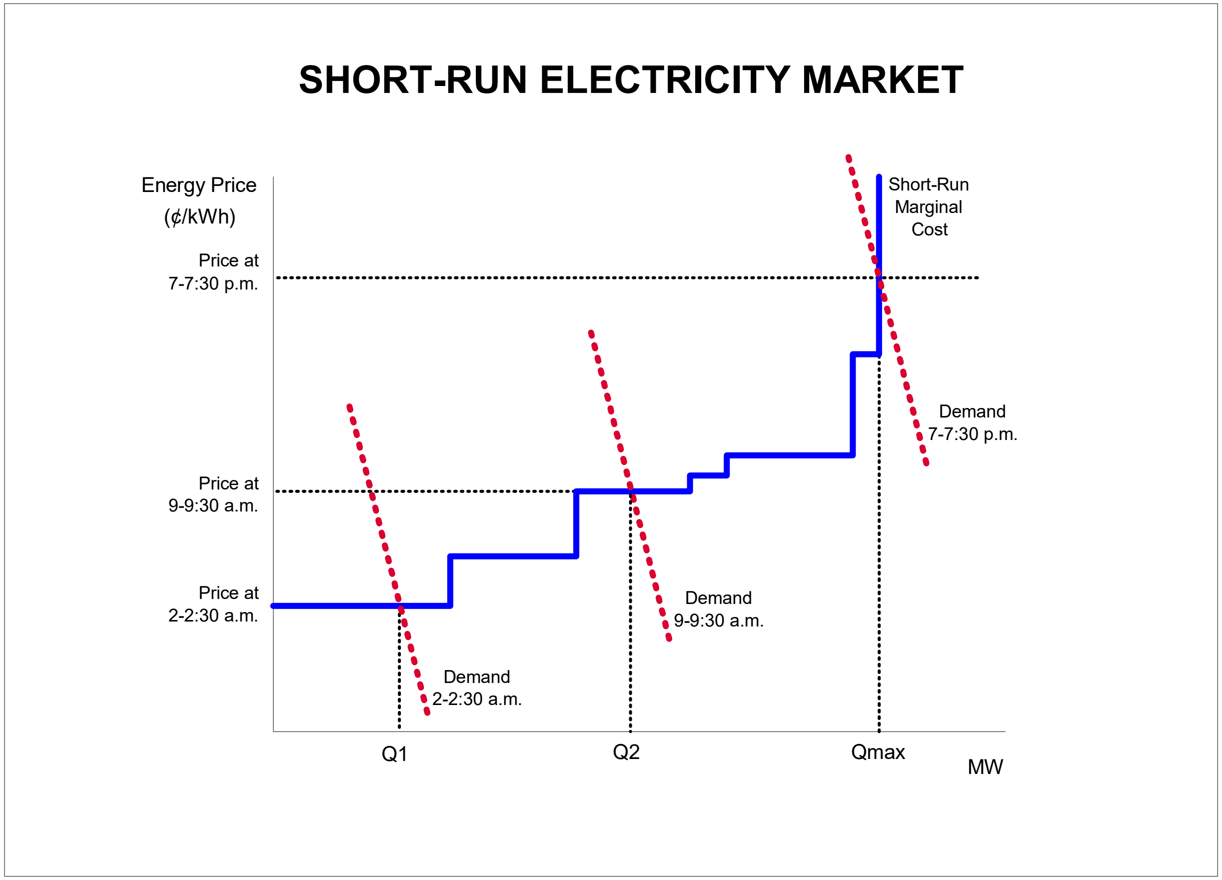
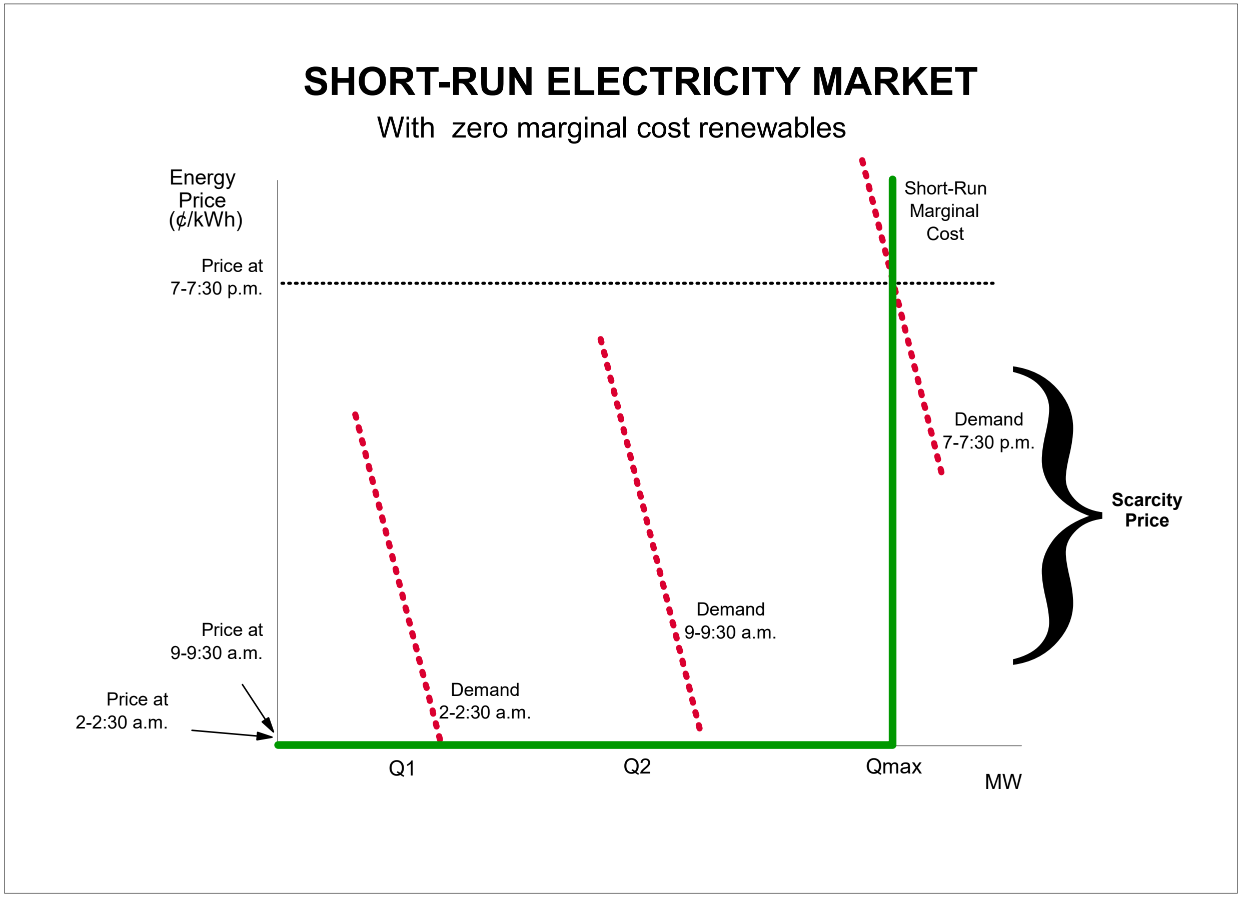
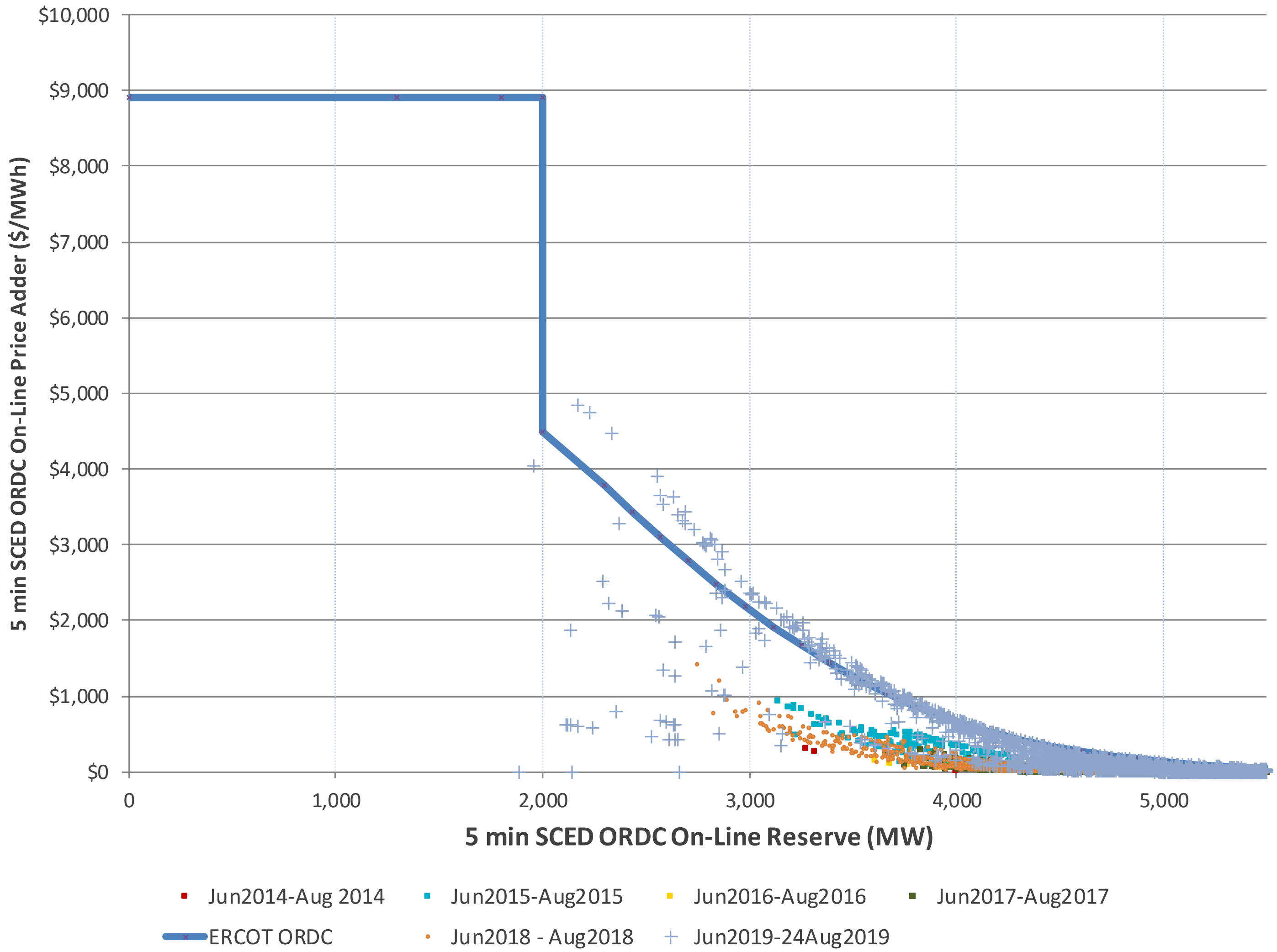


A limiting case illustrates a key issue. Electricity market design with even complete penetration by zero-variable cost renewables would follow the same analysis. But scarcity pricing would be critical to provide efficient incentives.



ERCOT launched implementation of the ORDC in in 2014. The summer peak is the most important period. The first five years of results show recent scarcity of reserves and higher reserve prices.

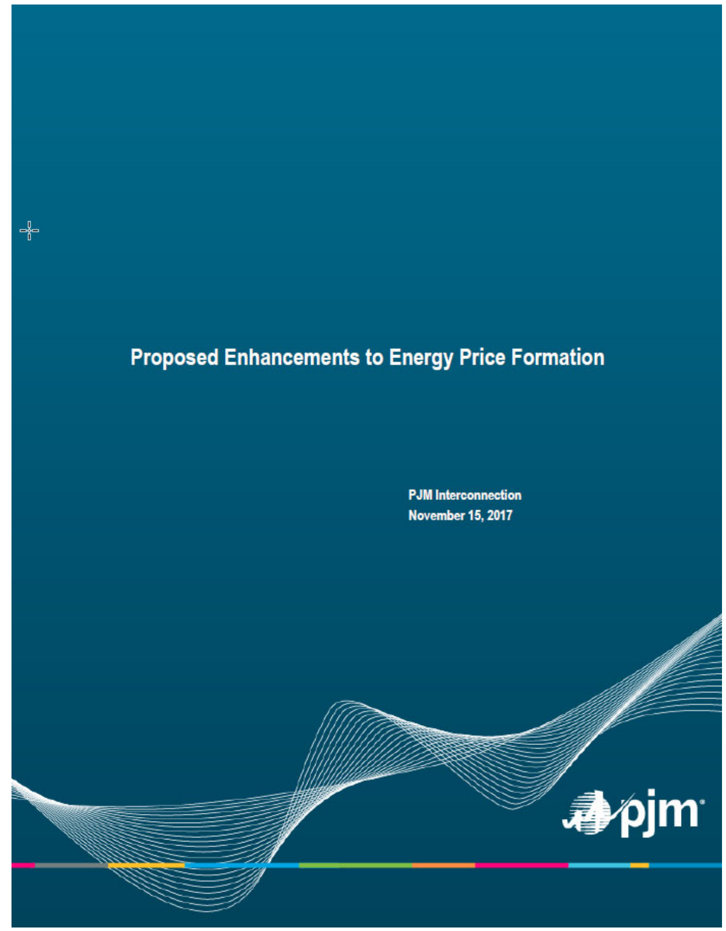


Source: Resmi Surendran, ERCOT, EUCI Presentation, Updated 8/31/2019. The ORDC is illustrative. See also (Hogan & Pope, 2017)

PJM has proposed a series of reforms for energy price formation, motivated in part by the impact of increased penetration of intermittent renewable resources. (PJM Interconnection, 2017) (PJM Interconnection, 2019)

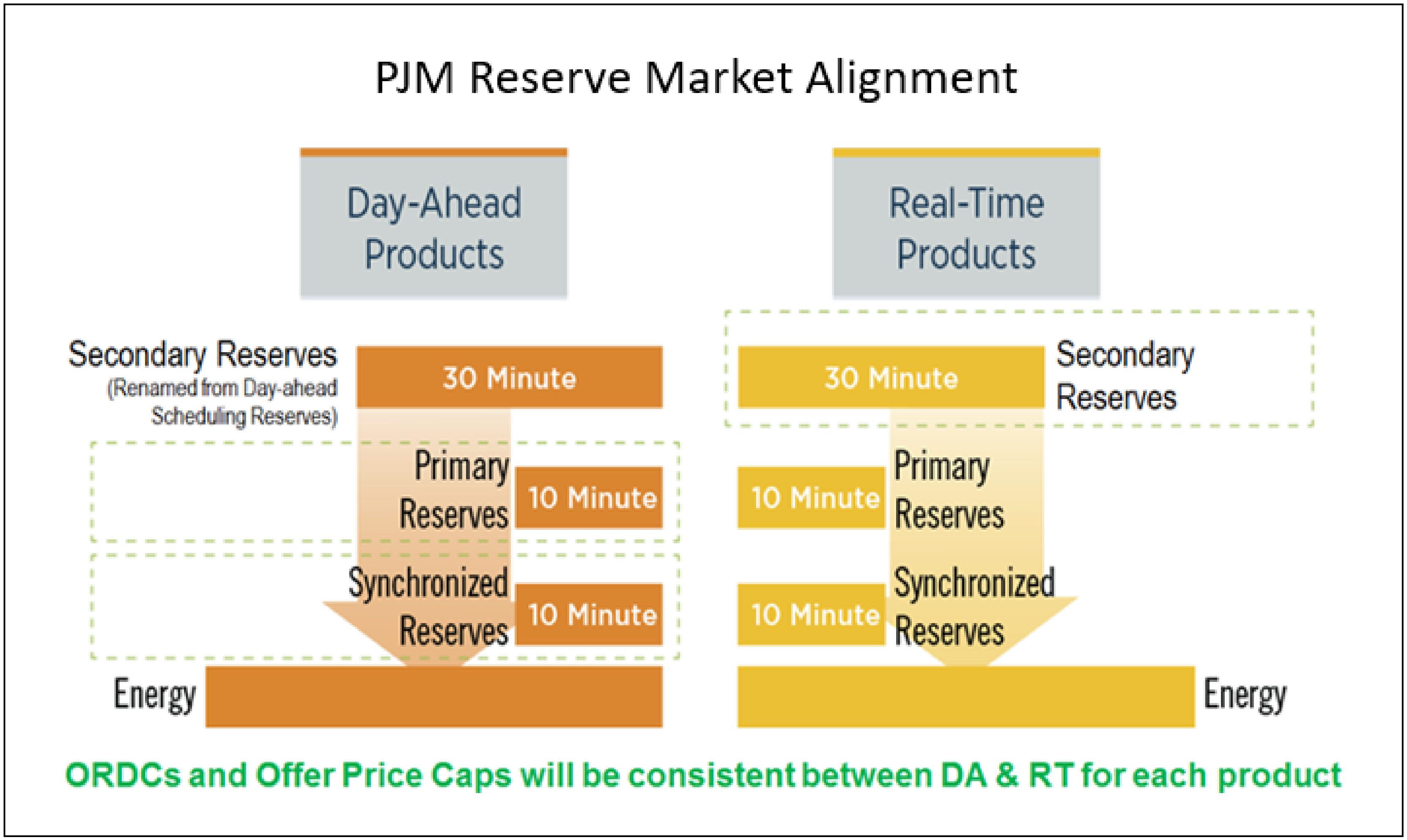
"…the continuing penetration of zero marginal cost resources, declining natural gas prices, greater generator efficiency and reduced generator margins resulting from low energy prices have resulted in a generation mix that is differentiated less by cost and more by physical operational attributes." (p. 1)

Figure 9. Demand Curve for Operating Reserves with Minimum Reserve Requirement

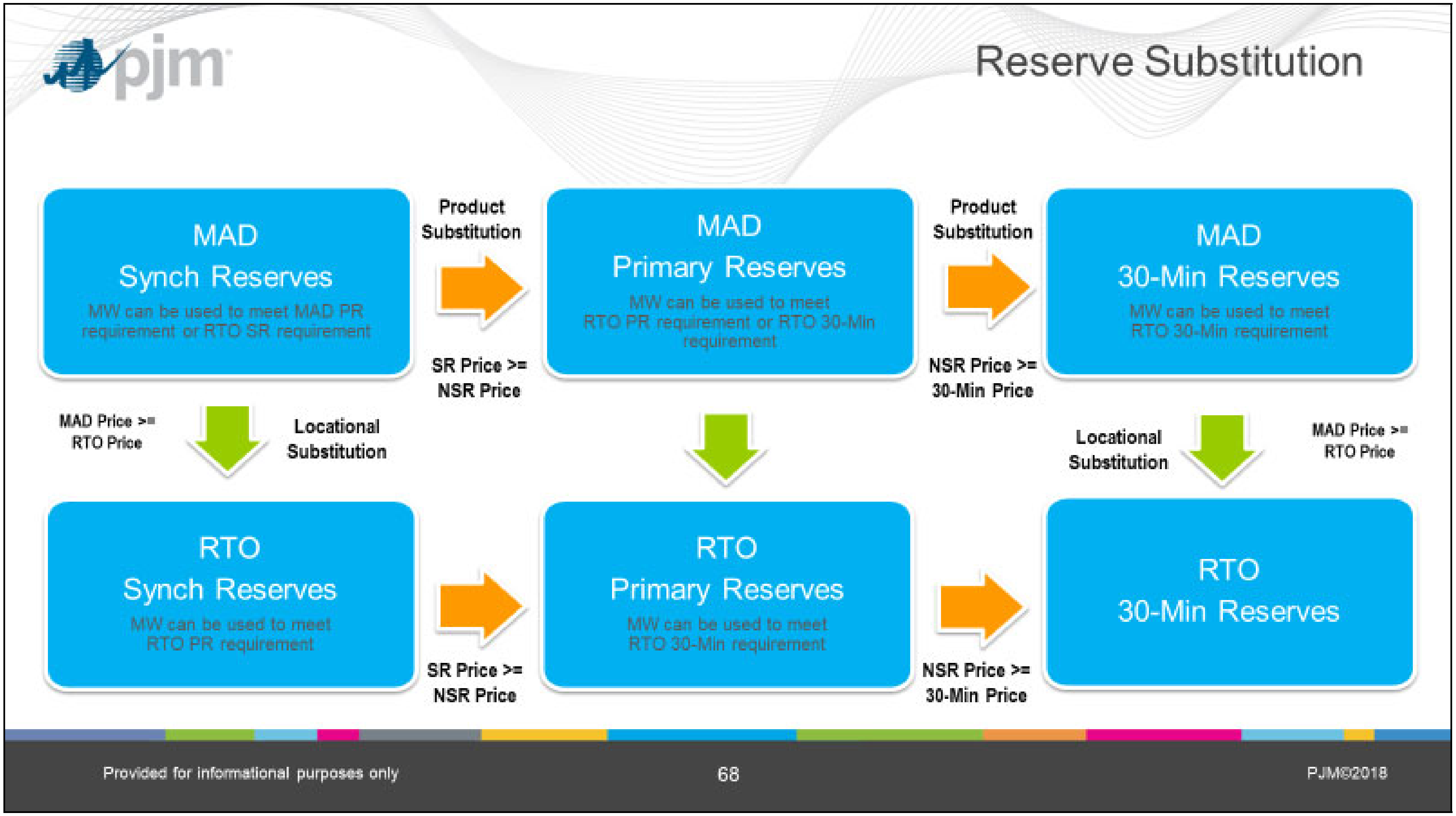


"Redefining PJM's ORDCs using this methodology would enhance PJM's shortage pricing mechanism by assigning a value to reserves consistent with their reliability benefit to the system. Additionally, this ORDC model allows reserves to be committed in excess of the nominal requirement when it lowers the LOLP but assures that the cost of such reserves will never exceed the reliability benefit." (p.23)

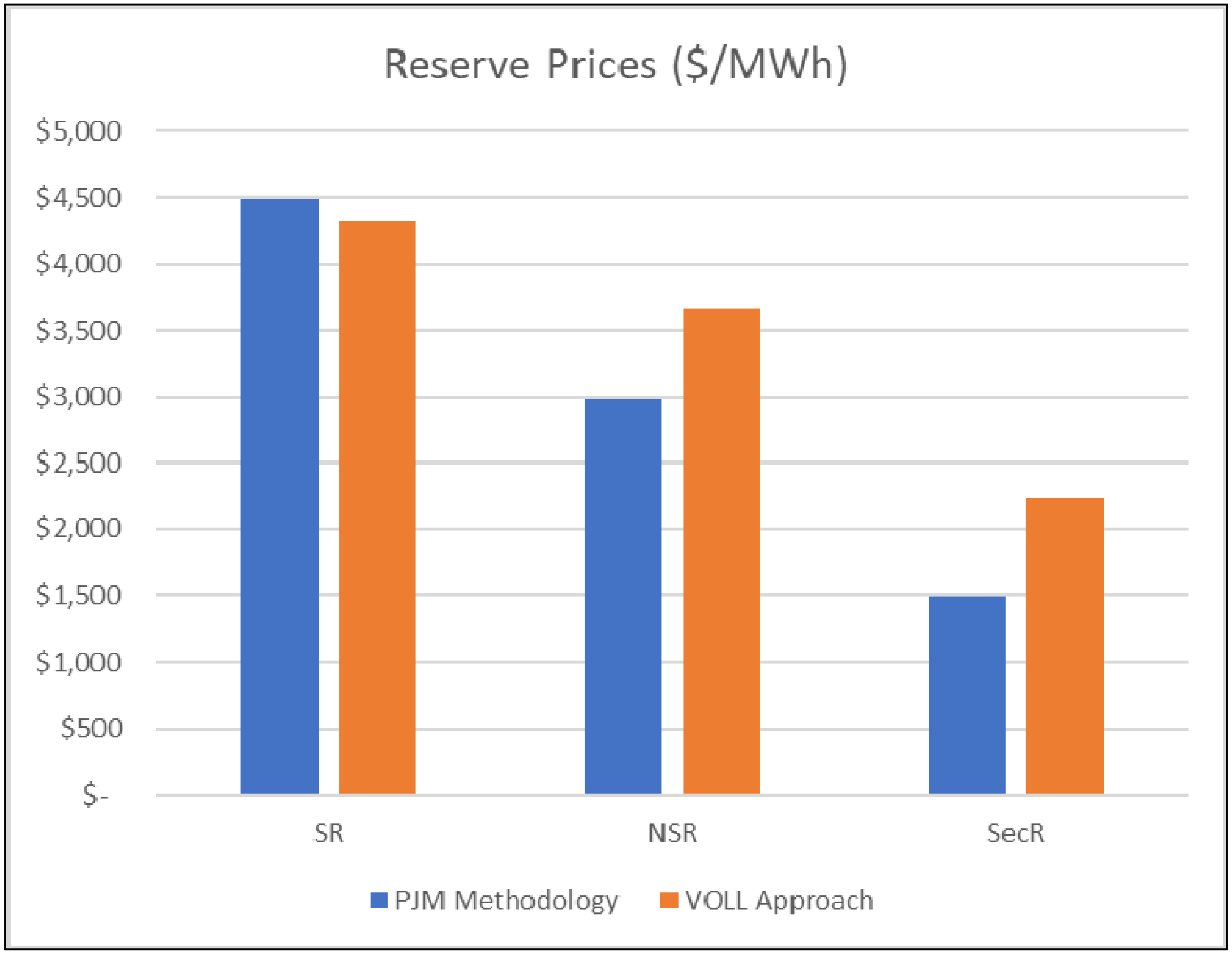
The PJM proposal reforms the structure of operating reserves, changes the pricing "penalty factors" and adopts a cascade model that addresses the interactions between reserve types. (Hogan & Pope, 2019)



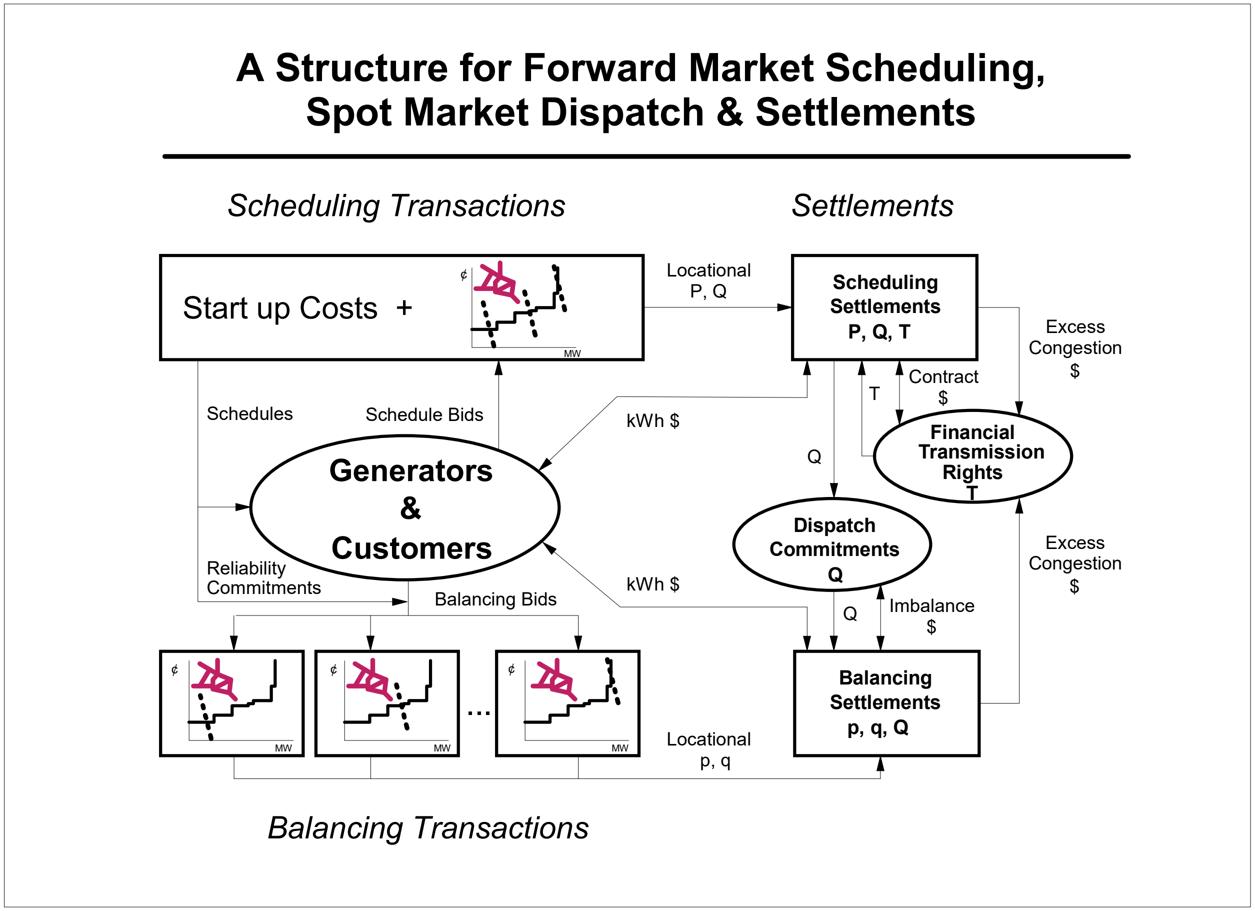
The PJM cascade model that addresses the interactions between reserve types. (Hogan & Pope, 2019)



The PJM "Probability of Reserves Falling Below the Minimum Reserve Requirement" (PBMRR), similar to a loss of load probability (Lolp), produces a downward sloping demand curve for additional operating reserves. At the MRR, PJM prices would be comparable to the assuming a $6000 VOLL. (Hogan & Pope, 2019)



Organized electricity markets utilize day-ahead markets with bid-in loads and generation offers. This structure produces day-ahead contracts that will be settled at real-time prices. The structure allows strictly financial participants in the day-ahead market.



Day-ahead markets provide a mechanism for short-term hedging of real-time prices. With virtual trading, risk neutral market participants, and no uplift allocation, the idealized day-ahead prices should equal the expected real-time price. Otherwise, traders are leaving money on the table. (Hogan, 2016)

$$P_{\text{Day Ahead}} \left| \text{Day Ahead Information} = E\left(P_{\text{Real Time}} \left| \text{Day Ahead Information} \right.\right) \right.$$

In the real system there are varying degrees of risk aversion and transaction costs. Market participants pay differing uplift charges depending on the nature of their virtual transactions. However, trading to capture arbitrage opportunities should produce a close connection between day-ahead and expected real-time prices.

$$P_{\text{Day Ahead}} \left| \text{Day Ahead Information} \approx E\left(P_{\text{Real Time}} \left| \text{Day Ahead Information} \right.\right) + \text{ Transaction Costs} \right.$$

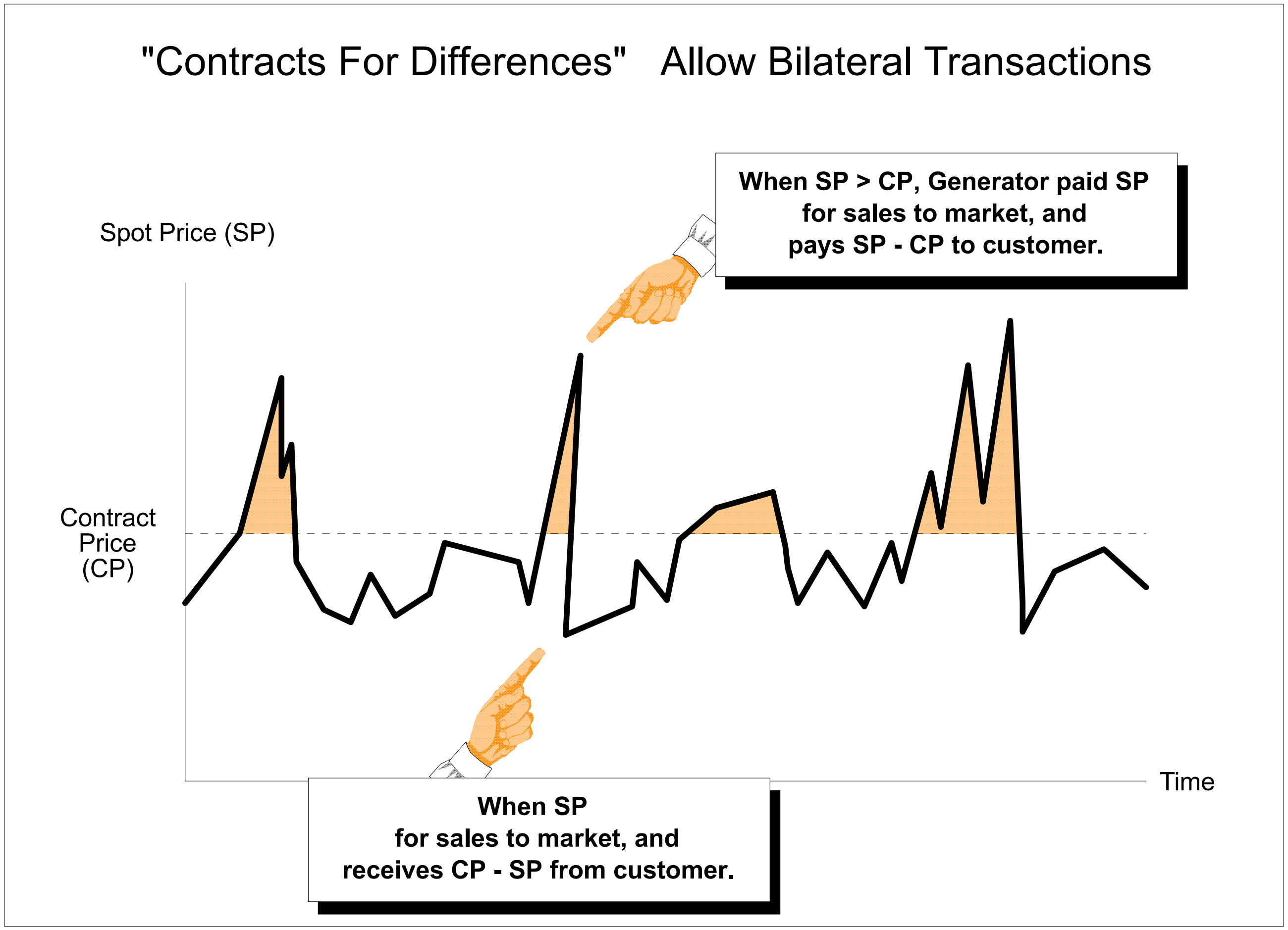
With virtual bids (offers) at P_V, the day-ahead dispatch becomes:

$$\begin{aligned}
&\underset{v,d\in D,g\in G,u\in U}{Max} \; Benefits_{DA}\left(d\right) - Costs_{DA}\left(g\right) + P_V v \\
&\quad s.t. \\
&\qquad d - g + v = y, \\
&\qquad L\left(y,u\right) + \iota^t y = 0, \\
&\qquad K\left(y,u\right) \le 0.
\end{aligned}$$

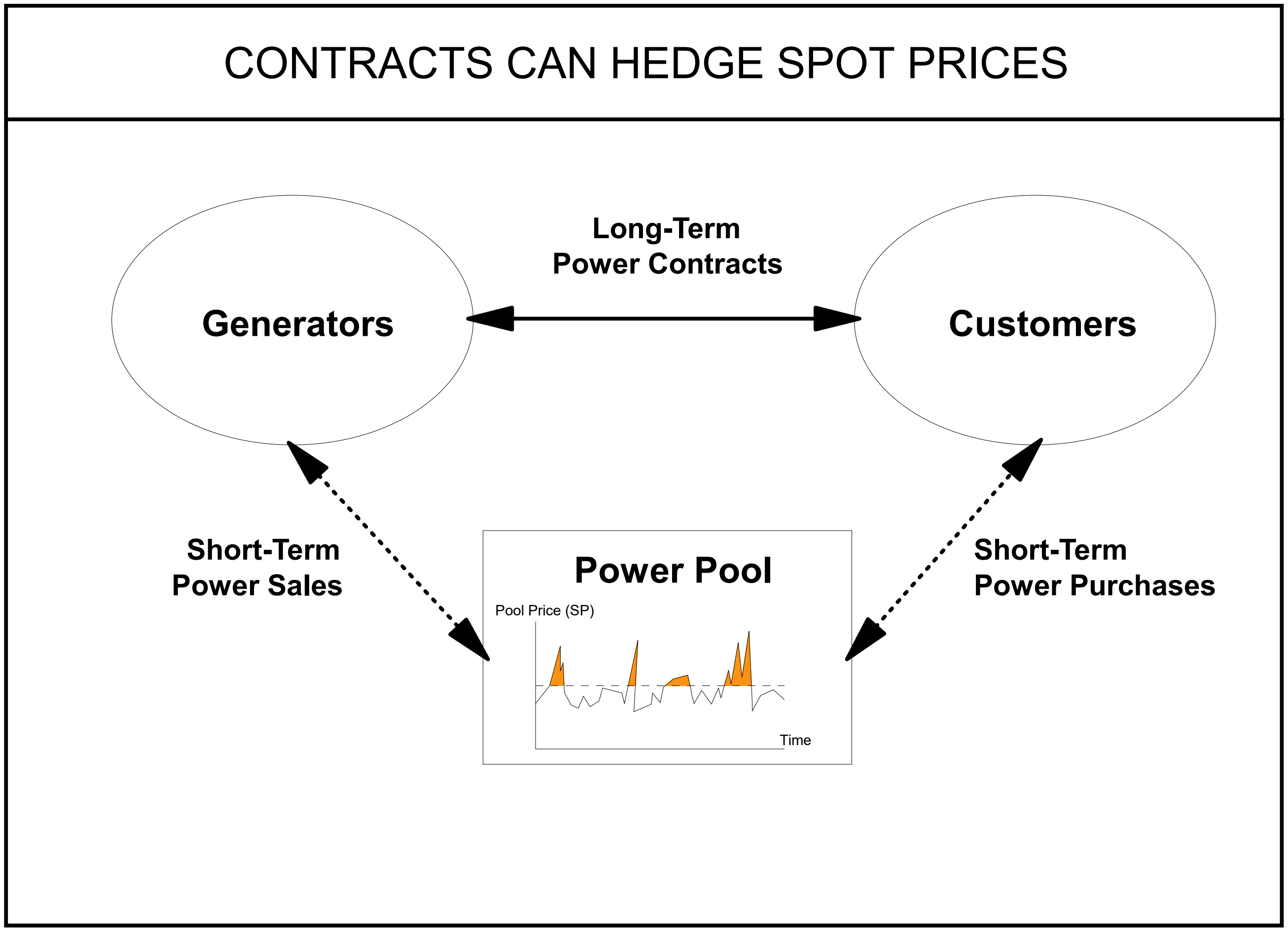
Virtual transactions provide many potential benefits for market performance and arbitrage between the Day Ahead (DA) market and Real Time (RT) market.

- Better price formation between DA and RT markets.
- Increased liquidity in the DA market.
- Moderate or eliminate ability to exercise market power.
- Hedging to reduce price variation for RT settlements.
- Impacts commitment and dispatch by incentivizing physical generation and load to participate in the DA market.

The spot price in an electricity market can be highly volatile. A contract for differences offers a simple financial contract that replicates a fixed price contract. The seller sells to the pool. The buyer buys from the pool. The CFD provides a means to replicate a bilateral transaction.

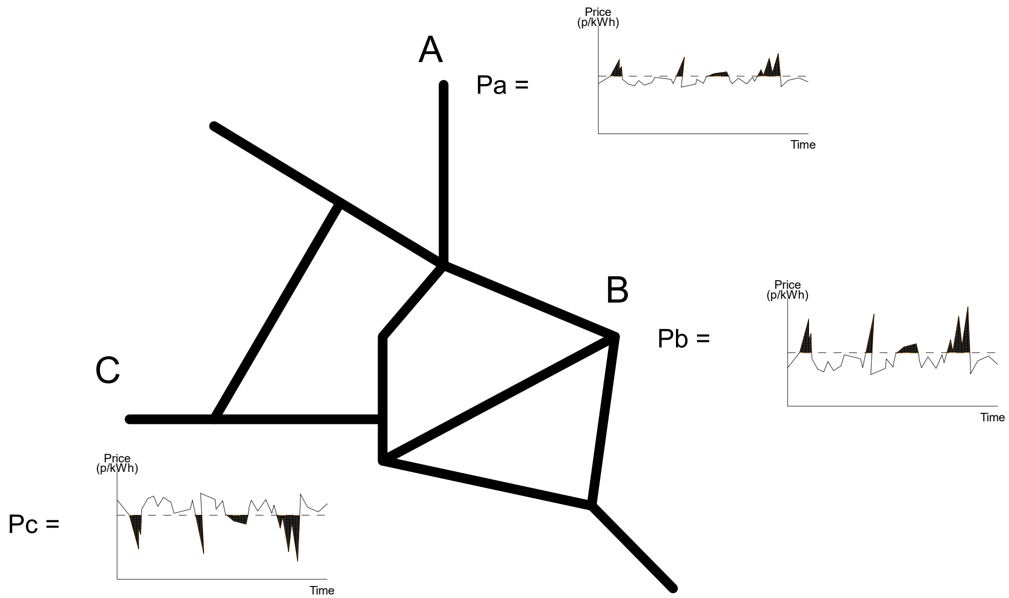


With the contracts for differences, the physical operation of the power pool becomes independent of the long-term contracts. Importantly, deliverability of the power does not depend on the contracts. The pool operates a spot market and produces spot prices for settlements.



For transmission between locations, the transmission opportunity cost is the difference in the locational prices. This difference of volatile prices will be even more volatile.

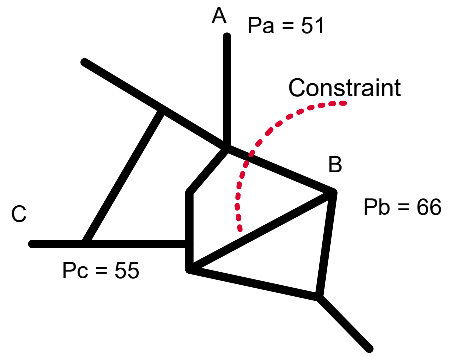
NEED "Hedges" FOR LOCATIONAL PRICING



Price of "Transmission" from C to B = Pb - Pc = Volatile Price

A mechanism for hedging volatile transmission prices can be established by defining financial transmission rights to collect the congestion rents inherent in efficient, short-run spot prices. (Hogan, 1992)

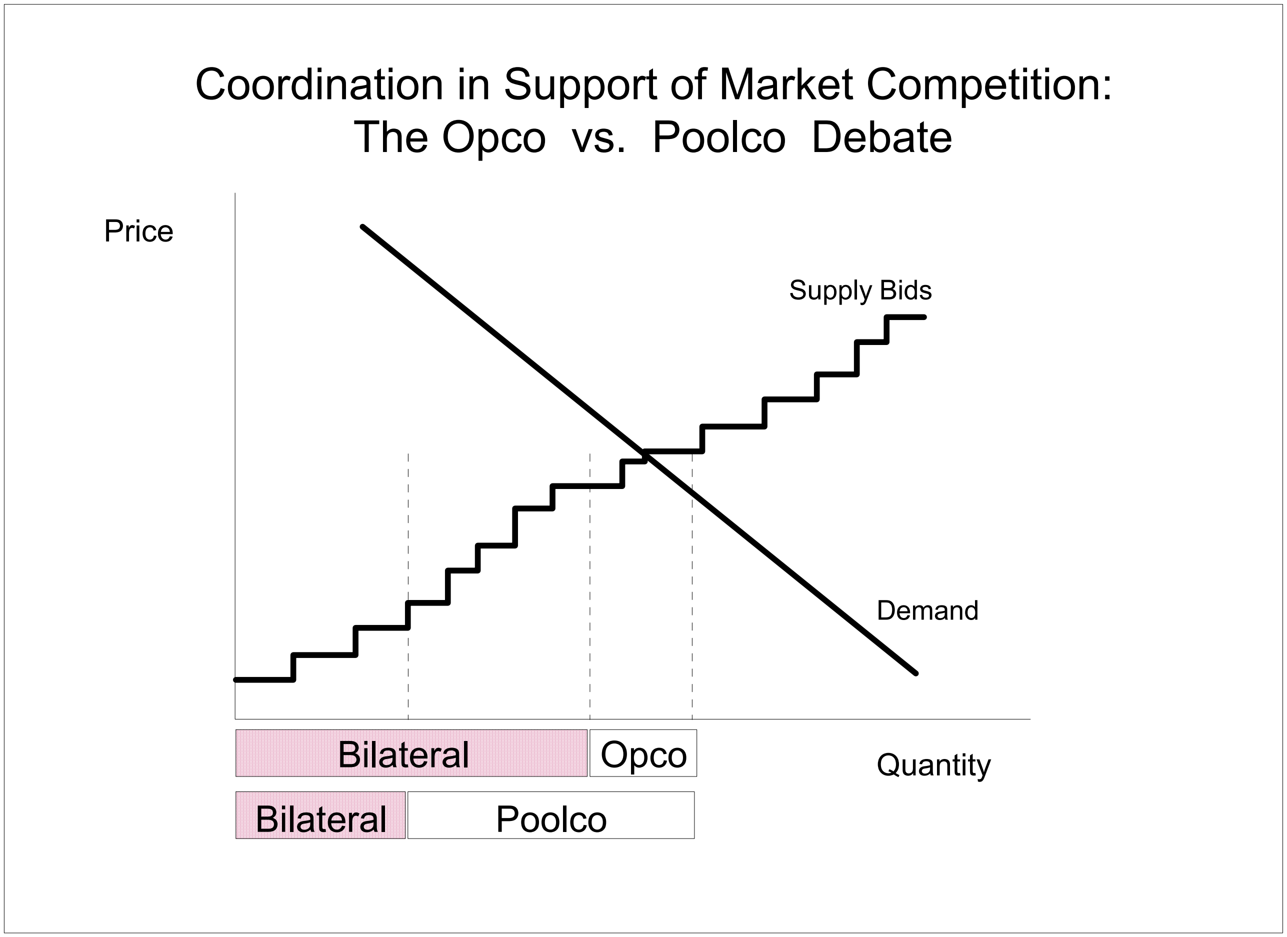
NETWORK TRANSMISSION FINANCIAL RIGHTS



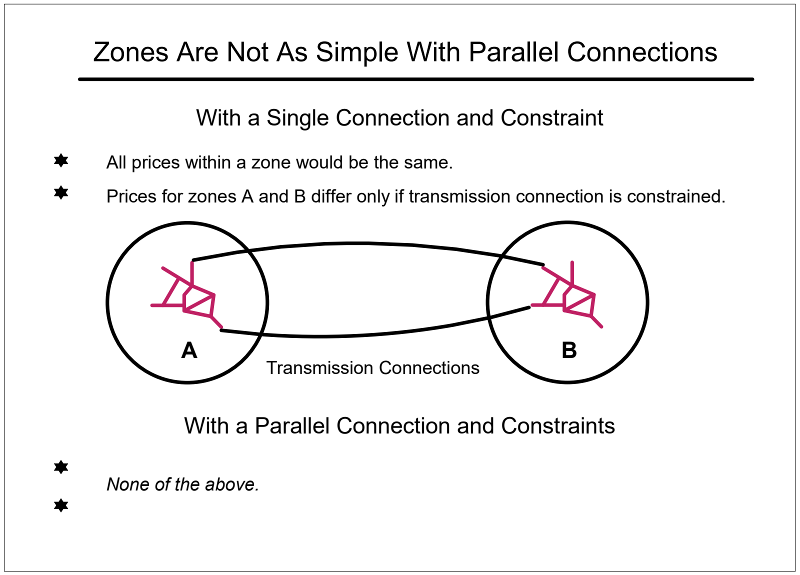
Price of "Transmission" from A to B = Pb - Pa = 15
Price of "Transmission" from C to A = Pa - Pc = -4

- DEFINE TRANSMISSION CONGESTION CONTRACTS BETWEEN LOCATIONS.
- FOR SIMPLICITY, TREAT LOSSES AS OPERATING COSTS.
- RECEIVE CONGESTION PAYMENTS FROM ACTUAL USERS; MAKE CONGESTION PAYMENTS TO HOLDERS OF CONGESTION CONTRACTS.
- TRANSMISSION CONGESTION CONTRACTS PROVIDE PROTECTION AGAINST CHANGING LOCATIONAL DIFFERENCES.

Debates over the role of bilateral transactions scheduled through and OPCO and coordinated spot markets operated by the POOLCO present a false dichotomy. The simple solution is to allow both and let the market decide on the mix of transactions.



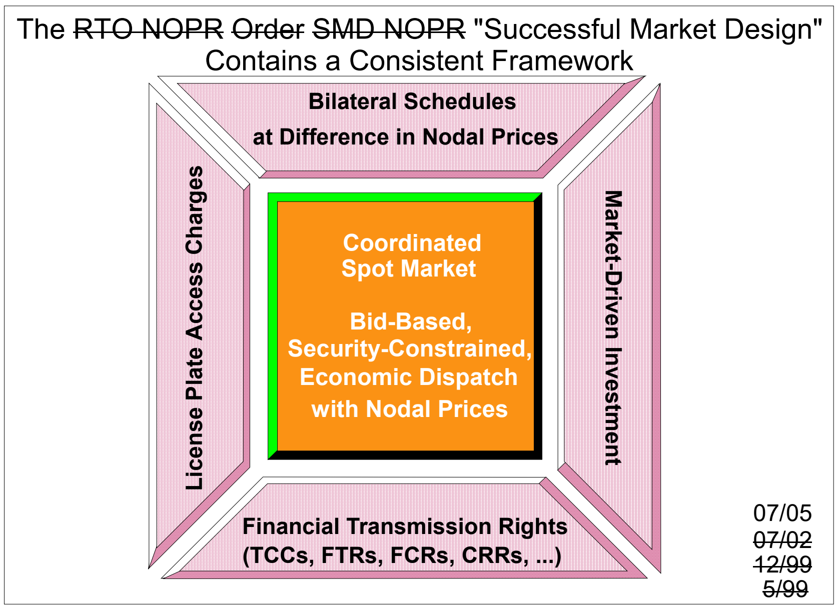
The use of zones versus nodal pricing is an issue. If the world divided naturally into zones, life would be simpler. However, aggregation of a real world with true locational differences into a fictional world with zones would not be simple. For competition to be flexible and work well, it will be important to get the prices right. A number of questions arise in making the choice between choosing aggregation into zones or using the actual locational prices.



- **If Zones are Defined by Nodes with Common Prices, Why Bother?** (Don't.)
- **How Would We Define the Zonal Prices?** (?)
- **Would Locational Prices Be Hard to Calculate and Come from a Black Box?** (No.)
- **Would It Be an Easy Matter to Set and Later Change the Zonal Boundaries?** (No.)
- **Is Transmission Congestion a Small Problem?** (No.)
- **Would Zonal Pricing Mitigate Market Power?** (No.)
- **Can the Market Operate With a Simpler System?** (Yes. Locational Pricing with Hub and Spokes.)

ELECTRICITY MARKET — A Consistent Framework

The example of successful central coordination, ~~CRT, Regional Transmission Organization (RTO) Millennium Order (Order 2000)~~ ~~Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR),~~ "Successful Market Design" provides a workable market framework that is working in places like New York, PJM in the Mid-Atlantic Region, New England, the Midwest, California, SPP, and Texas. This efficient market design is under (constant) attack.



Poolco…OPCO…ISO…IMO…Transco…RTO…ITP…WMP…: "A rose by any other name …"

"Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments." (International Energy Agency, 2007)

This is the only model that can meet the tests of open access and non-discrimination.

Supporting the Solution: Given the prices and settlement payments, individual optimal behavior is consistent with the aggregate optimal solution. Anything that upsets this design will unravel the wholesale electricity market. The basic economic dispatch model accommodates the green energy agenda, as in the expanding Western Energy Imbalance Market (EIM).

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William W. Hogan is the Raymond Plank Research Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. This paper draws on research for the Harvard Electricity Policy Group and for the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Aquila, AQUIND Limited, Atlantic Wind Connection, Australian Gas Light Company, Avista Corporation, Avista Utilities, Avista Energy, Barclays Bank PLC, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, California Suppliers Group, Calpine Corporation, CAM Energy, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, City Power Marketing LLC, Cobalt Capital Management LLC, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, COMPETE Coalition, Conectiv, Constellation Energy, Constellation Energy Commodities Group, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Deutsche Bank Energy Trading LLC, Duquesne Light Company, Dyon LLC, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Authority New Zealand, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Energy Endeavors LP, Exelon, Financial Marketers Coalition, FirstEnergy Corporation, FTI Consulting, GenOn Energy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GDF SUEZ Energy Resources NA, Great Bay Energy LLC, GWF Energy, Independent Energy Producers Assn, ISO New England, Israel Public Utility Authority-Electricity, Koch Energy Trading, Inc., JP Morgan, LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, Monterey Enterprises LLC, MPS Merchant Services, Inc. (f/k/a Aquila Power Corporation), JP Morgan Ventures Energy Corp., Morgan Stanley Capital Group, Morrison & Foerster LLP, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario Attorney General, Ontario IMO, Ontario Ministries of Energy and Infrastructure, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, Powerex Corp., Powhatan Energy Fund LLC, PPL Corporation, PPL Montana LLC, PPL EnergyPlus LLC, Public Service Company of Colorado, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Red Wolf Energy Trading, Reliant Energy, Rhode Island Public Utilities Commission, Round Rock Energy LP, San Diego Gas & Electric Company, Secretaría de Energía (SENER, Mexico), Sempra Energy, SESCO LLC, Shell Energy North America (U.S.) L.P., SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, TransAlta Energy Marketing (California), TransAlta Energy Marketing (U.S.) Inc., Transcanada, TransCanada Energy LTD., TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Twin Cities Power LLC, Vitol Inc., Westbrook Power, Western Power Trading Forum, Williams Energy Group, Wisconsin Electric Power Company, and XO Energy. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).