

# **ELECTRICITY MARKET DESIGN: Market Models for Coordination and Pricing**

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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.**

Consider three cases of interest that present difficult challenges for regulators. A focus on pricing illustrates an important thread of modeling and analysis. Constrained optimization provides a central organizing framework.

- **Design Framework: “Locational Marginal Pricing”**

LMP. Bid-based, security constrained economic dispatch.

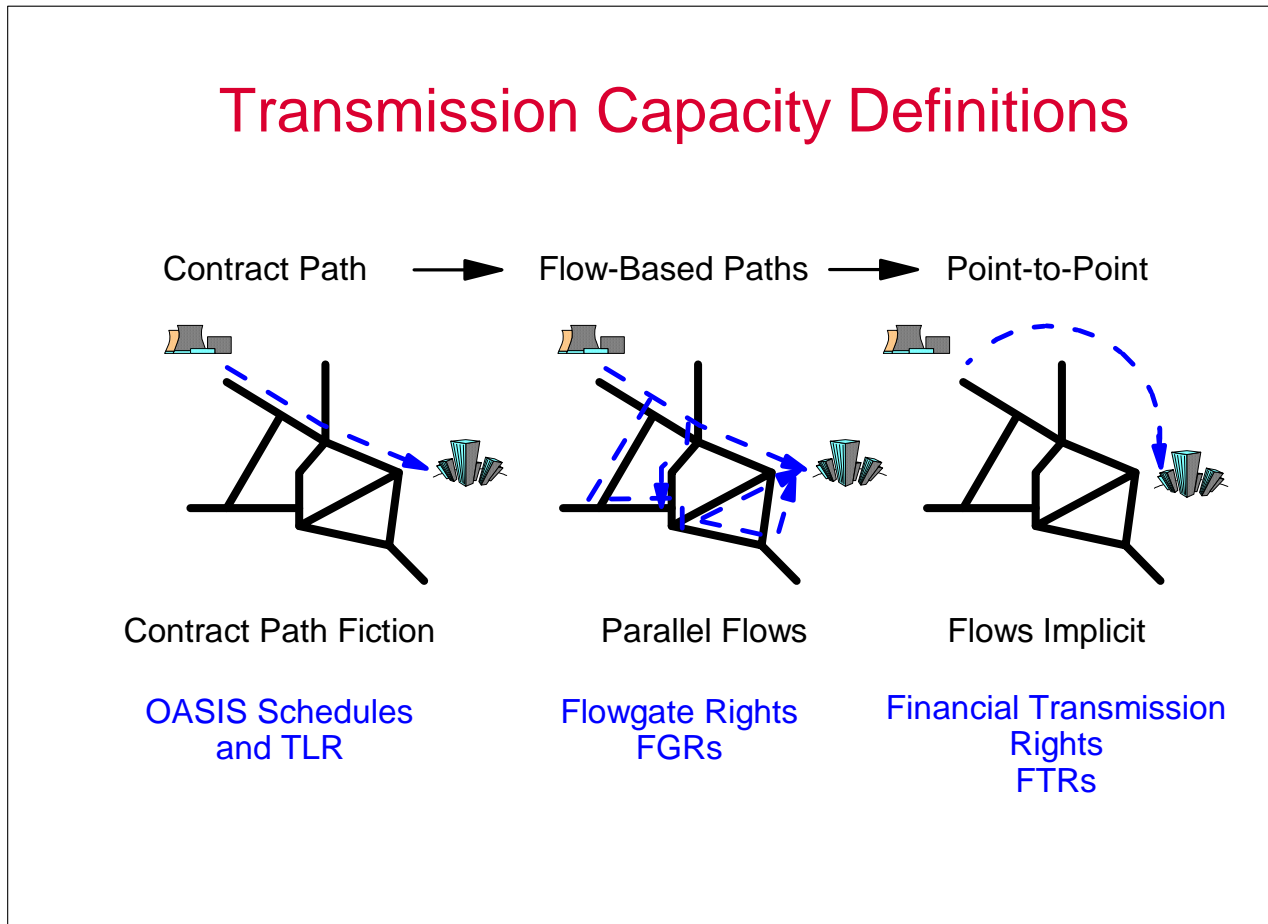
- **Design Implementation: Scarcity Pricing**

Better scarcity pricing to support resource adequacy.

- **Design Limitation: Uplift Payments**

Unit commitment and lumpy decisions. Coordination and bid guarantees.

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



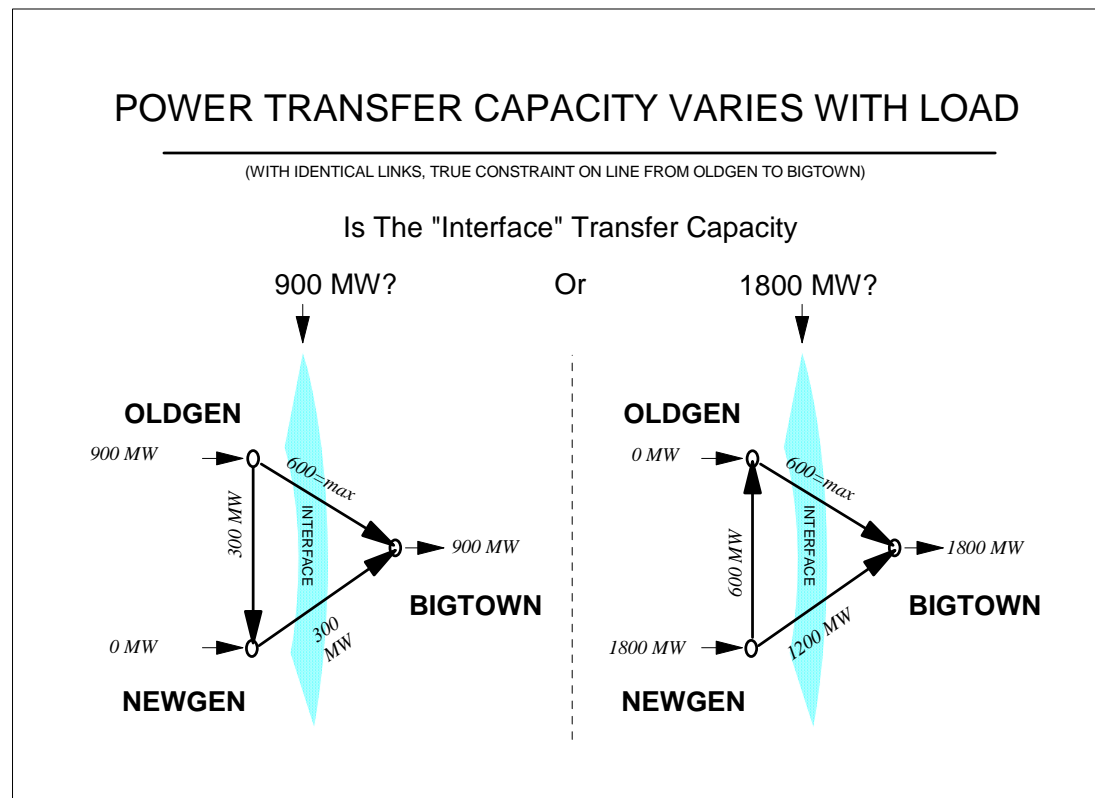
**Under Order 888 the FERC made a crucial choice regarding a central complication of the electricity system.**

“A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. ... Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime.” (FERC, Order 888, April 24, 1996, footnotes 184-185, p. 93.)

**Why is this important? A quick tutorial follows.**

Electric transmission network interactions can be large and important.

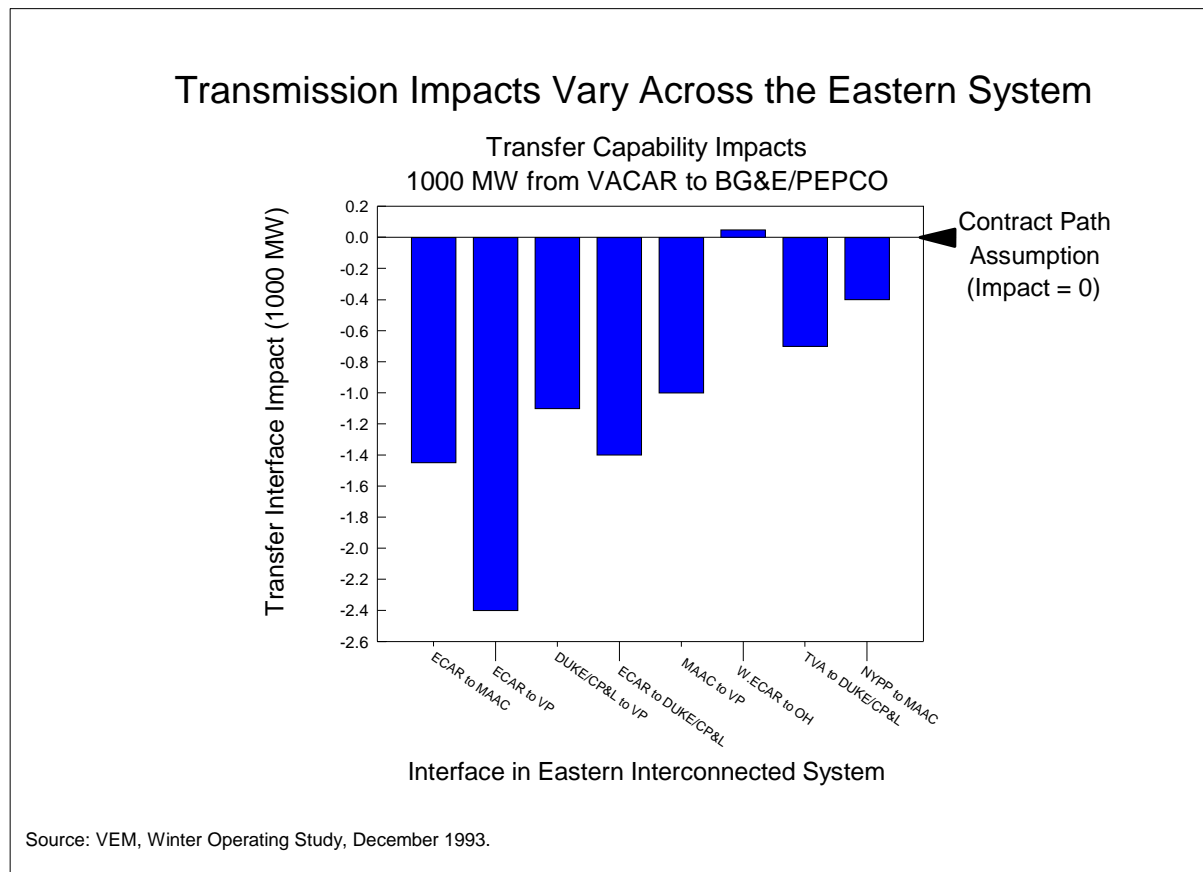
- Conventional definitions of network "Interface" transfer capacity depend on the assumed load conditions.
- Transfer capacity cannot be defined or guaranteed over any reasonable horizon.



# NETWORK INTERACTIONS

# Loop Flow

There is a fatal flaw in the old "contract path" model of power moving between locations along a designated path. The network effects are strong. Power flows across one "interface" can have a dramatic effect on the capacity of other, distant interfaces.



**Under Order 888 the FERC made a crucial choice regarding a central complication of the electricity system.**

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“We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described by Hogan and others. At the same time, however, contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. To require now a dramatic overhaul of the traditional approach such as a shift to some form of flow-based pricing and contracting could severely slow, if not derail for some time, the move to open access and more competitive wholesale bulk power markets. In addition, we believe it is premature for the Commission to impose generically a new pricing regime without the benefit of any experience with such pricing. We welcome new and innovative proposals, but we will not impose them in this Rule.” (FERC, Order 888, April 24, 1996, p. 96.)

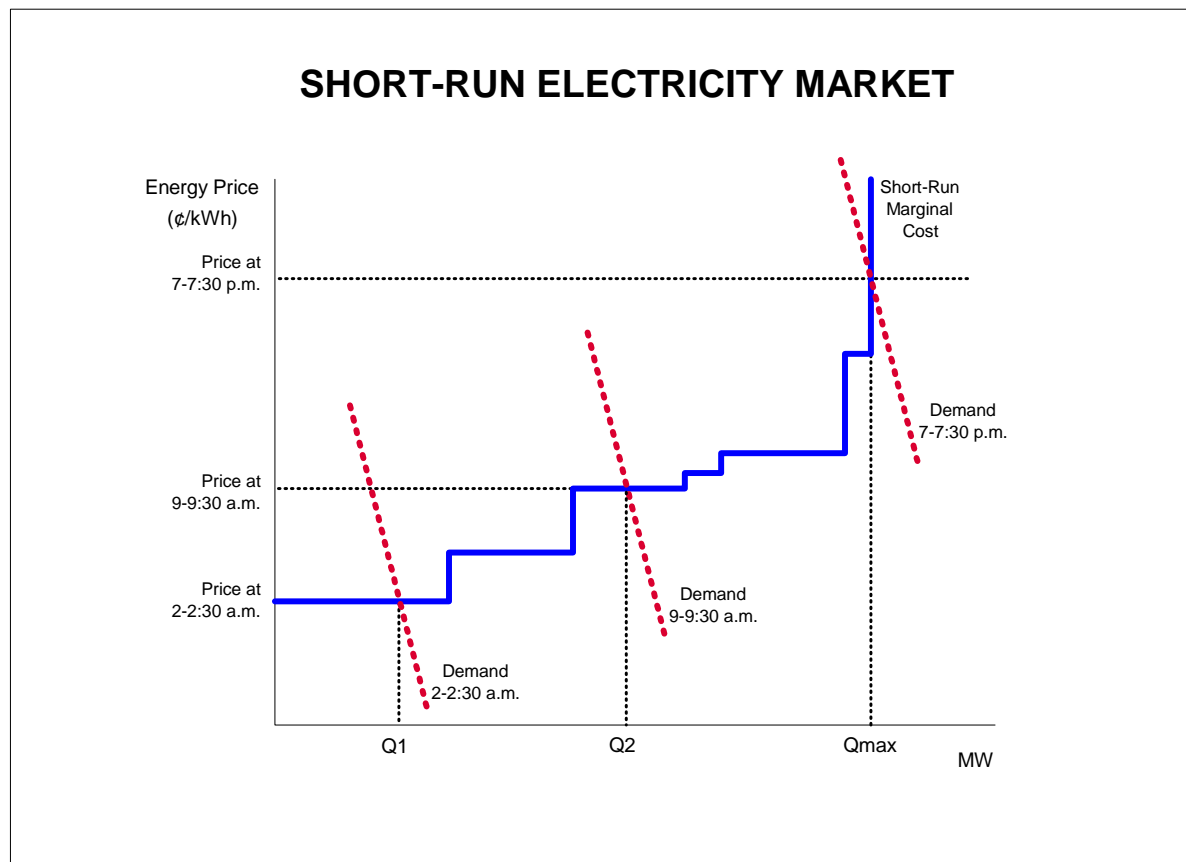
**Hence, although the fictional contract path approach would not work in theory, maintaining the fiction would be less disruptive in moving quickly to open access and an expanded competitive market!**



# ELECTRICITY MARKET

# Pool Dispatch

An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand. Everyone pays or is paid the same price.

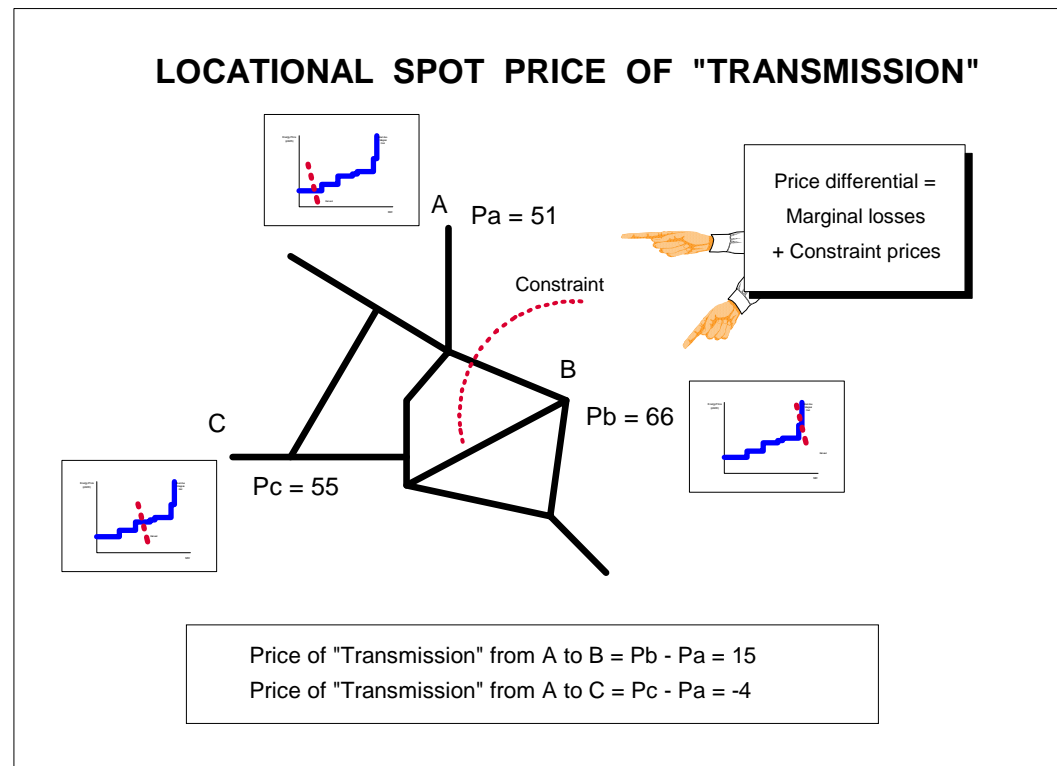


# NETWORK INTERACTIONS

# 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.



# NETWORK INTERACTIONS

# Locational Spot Prices

Locational prices (\$/MWh) arise from the standard formulation of security constrained economic dispatch to balance generation and load at each location. For instance, in PJM there are several thousand locations with thousands of constraints for each of thousands of contingencies.

Bid-Based, Security-Constrained, Economic Dispatch

$$\begin{aligned} & \text{Max}_{d,g,x,y} B(d) - C(g) \\ & \text{subject to} \\ & d - g = y \quad : p \\ & K(x, y) \leq 0. \quad : \mu \end{aligned}$$

PJM Real Time Hourly LMP Values for 20080224

							Range	551.94	550.57	23.80	127.90	126.10	21.06	138.60	137.61	16.42
							Max	516.16	434.34	16.38	142.74	71.28	14.18	166.06	109.89	11.13
							Average	69.79	-5.18	-0.53	66.17	-4.88	-0.53	48.86	-2.22	-0.44
							Min	-35.78	-116.23	-7.42	14.84	-54.82	-6.88	27.46	-27.72	-5.29
Start of Real Time LMP Data							100	100	100	1200	1200	1200	1800	1800	1800	
Node	Date	PnodeID	Name	Voltage	Equipm Type	Zone	TotalLM	Congesti	MarginalLossPri	TotalLMP	Congestic	MarginalLossPrice	TotalLMP	Congestic	MarginalLossPrice	
1	20080224	1	PJM-RTO		ZONE		75.90	0.34	0.06	71.84	0.20	0.06	51.63	0.07	0.04	
2	20080224	3	MID-ATL/APS		ZONE		97.78	19.30	2.97	90.79	16.52	2.69	60.51	6.89	2.11	
3	20080224	51291	AECO		ZONE		46.33	-33.86	4.69	91.28	15.17	4.53	48.86	-6.21	3.55	
4	20080224	8445784	AEP		ZONE		43.55	-28.48	-3.47	32.42	-35.94	-3.22	37.52	-11.51	-2.49	
...																
424	20080224	32406789	107 DIX138 KV TR76 3:LOAD	COMEL			41.23	-28.37	-5.90	32.16	-34.15	-5.27	35.61	-11.59	-4.32	
425	20080224	32406793	109 AP' 138 KV TR72 1:LOAD	COMEL			42.72	-28.66	-4.12	33.46	-34.39	-3.73	36.73	-11.74	-3.05	
426	20080224	32406795	109 AP' 138 KV TR73 1:LOAD	COMEL			42.69	-28.66	-4.15	33.43	-34.39	-3.76	36.71	-11.74	-3.07	
...																
8075	20080224	49498	ZIONS\115 KV 1B12	LOAD	METED		92.57	15.14	1.93	93.33	19.83	1.92	59.47	6.41	1.54	
8076	20080224	49499	ZIONS\115 KV 2B12	LOAD	METED		92.57	15.14	1.93	93.33	19.83	1.92	59.47	6.41	1.54	
8077	20080224	32413125	ZUBER 138 KV T1	LOAD	AEP		40.57	-31.29	-3.64	32.11	-36.24	-3.23	36.19	-12.85	-2.48	
End of Real Time LMP Data																

# NETWORK INTERACTIONS

# Locational Spot Prices

Locational spot prices for electricity exhibit substantial dynamic variability and persistent long-term average differences.

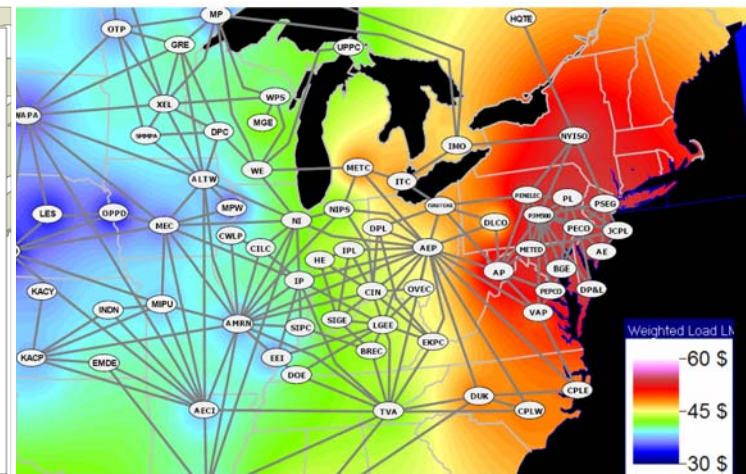
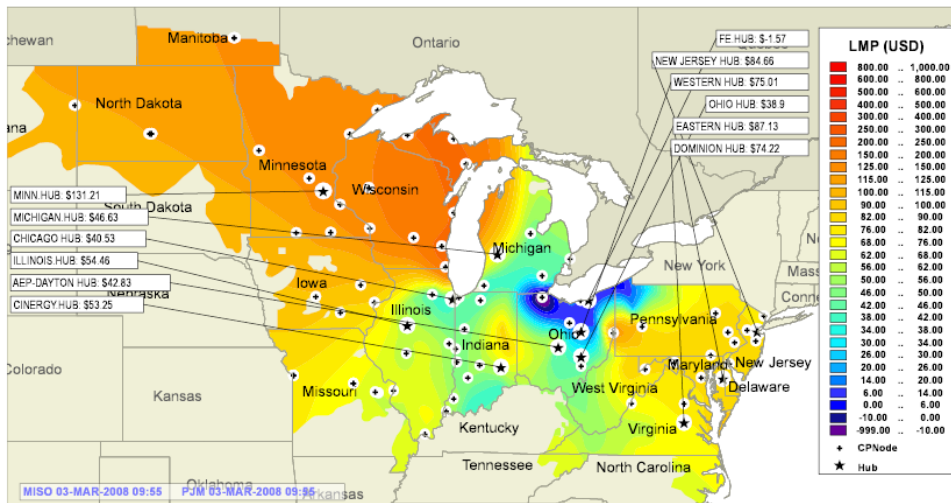


Figure 2.2-3 Contour Map of Annual Load Weighted LMP

From MISO-PJM Joint and Common Market, <http://www.jointandcommon.com/> for March 3, 2008, 9:55am. Projected 2011 annual average from 2006 Midwest ISO-PJM Coordinated System Plan.

# NETWORK INTERACTIONS

# Financial Transmission Rights

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.

**NETWORK TRANSMISSION FINANCIAL RIGHTS**

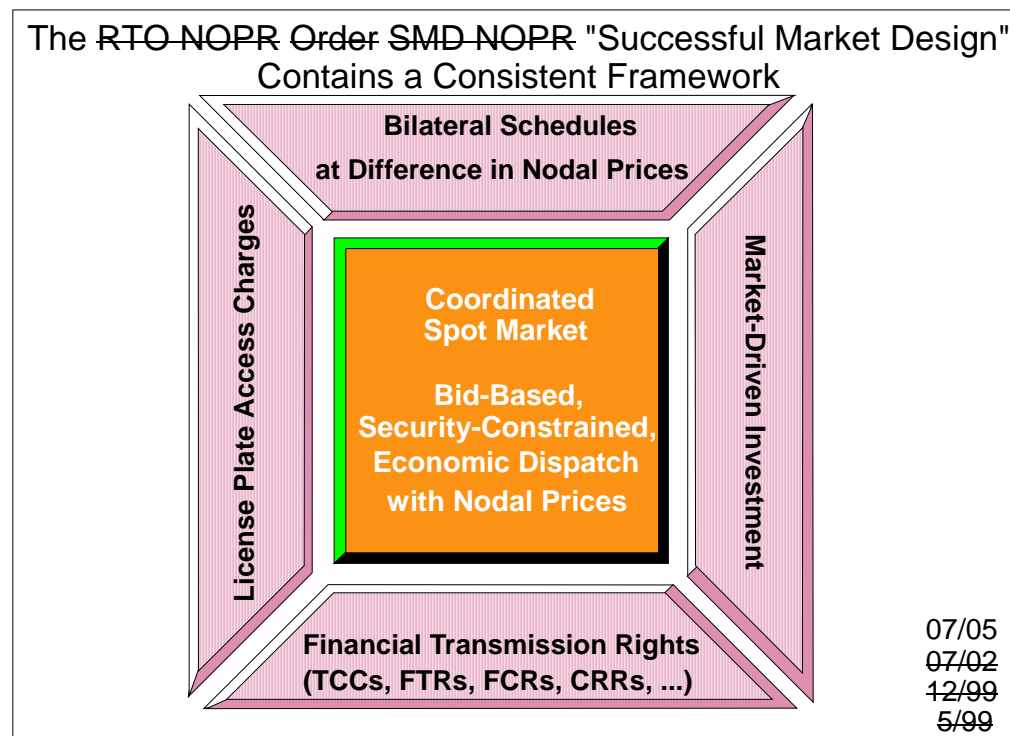
Price of "Transmission" from A to B =  $P_b - P_a = 15$   
Price of "Transmission" from A to C =  $P_c - P_a = -4$

- 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.

# ELECTRICITY MARKET

# A Consistent Framework

The example of successful central coordination, ~~GRT, 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, and the Midwest.

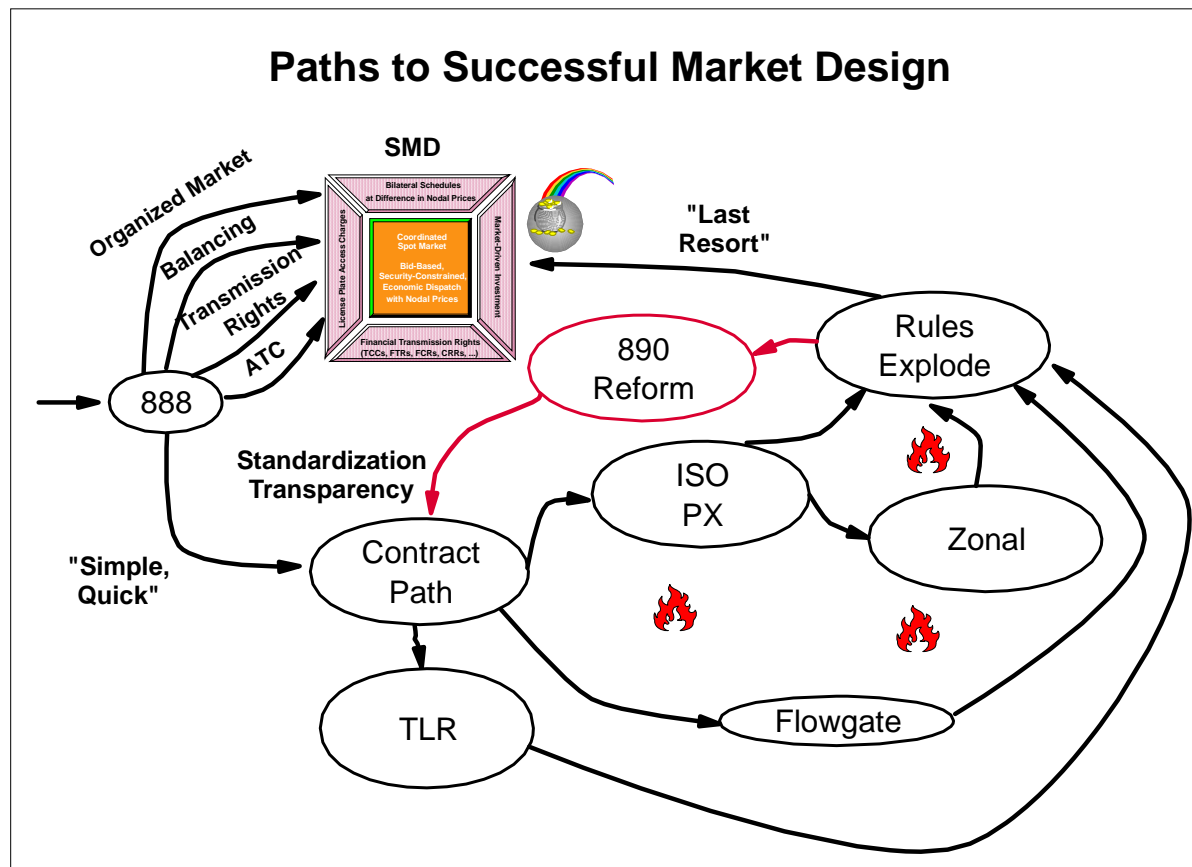


Poolco...OPCO...ISO...IMO...Transco...RTO... ITP...WMP...: "A rose by any other name ..."

# ELECTRICITY MARKET

# Path Dependence

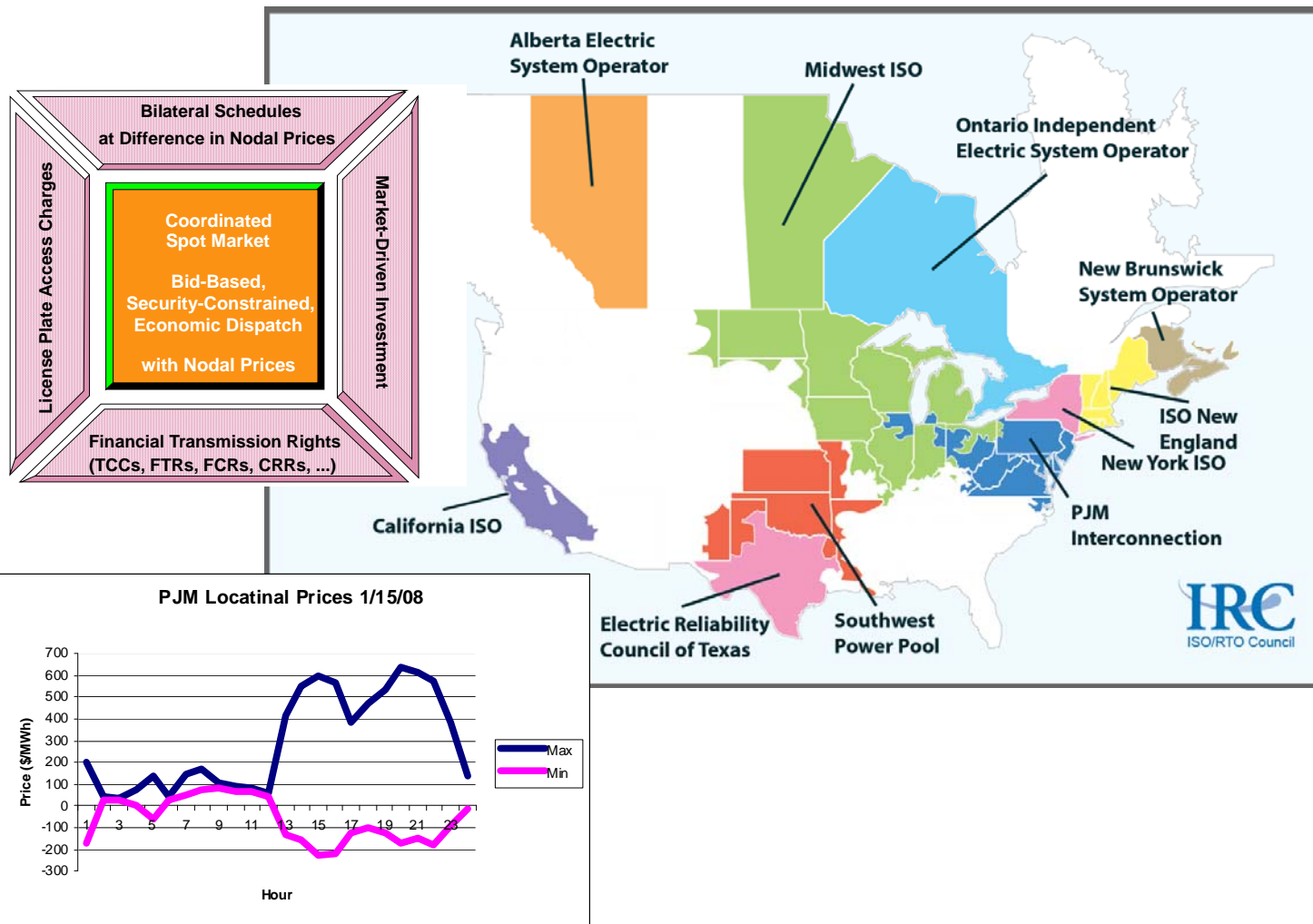
The path to successful market design can be circuitous and costly. The FERC “reforms” in Order 890 illustrate “path dependence,” where the path chosen constrains the choices ahead. Can Order 890 be reformed to overcome its own logic? Or is FERC trapped in its own loop flow?



# ELECTRICITY MARKET

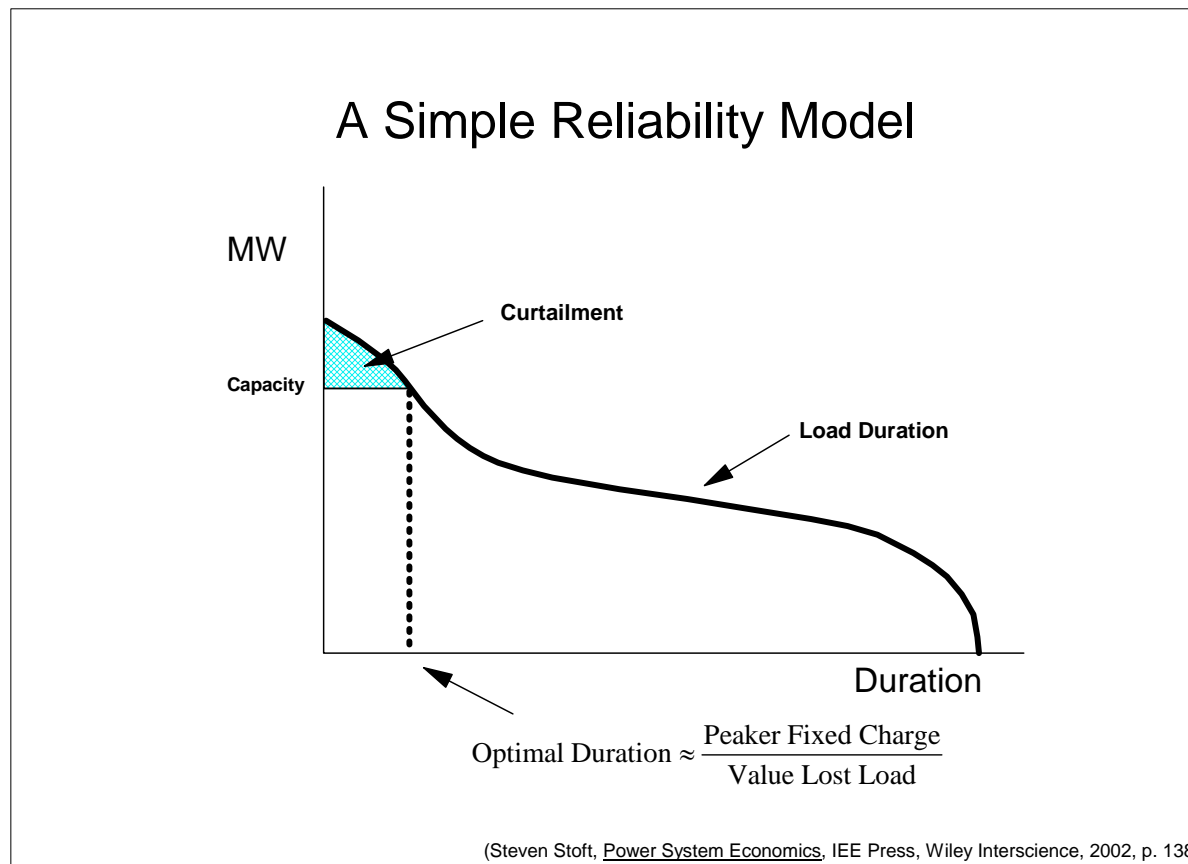
# A Consistent Framework

Regional transmission organizations (RTOs) and independent system operators (ISOs) have grown to cover 75% of US economic activity.

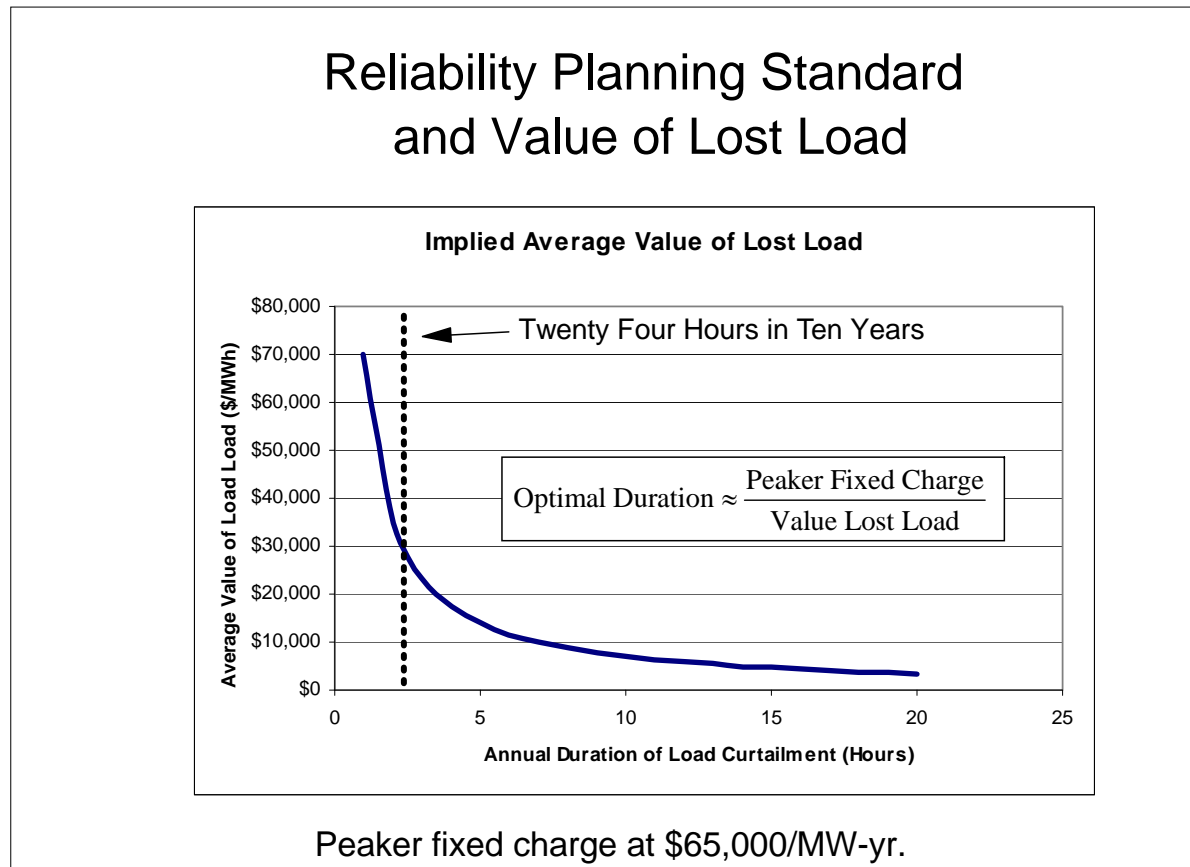




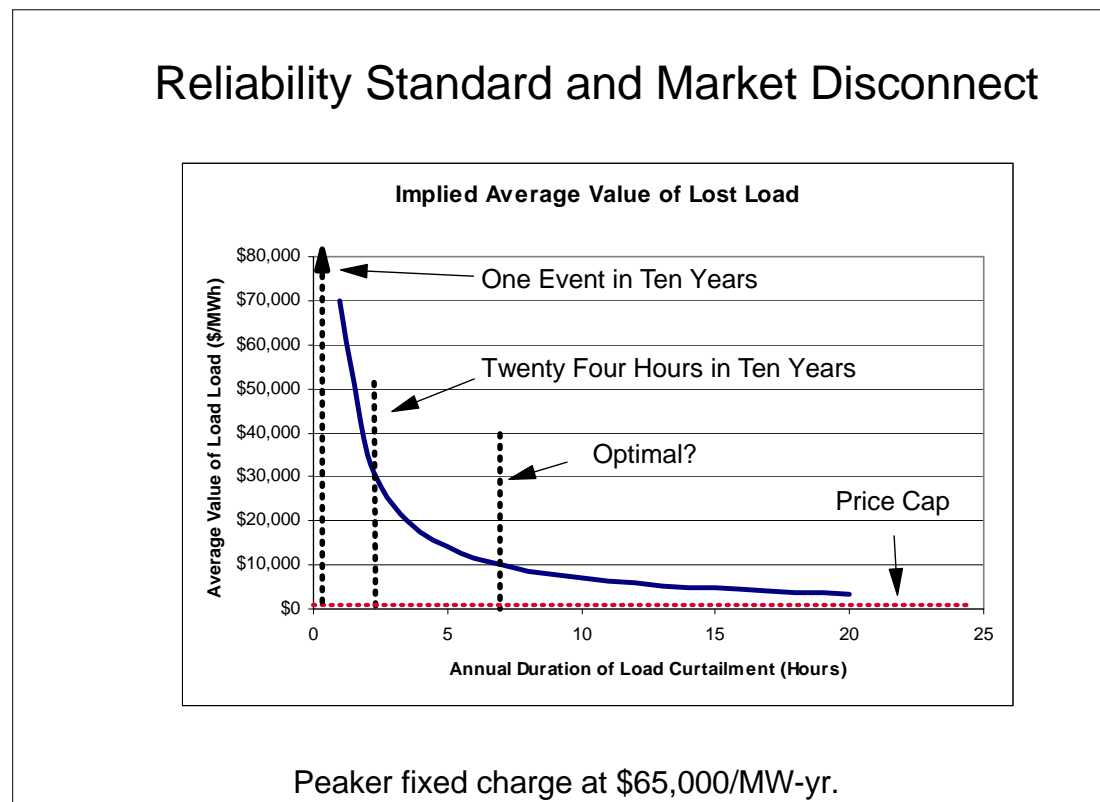
There is a simple stylized connection between reliability standards and resource economics. Defining expected load shedding duration, choosing installed capacity, or estimating value of lost load address different facets of the same problem.



The simple connection between reliability planning standards and resource economics illustrates a major disconnect between market pricing and the implied value of lost load.



There is a large disconnect between long-term planning standards and market design. The installed capacity market analyses illustrate the gap between prices and implied values. The larger disconnect is between the operating reserve market design and the implied reliability standard.

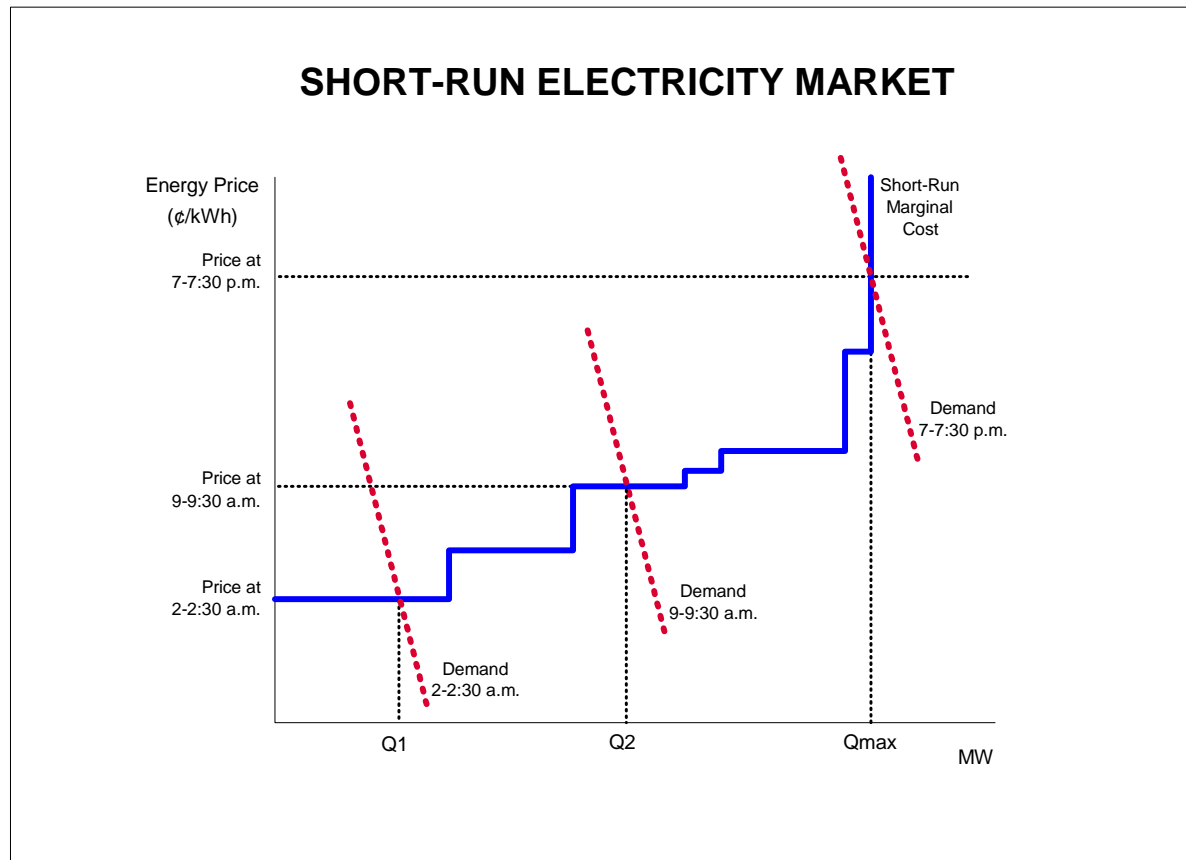


**Implied prices differ by orders of magnitude.** (Price Cap  $\approx \$10^3$ ; VOLL  $\approx \$10^4$ ; Reliability Standard  $\approx \$10^5$ )

# ELECTRICITY MARKET

# Pricing and Demand Response

Early market designs presumed a significant demand response. Absent this demand participation most markets implemented inadequate pricing rules equating prices to marginal costs even when capacity is constrained. This produces a “missing money” problem. The big “R” regulatory solution calls for capacity mandates. The small “r” approach addresses the pricing problem.



Begin with an expected value formulation of economic dispatch that might appeal in principle. Given benefit ( $B$ ) and cost ( $C$ ) functions, demand ( $d$ ), generation ( $g$ ), plant capacity ( $Cap$ ), reserves ( $r$ ), commitment decisions ( $u$ ), transmission constraints ( $H$ ), and state probabilities ( $p$ ):

$$\underset{y^i, d^i, g^i, r, u \in \{0,1\}}{\text{Max}} \quad p_0 \left( B^0(d^0) - C^0(g^0, r, u) \right) + \sum_{i=1}^N p_i \left( B^i(d^i, d^0) - C^i(g^i, g^0, r, u) \right)$$

*s.t.*

$$y^i = d^i - g^i, \quad i = 0, 1, 2, \dots, N,$$

$$t^i y^i = 0, \quad i = 0, 1, 2, \dots, N,$$

$$H^i y^i \leq b^i, \quad i = 0, 1, 2, \dots, N,$$

$$g^0 + r \leq u \cdot Cap^0,$$

$$g^i \leq g^0 + r, \quad i = 1, 2, \dots, N,$$

$$g^i \leq u \cdot Cap^i, \quad i = 0, 1, 2, \dots, N.$$

Suppose there are  $K$  possible contingencies. The interesting cases have  $K \gg 10^3$ . The number of possible system states is  $N = 2^K$ , or more than the stars in the Milky Way. Some approximation will be in order.<sup>1</sup>

<sup>1</sup> Shams N. Siddiqi and Martin L. Baughman, "Reliability Differentiated Pricing of Spinning Reserve," *IEEE Transactions on Power Systems*, Vol. 10, No. 3, August 1995, pp.1211-1218. José M. Arroyo and Francisco D. Galiana, "Energy and Reserve Pricing in Security and Network-Constrained Electricity Markets," *IEEE Transactions On Power Systems*, Vol. 20, No. 2, May 2005, pp. 634-643. François Bouffard, Francisco D. Galiana, and Antonio J. Conejo, "Market-Clearing With Stochastic Security—Part I: Formulation," *IEEE Transactions On Power Systems*, Vol. 20, No. 4, November 2005, pp. 1818-1826; "Part II: Case Studies," pp. 1827-1835.

The expected value formulation reduces to a much more manageable scale with the introduction of the implicit VEUE function.

$$\underset{y^0, d^0, g^0, r, u \in \{0,1\}}{\text{Max}} \quad B^0(d^0) - C^0(g^0, r, u) - \text{VEUE}(d^0, g^0, r, u)$$

*s.t.*

$$y^0 = d^0 - g^0,$$

$$H^0 y^0 \leq b^0,$$

$$g^0 + r \leq u \cdot \text{Cap}^0,$$

$$t^t y^0 = 0,$$

$$g^0 \leq u \cdot \text{Cap}^0.$$

The optimal value of expected unserved energy defines the demand for operating reserves. This formulation of the problem follows the outline of existing operating models except for the exclusion of contingency constraints.

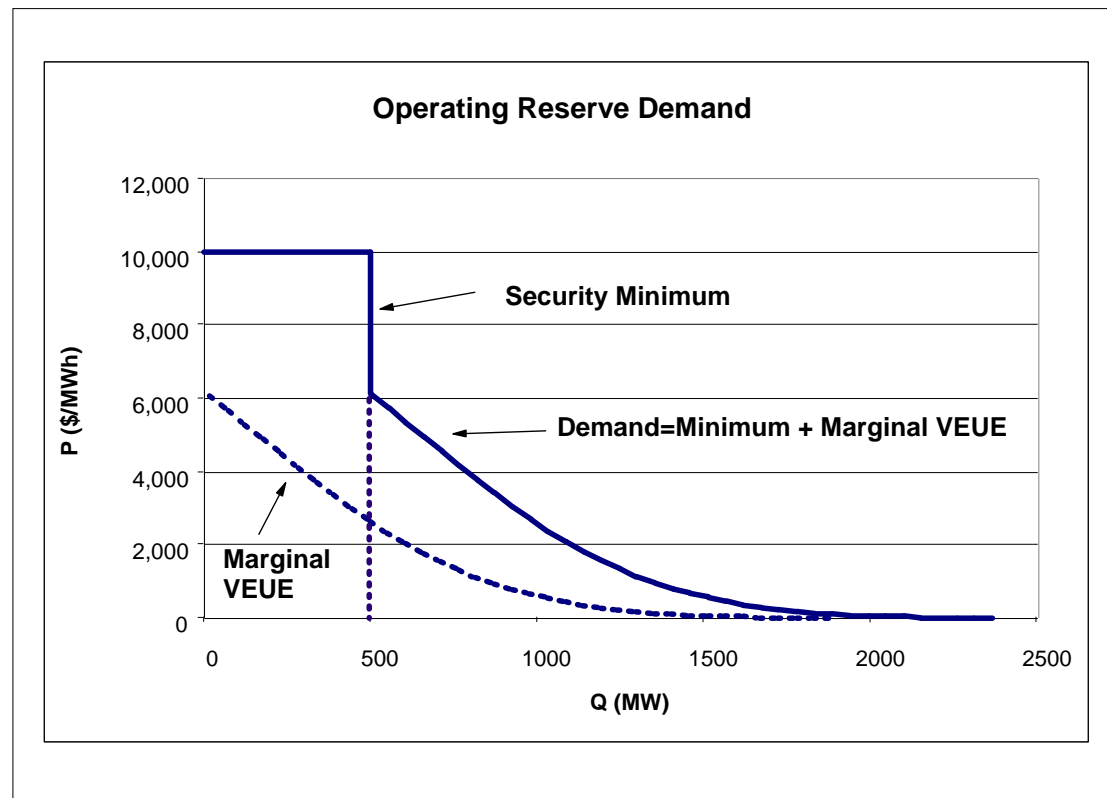
The deterministic approach to security constrained economic dispatch includes lower bounds on the required reserve to ensure that for a set of monitored contingencies (e.g., an n-1 standard) there is sufficient operating reserve to maintain the system for an emergency period.

Suppose that the maximum generation outage contingency quantity is  $r_{Min}(d^0, g^0, u)$ . Then we would have the constraint:

$$r \geq r_{Min}(d^0, g^0, u).$$

In effect, the contingency constraint provides a vertical demand curve that adds horizontally to the probabilistic operating reserve demand curve.

If the security minimum will always be maintained over the monitored period, the VEUE price at  $r=0$  applies. If the outage shocks allow excursions below the security minimum during the period, the VEUE starts at the security minimum.



In a network, security constrained economic dispatch includes a set of monitored transmission contingencies,  $K_M$ , with the transmission constraints on the pre-contingency flow determined by conditions that arise in the contingency.

$$H^i y^0 \leq \tilde{b}^i, \quad i = 1, 2, \dots, K_M.$$

The security constrained economic dispatch problem becomes:

$$\begin{aligned} & \underset{y^0, d^0, g^0, r, u \in (0,1)}{\text{Max}} && B^0(d^0) - C^0(g^0, r, u) - VEUE(d^0, g^0, r, u) \\ & \text{s.t.} && \\ & && y^0 = d^0 - g^0, \\ & && H^0 y^0 \leq b^0, \\ & && H^i y^0 \leq \tilde{b}^i, \quad i = 1, 2, \dots, K_M, \\ & && g^0 + r \leq u \cdot \text{Cap}^0, \\ & && r \geq r_{\text{Min}}(d^0, g^0, u) \\ & && t^t y^0 = 0, \\ & && g^0 \leq u \cdot \text{Cap}^0. \end{aligned}$$

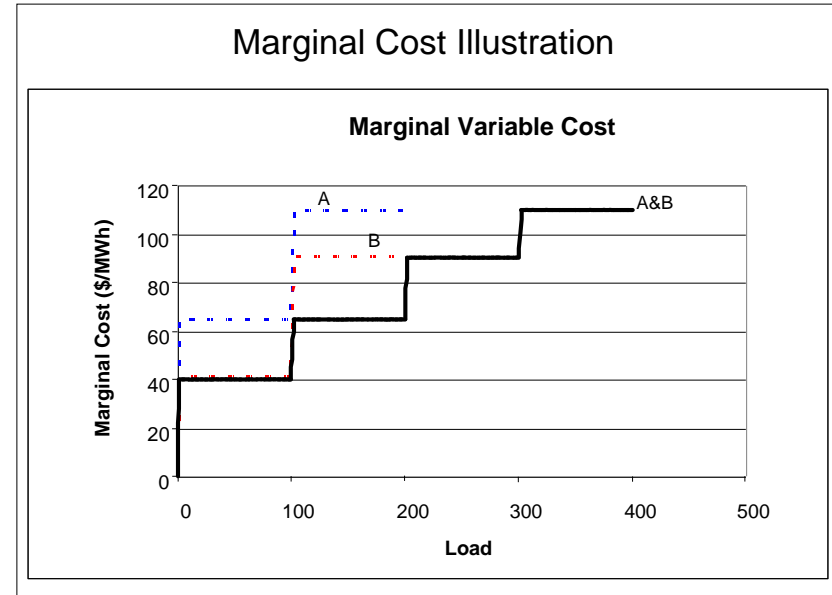
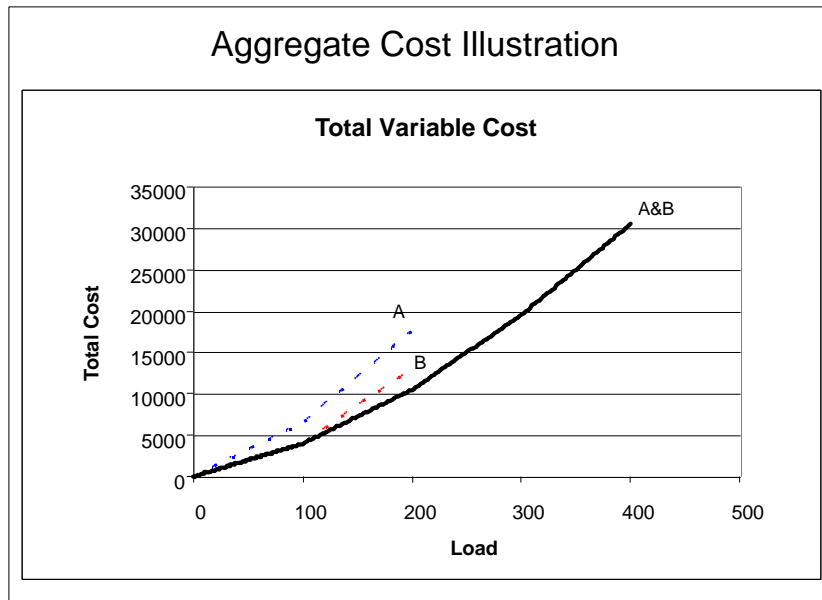
If we could convert each node to look like the single location examined above, the approximation of *VEUE*, would repeat the operating reserve demand curve at each node.



Energy dispatch is continuous but unit commitment requires discrete decisions. Bid-based, security constrained, combined unit commitment and economic dispatch presents a challenge in defining market-clearing prices.

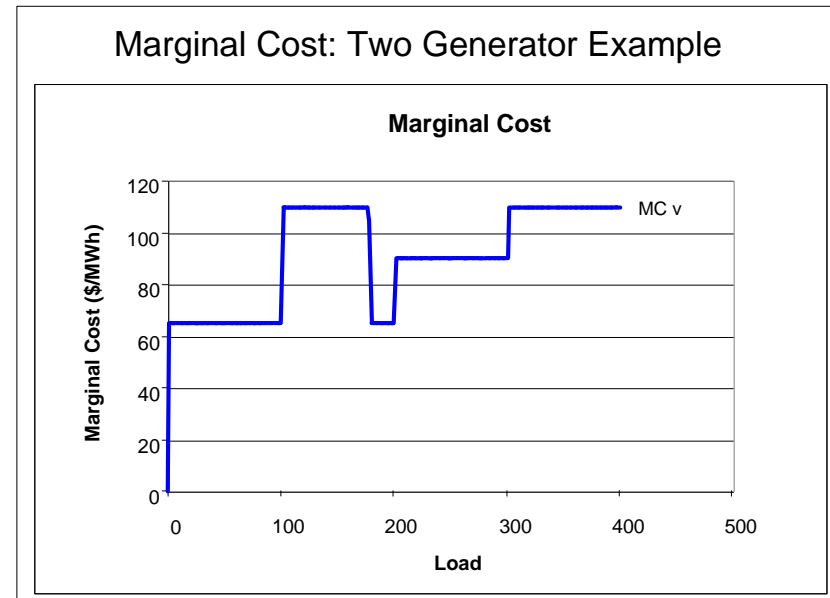
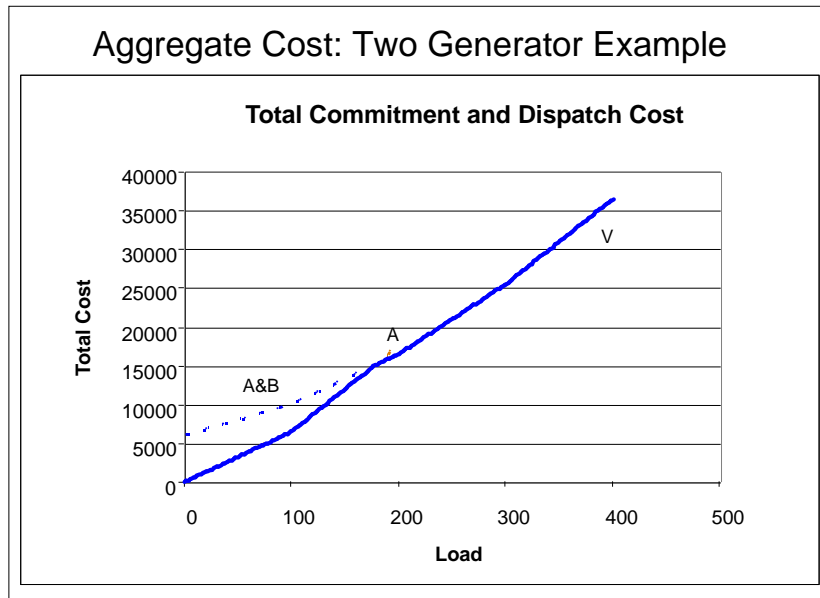
- **Continuous convex economic dispatch**
  - System marginal costs provide locational, market-clearing, linear prices
  - Linear prices support the economic dispatch
  
- **Discrete, economic, unit commitment and dispatch**
  - Start up and minimum load restrictions enter the model
  - System marginal costs not always well-defined
  - There may be no linear prices that support the commitment and dispatch solution

Energy dispatch is continuous, convex and yields linear prices.<sup>2</sup> A simplified example with two generating units illustrates the total and marginal costs.



<sup>2</sup> Paul R. Gribik, William W. Hogan, and Susan L. Pope, "Market-Clearing Electricity Prices and Energy Uplift," Harvard University, December 31, 2007, available at [www.whogan.com](http://www.whogan.com).

Unit commitment requires discrete decisions. Now the second unit (B) has a startup cost.



Marginal cost-based linear prices cannot support the commitment and dispatch. The solution has been to make “uplift” payments to assure reliable and economic unit commitment.

Selecting the appropriate approximation model for defining energy and uplift prices involves practical tradeoffs. All involve “uplift” payments to guarantee payments for bid-based cost to participating bidders (generators and loads), to support the economic commitment and dispatch.

### **Uplift with Given Energy Prices=Optimal Profit – Actual Profit**

- **Restricted Model (r)**
  - Fix the unit commitment at the optimal solution.
  - Determine energy prices from the convex economic dispatch.
- **Dispatchable Model (d)**
  - Relax the discrete constraints and treat commitment decisions as continuous.
  - Determine energy prices from the relaxed, continuous, convex model.
- **Convex Hull Model (h)**
  - Select the energy prices from the Lagrangean relaxation (i.e., usual dual problem for pricing the joint constraints).
  - Resulting energy prices minimize the total uplift.

Economic commitment and dispatch is a special case of a general optimization problem.

$$v(y) = \underset{x \in X}{\text{Min}} \quad f(x) \\ \text{s.t.} \quad g(x) = y.$$

From the perspective of a price-taking bidder, uplift is the difference between actual and optimal profits.

$$\begin{aligned} \text{Actual profits:} \quad & \pi(p, y) = py - v(y) \\ \text{Optimal Profits:} \quad & \pi^*(p) = \underset{z}{\text{Max}} \{pz - v(z)\} \\ \text{Uplift}(p, y) = & \pi^*(p) - \pi(p, y) \end{aligned}$$

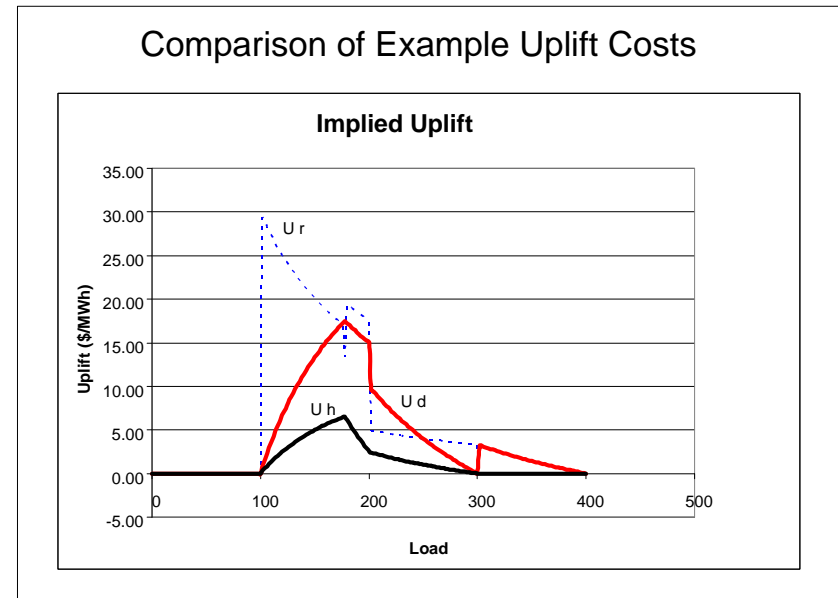
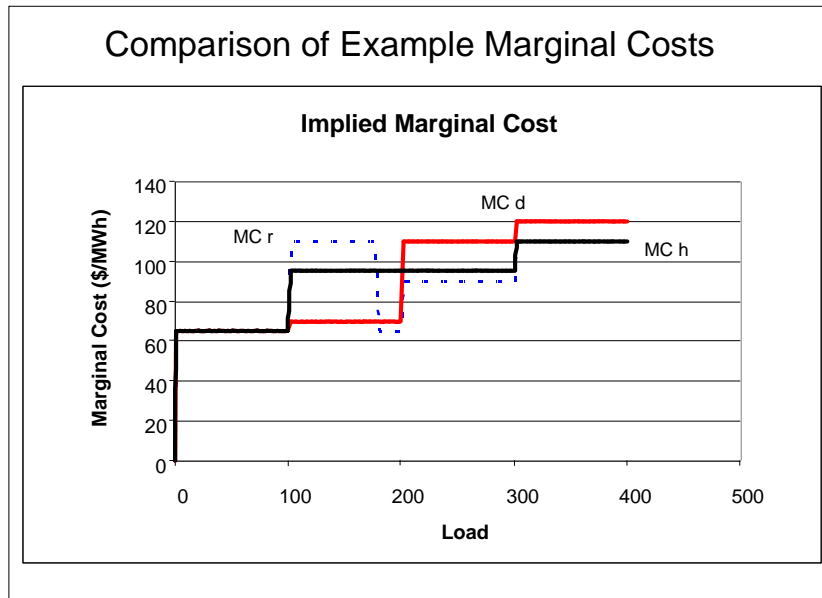
Classical Lagrangean relaxation and pricing creates a familiar dual problem.

$$\begin{aligned} L(y, x, p) &= f(x) + p(y - g(x)) \\ \hat{L}(y, p) &= \underset{x \in X}{\text{Inf}} \{f(x) + p(y - g(x))\} \\ L^*(y) &= \underset{p}{\text{Sup}} \hat{L}(y, p) = \underset{p}{\text{Sup}} \left\{ \underset{x \in X}{\text{Inf}} \{f(x) + p(y - g(x))\} \right\} \end{aligned}$$

The optimal dual solution minimizes the uplift, and the “duality gap” is equal to the minimum uplift.

$$v(y) - L^*(y) = \underset{p}{\text{Inf}} \text{Uplift}(p, y).$$

Comparing illustrative energy pricing and uplift models.



Both the relaxed and convex hull models produce “standard” implied supply curve. The convex hull model produces the minimum uplift.

**Alternative pricing models have different features and raise additional questions.**

- **Computational Requirements.** Relaxed model easiest case, convex hull model the hardest. But not likely to be a significant issue.
- **Network Application.** All models compatible with network pricing and reduce to standard LMP in the convex case.
- **Operating Reserve Demand.** All models compatible with existing and proposed operating reserve demand curves.
- **Solution Independence.** Restricted model sensitive to actual commitment. Relaxed and convex hull models (largely) independent of actual commitment and dispatch.
- **Day-ahead and real-time interaction.** With uncertainty in real-time and virtual bids, expected real-time price is important, and may be similar under all pricing models.

**With current technology, property rights are difficult to define and there is a continuing need for coordination to support markets. Regulation must adapt to the requirements of hybrid markets.**

- **Little “r” regulation:** Design rules and policies that are the “best possible mix” to support competitive wholesale electricity markets.
  - **Necessary functions for energy markets.**
    - Real-time, bid-based, security constrained economic dispatch with locational prices.
  - **Necessary functions for energy markets with effective long-term hedges.**
    - Financial transmission rights (FTRs).
  - **Valuable functions for energy markets with effective long-term hedges.**
    - Day-ahead energy market with associated reliability unit commitment.
    - Transmission planning and investment protocols.
  - **Necessary features of everything else**
    - Rules and pricing incentives compatible with the above.
      - Ancillary Services
      - Resource Adequacy
- **Big “R” regulation:** Frame every problem in its own terms—inadequate demand response, insufficient infrastructure investment, or market power—and design ad hoc regulatory fixes that accumulate to undermine market incentives. The slippery slope.



William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University and a Director of LECG, LLC. This paper draws on work for the Harvard Electricity Policy Group and 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, Australian Gas Light Company, Avista Energy, Barclays, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, Calpine Corporation, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, Conectiv, Constellation Power Source, Coral Power, Credit First Suisse Boston, Detroit Edison Company, Deutsche Bank, Duquesne Light Company, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, GPU Inc. (and the Supporting Companies of PJM), Exelon, GPU PowerNet Pty Ltd., GWF Energy, Independent Energy Producers Assn, ISO New England, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, JP Morgan, Morgan Stanley Capital Group, 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 IMO, Pepco, Pinpoint Power, PJM Office of Interconnection, PPL Corporation, Public Service Electric & Gas Company, PSEG Companies, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Corporation, Sempra Energy, SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, TransÉnergie, Transpower of New Zealand, Westbrook Power, Western Power Trading Forum, Williams Energy Group, and Wisconsin Electric Power Company. 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](http://www.whogan.com) ).