ELECTRICITY MARKET DESIGN:
Coordination, Pricing and Incentives

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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.

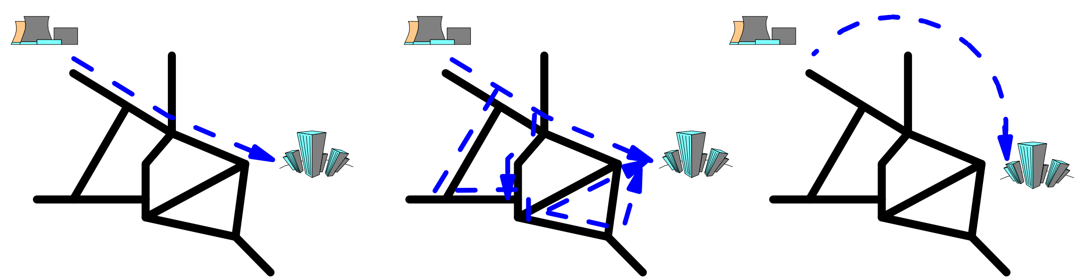
- **Design Limitation: Uplift Payments**

  Unit commitment and lumpy decisions. Coordination and bid guarantees.

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

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

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

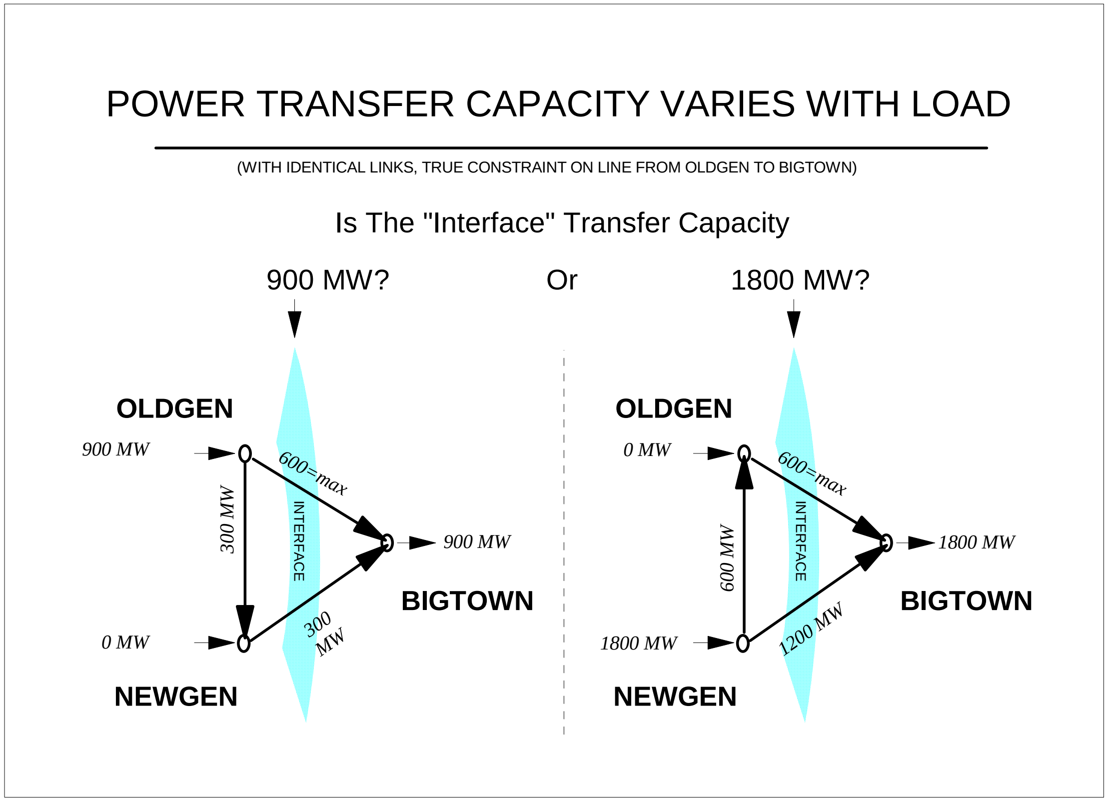
> "A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to 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.

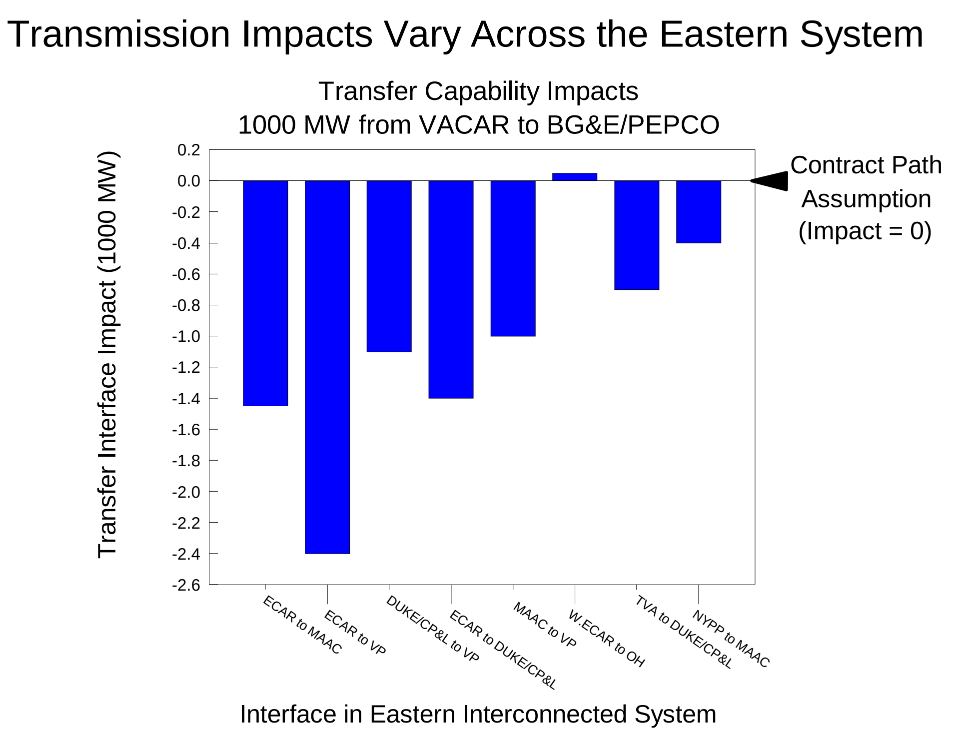
Electric transmission network interactions can be large and important.

- Conventional definitions of network "Interface" transfer capacity depend on the assumed load conditions.

- Transfer capacity cannot be defined or guaranteed over any reasonable horizon.



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.



Source: VEM, Winter Operating Study, December 1993.

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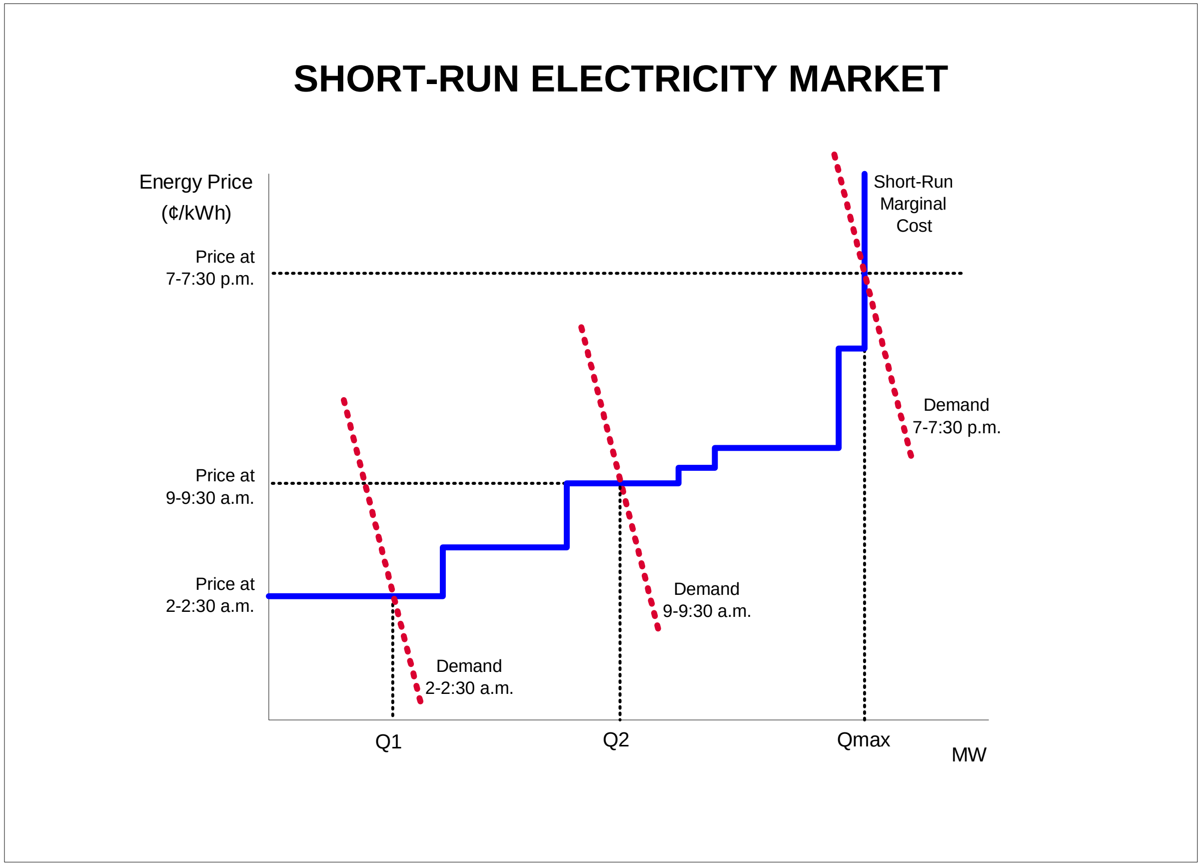
> "We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described 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!

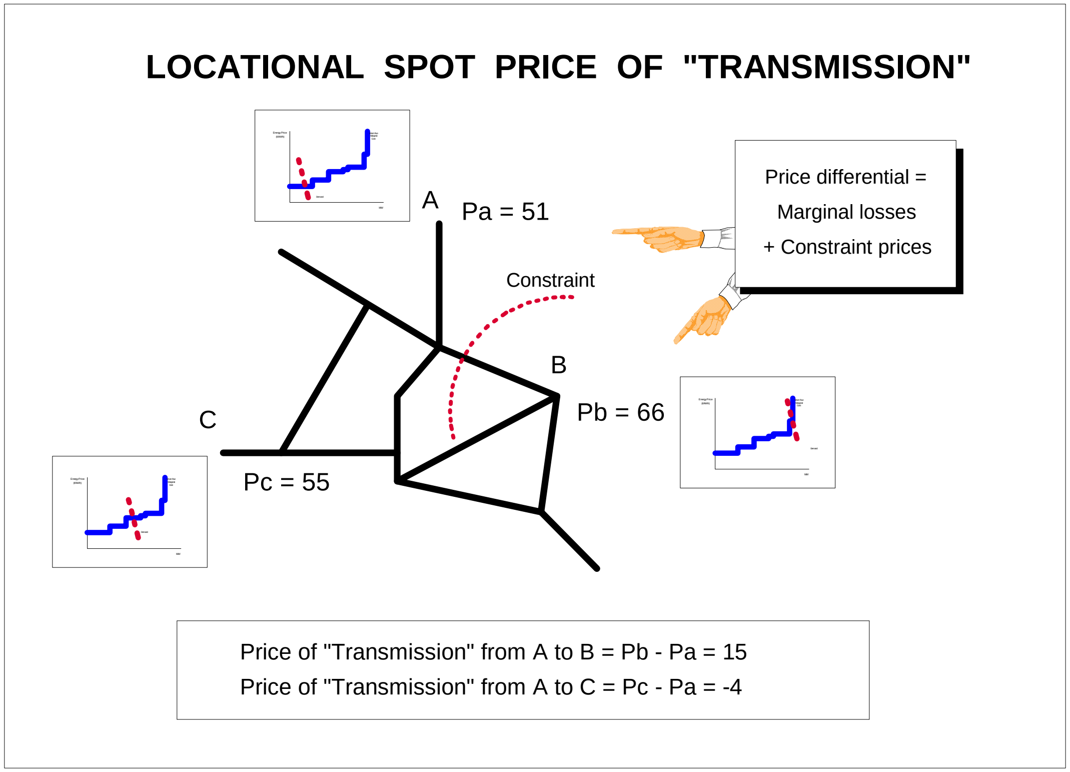
An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand. Everyone pays or is paid the same price.



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.



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

$$\underset{d,g,x,y}{Max} \quad B(d) - C(g)$$

$$subject\ to$$

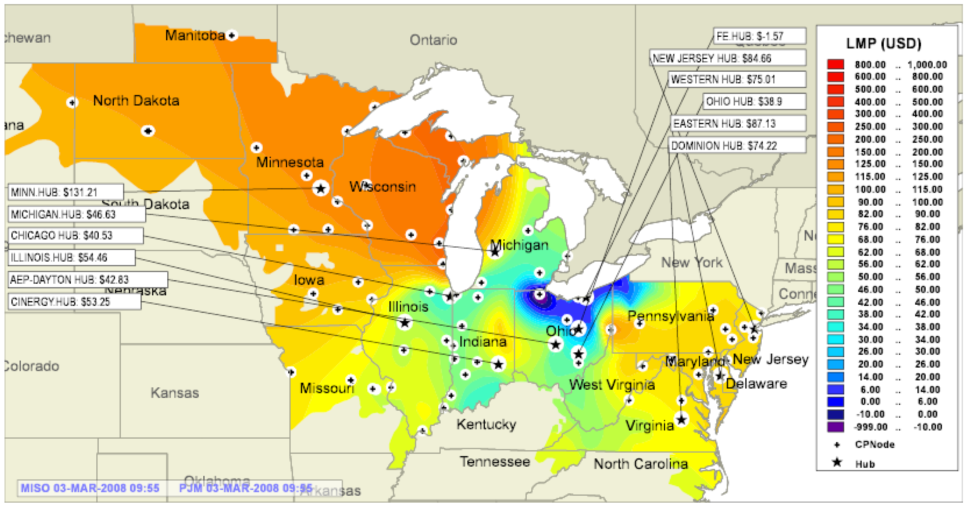
$$d - g = y \qquad : p$$

$$K(x, y) \leq 0. \qquad : \mu$$

PJM Real Time Hourly LMP Values for 20080224

Node	Date	PnodeID	Name	Voltage	Equipm	Type	Zone	100	100	100	1200	1200	1200	1800	1800	1800
							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															
								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 DIX	138 KV	TR76 3	LOAD	COMED	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	COMED	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	COMED	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															

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



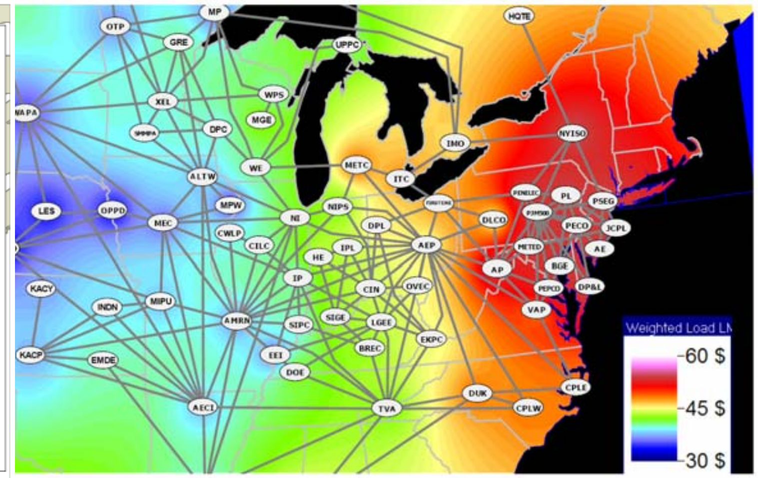
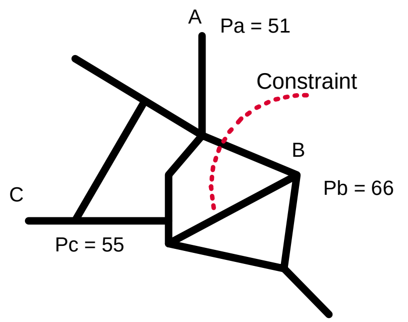


Figure 2.2-3 Contour Map of Annual Load Weighted LMP

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.

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.

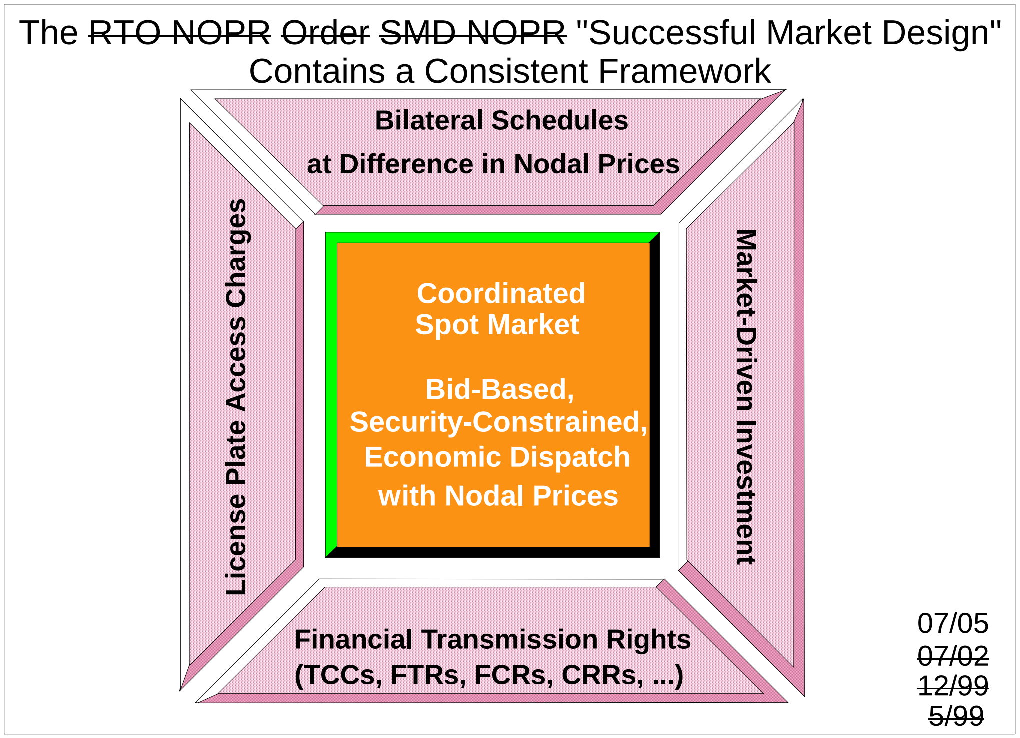
NETWORK TRANSMISSION FINANCIAL RIGHTS



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

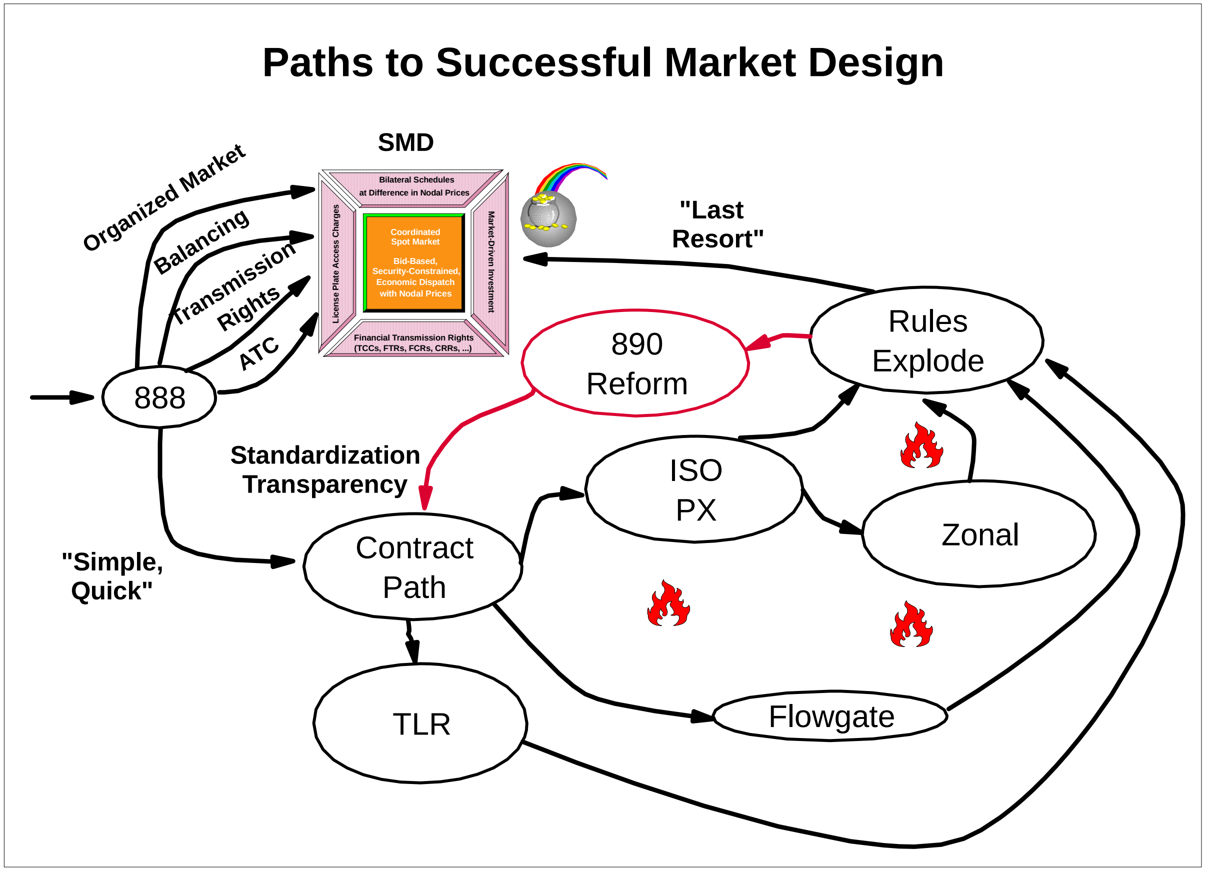
- DEFINE TRANSMISSION CONGESTION CONTRACTS BETWEEN LOCATIONS.
- FOR SIMPLICITY, TREAT LOSSES AS OPERATING COSTS.
- RECEIVE CONGESTION PAYMENTS FROM ACTUAL USERS; MAKE CONGESTION PAYMENTS TO HOLDERS OF CONGESTION CONTRACTS.
- TRANSMISSION CONGESTION CONTRACTS PROVIDE PROTECTION AGAINST CHANGING LOCATIONAL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

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, and the Midwest.

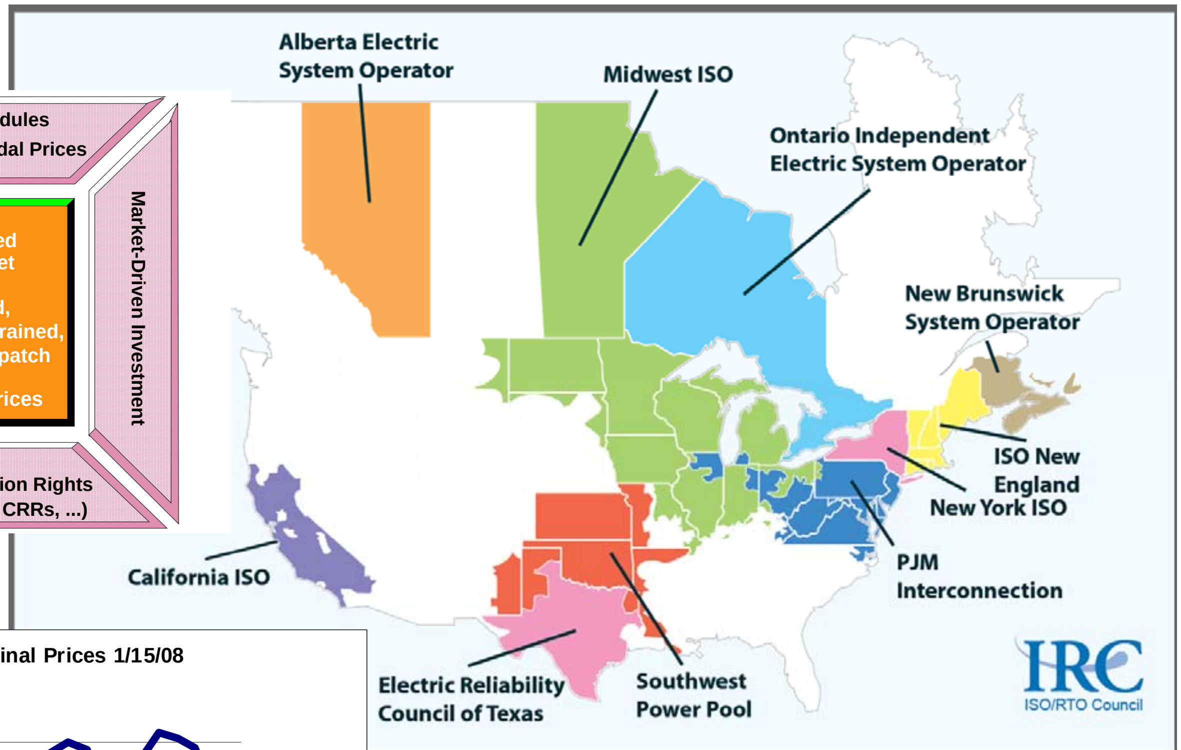


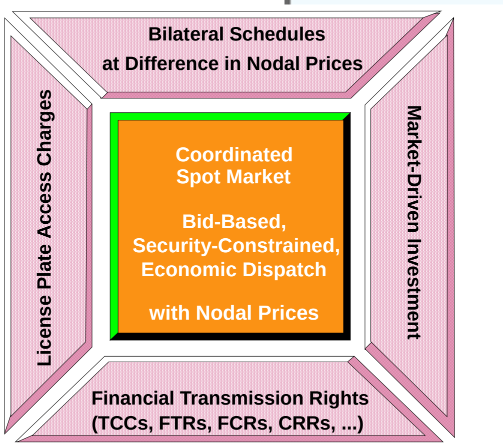
PoolCo…OPCO…ISO…IMO…Transco…RTO… ITP…WMP…: "A rose by any other name …"

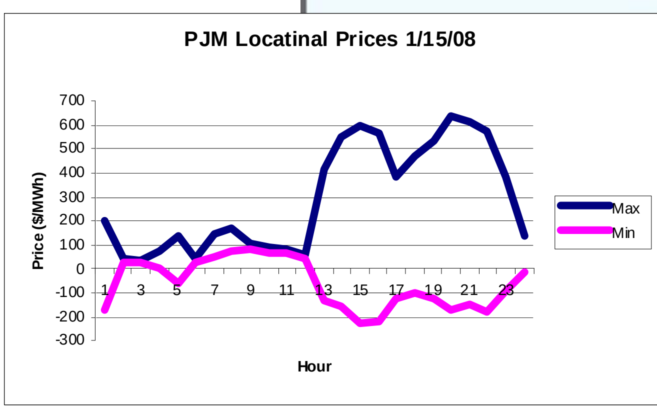
The path to successful market design can be circuitous and costly. The FERC "reforms" in Order 890 illustrate "path dependence," where the path chosen constrains the choices ahead. Can Order 890 be reformed to overcome its own logic? Or is FERC trapped in its own loop flow?



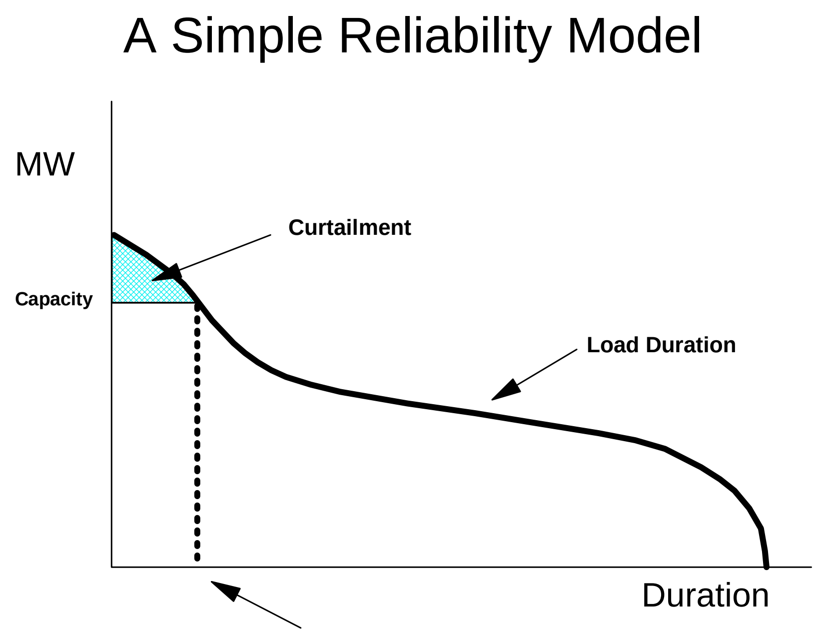
Regional transmission organizations (RTOs) and independent system operators (ISOs) have grown to cover 75% of US economic activity.







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.

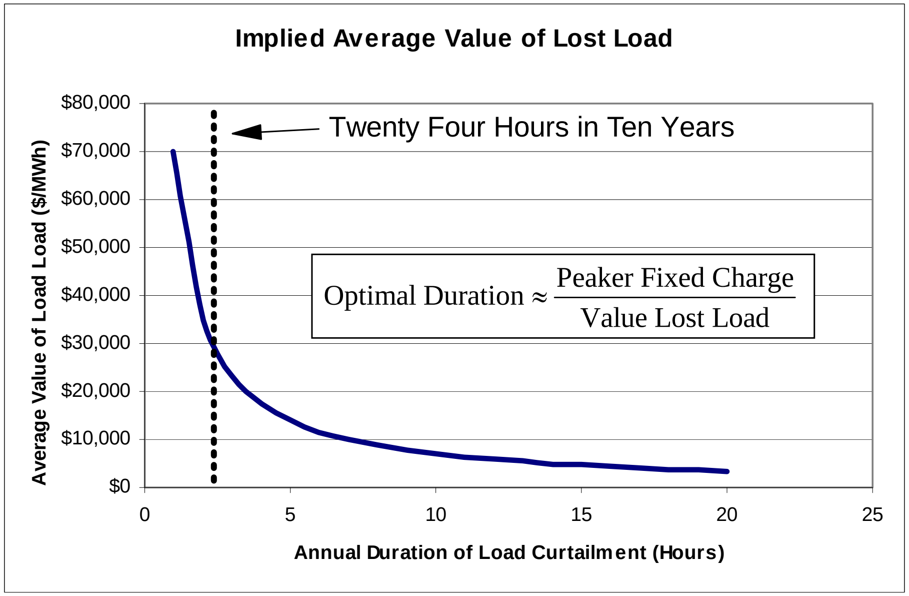


$$\text{Optimal Duration} \approx \frac{\text{Peaker Fixed Charge}}{\text{Value Lost Load}}$$

(Steven Stoft, Power System Economics, IEE Press, Wiley Interscience, 2002, p. 138)

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

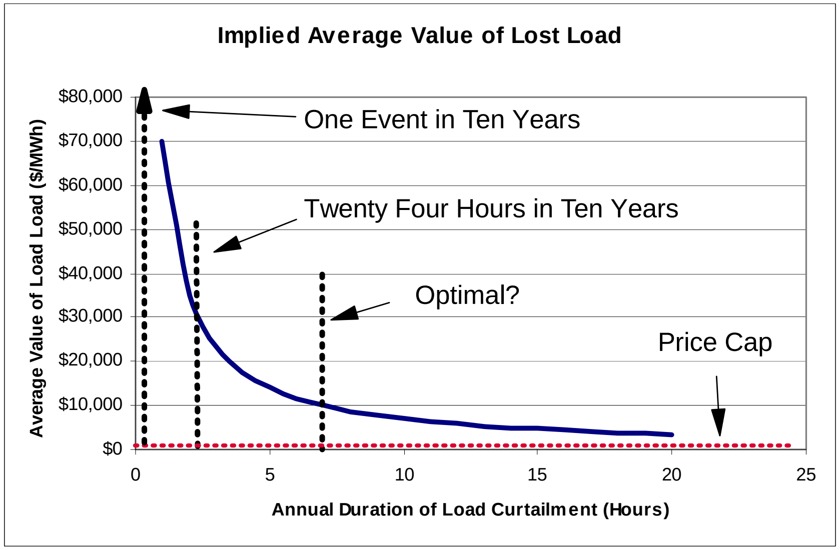
Reliability Planning Standard and Value of Lost Load



Peaker fixed charge at $65,000/MW-yr.

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.

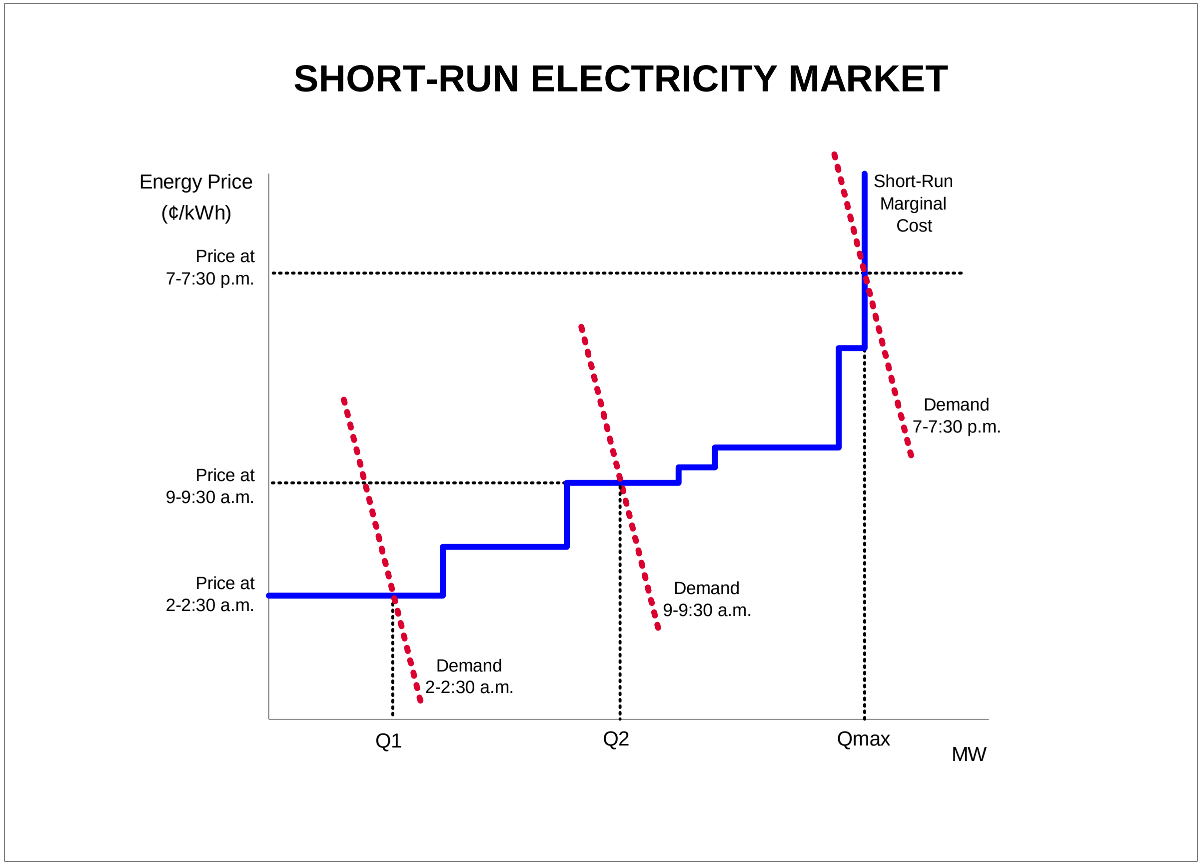
Reliability Standard and Market Disconnect



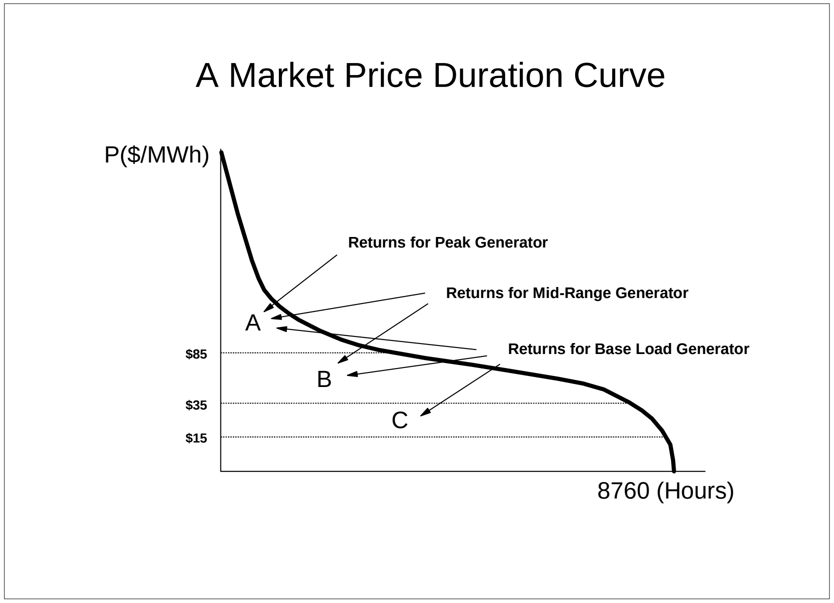
Peaker fixed charge at $65,000/MW-yr.

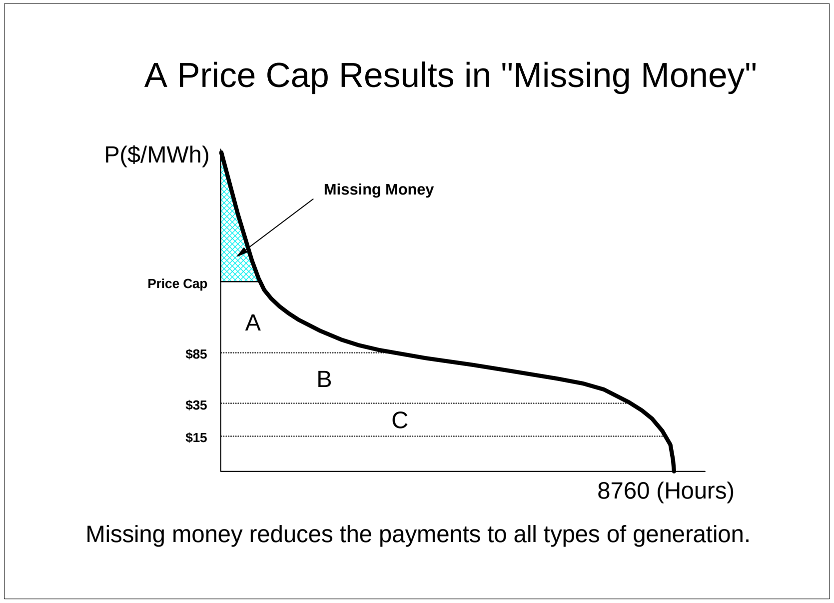
Implied prices differ by orders of magnitude. $\left(\text{Price Cap} \approx \$10^3;\ \text{VOLL} \approx \$10^4;\ \text{Reliability Standard} \approx \$10^5\right)$

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.



A variety of market rules for spot markets interact to create *de jure* or *de facto* price caps. The resulting "missing money" reduces payments to all types of generation.



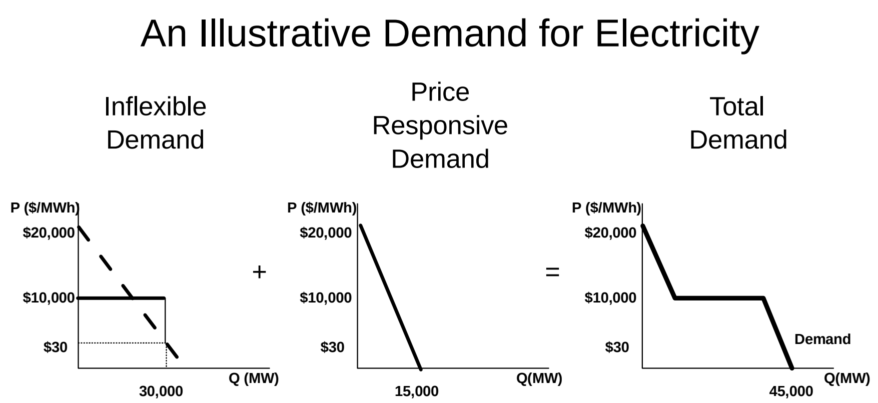


If market prices do not provide adequate incentives for generation investment, the result is a market failure. The market design defect creates the pressure for regulators to intervene to mandate generation investment.

A workable "energy only" market would eliminate the "missing money" problem and provide an alternative to the growing prescriptions of installed capacity markets. The concept is not that there should be no market interventions. But the interventions should not overturn the market.

An "Energy Only" Market Outline

- **Implicit demand for inflexible load would define the opportunity costs as the average value of lost load (VOLL).**

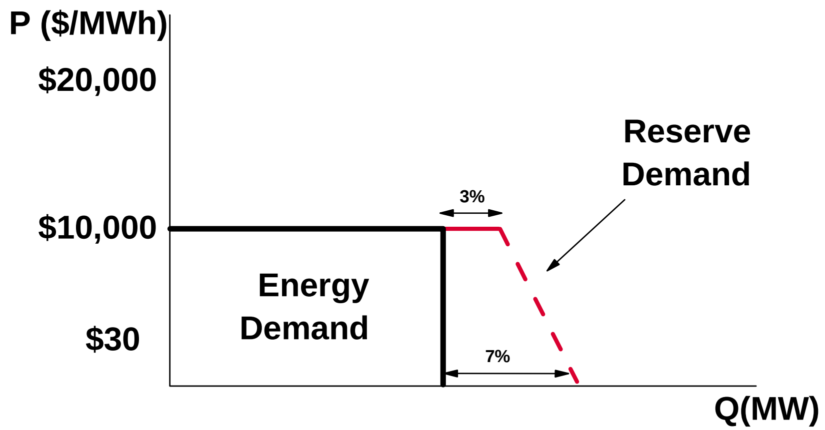


Involuntary curtailment of inflexible demand has an opportunity cost at the average value of lost load (VOLL).

… An "Energy Only" Market Outline

- **Operating reserve demand curve would reflect capacity scarcity.**

Illustrative Reserve Demand

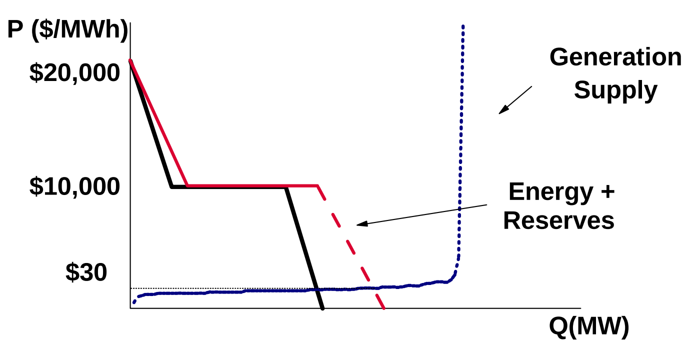


There is a minimum level of operating reserve (e.g., 3%) to protect against system-wide failure. Above the minimum reserve, reductions below a nominal reserve target (e.g., 7%) are price senstive.

… An "Energy Only" Market Outline

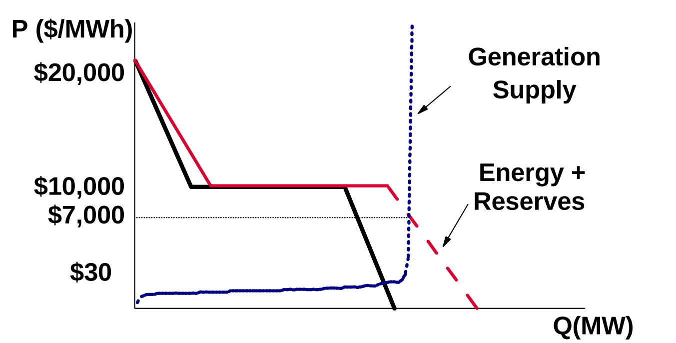
- **Market clearing eliminates the "missing money."**

Normal "Energy Only" Market Clearing



When demand is low and capacity available, reserves hit nominal targets at a low price.

Scarcity "Energy Only" Market Clearing



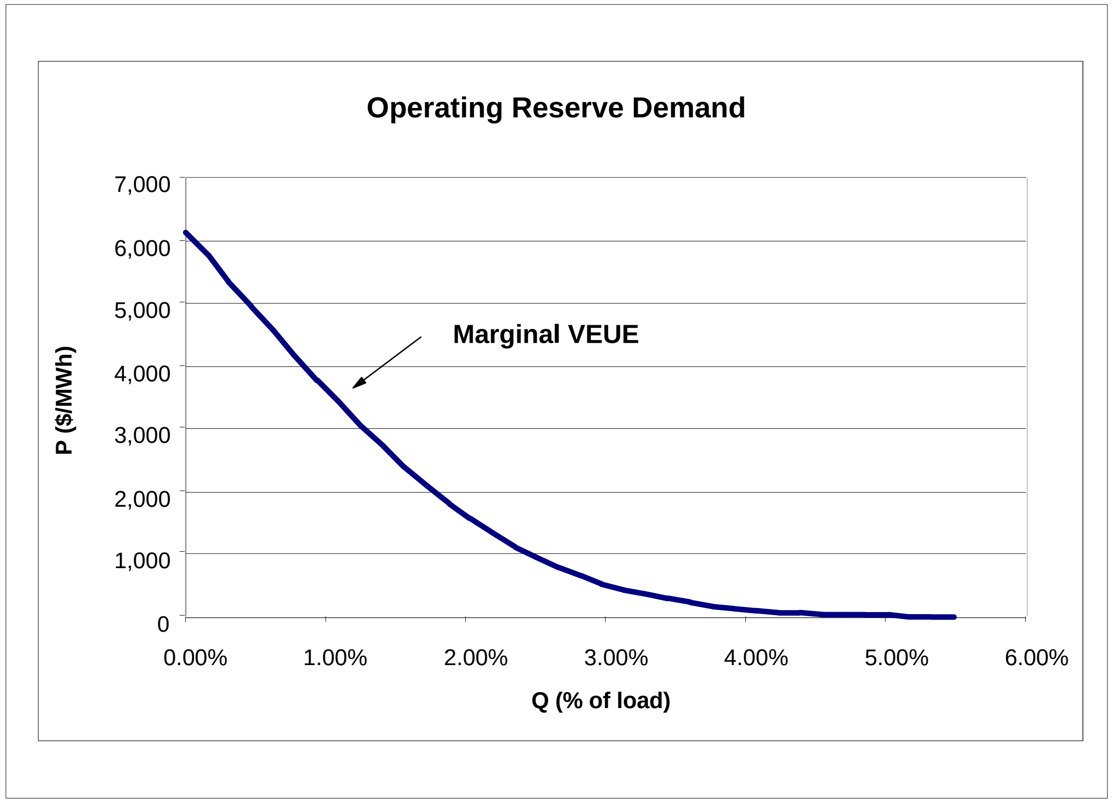
When demand is high and reserve reductions apply, there is a high price.

Operating reserve demand is a complement to energy demand for electricity. The probabilistic demand for operating reserves reflects the cost and probability of lost load. Pricing operating reserves could provide the missing money.

Example Assumptions

Expected Load (MW)	34000
Std Dev %	1.50%
Expected Outage %	0.45%
Std Dev %	0.45%
Expected Total (MW)	153
Std Dev (MW)	532.46
VOLL ($/MWh)	10000

Under the simplifying assumptions, if the dispersion of the LOLP distribution is proportional to the expected load, the operating reserve demand is proportional to the expected load. Total value is of same magnitude as the cost of meeting load.

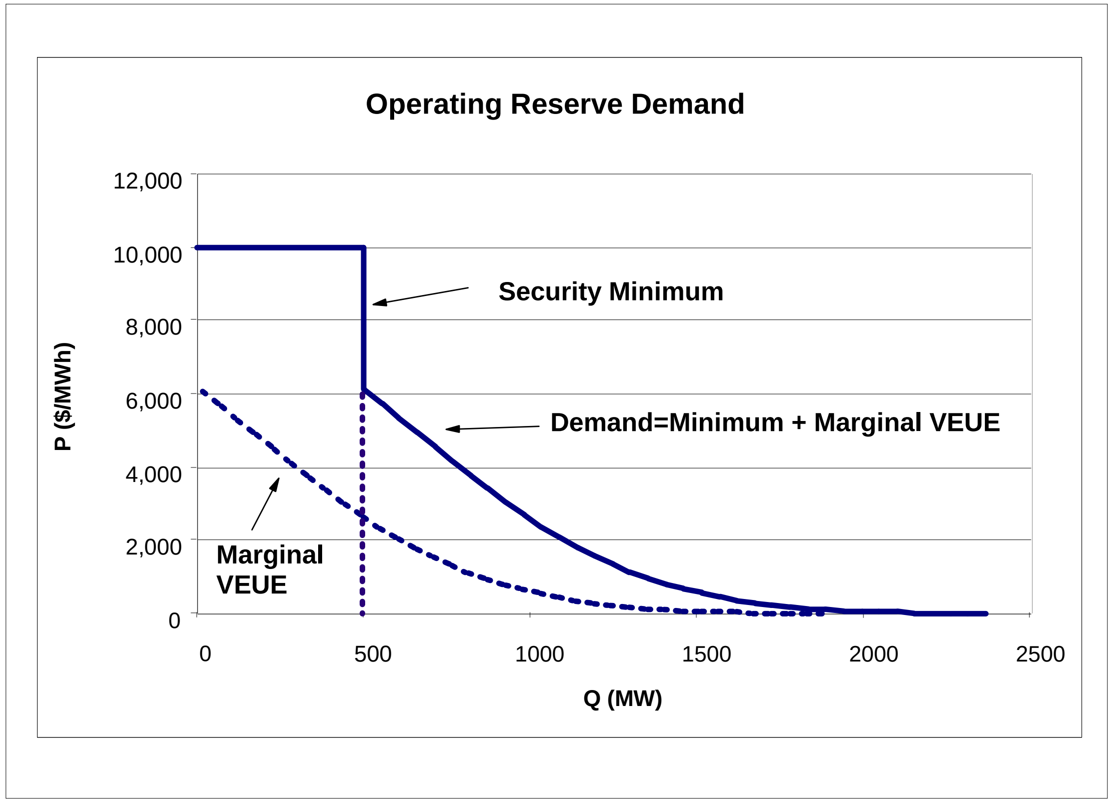


Existing market designs underprice scarcity and provide poor signals for investment. Hence we have the resource adequacy debate. A market approach would be reinforced by adopting an explicit operating reserve demand curve.

The maximum generation outage contingency quantity provides a vertical demand curve that adds horizontally to a 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.

A realistic operating reserve demand curve would address the missing money problem and help jump start greater demand participation.



Improved pricing through an explicit operating reserve demand curve raises a number of issues.

Demand Response: Better pricing implemented through the operating reserve demand curve would provide an important signal and incentive for flexible demand participation in spot markets.

Price Spikes: A higher price would be part of the solution. Furthermore, the contribution to the “missing money” from better pricing would involve many more hours and smaller price increases.

Practical Implementation: The NYISO and ISONE implementations dispose of any argument that it would be impractical to implement an operating reserve demand curve. The only issue is the level of the appropriate price.

Operating Procedures: Implementing an operating reserve demand curve does not require changing the practices of system operators. Reserve and energy prices would be determined simultaneously treating decisions by the operators as being consistent with the adopted operating reserve demand curve.

Multiple Locations: Transmission limitations mean that there are locational differences in the need for and efficacy of operating reserves. This would continue to be true with different demand curves for different locations.

Multiple Reserves: The demand curve would include different kinds of operating reserves, from spinning reserves to standby reserves.

Reliability: Market operating incentives would be better aligned with reliability requirements.

Market Power: Better pricing would remove ambiguity from analyses of high prices and distinguish (inefficient) economic withholding through high offers from (efficient) scarcity pricing derived from the operating reserve demand curve.

Hedging: The Basic Generation Service auction in New Jersey provides a prominent example that would yield an easy means for hedging small customers with better pricing.

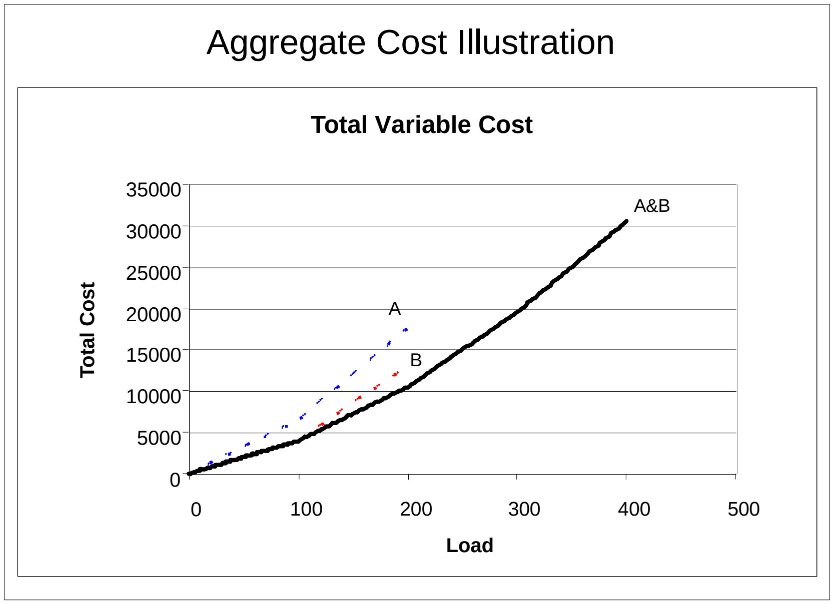
Increased Costs: The higher average energy costs from use of an operating reserve demand curve do not automatically translate into higher costs for customers. In the aggregate, there is an argument that costs would be lower.

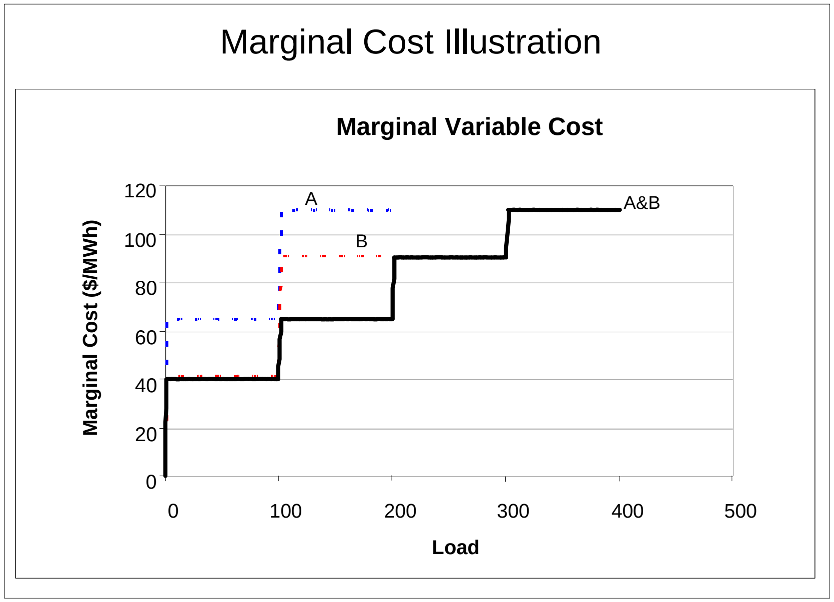
Energy dispatch is continuous but unit commitment requires discrete decisions. Bid-based, security constrained, combined unit commitment and economic dispatch presents a challenge in defining market-clearing prices.

- **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

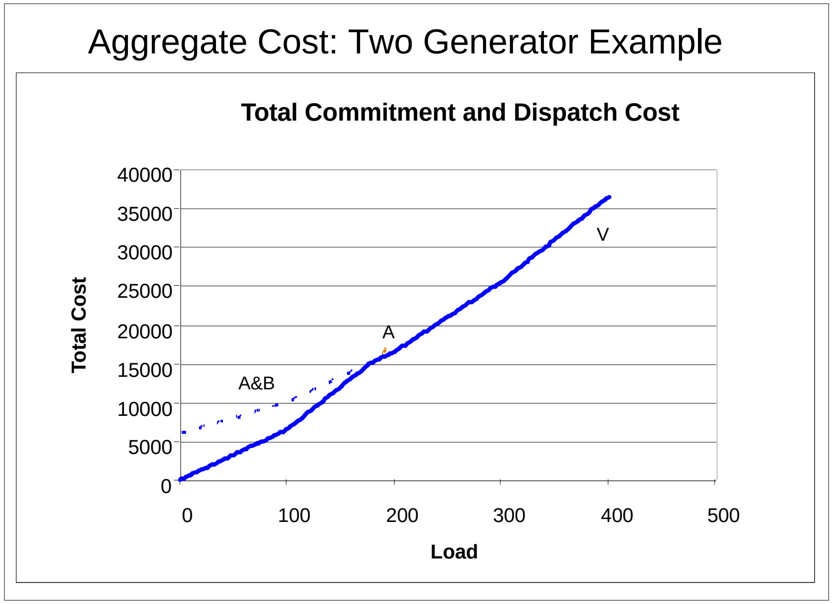
Energy dispatch is continuous, convex and yields linear prices.[1] **A simplified example with two generating units illustrates the total and marginal costs.**

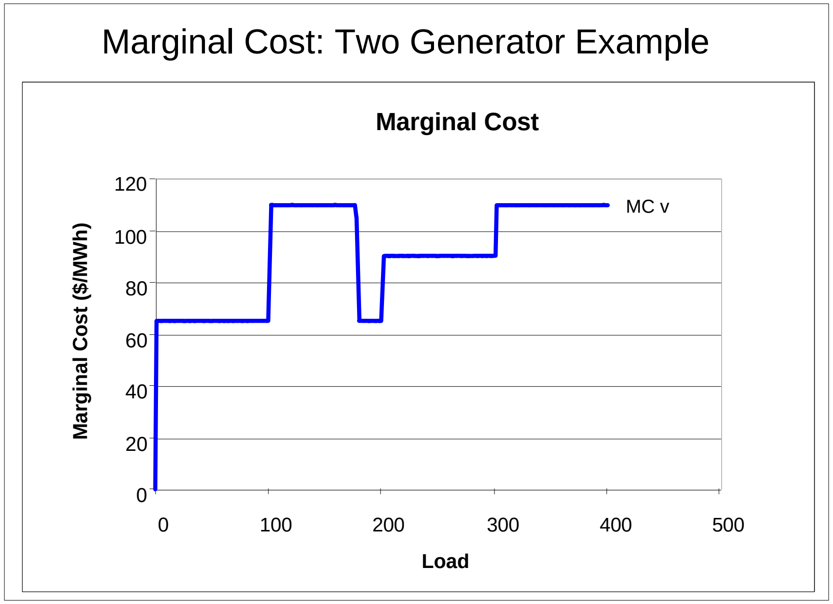




[1] Paul R. Gribik, William W. Hogan, and Susan L. Pope, "Market-Clearing Electricity Prices and Energy Uplift," Harvard University, December 31, 2007, available at www.whogan.com.

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.

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

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

Actual profits: $\pi(p, y) = py - v(y)$

Optimal Profits: $\pi^*(p) = \underset{z}{Max}\{pz - v(z)\}$

$$Uplift(p, y) = \pi^*(p) - \pi(p, y)$$

Classical Lagrangean relaxation and pricing creates a familiar dual problem.

$$L(y, x, p) = f(x) + p(y - g(x))$$

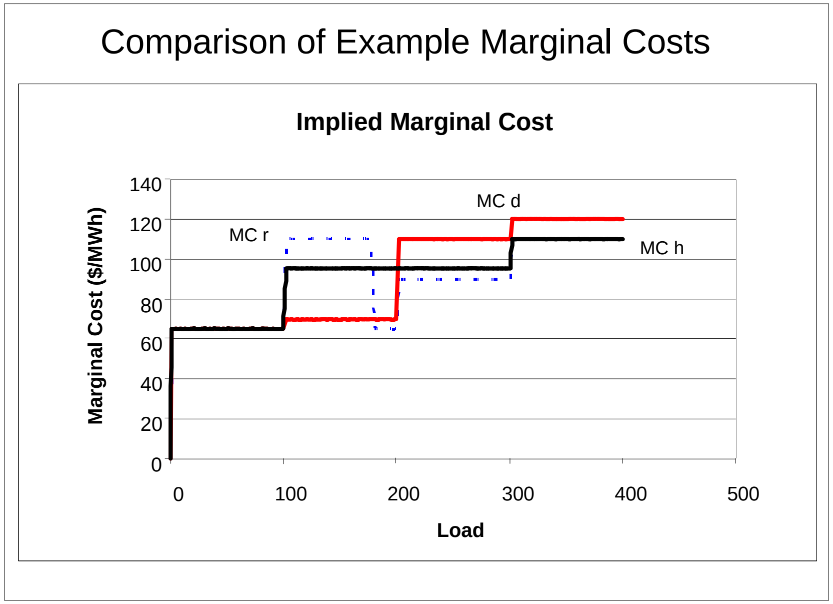
$$\hat{L}(y, p) = \underset{x \in X}{Inf}\{f(x) + p(y - g(x))\}$$

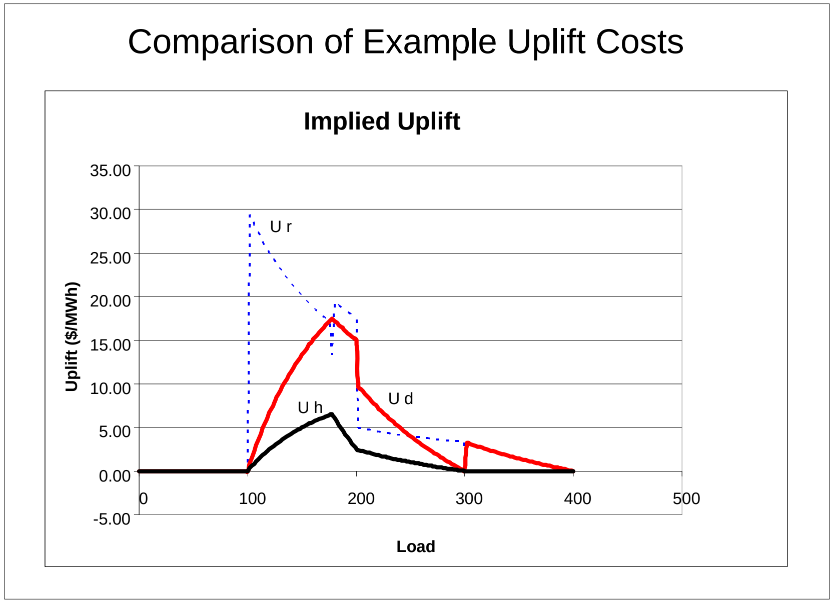
$$L^*(y) = \underset{p}{Sup}\,\hat{L}(y, p) = \underset{p}{Sup}\left\{\underset{x \in X}{Inf}\{f(x) + p(y - g(x))\}\right\}$$

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

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

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.

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