ACTING IN TIME: REGULATION AND WHOLESALE ELECTRICITY MARKETS

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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.**
  - **Market Power Mitigation.**
  - **Coordination for Competition.**

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

The Federal Energy Regulatory Commission has responsibility for regulating wholesale electricity markets. The stated framework emphasizes support for competition in wholesale markets as a clear and continuing national policy:

> "While competitive markets face challenges, we should acknowledge that competition in wholesale power markets is national policy. The Energy Policy Act of 2005 embraced wholesale competition as national policy for this country. It represented the third major federal law enacted in the last 25 years to embrace wholesale competition. To my mind, the question before the Commission is not whether competition is the correct national policy. That question has been asked and answered three times by Congress.
>
> If we accept the Commission has a duty to guard the consumer, and that competition is national policy, our duty is clear. It is to make existing wholesale markets more competitive. That is the heart of this review: to not only identify the challenges facing competitive wholesale markets but also identify and assess solutions."[1]

A task for regulation is to support this policy framework while developing hybrid markets and dealing with both the limits of markets and the failures of market designs.

[1] Joseph T. Kelliher, "Statement of Chairman Joseph T. Kelliher," Federal Energy Regulatory Commission, Conference on Competition on Wholesale Power Markets AD07-7-000. February 27, 2007.

There is a tension in choosing regulation to address immediate market failures and to deal with the continuing challenge of improving electricity market design.

- **Little "r' regulation:**

  Design rules and policies that are the "best mixture" to support competitive wholesale electricity markets. A key requirement is to relate any proposed solution to the larger framework and to ask for alternatives that better support or are complementary to the market design. Many seemingly innocuous decisions appear isolated and sui generis, but on closer inspection are fundamentally incompatible with and undermine the larger framework.

- **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. This creates a slippery slope problem, where one ad hoc solution creates another problem, and regulators are driven more and more to intervene in ever more ad hoc ways.

For example, socialized costs for preferred infrastructure investment can easily reduce the incentives for other market-based investments, thereby increasing the need for regulators to select among additional appropriate investments and socialize even more costs.

There have been repeated attempts to rethink the role of markets and Regional Transmission Organizations (RTOs). The demands of electricity markets impose many requirements and challenges. As a regulated provider of monopoly services, an RTO will never have complete freedom of action. An RTO must provide certain functions to support markets under open access and non-discrimination.

- **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

This is not new news. A review highlights the key issues.

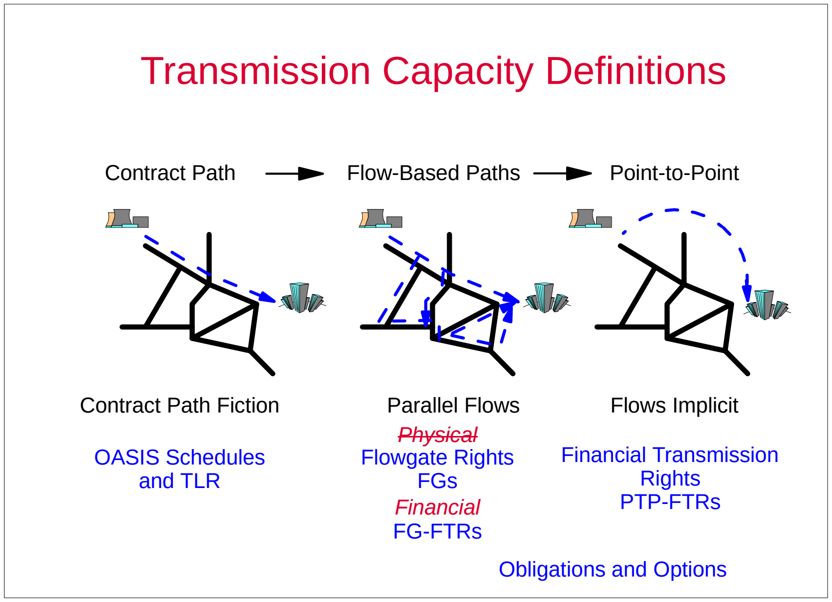
The evolution of electricity restructuring thread ...

The "Contract Path" won't work in theory, but will it work in practice?

- **Order 888, 1996.** Non-discrimination, Open Access to Transmission. Contract path fiction would not work in theory.
- **Capacity Reservation Tariff (CRT), 1996.** A new model.

"The proposed capacity reservation open access transmission tariff, if adopted, would replace the open access transmission tariff required by the Commission ..."[2]

- **NERC Transmission Loading Relief (TLR), 1997.** The unscheduling system to complement Order 888.
- **EPAct 2005.** Continued support for competitive markets but conflicting signals on market design.
- **Order 890 Reform 2007.** Too little. Too late?



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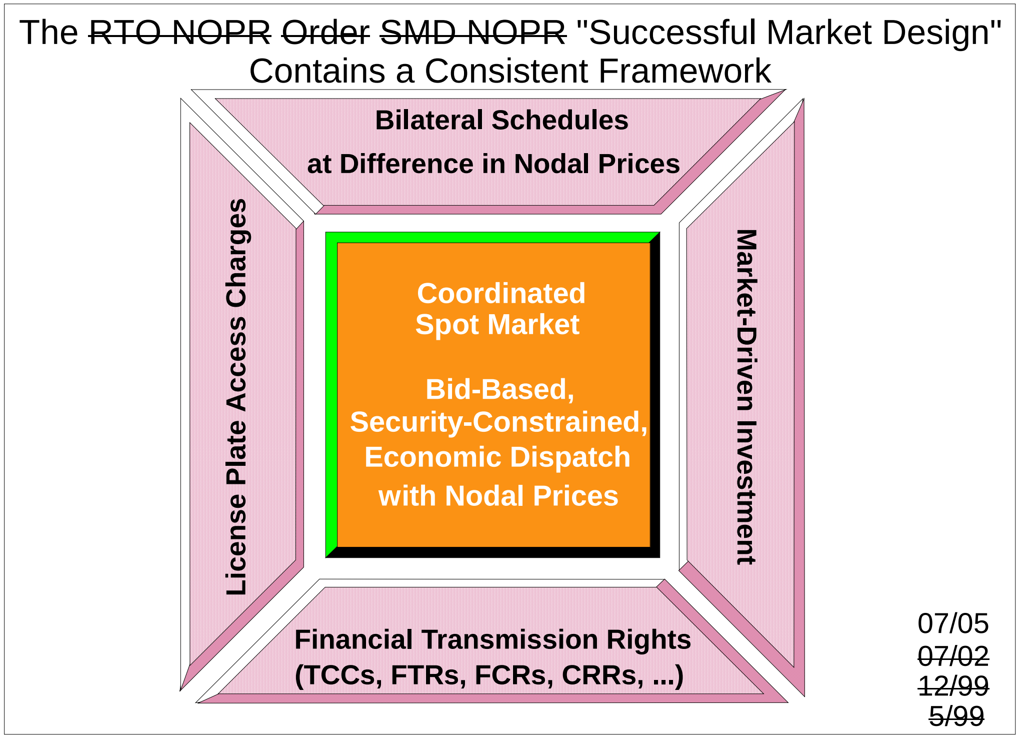
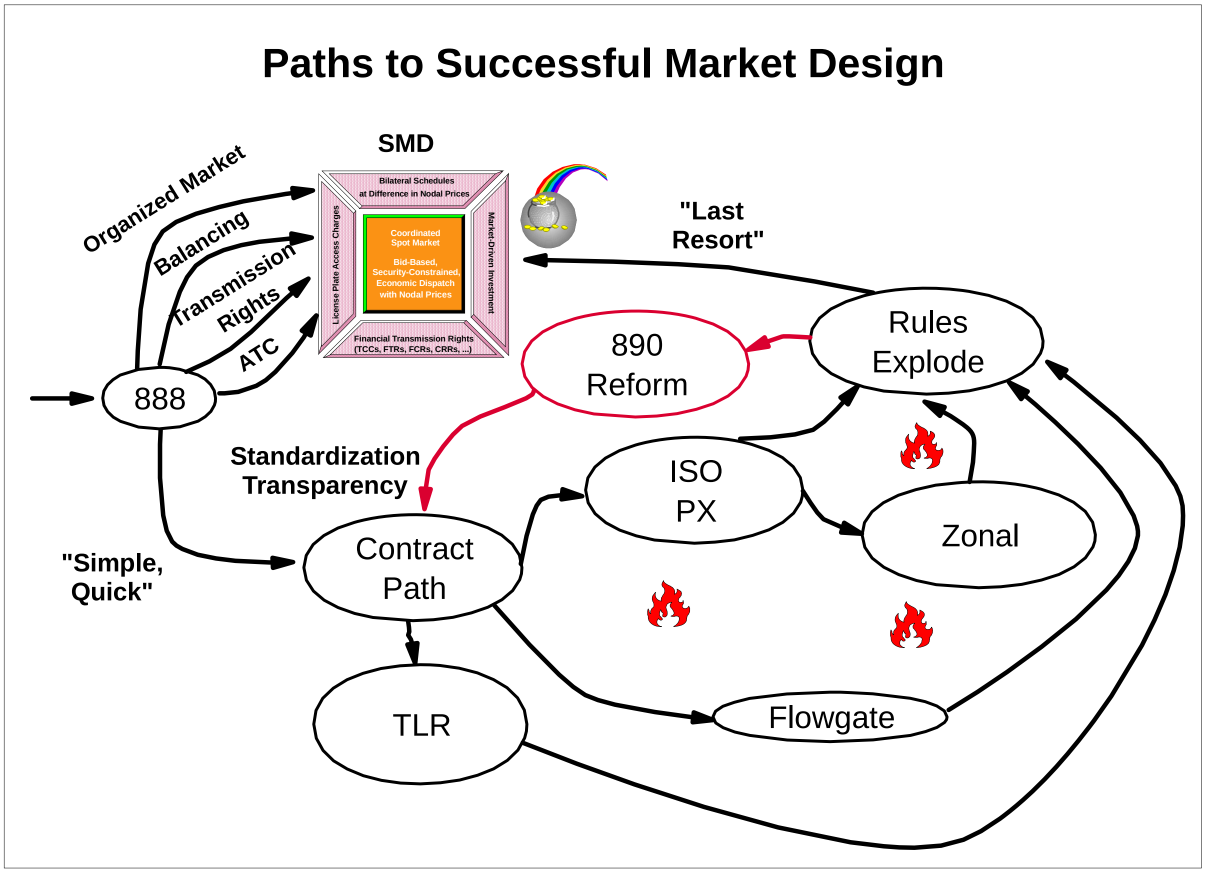
2 Federal Energy Regulatory Commission, "Capacity Reservation Open Access Transmission Tariffs," Notice of Proposed Rulemaking, RM96-11-000, Washington DC, April 24, 1996, p. 1.

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.

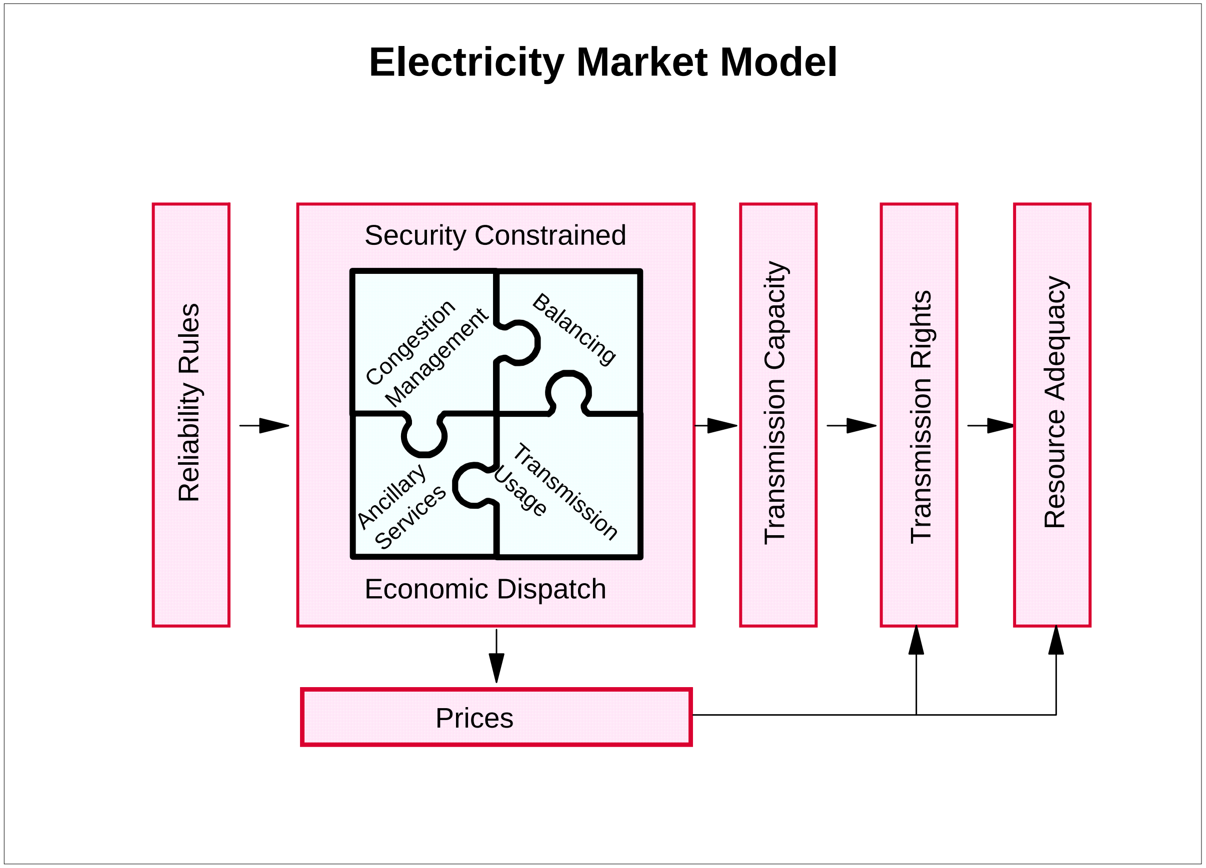


Poolco…OPCO…ISO…IMO…Transco…RTO… ITP…WMP…: "A rose by any other name …"

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?



(Re)formulating the model around the well-known principles of security-constrained economic dispatch integrates the pieces and simplifies or solves many of the most difficult policy problems.

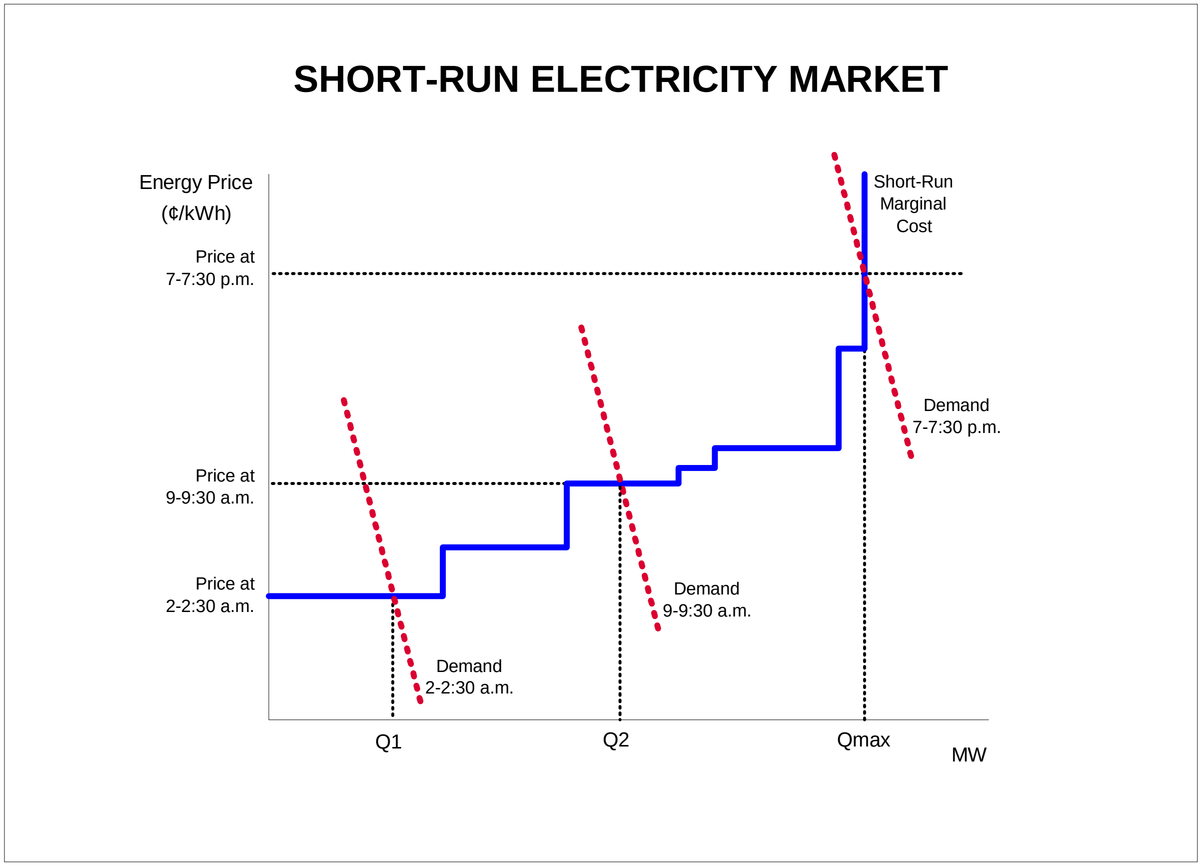


Wherever there is choice, it is critical to define the property rights and get the prices right. Wherever there are central mandates, it is important to design the rules and prices to be consistent with the fundamental market design. For example:

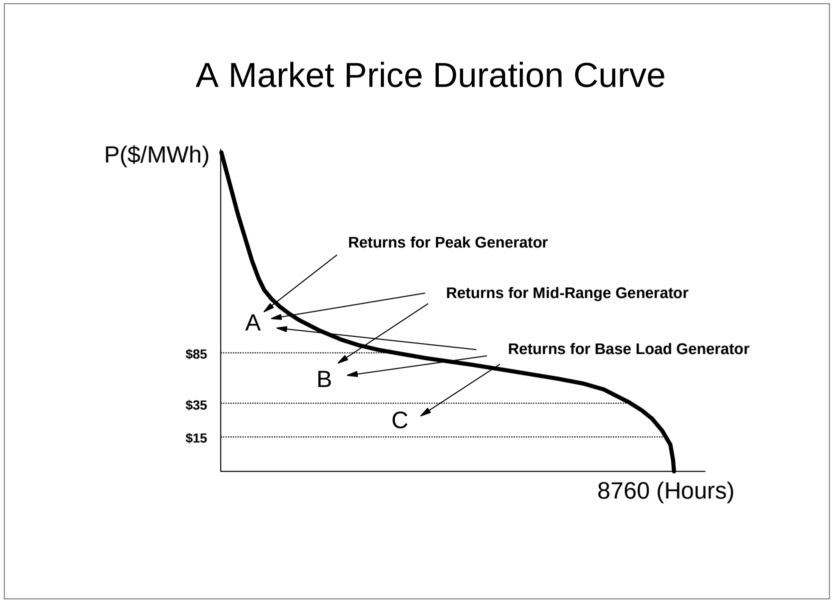
- **Get the Prices Right**
  - Scarcity pricing and resource adequacy.
  - Operating reserve demand curves.
- **Support Investment**
  - Transmission planning and investment.
  - Adapting the Argentine model.

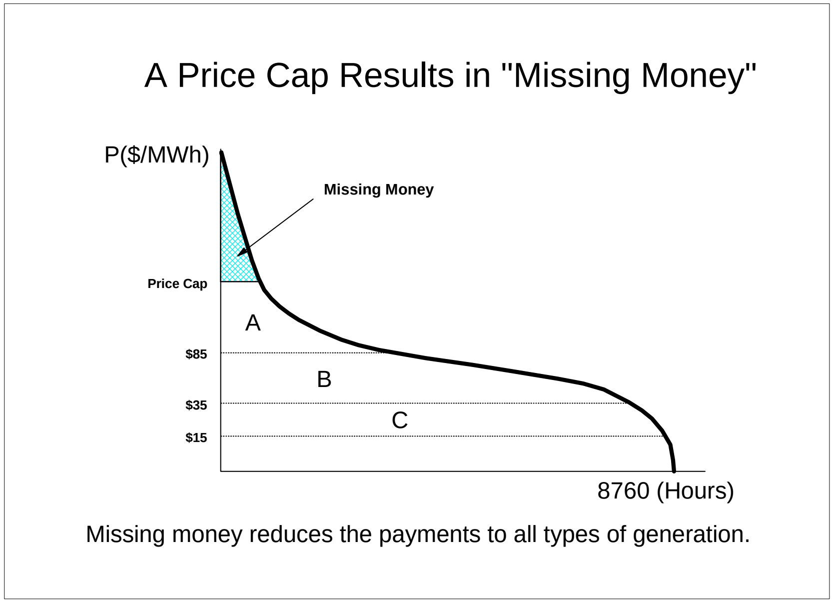
Balancing little "r" regulation through market design and decentralized decisions, and big "R" regulation through mandates and socialized costs.

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.



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.





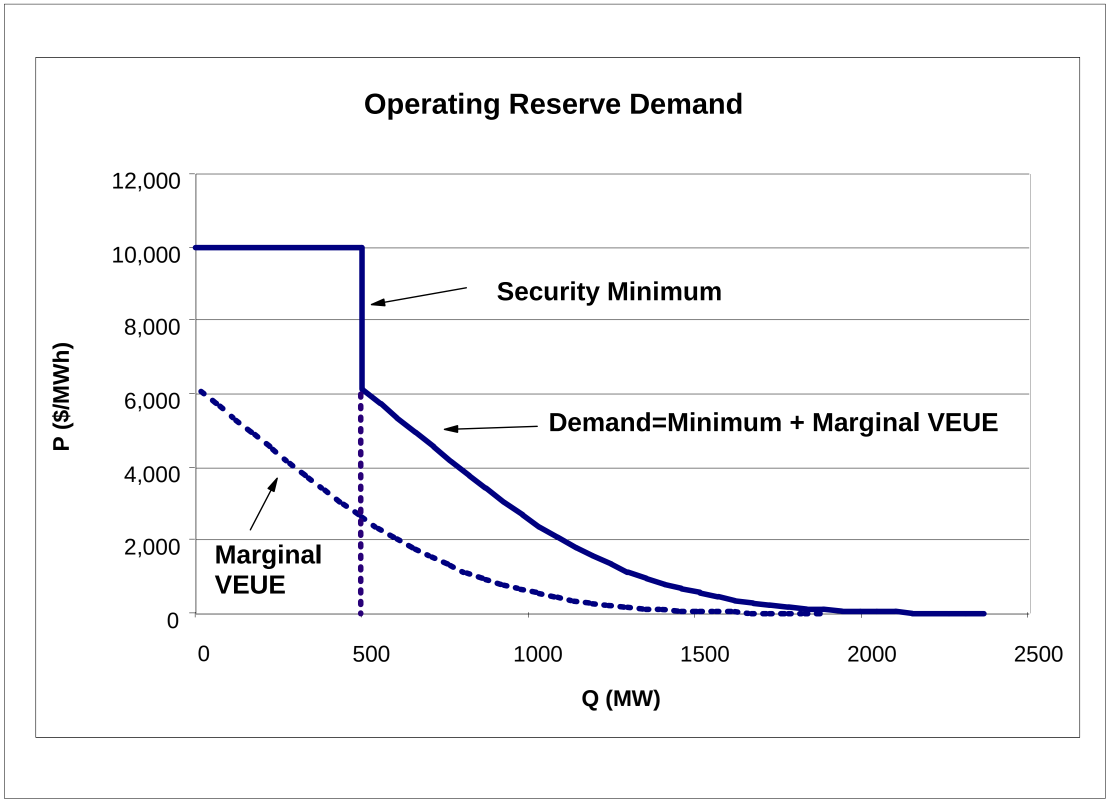
If market prices do not provide adequate incentives for generation investment, the result is a market failure. The market design defect creates the pressure for regulators to intervene to mandate generation investment.

Existing market designs underprice scarcity and provide poor signals for investment. Hence we have the resource adequacy debate. A market would approached 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 case of the NYISO disposes of any argument that it would be impractical to implement an operating reserve demand curve.

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: There are 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 the analysis 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.

TRANSMISSION INVESTMENT — Argentine Approach

An outline of the Argentine experience bears directly on the debate in the United States and elsewhere. (For details, see Stephen C. Littlechild and Carlos J. Skerk, "Regulation of Transmission Expansion in Argentina Part I: State Ownership, Reform and the Fourth Line," CMI EP 61, 2004, pp. 27-28.)

- **Coordinated Spot Market.** Organized under an Independent System Operator with Locational Marginal Pricing.
- **Expansion of Transmission Capacity by Contract Between Parties**. Allowed merchant transmission with voluntary participant funding.
- **Minor Expansions of Transmission Capacity (<$2M)**. Included regulated investment with assignment of cost, either through negotiation or allocation to beneficiaries as determined by regulator, with mandatory participant funding.
- **Major Expansions of Transmission by "Public Contest" Method**. Overcame market failure without overturning markets.
    - Regulator applies the "Golden Rule" (the traditional Cost-Benefit Test).
    - 30%-30% Rule. At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents.
    - Assignment of costs to beneficiaries with mandatory participant funding under "area of influence" methodology.
    - No award of Financial Transmission Rights!
    - Allocation of accumulated congestion rents to reduce cost of construction ("Salex" funds).

What impact did the Argentine approach have on transmission investment?

"To illustrate the change in emphasis on investment, over the period 1993 to 2003 the length of transmission lines increased by 20 per cent, main transformers by 21 per cent, compensators by 27 per cent and substations by 37 per cent, whereas series capacitors increased by 176 per cent. As a result, transmission capacity limits increased by 105 per cent, more than sufficient to meet the increase in system demand of over 50 per cent." (Stephen C. Littlechild and Carlos J. Skerk, "Regulation of Transmission Expansion in Argentina Part II: State Ownership, Reform and the Fourth Line," CMI EP 61, 2004, p. 56.)

Lessons

- **Transmission investment could be compatible with SMD incentives.**
- **Beneficiaries could be defined.**
- **Participant funding could support a market.**
- **Award of FTRs or ARRs would be an obvious enhancement.**

How would the Argentine model translate into the Unites States context?

- **Coordinated Spot Market.** Organized under an Independent System Operator with Locational Marginal Pricing. The Successful Market Design with financial transmission rights.

- **Expansion of Transmission Capacity by Contract Between Parties**. Allow merchant transmission with voluntary participant funding. This is the easy case. Allocate long-term financial transmission rights for the transmission expansion.

- **Minor Expansions of Transmission Capacity (<$2M)**. Includes regulated investment with assignment of cost either through negotiation or assignment to beneficiaries as determined by regulator with mandatory participant funding. Leaves small investments to the initiative of the existing wires companies. Auction incremental FTRs along with FTRs for existing system.

- **Major Expansions of Transmission by "Public Contest" Method**. Overcoming market failure without overturning markets.
  - Regulator applies the "Golden Rule" (Cost-Benefit Test). Use the same economic cost benefit analysis to identify expected beneficiaries.
  - 30%-30% Rule. At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents. This provides an alternative, or a complement, to the "Market Failure Test" to help the regulators limit intervention and support the broader market.
  - Assign costs to beneficiaries with mandatory participant funding.
  - Award either Auction Revenue Rights or long term FTRs to beneficiaries along with costs.

Apply the same general rules to all generation and demand investments that compete with transmission.

- **Coordinated Spot Market.** Organized under an Independent System Operator with Locational Marginal Pricing. The Successful Market Design with financial transmission rights.

- **Voluntary Investment by Contract Between Parties**. Allow merchant generation and demand investment with voluntary participant funding. This is the easy case.

- **Major Investments by "Public Contest" Method**. Overcoming market failure without overturning markets.
  - Regulator applies the "Golden Rule" (Cost-Benefit Test). Use the same economic cost benefit analysis to identify expected beneficiaries.
  - 30%-30% Rule. At least 30% of beneficiaries must be proponents. No more than 30% of beneficiaries can be opponents. Absent a very lumpy investment, the beneficiaries should be a very limited group. Virtually all demand investments and most generation investments would have a single beneficiary.
  - Assign costs to beneficiaries with mandatory participant funding.

In principle, this provides a level playing field while recognizing that there may be market failures that require regulated investments.

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