RTO (AND CRT) NOPR:
DESIGNING MARKET INSTITUTIONS
FOR ELECTRIC NETWORK SYSTEMS

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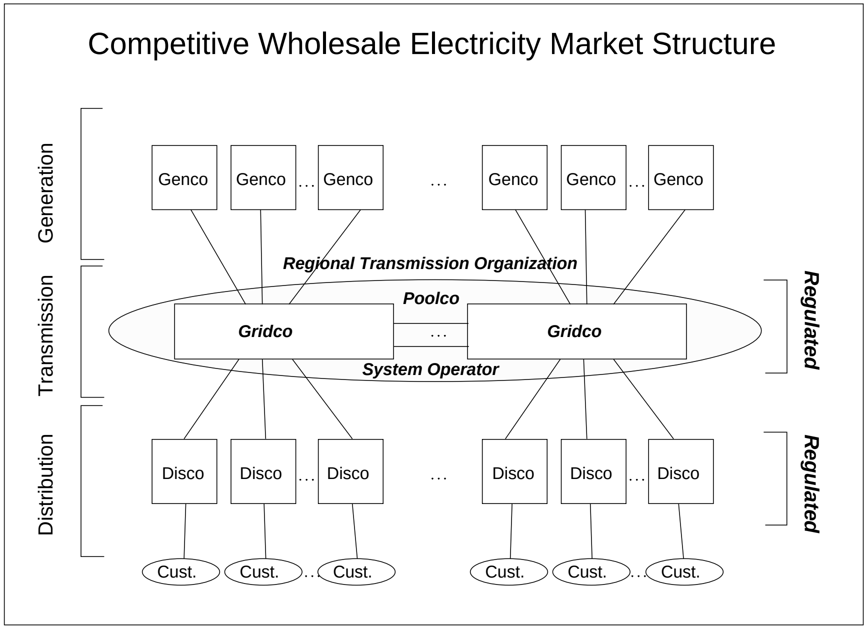
The usual separation into generation, transmission, and distribution is insufficient. In an electricity market, the transmission wires and the pool dispatch are distinct essential facilities.



The special conditions in the electricity system stand as barriers to an efficient, large-scale bilateral market in electricity. A pool based market model helps overcome these barriers.

The Federal Energy Regulatory Commission's (FERC) Regional Transmission Organizations Notice of Proposed Rulemaking (RTO-NOPR) sets forward a framework for electricity restructuring in support of competitive markets. This NOPR recognizes the importance of a coordinated spot or balancing market, and builds on this core idea.

The FERC has established "characteristics" and "functions" for RTOs:

"There are four minimum characteristics for an RTO:

(1) independence from market participants;

(2) appropriate scope and regional configuration;

(3) possession of operational authority for all transmission facilities under the RTO's control; and

(4) exclusive authority to maintain short-term reliability."

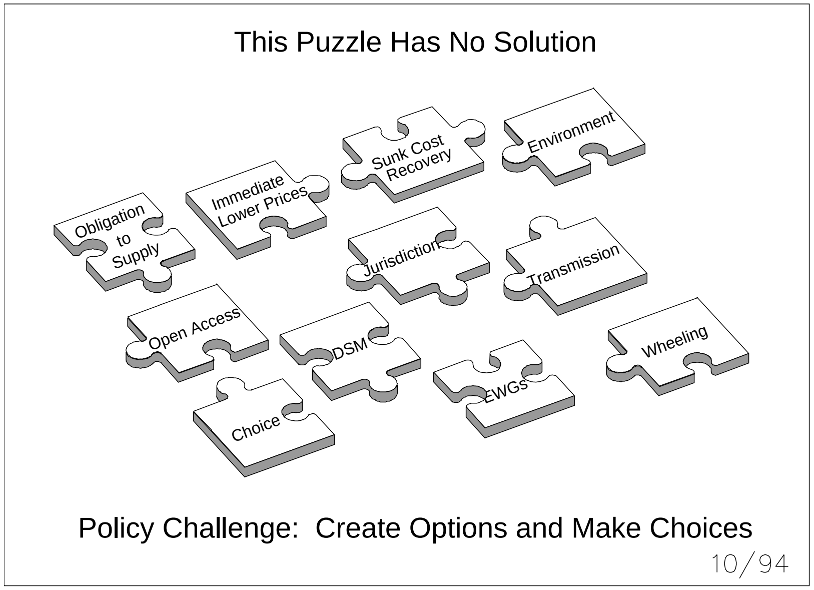
(FERC, Docket No. Rm99-2-000, May 13, 1999, pp. 115.)

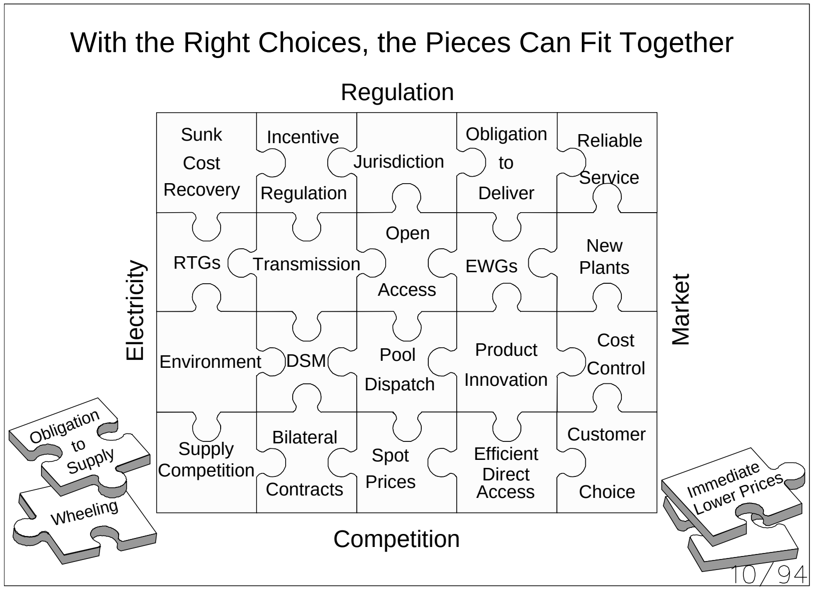
The FERC RTO-NOPR sets forward a framework for electricity restructuring in support of competitive markets.

> "In addition, there are seven minimum functions that an RTO must perform. An RTO must:
>
> (1) administer its own tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities;
>
> (2) create market mechanisms to manage transmission congestion;
>
> (3) develop and implement procedures to address parallel path flow issues;
>
> (4) serve as a supplier of last resort for all ancillary services required in Order No. 888 and subsequent orders;
>
> (5) operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating TTC and ATC;
>
> (6) monitor markets to identify design flaws and market power; and
>
> (7) plan and coordinate necessary transmission additions and upgrades."
>
> (FERC, Docket No. Rm99-2-000, May 13, 1999, pp. 115-116.)

The RTO-NOPR provides a substantial discussion of each of these items. The details matter, but there is a great deal of guidance.

From the beginning, the electricity restructuring debate has needed better options and a sharper description of the choices. There are solutions, but only when the choices are recognized.





The debate has progressed and defined some of the most important choices, such as treatment of sunk costs. The role of system operations and dispatch, at least for an energy balancing market, is a key decision that affects the design of market institutions.

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 operator consider customer bids and provide 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.

The RTO-NOPR addresses the three critical questions. The RTO-NOPR answer is "Just Say Yes."

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

Yes. "Real-time balancing is usually achieved through the direct control of select generators (and, in some cases, loads) who increase or decrease their output (or consumption in the case of loads) in response to instructions from the system operator." (p. 175) "Proposals should ... ensure that the generators that are dispatched in the presence of transmission constraints must be those that can serve system loads at least cost, and limited transmission capacity should be used by market participants that value that use most highly." (p. 198)

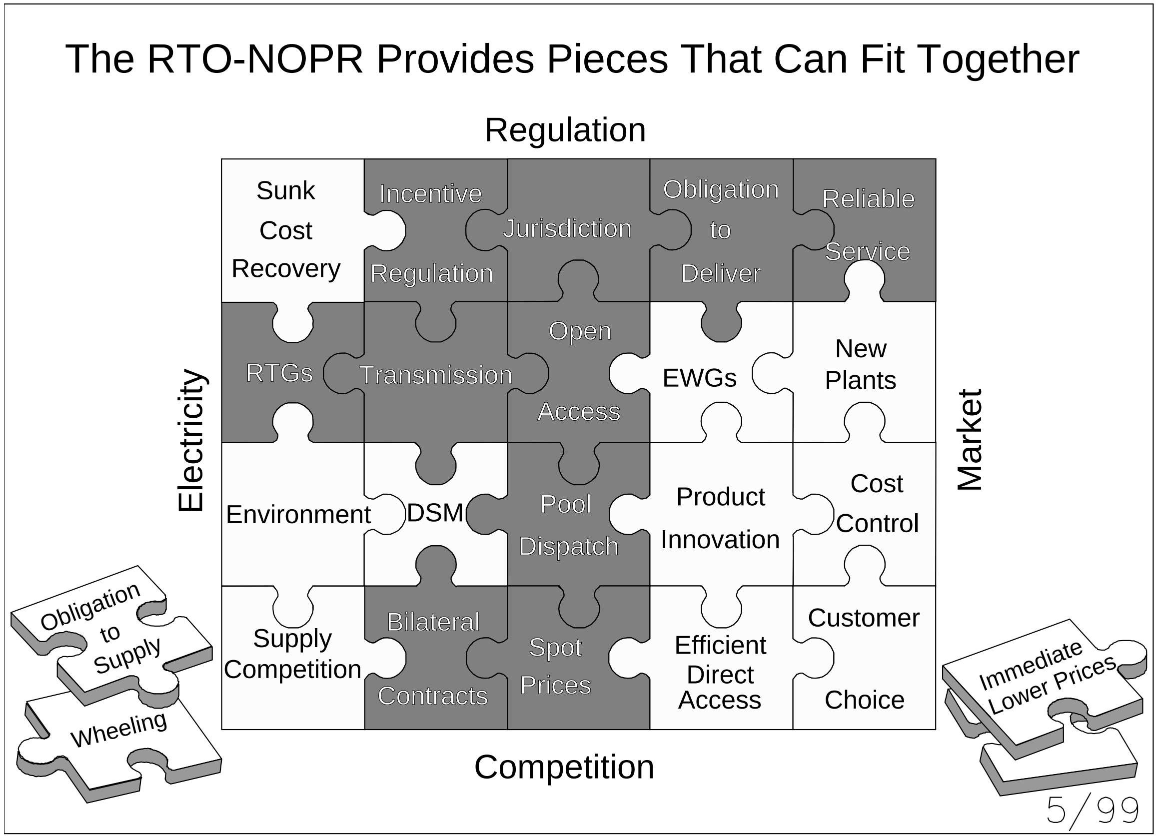
Should the system operator apply marginal cost prices for power provided through the dispatch?

Yes. "The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals regarding the consequences of their transmission usage decisions." (p.162)

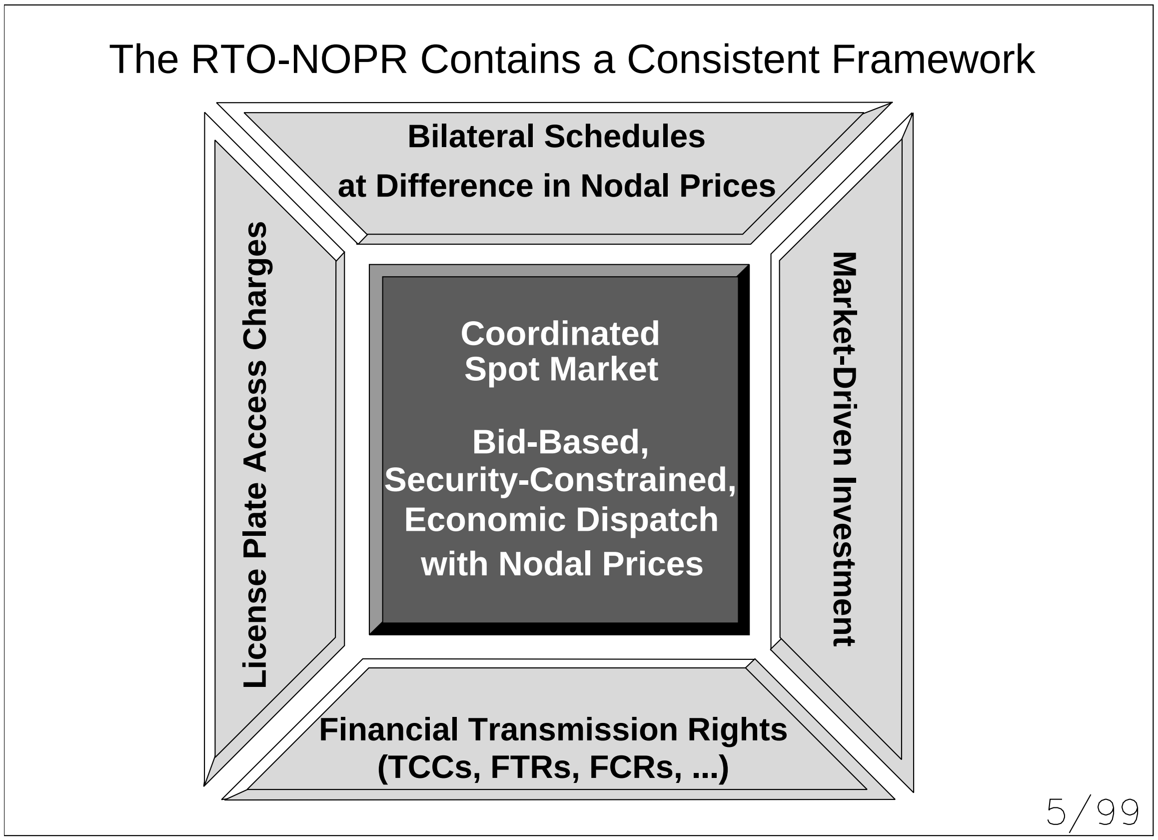
Should generators and customers be allowed to participate in the economic dispatch offered by the system operator?

Yes "... the Commission proposes to require that RTOs operate a real-time balancing market that would be available to all transmission customers, or ensure that this task is performed by another entity not affiliated with market participants." (p. 176)

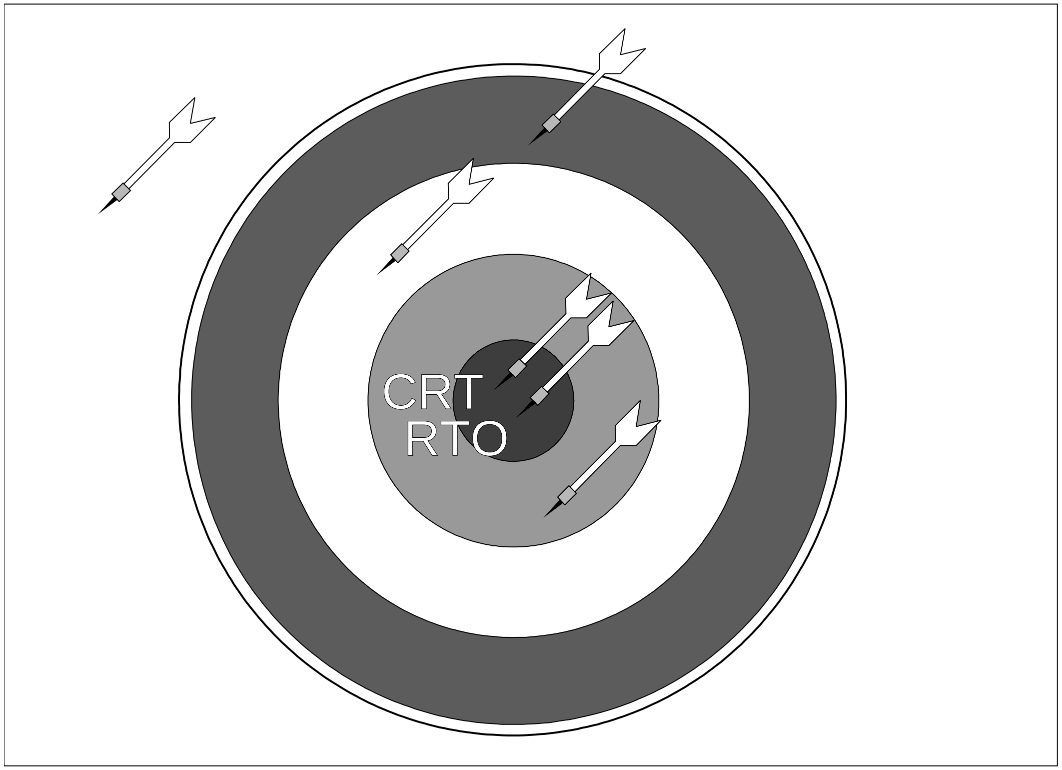
The FERC RTO-NOPR, along with the earlier Capacity Reservation Tariff (CRT) NOPR, covers the critical institutions and policy choices.



The FERC RTO-NOPR and the earlier CRT-NOPR contain a market framework that works, and is already working in places like the Pennsylvania-New Jersey-Maryland Interconnection (PJM).



The NOPR is on target. However, the success of the CRT/RTO proposal depends on two big "ifs". The framework can work ...



- **If FERC means what it says.** The record is encouraging here. The basic elements of the CRT proposal, originally criticized by the industry as being unworkable, have been approved by FERC and are working fine in PJM. Soon in New York and New England.

- **If FERC follows through.** The incentive-based carrots may not be enough. In the case of gas open access, and Order 436, the "volunteers" were responding to many FERC-sticks as well. Some regions will do the right thing on their own, but not all. And the interactions, such as through TLR, cry out for more consistency. How long before FERC makes this mandatory? "If you know what to do, do it." We know what to do.

There is a continuing debate about the best model for organizing coordination and control of the transmission system, including dispatch and coordination of energy balancing or spot markets.

- **Transco.** An independent company that combines ownership of the grid and responsibility for system operations in managing the use of the grid. May be a for-profit or not-for-profit entity. (National Grid Company in England and Wales.)

- **Gridco.** An independent company that owns the grid but does not have responsibility for operating the system. Works in conjunction with a system operator. May be a for-profit or not-for-profit entity. (GPU PowerNet in Victoria)

- **ISO/PX.** An independent system operator with restrictions to allow for separate operation of a power exchange. (California ISO and PX.)

- **ISO.** An independent system operator that has responsibility for managing use of the grid and coordinating the spot market. (Pennsylvania-New Jersey-Maryland Interconnection, PJM.)

- **TLR.** The institution for coordinating transmission loading relief across regional system operators. (NERC Security Coordinators in the U.S. Eastern Interconnect.)

A single regional entity which owns and operates the transmission system, but is independent of generation and load.

- **Profit or Non-Profit?** The leading proposals call for regulated profit-making entities (Entergy, NSP?). However, the large public power authorities in the United States provide an alternative model with non-profit organizations.

- **Shortcut to Market?** The strongest claims are that the profit motive is all that is needed, and with incentive regulation the Transco could be left to devise its own rules for transmission access, operations and detailed pricing. The Federal Trade Commission has identified the flaw in this argument. In the end, it is unlikely that the Transco would avoid any of the difficulties that must be addressed in creating an ISO. In effect, a true Transco would be an ISO that acquired ownership of the wires.

- **Independence of Market Participants?** Can market participants make transmission investments? The "Direct Link" project in Australia is a merchant transmission line. Generators paid to expand the system in Argentina.

- **Significant Incentives.** With ownership of significant assets, there is an argument that regulators would have greater leverage in controlling the performance of Transcos.

- **Regional Coverage?** A major hurdle would be in creating Transcos that match the regional requirements of system operations. This is easy in New Zealand (Transpower) but more difficult in the United States with its large interconnected systems.

A regional entity that owns transmission wires and is independent of generation and load. The Gridco is not responsible for controlling use of the system, and must be paired with a system operator.

- **Profit or Non-Profit?** As with Transcos, the leading proposals call for regulated profit making entities (NEES-NGC, GPU). However, the arguments of the large public power authorities apply as well for a mix that includes non-profit organizations.

- **ISO.** Control of operations by an ISO is compatible with the GRIDCO model. The rules for access and pricing would be the same as under the regime where traditional utilities own the grid. The distinction of the GRIDCO is that maintenance and, possibly, expansion of the grid would be the responsibility of the GRIDCO, which is also independent of generation and load.

- **Incentives.** Incentives for the GRIDCO, which would own significant assets, would be similar to those of the Transco but without the conflicts of interest in operations identified by the FTC.

- **Regional Coverage.** Regional coverage for the GRIDCO need not and probably would not coincide with the regional coverage of system operations. This would be a great simplification compared to the Transco model. It would allow an evolution of GRIDCOs, with different models, without confronting the complications of balkanized operations.

The independent system operator functions in conjunction with a separate and distinct power exchange for market operations, with separate rules and pricing for system operations. Neither the ISO or PX owns transmission lines.

- **Horizon.** The distinction between the functions of market operations and system operations depend on the time horizon and the relative importance of network interactions. For the short-run, the two functions are difficult (impossible) to separate.

- **Restrictive Rules.** Over the short-run, maintaining a distinction between the ISO and the PX requires creation of complex rules to restrict the system operator. It is well recognized that if the system operator performs its functions through a voluntary, bid-based, security-constrained, economic dispatch--following the principles power systems have used for decades--the separate power exchange would have little to do other than arrange settlements. Hence, the only model like this (CA ISO/PX) precludes the ISO from economic dispatch and segments interdependent functions, reducing options and increasing costs.

- **ISO Lite.** Restrictions on ISOs reappear in various proposals that limit the use of economic dispatch and transmission coordination, assuming that the complex interactions can somehow be internalized in a market, even without a formal power exchange (MISO). Inevitably these approaches reduce capacity, socialize costs and add to the complexity of real operations.

The independent system operator provides a dispatch function that coordinates the spot market. The ISO does not own transmission lines.

- **Power Exchange.** If there is a separate entity called a Power Exchange, it does not have responsibility for coordinating the spot market and transmission usage. The PX may handle bidding and settlements, (EMCO, Nord Pool) but the dispatch activity falls to the ISO. In many cases, there is no separate PX with any special status (PJM, Australia).

- **Pricing and Access Rules.** The services provided by the ISO are complex and interconnected. It is a challenge to find the best mix of unbundled activities and associated pricing rules. The key is to match the degree of customer choice with the pricing incentives. Where customers have flexibility, such as between spot market transactions and bilateral transmission scheduling, it is important to get the prices right. There are many models (England and Wales, Norway, PJM, NEMMCO).

- **Regional Coverage.** The appropriate size and regional coverage of the ISO depends on many factors, including the degree of coordination required across the entities in arranging for transmission loading relief.

Regional system operators must coordinate use of the transmission grid on interconnected networks. Transmission loading relief (TLR) is required when system constraints would be violated. The rules for inter-regional coordination interact strongly with the pricing and access rules within the regions.

- **Markets Matter.** In the United States, the North American Electric Reliability Council (NERC) filled the vacuum in developing a TLR. However, the institutional design limits imposed or assumed required non-market mechanisms for curtailing transactions. The system is cumbersome, reduces real capacity, and has had severe impacts on the market, contributing to problems in the Mid-West that produced $7000/MWh transactions.

- **Price Directed Coordination.** With TLR integrated in the market, prices and bids would matter. There are alternative market mechanisms in principle. The PJM system has proposed implementing the first consistent market mechanism for managing TLR by allowing participants to choose to pay for congestion.

- **Regional Coverage.** The market mechanisms for TLR coordination provide guidance for the design of regional coverage of system operations.

- **Market Redispatch.** The pilot redispatch program requires critical information from the security coordinators, but prevents them from using the information to coordinate the trades.

Opportunities to design institutions that create problems appear in the many areas that must be the responsibility of the system operator. There are many ways to get it wrong.

- **Impose Balancing Penalties.** The ISO must provide real time balancing to maintain system integrity. Balancing imposes costs, and those relying on the balancing services should pay these costs. However, a strong burden of proof should face those who would charge balancing penalties in excess of costs, or restrict voluntary access to balancing services.

- **Require Individual Balancing Constraints.** The ISO must maintain aggregate energy balance in the system, but there is no physical necessity and no public policy interest in requiring particular combinations of transactions to remain balanced. Quite the contrary. Individual balancing requirements both complicate the task for the ISO and provide a device to reinforce market power. This goes against the public interest.

- **Prohibit Least-Cost (Re)Dispatch.** The ISO must be able to (re)dispatch plants in order to manage transmission congestion. Rules designed to prevent the ISO from applying the familiar principles of economic dispatch run contrary to the notion of competitive markets and the public interest.

- **Reject Voluntary Bids.** When doing an economic dispatch, it seems logical for the ISO to make the adjustments taking into account the preferences of the market participants as expressed by their voluntary bids. There should be a strong burden of proof for those who argue that it is necessary to restrict the voluntary bids, or discard consideration of some bids.

There are many ways to get it wrong.

- **Separate Transmission Rights and Dispatch.** The ISO must coordinate the use of the transmission system. And once the actual use of the transmission system is determined, so is the dispatch. Regulators should look with skepticism on any proposal built on the flawed foundation that transmission usage and dispatch can be separated.

- **Restrict the Capacity of the Grid.** The real reliability conditions for the electric grid include an ensemble of contingency conditions and complicated network interactions. Relatively few of these real constraints are simple limits on the actual flow across certain interfaces. Regulators should look skeptically at proposals that require derating the real capacity of the grid in order to make a few flow limits sufficient to guarantee reliability under a simple market model.

- **Suppress Pricing Information.** Only the ISO would have the information needed to calculate and post locational prices, as in PJM. The computations are easy for a given dispatch, but only the ISO has all the information about the dispatch. Given the striking gap between the previous claims that congestion is insignificant and the observed reality of true locational marginal costs in the first real implementation in the United States, all regulators should have a strong interest in prescribing that the real locational marginal costs--considering the real network interactions, and not just simplified zonal aggregations--be made available on a regular basis.

Appendix

Postage stamp rates or one-part transmission prices based on actual usage are simple and familiar, but may not be adequate in supporting a more competitive electricity market.

- For the vertically integrated electricity industry, usage did not depend on pricing incentives. Historical focus of transmission pricing has been on revenue recovery without concern for economic incentives affecting use of the grid.

- Open access and competition require and reinforce a focus on economic incentives and equivalent pricing for equivalent unbundled services.

- Economies of scale and network interactions in transmission loom large, and economic efficiency may require two-part tariff structures:

  -- License plate fixed charges to cover revenue requirements and pay for long-term transmission rights;

  -- Short-term opportunity cost pricing for actual system use.

- Open-access on an equivalent basis is defined as the right to connect to the grid and pay short-term usage prices for actual power flows.

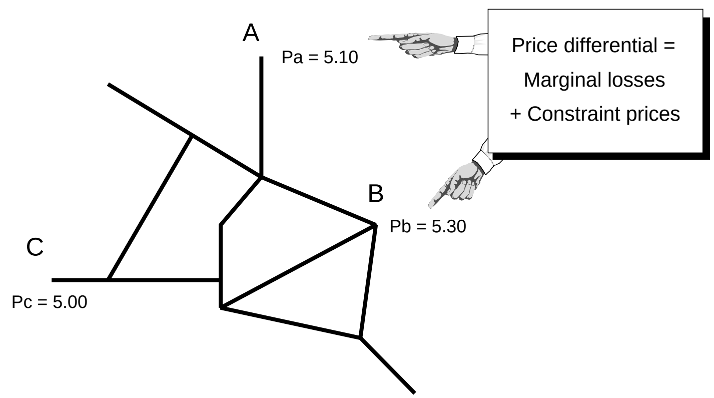
- Consistent with a two-part tariff structure, the long-term transmission right is to collect congestion rentals to hedge the changes in usage prices.

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.

LOCATIONAL SPOT PRICE OF "TRANSMISSION"

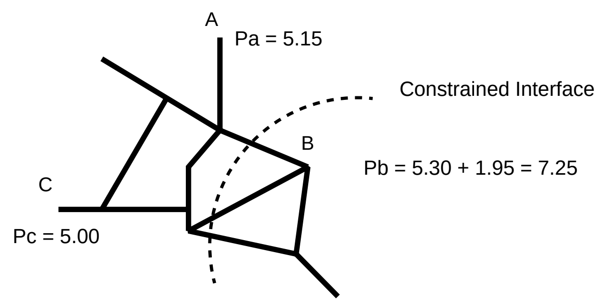


Price of "Transmission" from A to B = Pb - Pa = 0.20
Price of "Transmission" from A to C = Pc - Pa = -0.10

A mechanism for hedging volatile transmission prices can be established by defining transmission congestion contracts to collect the congestion rents inherent in efficient, short-run spot prices.

NETWORK TRANSMISSION CONGESTION CONTRACTS

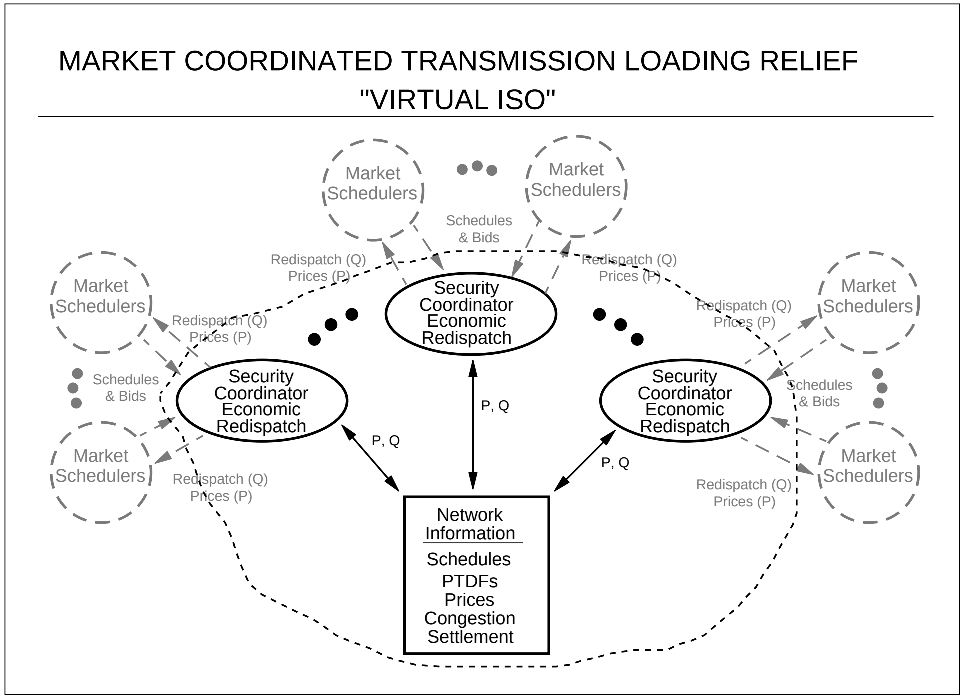
Bus Price = Generation Cost + Marginal Losses + Congestion Costs



Pcb = Pb - Pc = Marginal Losses + Congestion Costs = 0.3 + 1.95 = 2.25

- 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.

Through repeated exchange of information in a common data base, the regional security coordinators could solve their local problems to update the schedules and price estimates. A consistent solution would be an overall market equilibrium as though obtained by a "virtual ISO."[1]



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[1] Michael Cadwalader, Scott Harvey, William Hogan, and Susan Pope, "Market Coordination of Transmission Loading Relief Across Multiple Regions," Center for Business and Government, Harvard University, December 1, 1998.

A challenge for transmission pricing and access is to balance the goals of commercial practicality and flexibility in customer choice.

- If customers have flexibility in the choice of generation, spot purchases, bilateral transactions, and so on -- then prices must reflect the cost impacts.

- If prices do not reflect cost impacts, customers will respond and the system will be driven to a combination of reduced choice, higher costs and accretion of administrative fixes.

- The focal point for the tradeoff has been in transmission congestion pricing. The FERC order for PJM has set us on the right path with locational prices at nodes -- "We have seen the future and it is PJM." However, the debate will continue elsewhere with proposals to average congestion costs across one or more zones. The simplicity of zones is deceptive; in the end, nodal pricing is simpler in the context of competitive markets and customer choice.

A (The) Simple Design That Works:

Bid-based, security-constrained, economic dispatch with nodal pricing and financial transmission congestion contracts.

"A theory should be as simple as possible -- and no simpler." (Einstein)

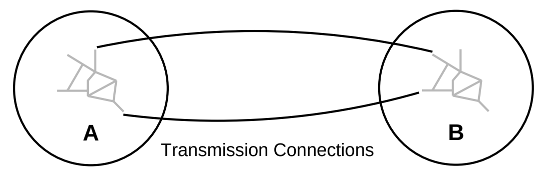
Within ISO models, the use of zones versus nodal pricing is an issue. If the world divided naturally into zones, life would be simpler. However, aggregation of a real world with true locational differences into a fictional world with zones would not be simple. For competition to be flexible and work well, it will be important to get the prices right.

- **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.)

Zones Are Not As Simple With Parallel Connections

With a Single Connection and Constraint

- All prices within a zone would be the same.
- Prices for zones A and B differ only if transmission connection is constrained.



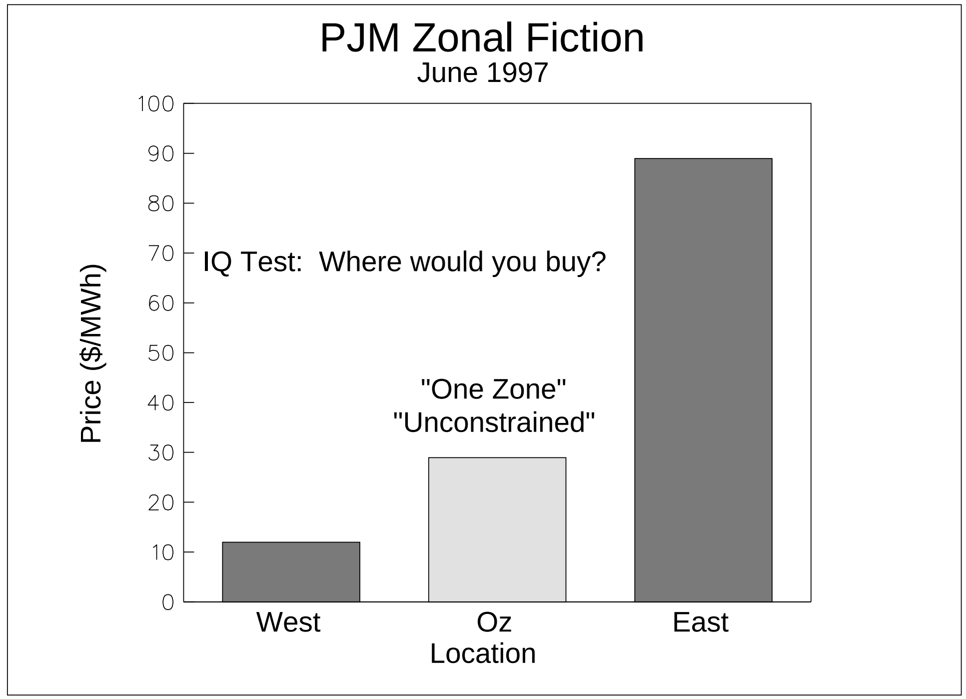
With a Parallel Connection and Constraints

- *None of the above.*

- **Would Zonal Prices Discourage Distributed Generation?** (Yes.)
- **Would Zonal Pricing Mitigate Market Power?** (No.)
- **Can the Market Operate With a Simpler System?** (Yes. Locational Pricing with Hub and Spokes.)

In June of 1997, Pennsylvania-New Jersey-Maryland Interconnection (PJM) saw marginal cost in the east at about $89 per MWh, when at the same time the marginal cost in the west was $12 per Mwh. The "unconstrained" price for the "One Zone" (Oz) was approximately $29 per MWh.

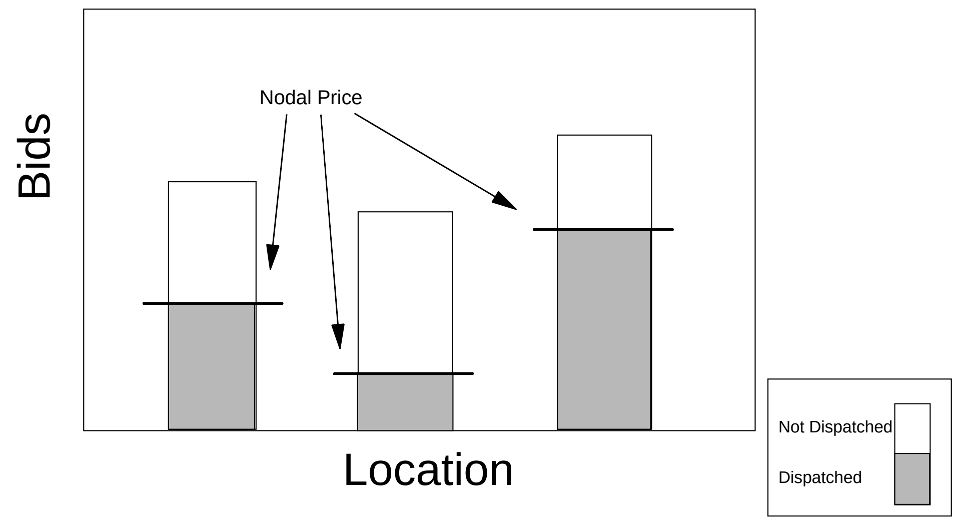
A customer could buy from the spot-market dispatch at $29, or it could arrange a bilateral transaction with a constrained-off generator in the west at a price closer to $12. The choice presented a low-level IQ test. Market participants passed the test. Constrained-off generators quickly arranged bilateral transactions and scheduled their power for delivery. Soon the ISO had no more controllable generating units with which to manage the transmission constraints. Unable to fix the perverse pricing incentives, the ISO prohibited bilateral transactions. The unintended consequences of superficially simple pricing spawned administrative rules to foreclose the market.



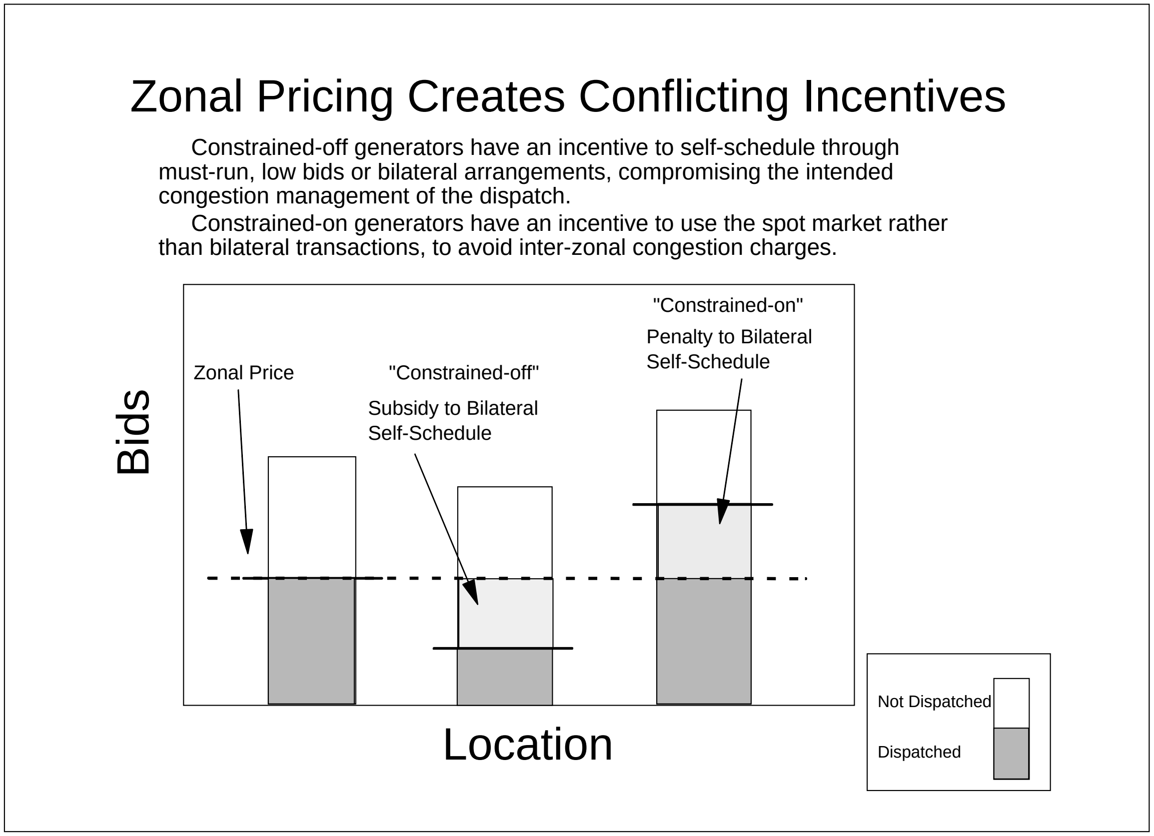
Nodal prices provide incentives that conform to the competitive market and the principles of economic dispatch. Nodal prices are self-policing and self-auditing.

Nodal Pricing Is "Self-Policing"

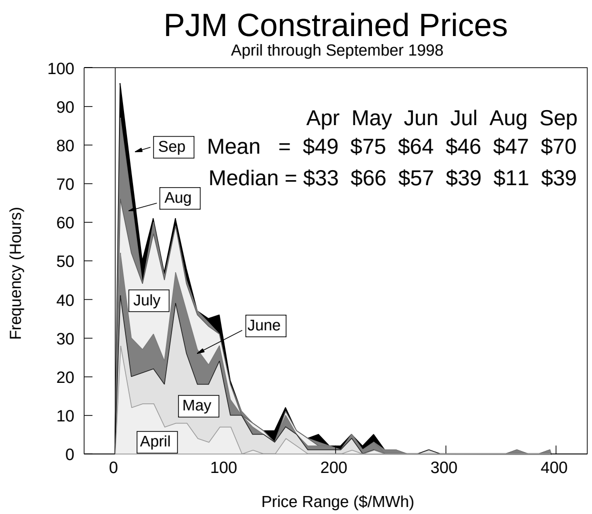
"The price is set by the bids in such a way that no generator is generating if the price is below his bid, and no generator is not generating if the price is above his bid - it is self-policing. Generators always want to generate at the appropriate time, in their own financial interest, which is very important since if they do not follow instructions, the system can go out of control." (NERA)



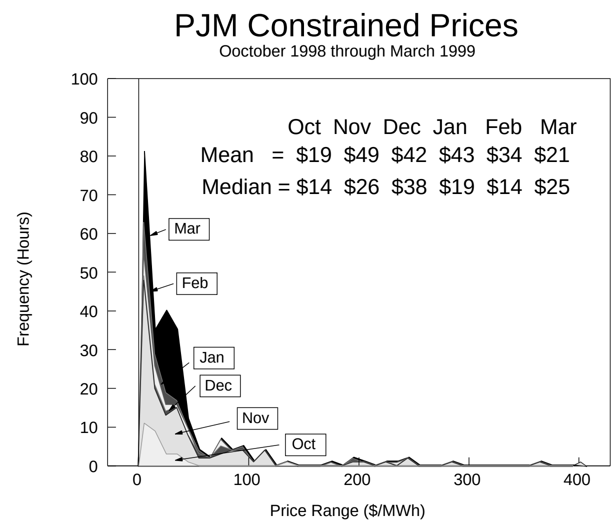
Zonal prices create incentives to deviate from the reliable dispatch. Zonal pricing requires rules to prevent certain behavior or eliminate the market profits. Real zonal systems soon become complicated.



The range of prices and degree of congestion exhibited in the first year of operation of the PJM locational pricing system disproved the oft repeated argument that transmission congestion was rare and inconsequential.

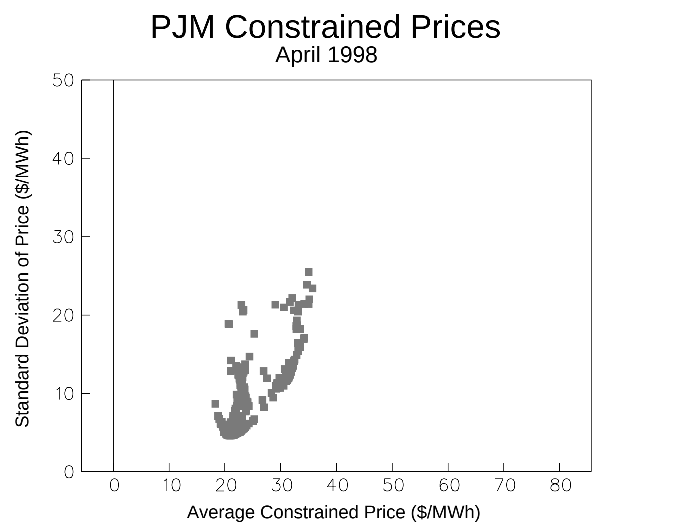


Maximum difference in locational prices for constrained hours.

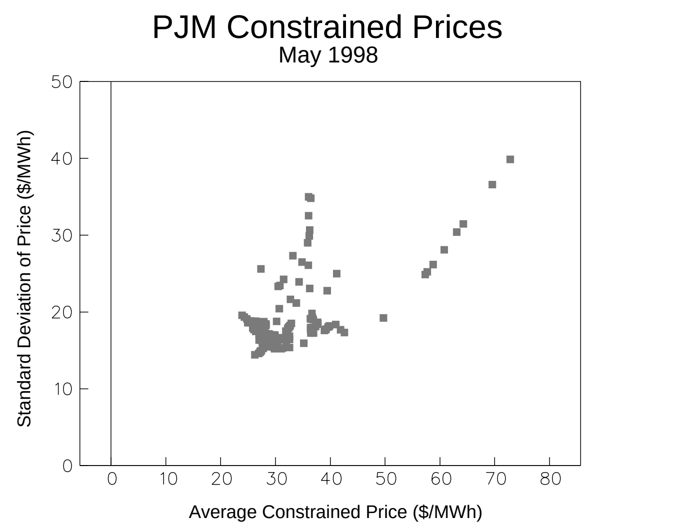


Maximum difference in locational prices for constrained hours.

An argument applied around the world evokes the use of zones to average or aggregate transmission congestion prices. The argument was made that PJM would have only a few zones with clusters of similar locational prices. Results from the first months of operation in 1998 reject that hypothesis. Using a threshold of an average congestion difference of $1 MWh over a month, there were at least 132 zones required to capture the price differences in PJM for just April and May. The zonal approach is neither accurate nor simple.



Mean and standard deviation over 119 constrained hours at different locations.



Mean and standard deviation over 183 constrained hours at different locations.

Analysis of the PJM locational prices reveals that defining zones in which all prices were within $1/MW in average constrained price and standard deviation would have required:

- 94 zones in April.
- 83 zones in May.
- 75 zones in June.
- 57 zones in July.
- 52 zones in August.
- 64 zones in September.
- 61 zones in the combined period of October 1998 through March 1999.

Moreover, the nodes making up these zones would change from month to month and were not necessarily contiguous.

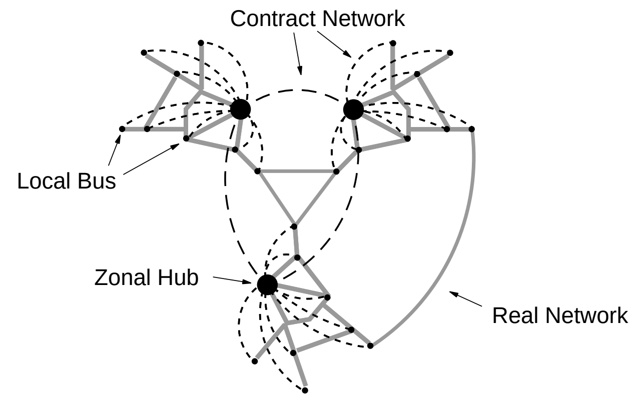
Locational pricing provides a sound foundation for a competitive electricity market. However, different prices at every location appears complex. Can the market operate with a simpler system? Yes, the hub and spoke model works in theory and in practice.

Locational marginal cost pricing lends itself to a natural decomposition. For example, even with loops in a network, market information could be transformed easily into a hub-and-spoke framework with locational price differences on a spoke defining the cost of moving to and from the local hub, and then between hubs.

Creation or elimination of hubs would require no intervention by regulators or the ISO. New hubs could arise as the market requires, or disappear when not important. A hub is simply a special node within a zone. The ISO still would work with the locational prices, but the market would decide on the degree of simplification needed. However, everyone would still be responsible for the opportunity cost of moving power to and from the local hub. There would be locational prices and this would avoid the substantial incentive problems of averaging prices. This system works in PJM for congestion pricing, and is used in Australia for loss pricing--simplifying without distorting locational prices.

Contract Network Connects with Real Network

Determine Locational Prices for Real Network; Implement Transmission Congestion Contracts and Trading on Contract Network



Supporting papers and additional detail can be obtained from the author. William W. Hogan is the Lucius N. Littauer Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University. He is a Director of the Law and Economics Consulting Group. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. Many individuals have provided helpful comments, especially Robert Arnold, John Ballance, Jeff Bastian, Ashley Brown, Michael Cadwalader, Judith Cardell, John Chandley, Doug Foy, Hamish Fraser, Geoff Gaebe, Don Garber, Scott Harvey, Stephen Henderson, Carrie Hitt, Jere Jacobi, Paul Joskow, Maria Ilic, Laurence Kirsch, Jim Kritikson, Dale Landgren, William Lindsay, Amory Lovins, Rana Mukerji, Richard O'Neill, Howard Pifer, Susan Pope, Grant Read, Bill Reed, Joseph R. Ribeiro, Brendan Ring, Larry Ruff, Michael Schnitzer, Hoff Stauffer, Irwin Stelzer, Jan Strack, Steve Stoft, Richard Tabors, Julie Voeck, Carter Wall and Assef Zobian. The author is or has been a consultant on electric market reform and transmission issues for American National Power, British National Grid Company, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd, Duquesne Light Company, Electricity Corporation of New Zealand, National Independent Energy Producers, New England Power Company, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, PJM Office of Interconnection, San Diego Gas & Electric Corporation, Transpower of New Zealand, Westbrook Power, 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. (http://ksgwww.harvard.edu/people/whogan).