REGIONAL TRANSMISSION ORGANIZATIONS: DESIGNING MARKET INSTITUTIONS FOR ELECTRIC NETWORK SYSTEMS

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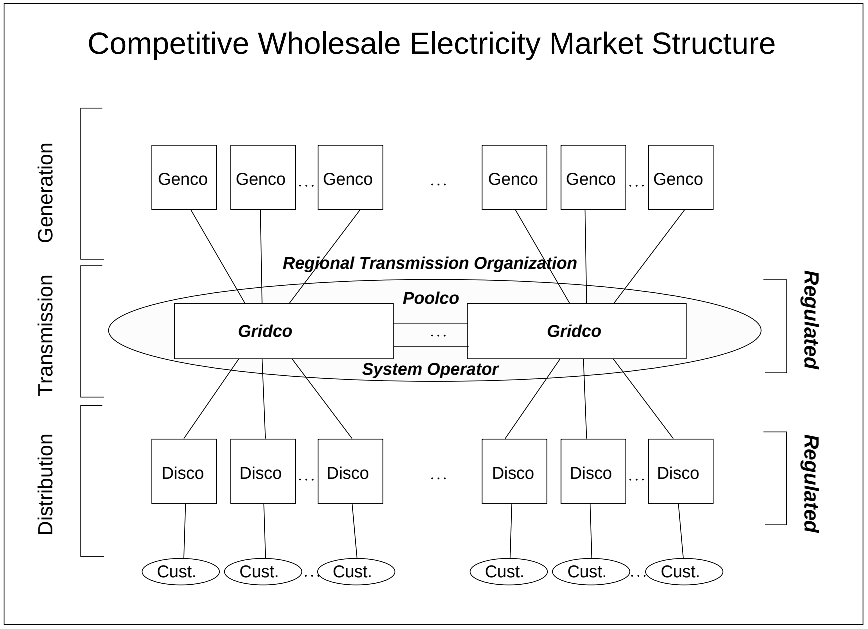
The usual separation into generation, transmission, and distribution is insufficient. In an electricity market, the transmission wires and the pool dispatch are distinct essential facilities.



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

Electricity restructuring requires open access to the transmission essential facility. A fully decentralized competitive market would benefit from tradable property rights in the transmission grid. However, the industry has never been able to define workable transmission property rights:

> "A primary purpose of the RIN is for users to learn what Available Transmission Capacity (ATC) may be available for their use. Because of effects of ongoing and changing transactions, changes in system conditions, loop flows, unforeseen outages, etc., ATC is not capable of precise determination or definition. "
>
> Comments of the Members of the PJM Interconnection, Request for Comments Regarding Real-Time Information Networks, Docket No. RM95-9-000, FERC, July 5, 1995, p. 8.

The difficulty is fundamental.

- **Contract-Path Fiction:** Electric power does not follow a simple "contract path" through the network. Power flows throughout the network, creating complex interactions that give rise to significant "network externalities" and the failure of property rights.

- **Physical versus Financial Approaches:** Physical property rights, to match with physical flows, have proven to be elusive. There is an alternative through a mixture of physical flows and financial contracts that can internalize the externalities and create the equivalent of property rights in the transmission system.

A workable definition of "Available Transmission Capacity" would be radically different from the notional physical right that is the implicit foundation of the present regulatory approach.

The role of loop flow and its effects in the system needed to support a competitive market are important matters. The problems are fundamental in the presence of customer choice and competition. The principal implications of the ubiquitous and important effects of loop flow include:

No Property Rights. There is no workable system of property rights governing use of the transmission grid that would support a fully decentralized electricity market.

No Definition of "Available Transmission Capacity." It is not possible to define available transmission capacity (ATC) for a transmission interface without knowing everything about the use of the network at the time.

No Separation of Transmission Pricing and Spot Market. The opportunity cost of transmission depends critically on the marginal costs of power at different locations, and these costs are determined simultaneously with the dispatch and the spot market.

No Escape from the Network Externalities. There is a fundamental externality in transmission use, and decentralized markets do not deal well with externalities.

Two broad approaches suggest themselves for dealing with the problem of the commons associated with network externalities in a manner compatible with a competitive generation market.

- **Monopoly Management with Incentive Pricing:** Treat transmission like a large "black box" run by a monopoly that takes on the obligation to provide unlimited transmission service for everyone. With the appropriate price cap or other incentive regulation, the monopoly would make efficient investments or contract with market participants to remove or manage the real transmission limitations. This approach is pursued in part in England and Wales. It results in a very powerful monopoly with the familiar problems of finding the "right" incentive regulation. It works in theory, but does it work in practice?

- **Market Mechanisms with Tradeable Transmission "Rights":** Create and allocate a set of transmission "rights" that would be used by market participants to match the actual flow of power or be traded in a secondary market. This is the approach that dominates thinking in the United States and stands behind the policy at the Federal Energy Regulatory Commission and proposals across the country. The central problem is in the impossibility of defining the available physical transmission capacity that would accompany future dispatch requirements. Can it work in both theory and practice?

A coordinated short-term electricity market provides the foundation for building a system that includes tradeable transmission "rights" in the form of transmission congestion contracts. Coordination through the system operator is unavoidable, and spot-market locational prices define the opportunity costs of transmission that would determine the market value of the transmission rights, without requiring physical trading and without restricting the actual use of the system.

The Federal Energy Regulatory Commission's (FERC) Regional Transmission Organizations [RTO] Final Rule in Order 2000 sets forward a framework for electricity restructuring in support of competitive markets. This RTO Rule recognizes the importance of a coordinated spot or balancing market, and builds on this core idea.

"...it is clear that RTOs are needed to resolve impediments to fully competitive markets."

(FERC, Docket No. RM99-2-000,Order No. 2000, December 20, 1999, p. 115.)

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

"...the 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,Order No. 2000, December 20, 1999, p. 152.)

The FERC RTO Final Rule sets forward a framework for electricity restructuring in support of competitive markets. The details matter, but there is a great deal of guidance.

In addition, there are eight 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;

(7) plan and coordinate necessary transmission additions and upgrades; [and]

(8) ... ensure the integration of reliability practices within an interconnection and market interface practices among regions."

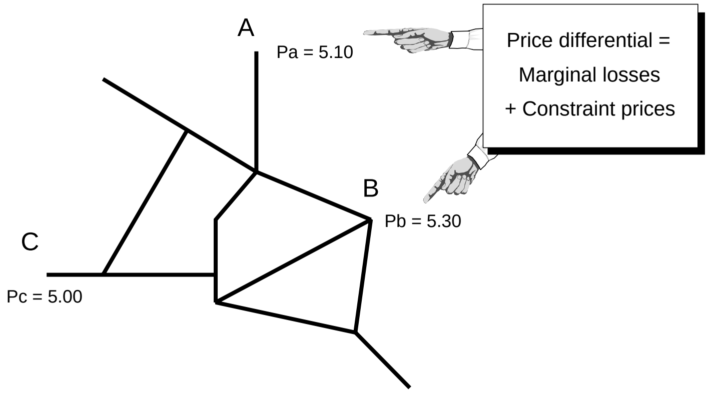
(FERC, Docket No. RM99-2-000,Order No. 2000, December 20, 1999, pp. 323-497.)

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

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 Final Rule addresses the three critical questions. The RTO 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. 635.) "...proposals should ensure that (1) the generators that are dispatched in the presence of transmission constraints must be those that can serve system loads at least cost, and (2) limited transmission capacity should be used by market participants that value that use most highly." (pp. 332-333.)

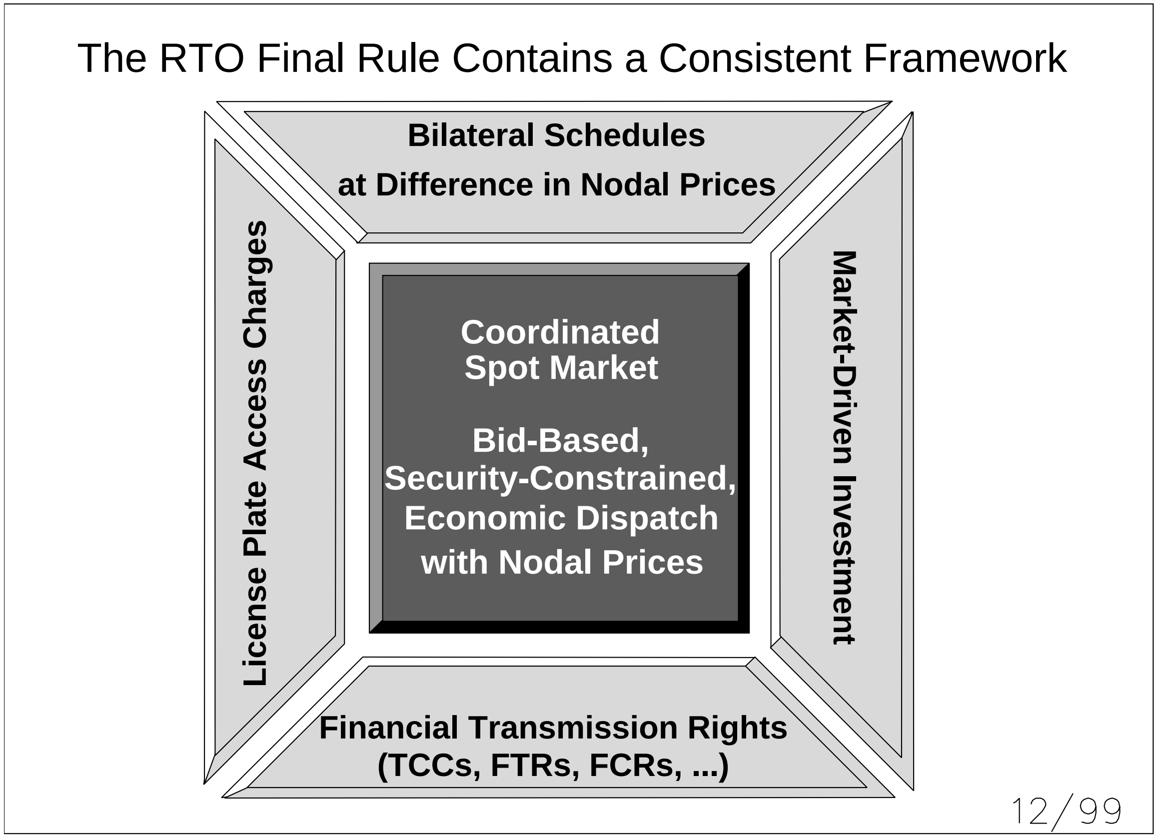
Should the system operator apply marginal cost prices for power provided through the dispatch?

Yes. "...we will require the RTO to implement a market mechanism that provides all transmission customers with efficient price signals regarding the consequences of their transmission use decisions." (p. 382.)

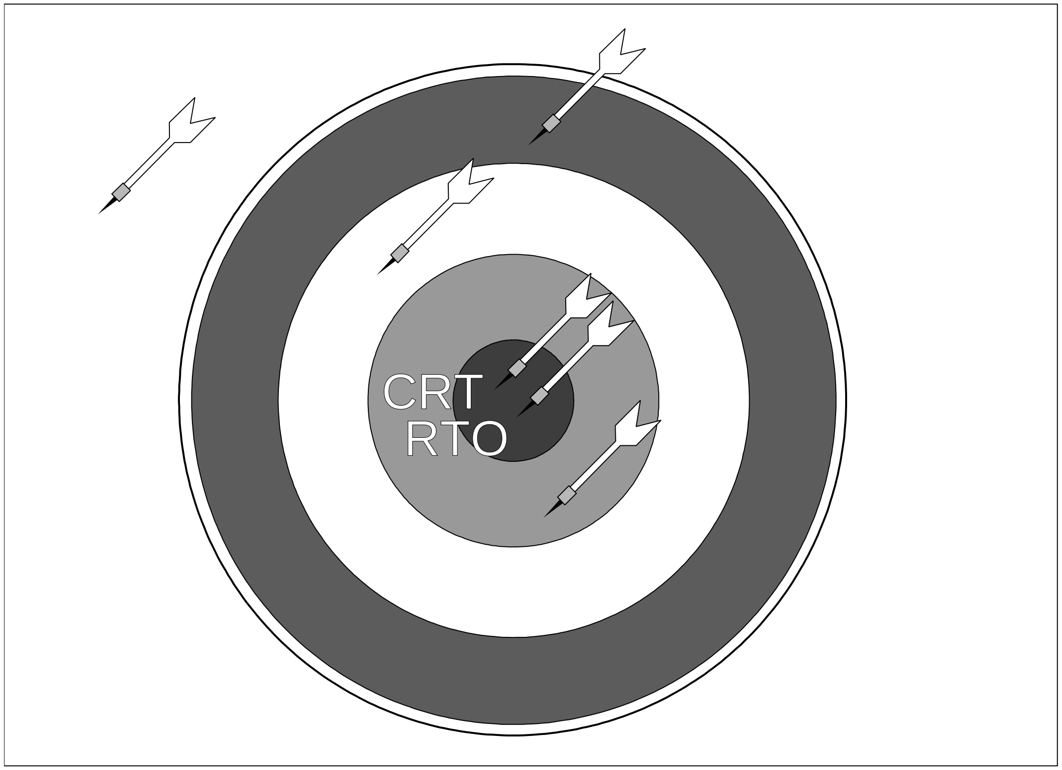
Should generators and customers be allowed to participate in the economic dispatch offered by the system operator?

Yes "The Regional Transmission Organization must ensure that its transmission customers have access to a real-time balancing market. The Regional Transmission Organization must either develop and operate this market itself or ensure that this task is performed by another entity that is not affiliated with any market participant" (p. 715.)

The RTO-Rule and earlier Capacity Reservation Tariff [CRT] contain a workable market framework that is working in places like the Pennsylvania-New Jersey-Maryland Interconnection (PJM).



The FERC 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.

The RTO Final Rule summarizes many lessons learned through the developing experience in electricity restructuring. (RTO Rule, pp. 632-643]

" **9. Market Design Lessons**

We expect that bid-based markets will be a central feature in many RTO proposals. To date, the Commission has analyzed and approved, with various modifications, bid-based market designs for four ISOs. The purpose of this section is to summarize the lessons learned from these real-world market experiments.

a. Multiple Product Markets: ... if more than one product is being sold in the same temporal market, efficiency is maximized when arbitrage opportunities reflected in the bids are exhausted (i.e., after the RTO's markets have cleared, no technically qualified market participant would have preferred to be in another of the RTO's markets). In addition, efficient bid-based markets elicit prices that are consistent with technical and cost requirements. ...

b. Physical Feasibility: Proper design of the market clearing procedures ensures that prices balance the supply and demand for energy, and all transactions, in the aggregate, are physically feasible with appropriate levels of reserves. ...

The RTO Final Rule summarizes many lessons learned through the developing experience in electricity restructuring. (RTO Rule, pp. 632-643]

c. **Access to Real-Time Balancing Market**: Making a real-time balancing market available to all grid users ensures that all users are treated equally for purposes of settling their individual imbalances. ...

d. **Market Participation:** Markets are most efficient when generators and loads, whether internal or external to the RTO, are allowed full and flexible participation in the markets. While generators and loads have the option to choose between participating in any RTO-facilitated markets or other markets, the RTO must have generation and ancillary service quantity information, and any necessary technical information, from self-schedulers in order to balance the system and ensure reliability. This allows bilateral and forward financial markets and independent PX markets to co-exist and complement RTO physical markets. Participants that self-schedule would be expected to pay for the costs that they impose on the physical system at market prices and be paid for the benefits that they supply to the physical system at market prices. ...

The RTO Final Rule summarizes many lessons learned through the developing experience in electricity restructuring. (RTO Rule, pp. 632-643]

e. **Demand-Side Bidding**: Demand-side bidding is desirable to the extent it is technically feasible, because without it, demand response decreases and market power is easier to exercise. The availability of price responsive demand also reduces price volatility in the markets.

f. **Bidding Rules**: A market that provides the flexibility for all generators to bid a reasonable approximation of the costs they incur including start-up, minimum load, energy, and ramping costs will be efficient. ...

g. **Transaction Costs and Risk**: Transaction costs associated with participation in well functioning RTO markets should be low, and market participation should involve no unnecessary risks. ...

h. **Price Recalculations**: In circumstances where time does not permit all changes in dispatch to be communicated and effected through manual processes in a timely manner, the market clearing price resulting from the computer algorithm must be adjusted to reflect the actual dispatch in the hour. ...

The RTO Final Rule summarizes many lessons learned through the developing experience in electricity restructuring. (RTO Rule, pp. 632-643]

i. **Multi-Settlement Markets**: Multi-settlement markets may involve a day-ahead and real-time market. For real-time markets, prices are determined by real-time dispatch quantities, and deviations from day-ahead schedules are priced at the real-time price. When day-ahead schedules are financially binding, they are financial commitments subject to payments for deviations at the real-time price. If market participants adhere to day-ahead schedules, they need not participate in the real-time markets. If needed for reliability, bids need to be physically binding and may be subject to Commission-approved penalties for failure to adhere to the bid. Without financially binding commitments in the day-ahead market, the riskiness of market participation increases since the day-ahead bids could be changed before real-time dispatch. ...

j. **Preventing Abusive Market Power**: An efficient market design does not favor market participants that have the potential to exercise market power and minimizes the incentives for market participants to engage in abuse of market power. For example, since large players are more likely to cause market power problems, a market design that favors large players (e.g., portfolio bidding) may create an incentive for consolidation and resulting market power problems. ...

The RTO Final Rule summarizes many lessons learned through the developing experience in electricity restructuring. (RTO Rule, pp. 632-643]

k. **Market Information and Market Monitoring**: One property of an efficient market has market clearing prices and quantities being made available immediately. This information enables market participants and potential future market participants to assess the market and plan their businesses efficiently. It will also allow market participants to spot errors in the market clearing process and get them corrected. ...

l. **Prices and Cost Averaging**: Market designs that base prices on the averaging or socialization of costs, may distort consumption, production, and investment decisions and ultimately lead to economically inefficient outcomes. Where possible and cost effective, cost causality principles can be used to price services and eliminate averaging. Moreover, if pass-throughs or uplift charges are paid by all load to ensure bid-cost recovery, as in some approved ISO market designs, it may be appropriate to couple these pricing mechanisms with incentive mechanisms for the RTO to control them. "

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.)

The RTO Final Rule sets for a timetable for voluntary formation of RTOs. If there are not enough volunteers, then ... ?

> "...all public utilities (with the exception of those participating in an approved regional transmission entity that conforms to the Commission's ISO principles) that own, operate or control interstate transmission facilities must file with the Commission by October 15, 2000, a proposal for an RTO with the minimum characteristics and functions to be operational by December 15, 2001, or, alternatively, a description of efforts to participate in an RTO, any existing obstacles to RTO participation, and any plans to work toward RTO participation."

(FERC, Docket No. RM99-2-000,Order No. 2000, December 20, 1999, p. 7.)

> " The goal of this rulemaking is to form RTOs voluntarily and in a timely manner. The alternative to a voluntary process is likely to be a lengthy process that is more likely to result in greater standardization of the Commission's RTO requirements among regions. Although the Commission has specific authorities and responsibilities under the FPA to protect against undue discrimination and remove impediments to wholesale competition, we find it appropriate in this instance to adopt an open collaborative process that relies on voluntary regional participation to design RTOs that can be tailored to specific needs of each region.""

(FERC, Docket No. RM99-2-000,Order No. 2000, December 20, 1999, p. 8.)

Appendix

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.

Zones and Nodes

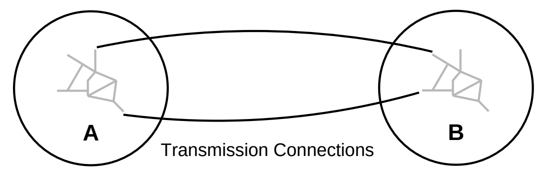
Within ISO models, the use of zones versus nodal pricing is an issue. If the world divided naturally into zones, life would be simpler. However, aggregation of a real world with true locational differences into a fictional world with zones would not be simple. For competition to be flexible and work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

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- *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.)

Every electricity market must confront the problem of congestion management and the tradeoff between monopoly control and market mechanisms.

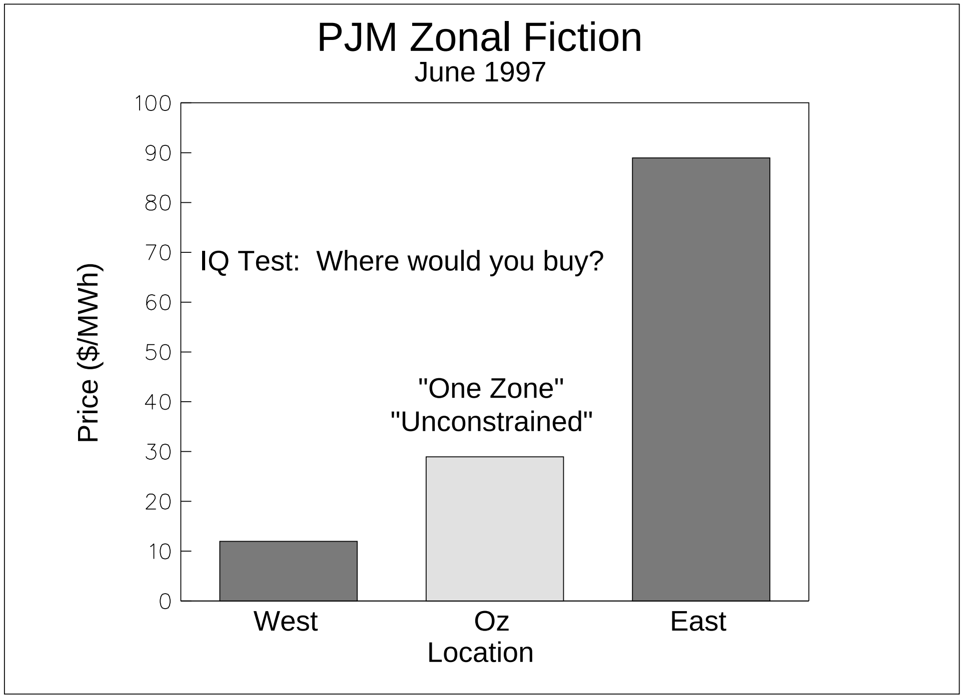
> *Reliance on markets creates an important connection between prices and operating decisions. Market participants want flexibility and choice, but object to consistent pricing as too complex. This is a mistake, and produces only an illusion of simplicity. If customers have flexibility in the choice of generation, spot purchases, bilateral transactions, and so on--then prices matter and competitive prices should reflect marginal costs. In large part, control of operating decisions is moving from engineers motivated by principles of technical efficiency, to market participants motivated by prices and profits. This is a major purpose of electricity restructuring--to change the locus of such key decisions. If we want the market to be guided by prices, and we expect and intend for people to take these prices seriously, it becomes important to follow the usual advice to "get the prices right."*

The experience elsewhere is that this issue matters, and many problems in developing markets can be traced to congestion management systems that were incompatible with market flexibility.

- PJM and reliability.
- ISONE and new generation.
- CAISO and new generation.
- Australia and firm access rights.
- TLR everywhere.

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.

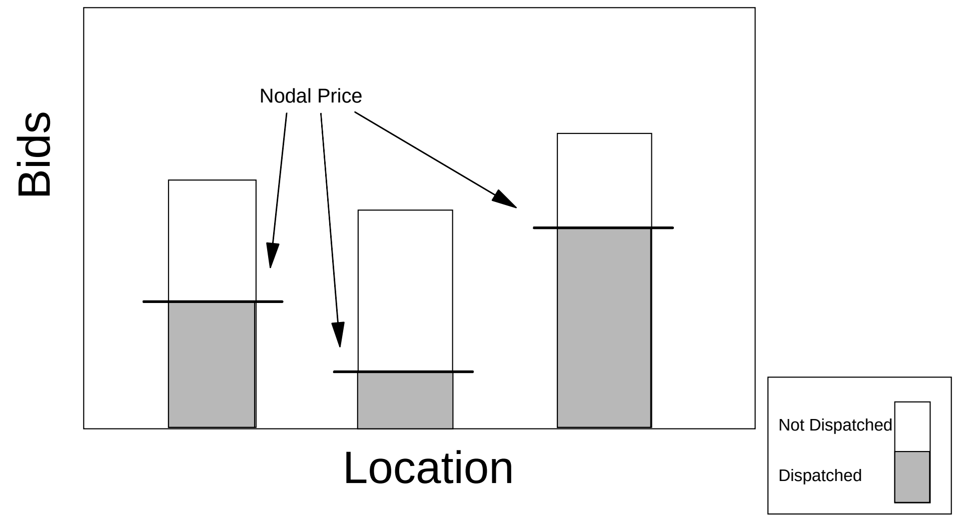


Nodal prices provide incentives that conform to the competitive market and the principles of economic dispatch. Nodal prices are self-policing and self-auditing.

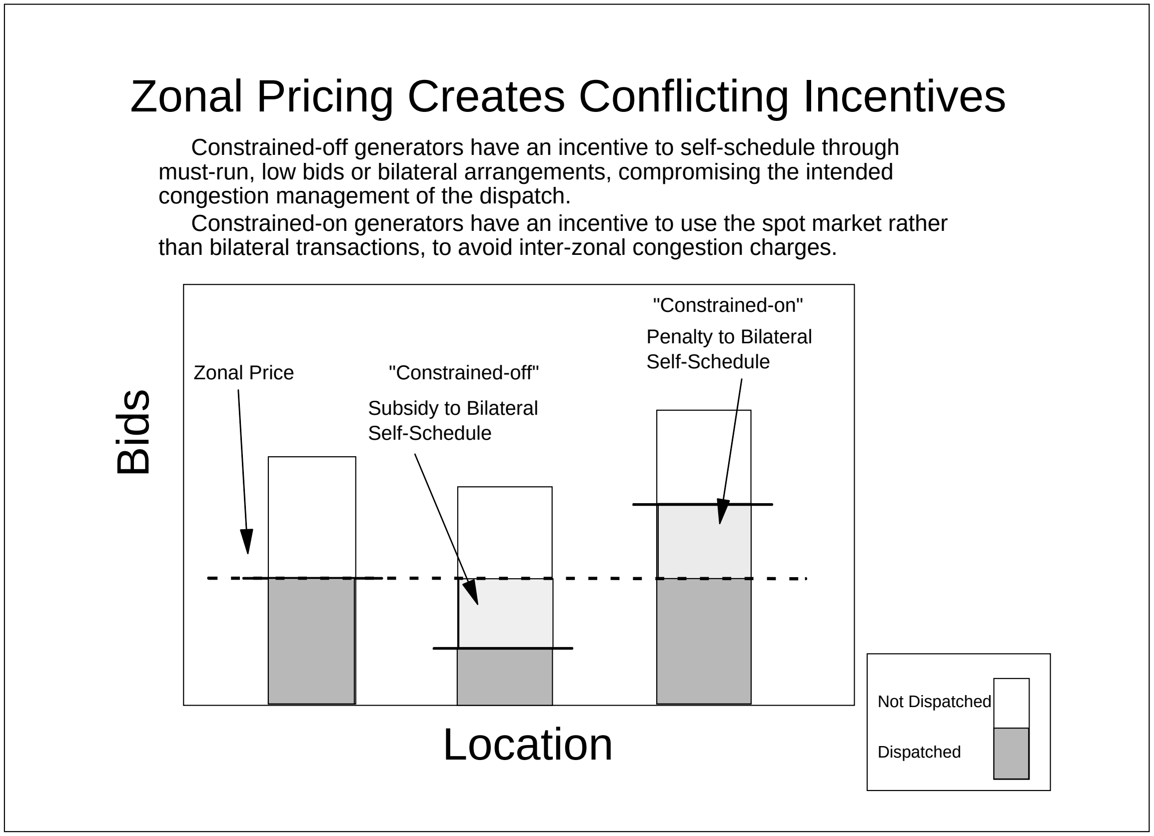
Nodal Pricing Is "Self-Policing"

"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."

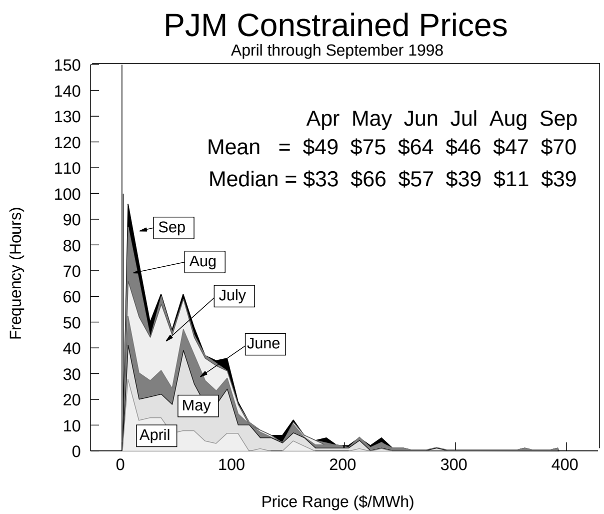
(NERA)



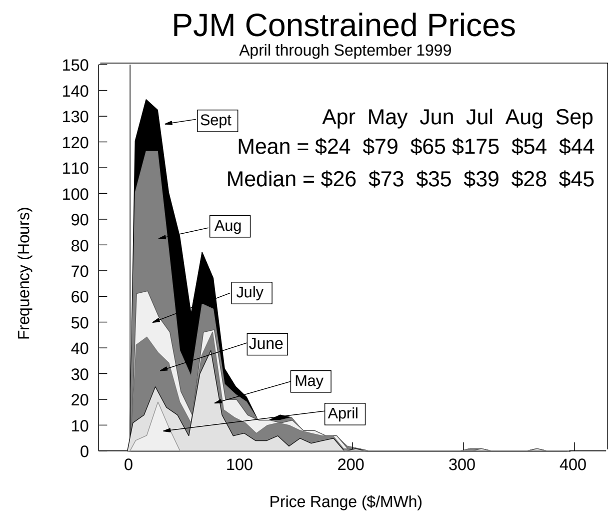
Zonal prices create incentives to deviate from the reliable dispatch. Zonal pricing requires rules to prevent certain behavior or eliminate the market profits. Real zonal systems soon become complicated.



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.

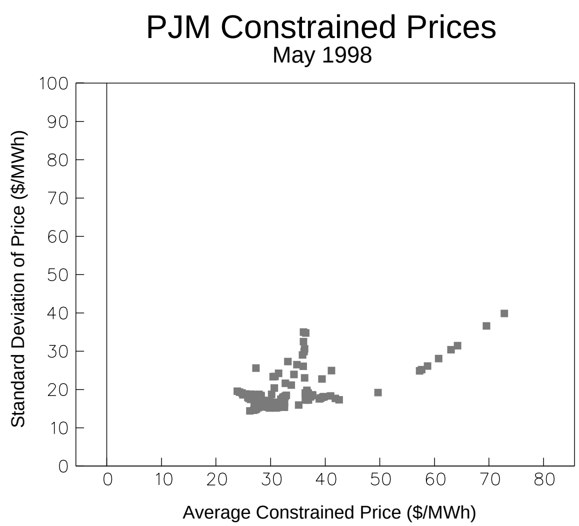


Maximum difference in locational prices for constrained hours.

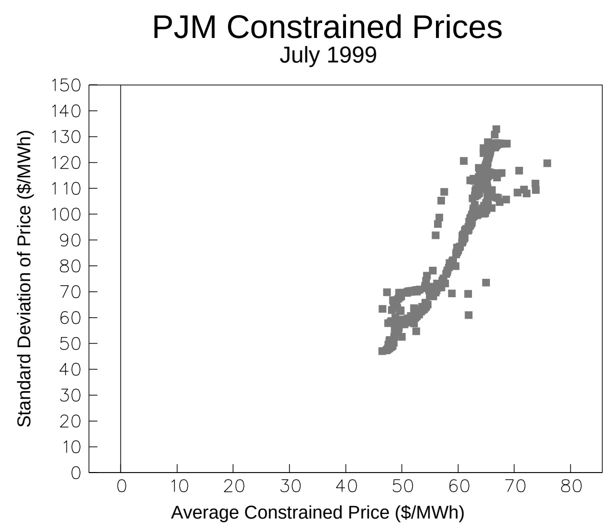


Maximum difference in locational prices for constrained hours.
Excludes 3, 19, and 6 hours off scale in April, July, and Sept, respectively.

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 PJM rejected that hypothesis. Using a threshold of an average congestion difference of $1 MWh over a month, there were at least hundreds of zones required to capture the price differences in PJM. The zonal approach is neither accurate nor simple.



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



Mean and standard deviation over 126 constrained hours at different locations.
Excludes 9 observations out to double the scale.

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:

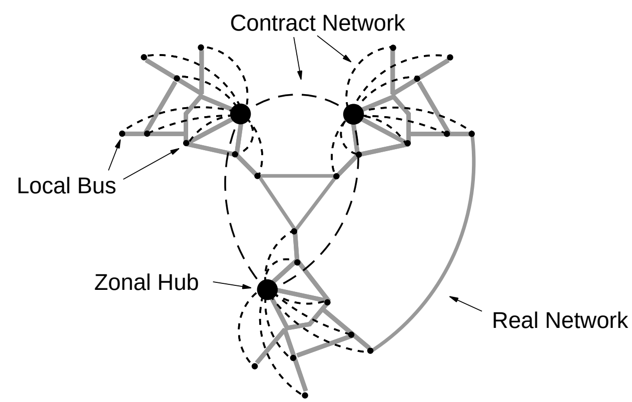
Required Zones in PJM							
	Apr	May	Jun	Jul	Aug	Sept	Oct-Mar
1998-1999	94	83	75	57	52	64	61
1999-2000	22	63	60	210	96	62	

Moreover, the nodes making up these zones would change from month to month and were not necessarily contiguous. To have stable zones over an extended period would require at least hundreds of separate zones. This provides no simplification, as has been recognized in PJM. Using the prices for the actual nodes is the simple solution that allows for choice, reinforces market incentives, and provides the opportunity for many other innovations such as financial transmission rights auctioned for the full capacity of the system.

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.

Contract Network Connects with Real Network

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

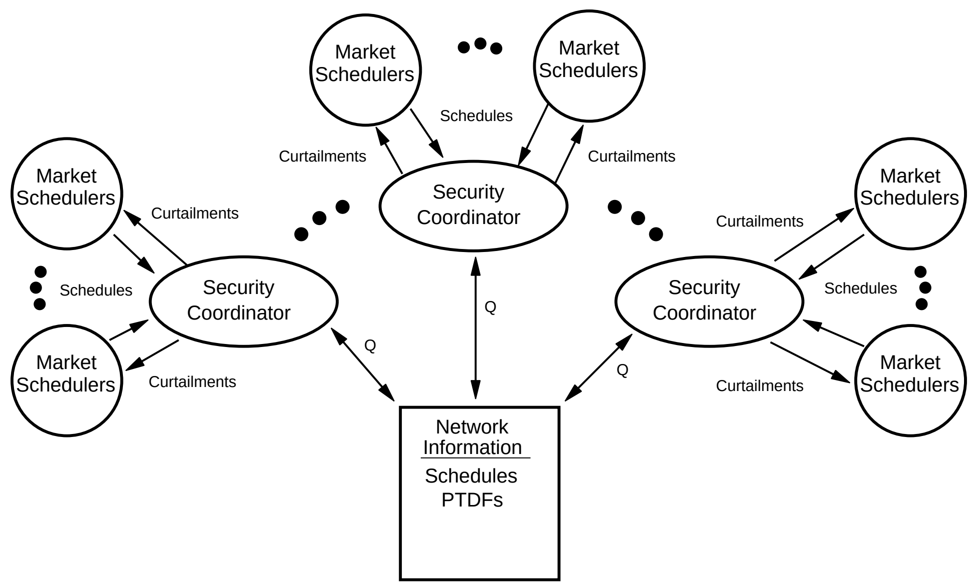


Locational marginal cost pricing lends itself to a natural decomposition. For example, even with loops in a network, market information could be transformed easily into a hub-and-spoke framework with locational price differences on a spoke defining the cost of moving to and from the local hub, and then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

To relieve transmission overloads, the existing NERC system exchanges quantity information about scheduled loads to determine the impact on the grid. Administrative rules and priorities determine schedule curtailments.

NERC ADMINISTRATIVE TRANSMISSION LOADING RELIEF



Movement to greater use of market forces would require an alternative to the NERC transmission loading relief procedures.

- **Prices.** The use of markets implies pricing and the associated incentives. Participants must have economic information and face real prices to induce market support of transmission loading relief.

- **Schedules, Bids and Economic (Re)Dispatch.** The ISO framework of schedules supplemented by incremental and decremental bids provides the opportunity to use security constrained economic dispatch to redispatch schedules and respect security limits to achieve efficient transmission loading relief.

- **Iteration.** Regional system operators or security coordinators could exchange information about both schedules and prices in an iterative process to establish a mutually consistent redispatch for transmission loading relief.

- **Settlements.** A system-wide settlements system could handle payments between and among the regional system operators.

- **Integration of Markets and Reliability.** The supposed dichotomy between markets and reliability is false. And the implied separation between reliability (ISOs) and short-term markets (Power Exchanges) is counterproductive. At best, the false separation is expensive. At worst, it is dangerous. Both markets and reliability can be improved if the essential interactions are recognized and integrated.

A market oriented system would require information on scheduled loads, bids and prices to determine an economic redispatch of the system.

The basic outline involves a communication between system operators and market participants to obtain market information, and among system operators to achieve coordinated congestion relief:

1. Market Participants Submit Schedules and Bids for Dispatch Hour.

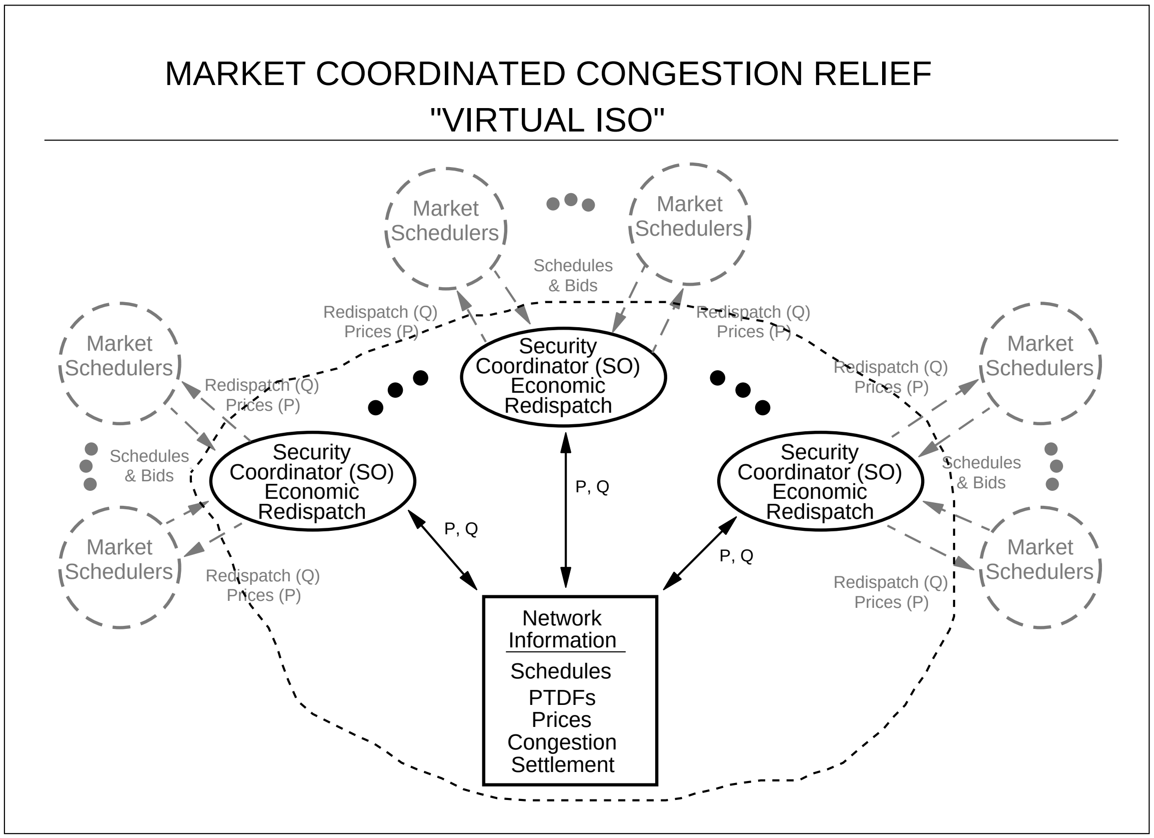
2. System Operators Interact to Achieve Coordinated Congestion Relief.

3. System Operators Publish (Re)Dispatch and Prices.

Further details of the redispatch protocol can be found in:

Michael Cadwalader, Scott Harvey, William Hogan, and Susan Pope, "Coordination of Congestion Relief Across Multiple Regions," Center for Business and Government, Harvard University, October 7, 1999.

Through repeated exchange of information in a common data base, the regional system operators would 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."



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 in Navigant Consulting, Inc. 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 American National Power, British National Grid Company, Calpine Corporation, Commonwealth Edison Company, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd, Duquesne Light Company, Electricity Corporation of New Zealand, Independent System Operator New England, 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, Sempra Energy, TransÉnergie, 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).