

# **ENABLING THE POWER OF MARKETS**

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**The residual monopolies of the electric industry should have two complementary mandates. These would make for good public policy and good business strategy.**

- **Create a level playing field.**

If the playing field is tilted, it is more likely to be tilted in favor of the new entrants. The details matter and the issues can appear complex. The remaining regulated monopolies should have a strong self-interest in clarifying the choices and supporting a fully restructured, non-discriminatory electricity market.

- **Create an efficient market.**

Poor market designs will lead to higher overall costs. In the end, competitive forces will leave the residual monopolies as the home for these higher costs. The pressures of customer choice and new technology will create new stranded costs.

**These outcomes cannot be assumed or assured. The leaders of the remaining regulated companies are in a position to make a difference with the regulators and the rest of the industry.**

The developing experience with electricity market design highlights a few common sense rules that have been commonly violated.

- **Support competition not competitors.**

Emergence of many new and profitable competitors could be evidence of a successful market restructuring. But evidence of many new competitors is not necessary. And it may be evidence of failure rather than success. With enough subsidies, it would be an easy matter to create competitors. Look out for high energy credits or restrictions on efficient system operations.

- **Keep market design consistent with the real choices.**

When market participants have choices, it will be essential that the choices relate to the reality. The very foundation of restructuring is, after all, the belief that market participants will respond to incentives. If pricing and operating choices are not consistent, as we have seen the system operator and the regulators will have to intervene. Costs will be socialized and the market will be the casualty.

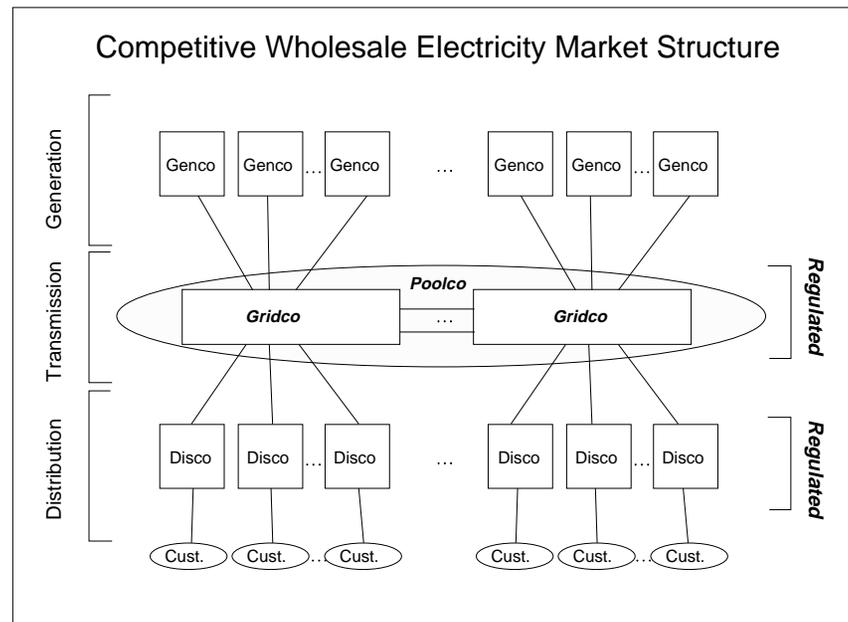
- **Lean towards market solutions.**

When looking for solutions, lean in the direction of market-based approaches. Correct market failures and limit the monopoly activities to the few essential areas dealing with essential facilities. The burden of proof for intervention should rest with the monopoly. When the burden is met, make the result efficient and consistent with the rest of the market.

# ELECTRICITY MARKET

# Competitive Structure

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 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.

**There is a continuing debate about the best model for organizing coordination and control of the transmission system.**

- **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.
- **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 transmission companies that match the regional requirements of system operations. This is easy in New Zealand (Transpower) but more difficult in the United States, Japan, or Europe with their 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.

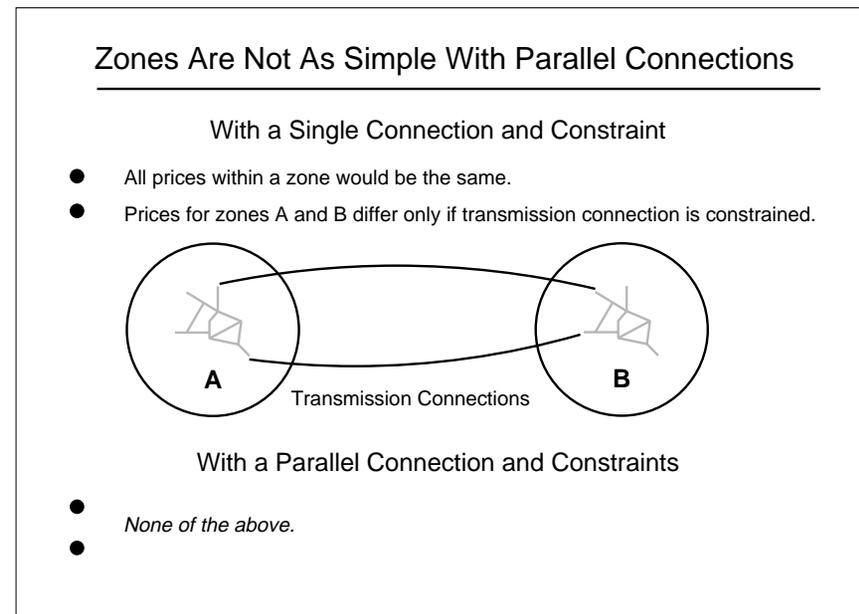
- **Power Exchange.** If there is a separate entity called a Power Exchange, it does not have responsibility for coordinating the spot market and transmission usage. The PX may handle bidding and settlements, (EMCO, Nord Pool) but the dispatch activity falls to the ISO. In many cases, there is no separate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

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. A number of questions arise in making the choice between aggregation into zones or using the actual locational prices.

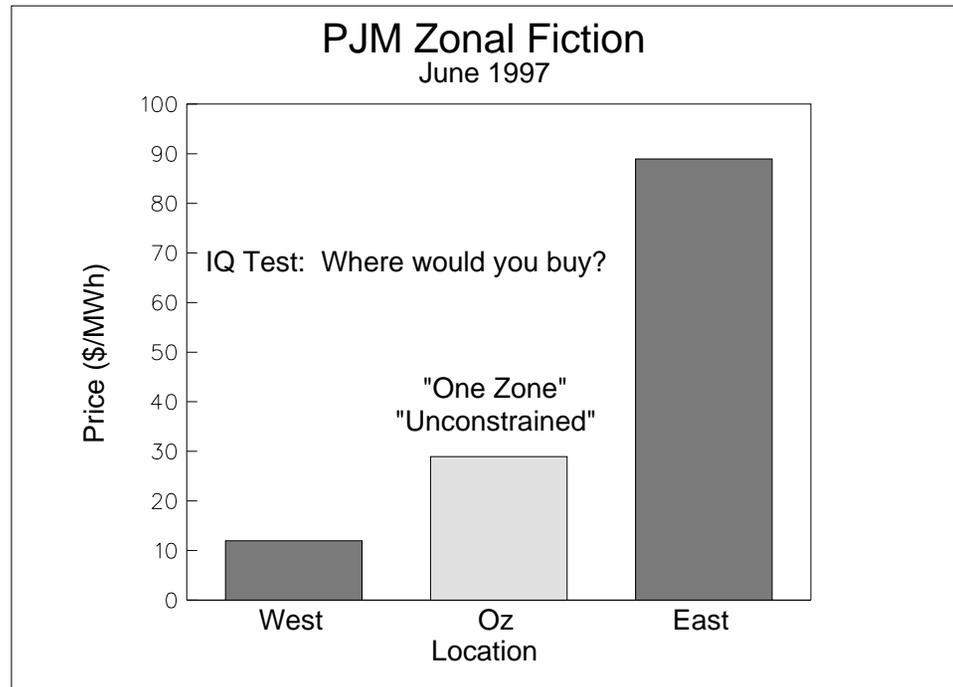
- **If Zones are Defined by Nodes with Common Prices, Why Bother? (Don't.)**
- **How Would We Define the Zonal Prices? (?)**
- **Would Locational Prices Be Hard to Calculate and Come from a Black Box? (No.)**
- **Would It Be an Easy Matter to Set and Later Change the Zonal Boundaries? (No.)**
- **Is Transmission Congestion a Small Problem? (No.)**
- **Would Zonal Pricing Mitigate Market Power? (No.)**
- **Can the Market Operate With a Simpler System? (Yes. Locational Pricing with Hub and Spokes.)**



## TRANSMISSION ACCESS AND PRICING Getting the Prices Wrong in PJM

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.



**The PJM order includes a number of important elements that support both open access and competition in the electricity generation market.**

- Open access with non-discriminatory pricing.
- Transmission fixed cost recovery through system-wide (but not necessarily uniform) access charges.
- The ISO administers both a spot market and bilateral schedules, while maintaining reliability under principles of bid-based, economic, security-constrained dispatch.
- Transmission congestion charges determined by locational prices from the bid-based spot market.
- Fixed transmission rights (i.e., transmission congestion contracts) for congestion costs between locations.
- Future developments to include multi-settlement systems, other bidding protocols and transmission right trading.

**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.

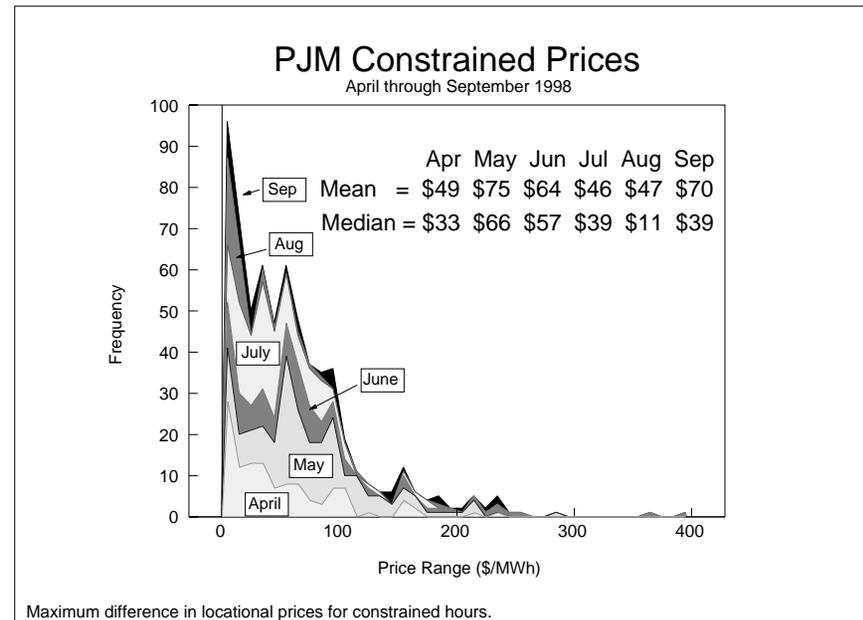
**"A theory should be as simple as possible -- and no simpler." (Einstein)**

# TRANSMISSION ACCESS AND PRICING      Getting the Prices Right in PJM

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

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



The "simple" solutions that avoid nodal pricing soon create problems that are more complex and lead to more regulation and less reliance on the market.

### **New England and Barriers to Entry.**

- The simple zonal system assumed no transmission congestion and could not accommodate entry without substantial transmission upgrades. This would impose substantial costs and long delays.
- In November 1998, the Federal regulators struck down these barriers to entry.
- NEPOOL is now struggling to put a locational pricing system in place. The existing system combines the worst features of the failed experience in PJM (a single zone) with the problematic separation of ancillary service markets as in California.
- Subsequent drop in value of existing generation cited in litigation over major asset sale (FPL from CMP).

The "simple" solutions that avoid nodal pricing lead to inefficient operations and poor signals for system expansion.

## California and Loss of Economic Dispatch.

- Congestion pricing applied to a number of zones, but the rules are ad hoc and opaque.
- Markets are segmented and treated separately, resulting in \$10,000/MWh standby reserves.
- The ISO is not allowed to seek a least cost dispatch. Furthermore, there is an increasing reliance on Reliability Must Run (RMR) contracts for plants that relieve the intra-zonal congestion that is not reflected in pricing.
- New rules propose entry restrictions on generators, in just the form already rejected for New England.

The "simple" solutions that avoid nodal pricing soon create problems that may make it difficult to define transmission rights or hedges.

## **Australian Pursuit of "Firm" Rights Between and Within Regions.**

- The existing NEMMCO pricing system is a mixture of zonal and nodal differentiation. Loss prices differ by node, but congestion is treated on a zonal basis, with large zones such as Victoria and New South Wales.
- The lack of nodal congestion pricing makes it impossible to define inter-regional hedges or transmission rights for the full capacity of the inter-regional connections. The true capacity depends on the pattern of usage, reflecting the same facts that give rise to different nodal congestion costs.
- Within regions, generators cannot be guaranteed to run and receive the regional price, even though it would appear profitable. Generators who do not run are not paid, and they do not have firm rights which would be naturally available in a nodal pricing system.
- It is difficult to define the benefits that would accrue from transmission expansion.

The “simple” solutions that avoid nodal pricing soon create problems that are more complex and lead to reforms that promise to increase costs.

### England and Wales and the Pool Reforms.

- Proposed reforms may reduce the National Grid Company's ability to manage congestion “efficiently.”
- Provides no markets or rights that might help manage congestion.
- Paying expensive generators to run and cheaper generators not to run, which creates bad incentives and need for countervailing rules to limit new entry.
- Paying loads to increase or decrease?

**In summary: Create a level playing field. Create an efficient market. Support competition not competitors. Keep market design consistent with the real choices. Lean towards market solutions. Work with regulators to fashion the details.**

**The key elements of the wholesale market design include:**

- A short-term spot market with bid-based security-constrained economic dispatch coordinated by the system operator.
- Spot-market transactions at market clearing locational prices to include marginal losses and congestion.
- Bilateral transactions with short-term transmission usage charges equal to the difference in the locational prices at source and destination.
- A two settlement system using day-ahead bidding, pricing and contracts, with real-time balancing at the real-time market prices.
- Transmission congestion contracts to allocate the benefits of transmission rights.
- Network access charges to cover the embedded costs of the grid and other fixed charges.
- Usage charges for loads to recover other unbundled ancillary service costs.

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, and Senior Advisor, Putnam, Hayes & Bartlett, Inc. 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, Brendon 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 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 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>).