COORDINATION FOR COMPETITION: ELECTRICITY MARKET DESIGN PRINCIPLES

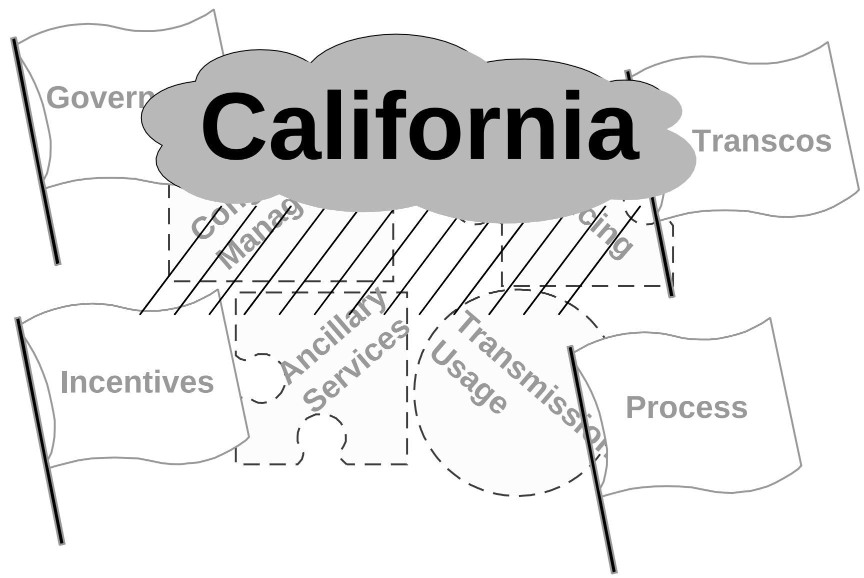
WILLIAM W. HOGAN
Center for Business and Government
John F. Kennedy School of Government
Harvard University
Cambridge, Massachusetts 02138 USA

Public Utility Commission of Texas Workshop on ERCOT Protocols
Austin, Texas

February 15, 2001

Hanging over all market reform is the cloud of the crisis in California. The problems are occupying a great deal of time. The precedents will affect speed and the content of restructuring everywhere.

The Cloud on Everyone's Horizon



ERCOT is not California. There are differences in market conditions and restructuring policy.

Market Conditions: ERCOT is reported to have both adequate generation capacity and sufficient transmission resources.

Retail Access: Unlike California, the ERCOT rules for retail access and market competition do not prohibit long-term contracts to hedge retail rates. Furthermore, retail rates in ERCOT can adjust to changes in fuel costs or other market conditions.

> **These facts alone distinguish ERCOT from California, where the restrictions on hedging and fixed rates confronted shortage conditions and created a financial crisis.**

Wholesale Market Design: The ERCOT protocols reflect a wholesale market design approach that has much in common with California. Even before the current policy meltdown in California, these market design flaws were the subject of intense review and much needed reform. These flaws may not be fatal, but ERCOT should avoid repeating the mistakes.

There is an underlying premise in the ERCOT protocols that the functions of the ISO can be largely separated from the operation of a wholesale spot market. This is a mistake.[1]

A False Goal

Minimize the role of the ISO: In an attempt to have a small footprint for the ISO, there is a common argument that the ISO functions should be restricted to reliability and separated from the operation of the spot market. In practice, the lack of an efficient spot market and efficient pricing drives the ISO to intervene ever more, but without the tools of the market. The ISO ends up large and intrusive, and the market works badly or not at all.

Better to

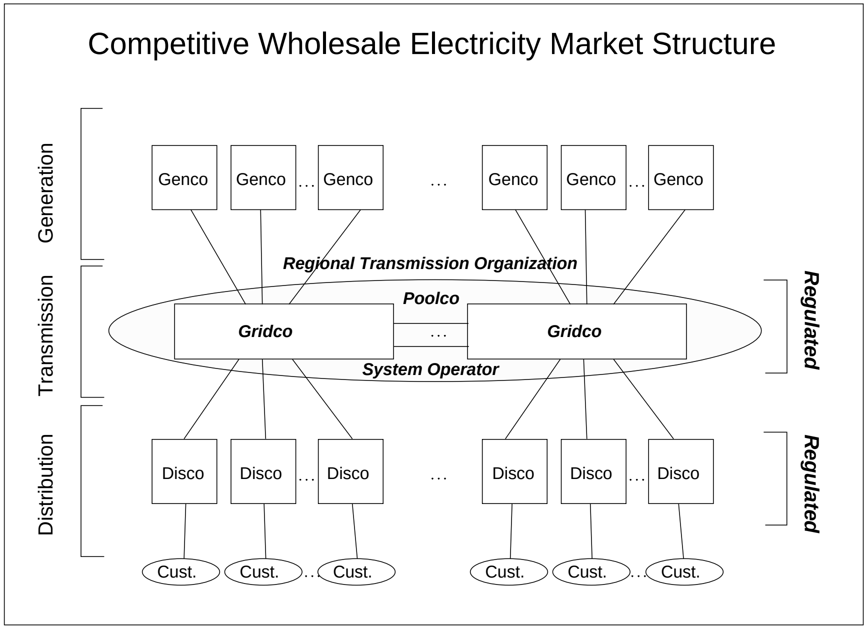
Recognize the minimum requirements of an ISO: There are certain functions that only the ISO can perform, and these should be done both efficiently and to support a competitive market. Done right, the result is healthy bilateral trading, liquidity, and ease of entry.

It is not good public policy to intentionally design the ISO functions to be inefficient. If we do so, we will succeed, and the ISO will not be able to provide the services that the market needs to handle the complexity of the electricity system. A well designed ISO, operating a spot market, providing price signals, and supporting transmission hedges, results in the smallest footprint possible.

---

1 W. Hogan, "A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy," The Electricity Journal, December 1995, pp. 26-37.

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.

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.

Just say yes. The basic lessons from both theory and practice identify the importance of the coordinated wholesale spot market and efficient pricing to handle the complexities of the electricity system.

- **Choose Efficient Coordination:** The choice is not between centralized and decentralized spot markets. The choice is between good and bad coordination.

- **Use the Least-Cost Approach:** Economic (re)dispatch for energy and ancillary services is the solution, not the problem.

- **Get the Prices Right**: Market participants will respond to the price incentives, for good or for ill. That, after all, is a fundamental premise of electricity market restructuring.

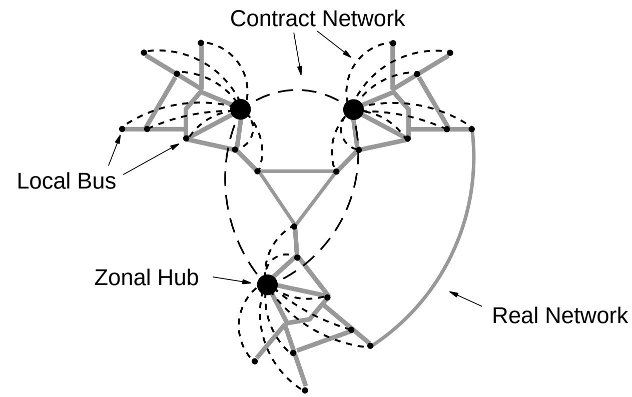
- **Offer Financial Transmission Rights:** Provide hedging for transmission congestion using financial rights. It is simple for the ISO to support, but virtually impossible for anyone else.

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.

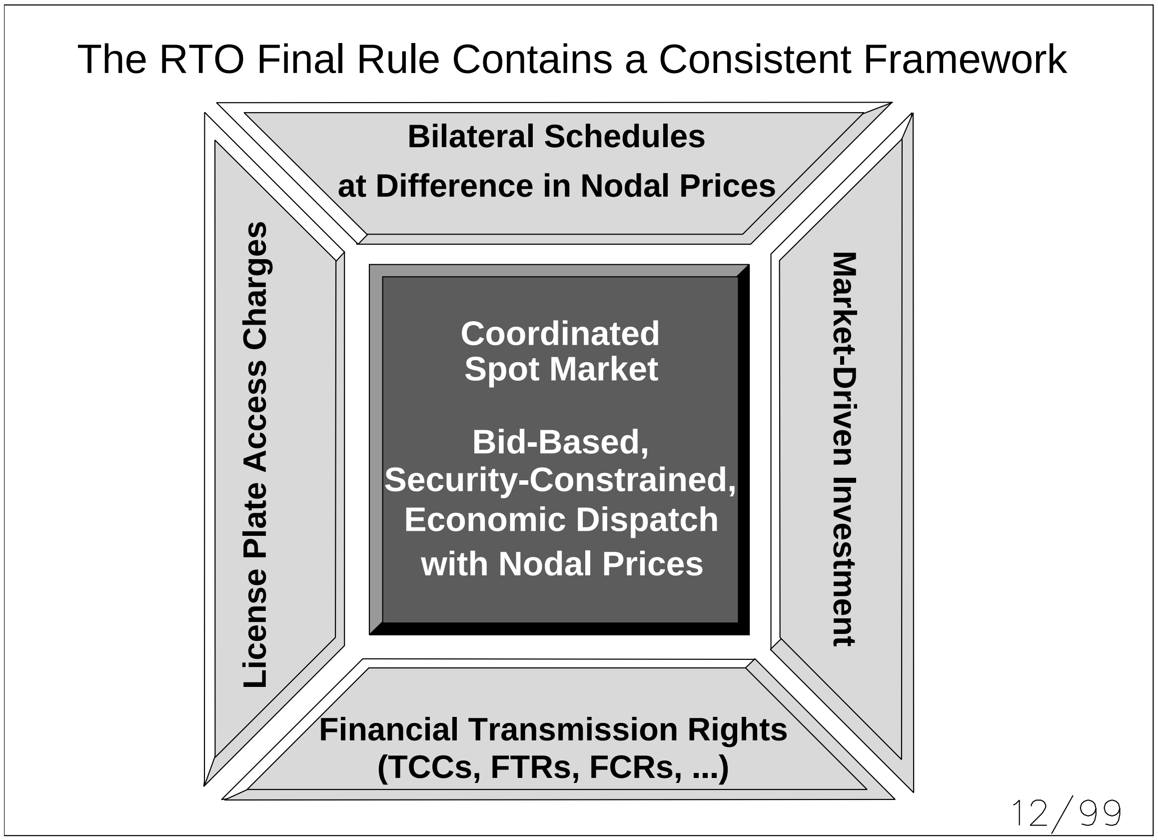
Contract Network Connects with Real Network

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



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.

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 core feature of a bid-based, security constrained economic dispatch with locational prices can be found in many existing or announced market designs.

- Argentina.
- Bolivia.
- Chile.
- Mexico (proposed).
- New England (proposed).
- New York.
- New Zealand.
- Norway (dynamic zones).
- PJM.
- Peru.
- and more .... .

The breadth of application and success of the framework dispel the notion that the model is too complex to be implemented. We now have both the theory and substantial operating experience.

Electricity systems are not simple. The reality of electricity systems creates an interest in simplifying market design to provide better support for commercial transactions. The benefits of simplification are clear, other things being equal. However, other things are usually not equal, and the law of unintended consequences often dictates that what appears simple may turn out to be complex in the end. What may appear complex can be simple in the end if it is consistent with the reality of the electric system and does not require substantial non-market interventions to make the market work.

- **Congestion Zones**. Full locational pricing at every node in the network is a natural consequence of the basic economics of a competitive electricity market. However, it has been common around the world to assert, usually without apparent need for much further justification, that nodal pricing would be too complicated and aggregation into single price zones, with socialization of the attendant costs, would be simpler and solve all manner of problems.

- **Flowgates and Decentralized Congestion Management.** If a single contract path is not good enough, perhaps many paths would be better. Since power flows along many parallel paths, there is a natural inclination to develop an approach to transmission services that would identify the key links or "flowgates" over which the power may actually flow, and to define transmission rights according to the capacities at these flowgates.

The debate over alternative electricity market institutions often confuses two design issues that could, in principle, be treated separately. The distinction is between what is appropriate as a basis for the design of an RTO, and what would be appropriate as the design of a stand alone business offering a service within the framework of an RTO.

Aggregation of many locations into a few congestion zones creates problems when market participants have choices. In general, zonal pricing is not consistent with market opportunity costs. The costs of transmission congestion can be very high, and failure to internalize these costs can disrupt the energy market. This is not a mere technical detail. From the perspective of designing market institutions, response to prices is the most important phenomenon.

> **Fact:** A single transmission constraint in an electric network can produce different prices at every node. Simply put, the different nodal prices arise because every location has a different effect on the constraint. This feature of electric networks is caused by the physics of parallel flows. Unfortunately, if you are not an electrical engineer, you probably have very bad intuition about the implications of this fact. You are not alone.
>
> **Fiction:** We could avoid the complications of dealing directly with nodal pricing by aggregating nodes with similar prices into a few zones. The result would provide a foundation for a simpler competitive market structure.

If prices closely reflect operating conditions and marginal costs, then market participants can have numerous choices in the way they use the transmission system. However, if pricing does not conform to the operating conditions, then substantial operating restrictions must be imposed to preserve system reliability. Customer flexibility and choice require efficient pricing; inefficient pricing necessarily limits market flexibility.

Complex problems have been created by the simplification of zonal congestion pricing:

- The first region in the United States to abandon a zonal pricing model after it failed in practice was PJM, from its experience in 1997 when its zonal pricing system prompted actions which caused severe reliability problems. Given this experience, PJM adopted a nodal pricing system that has worked well since March 1998.[2]

- Subsequently, the original one-zone congestion pricing system adopted for the New England independent system operator (ISONE) created inefficient incentives for locating new generation.[3] To counter these price incentives, New England proposed a number of limitations and conditions on new generation construction. Following the Commission's rejection of the resulting barriers to entry for new generation in New England, there developed a debate over the preferred model for managing and pricing transmission congestion.[4] In the end, New England proposed go all the way to a nodal pricing system.[5]

---

[2] William W. Hogan, "Restructuring the Electricity Market: Institutions for Network Systems," Harvard-Japan Project on Energy and the Environment, Center for Business and Government, Harvard University, April 1999, pp. 37-44.

[3] The use of zones for collecting transmission fixed charges is not the issue here. The focus is on managing transmission congestion. For a critique of the previously proposed one-zone congestion pricing system, see Peter Cramton and Robert Wilson, "A Review of ISO New England's Proposed Market Rules," Market Design, Inc., September 9, 1998.

[4] Federal Energy Regulatory Commission, New England Power Pool Ruling, Docket No. ER98-3853-000, October 29, 1998.

[5] ISO New England, "Congestion Management System and a Multi-Settlement System for the New England Power Pool," FERC Docket EL00-62-000, ER00-2052-000, Washington DC, March 31, 2000. The proposal includes full nodal pricing for generation and, for a transition period, zonal aggregation for loads.

Complex problems have been created by the simplification of zonal congestion pricing (cont.):

- A similar zonal congestion management market design created similar problems in California, which prompted the FERC to reject a number of ad hoc market adjustments and call for fundamental reform of the zonal congestion management system. "The problem facing the [California] ISO is that the existing congestion management approach is fundamentally flawed and needs to be overhauled or replaced."[6]

- The zonal pricing system in Alberta, Canada, apparently produced a related set of incentives that failed to give generators the price signal to locate consistent with the needs of reliability: "Most of the electricity generation sources are located in the northern part of the province and ever-increasing amounts of electricity are being transported to southern Alberta to meet growth, … [t]his is causing a constraint in getting electricity into southern Alberta and impacting overall security of the high-voltage transmission system."[7] As a result, Alberta has proposed a central generation procurement process under the transmission operator to provide a means to get generation built in the right place. This is hardly a true simplification, nor is it consistent with the original intent to move towards a competitive market and away from monopoly procurement.

---

6 Federal Energy Regulatory Commission, "Order Accepting for Filing in Part and Rejecting in Part Proposed Tariff Amendment and Directing Reevaluation of Approach to Addressing Intrazonal Congestion," Docket ER00-555-000, 90 FERC 61, 000, Washington DC, January 7, 2000, p. 9. See also Federal Energy Regulatory Commission, "Order Denying Requests for Clarifications and Rehearing," 91 FERC 61, 026, Docket ER00-555-001, Washington DC, April 12, 2000, p. 4.

7 "Alberta Transmission Czar Wants More Generation," Electricity Daily, Vol. 14, No. 77, April 21, 2000, p. 3.

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:

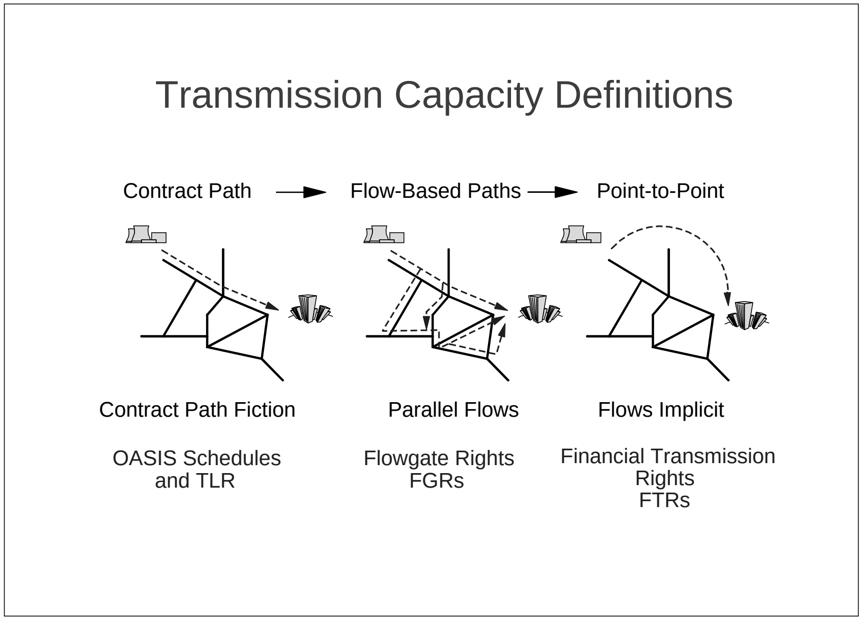
Required Zones in PJM							
	Apr	May	Jun	Jul	Aug	Sept	Oct-Mar
1998-1999	94	83	75	57	52	64	61
1999-2000	22	63	60	210	96	62	

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.

If a single contract path is not good enough, perhaps many paths would be better. Since power flows along many parallel paths, there is a natural inclination to develop transmission services that would identify the key links or "flowgates" over which the power may actually flow, and to define transmission rights according to the capacities at these flowgates. The assertion is that the commercially significant congestion can be represented by a system with:

- Few flowgates or constraints.
- Known capacity limits at the flowgates.
- Known power transfer distribution factors (PTDF) that decompose a transaction into the flows over the flowgates.

Under these simplifying assumptions, the decentralized model might work in practice. Trading of capacity rights would take place in decentralized forward markets. Transactions that had assembled all the capacity rights needed would then be scheduled without further congestion charges. Real-time operations would be handled somehow, typically not specified as part of the flowgate model.

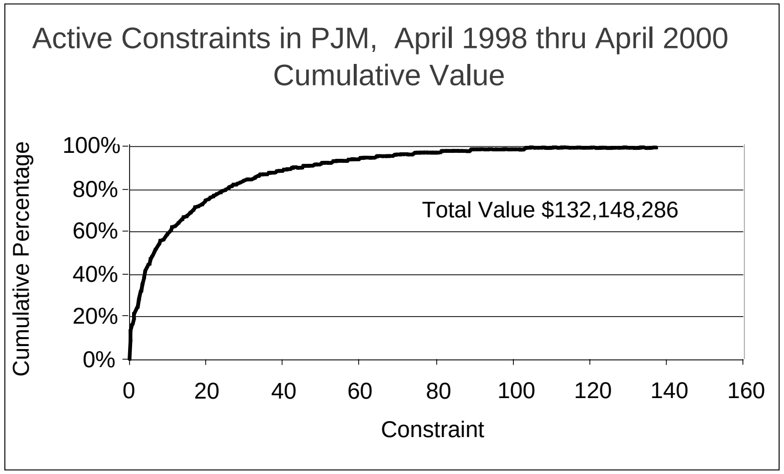


There is some experience with this flowgate model. However, the experience is limited and what experience we do have is not good. The flowgate model for decentralized congestion management were applied as part of the NERC Pilot Project for Market Redispatch in 1999, as a decentralized alternative to administrative TLR curtailments. Despite substantial turmoil created by the TLR system, there were *no* successful applications of any decentralized trades under this approach.[8]

The simplifying assumptions do not apply in the typical network. Consider PJM:

- **Few flowgates or constraints?**

  Over the period January 1998 to April 2000, there were 161 unique constraints that produced congestion and different locational prices in PJM. Apparently a complete flowgate model would require purchase of at least 161 capacity rights to secure a single point-to-point transaction.



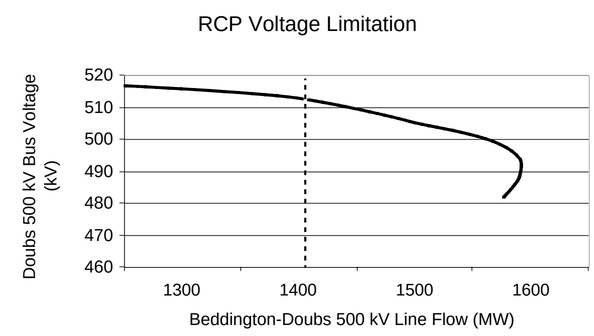
Source: Andrew L. Ott, "Can Flowgates Really Work? An Analysis of Transmission the PJM Market from April 1, 1998 - April 30, 2000", PJM, September 15, 2000.

[8] Congestion Management Working Group of the NERC Market Interface Committee, "Final Report on the NERC Market Redispatch Pilot," November 29, 1999, filed with FERC on December 1, 1999.

The simplifying assumptions do not apply in the typical network.[9] Consider PJM (cont.):

- **Known capacity limits at the flowgates?**

  The assumptions used to set the reactive limit depend upon the pattern of use assumed in the base case and the pattern for incrementing the interface flows. This contradicts the assertion of the flowgate proposals that "[i]n contrast, the capacity of each link or flowgate is determined by physical factors associated with the link (e.g. thermal limit, voltage stability, and dynamic stability) and is generally insensitive to the power flow pattern."[10] The PJM Eastern Reactive Transfer Limit is reset at least every 15 minutes and can vary over a range of 4000 MW to 7000 MW, depending on system conditions.[11]



Source: VEM Study Procedure Manual, May 3, 1999

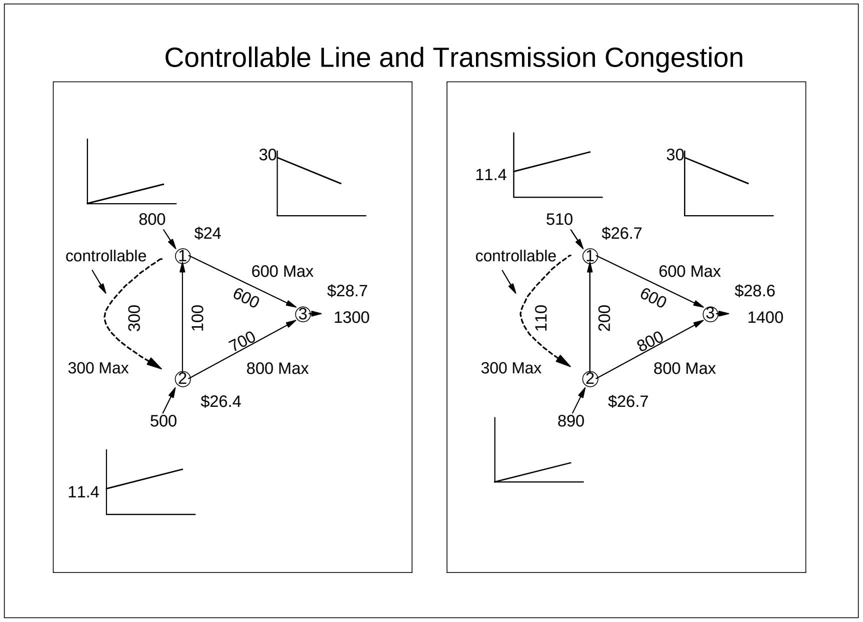
[9] See the PJM web page spreadsheet report on historical transmission limits, "Historical_TX_Constraints.xls." Over the period January 1998 to April 2000 there were 610 constraint-days recorded, with the same constraint appearing on more than one day. Based on the "Monitor" and "Contingency" names, there were 161 unique constraints.

[10] Hung-po Chao, Stephen Peck, Shmuel Oren, and Robert Wilson, " Flow-based Transmission Rights and Congestion Management," May 8, 2000, Draft, Revised June 23, 2000, p. 4.

[11] Andy Ott, PJM, personal communication.

- **Known power transfer distribution factors (PTDF) that decompose a transaction into the flows over the flowgates?**

The PTDFs are a function of the entire configuration of the grid. With any line change, there are different PTDFs, and the configuration of the grid is changing all the time. Furthermore, there are electrical devices, such as phase angle regulators, whose very purpose is to change the PTDFs throughout the system. Furthermore, there are inherent nonlinearities in the flows and constraints, especially the ubiquitous so-called "nomogram" constraints that attempt to approximate even more complex interactions in the system. It is for these reasons that PJM updates both the load flow estimate and calculation of its equivalent of PTDF tables every five minutes.[12]



[12] Andy Ott, PJM, personal communication.

If the simplifying assumptions are approximately true, they present a case for a business venture, not an argument for the design of the regional transmission organization.

Congestion Zones: The differences in nodal prices may be small, most of the time, and the occasional excursions would not be commercially significant. Or, to be more precise, the occasional excursions would not be significant as long as the system operator did not socialize the costs. Under these circumstances, there is a clear business opportunity.

Flowgates: Under the simplifying assumptions of the flowgate model, it would be possible to decompose these point-to-point financial transmission rights into their component flowgates, implied flow capacities on flowgates, and the associated PTDFs. If the approximation errors of the flowgate model are not large, then it would be possible for a new business to provide the service of organizing trading of flowgate rights that could be reconfigured to create new FTRs. The differences in flows and capacities might be small, most of the time, and the occasional excursions would not be commercially significant. Or, to be more precise, the occasional excursions would not be significant as long as the system operator did not socialize the costs. Under these circumstances, there is a clear business opportunity.

When viewed from this perspective, the arguments in favor of congestions zones and the flowgate approach should not be seen as applying to the RTO. When the RTO follows this path, trouble is likely to appear because the real system is more complicated. Rather, the arguments for the approximations should be seen as either wrong or right. If wrong, they should be ignored. If right, they should lead to a successful business. But the simplified model is likely to be a problematic market design for an RTO.

The list of reforms for the California market is long, and the difficulty of identifying and fixing all the problems has been exacerbated by repeated *ad hoc* reforms that have dismissed theoretically sound and proven design principles. These principles, which apply to ERCOT, include:[13]

- The ISO must operate, and provide open access to, short-run markets to maintain short-run reliability and to provide a foundation for a workable market.
- An ISO should be allowed to operate integrated short-run forward markets for energy and transmission.
- An ISO should use locational marginal pricing to price and settle all purchases and sales of energy in its forward and real-time markets and to define comparable congestion (transmission usage) charges for bilateral transactions between locations.
- An ISO should offer tradable point-to-point financial transmission rights that allow market participants to hedge the locational differences in energy prices.
- An ISO should simultaneously optimize its ancillary service markets and energy markets.
- The ISO should collaborate in rapidly expanding the capability to include demand side response for energy and ancillary services.

---

[13] John D. Chandley, Scott M. Harvey, William W. Hogan, "Electricity Market Reform in California," Comments in FERC Docket EL00-95-000, Center for Business and Government, Harvard University, November 22, 2000. pp. 15-25.

The simplified alternative market models at best are distractions, and at worst are proven failures.

Congestion Zones: Either they don't matter or they don't work.

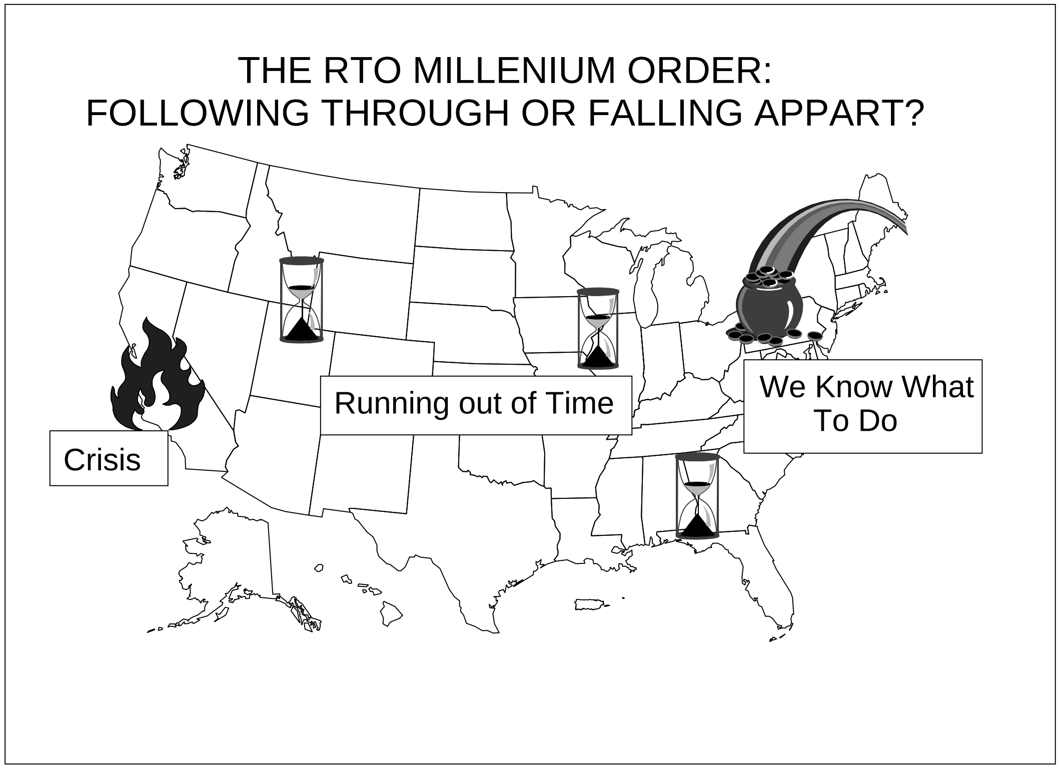
Flowgates: Developers of flowgate models eventually acknowledge that balancing and congestion management must, in the end, be done with a bid-based, security constrained, economic dispatch with locational prices. For RTO design, the flowgates are a distraction.

"It is in public interest to improve the design and operation of short-term electricity markets. Once done, many of the other problems in the electric network would either disappear or would be greatly simplified. The problems are real, significant, and here. The Commission must address them, and will, one way or another. The best way to face the inevitable is to recognize it and do the best we can under the circumstances. The Commission knows what to do. Doing it may require using all its powers to persuade, or it may require legislation to clarify its authority to mandate. It may require both. ...

In the interest of good public policy and well functioning electricity markets, it would be best to make the voluntary approach work, soon."[14]

[14] William W. Hogan, "Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems,"Center for Business and Government, Harvard University, May 2000, pp. 35-36

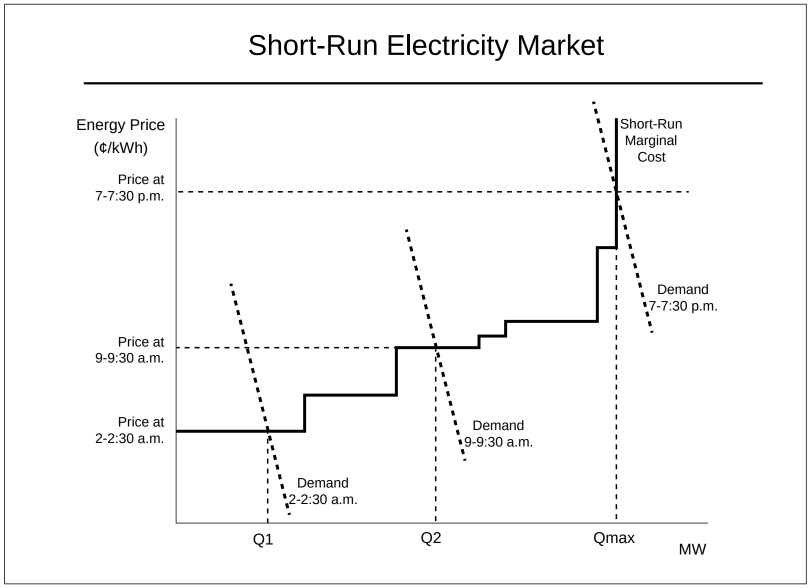
The crisis in California and the delay everywhere else could easily cause the collapse of the restructuring agenda. We know what to do. But it requires leadership to make it happen.

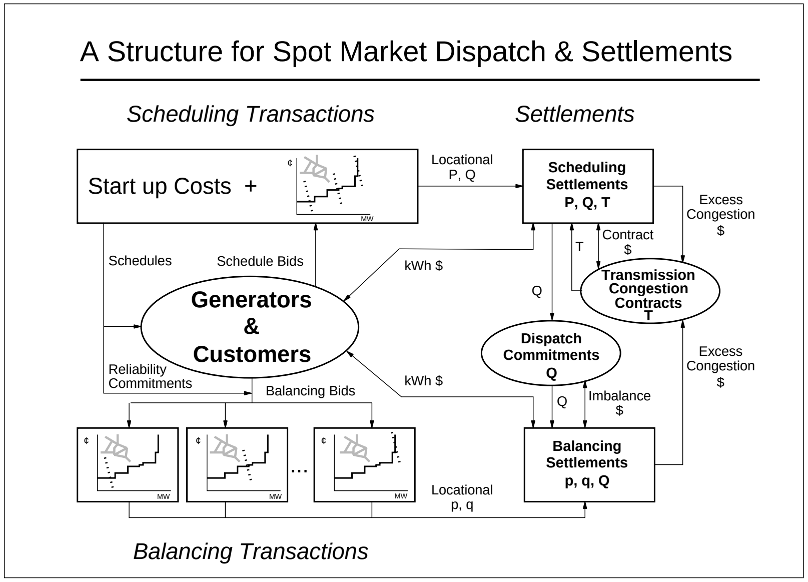


Appendix

COORDINATED SPOT MARKET   Security-Constrained Economic Dispatch

An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand. Bid-based, security-constrained, economic dispatch yields nodal prices. Everyone pays or is paid the same price at a location or between locations.





Flexible demand and short-term reserves provide reliability. Adequacy concern converts to price volatility and congestion costs. Financial transmission rights provide transmission "adequacy."

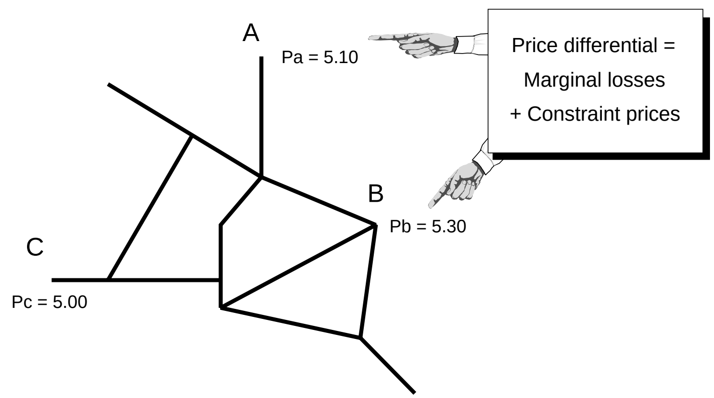
NETWORK INTERACTIONS — Locational Spot Prices

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"

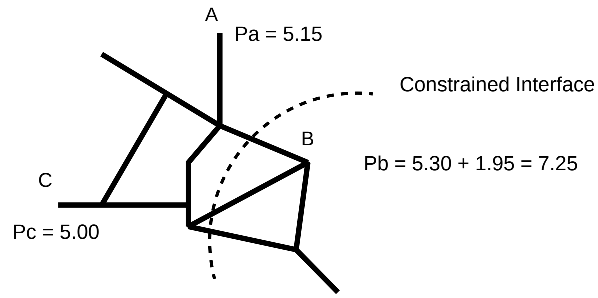


Price of "Transmission" from A to B = Pb - Pa = 0.20
Price of "Transmission" from A to C = Pc - Pa = -0.10

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

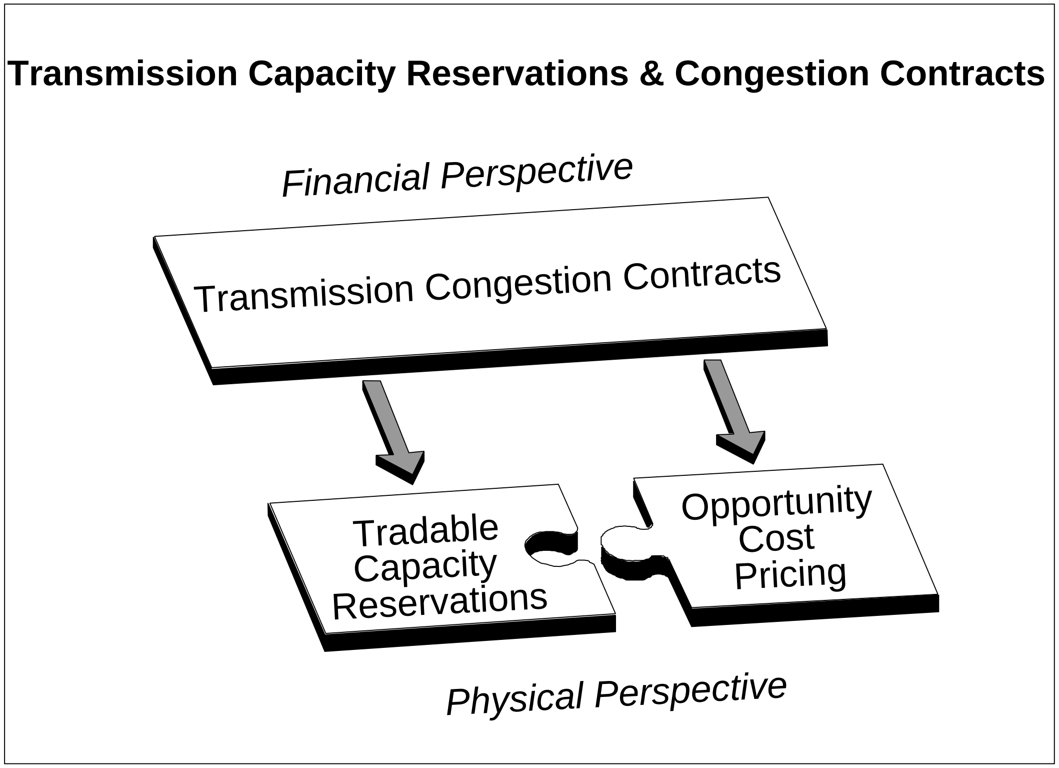
Bus Price = Generation Cost + Marginal Losses + Congestion Costs



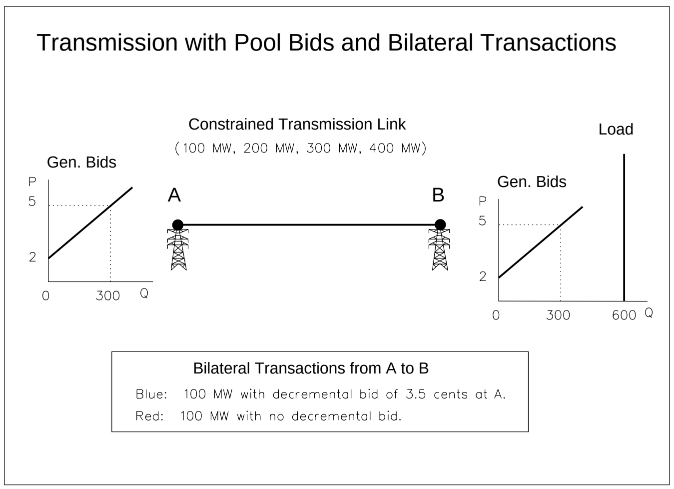
Pcb = Pb - Pc = Marginal Losses + Congestion Costs = 0.3 + 1.95 = 2.25

- 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.

With opportunity cost pricing and tradable transmission capacity reservations, any use of the system not matched by a reservation would be settled at opportunity cost prices determined by the final dispatch or actual use of the system. This physical perspective becomes indistinguishable from the financial perspective and transmission congestion contracts.



Locational spot prices define the opportunity cost of transmission usage. The pricing principles for a single line apply to complex networks, even though the physical flows would no longer follow a contract path. Pricing offers an alternative to physical property rights.



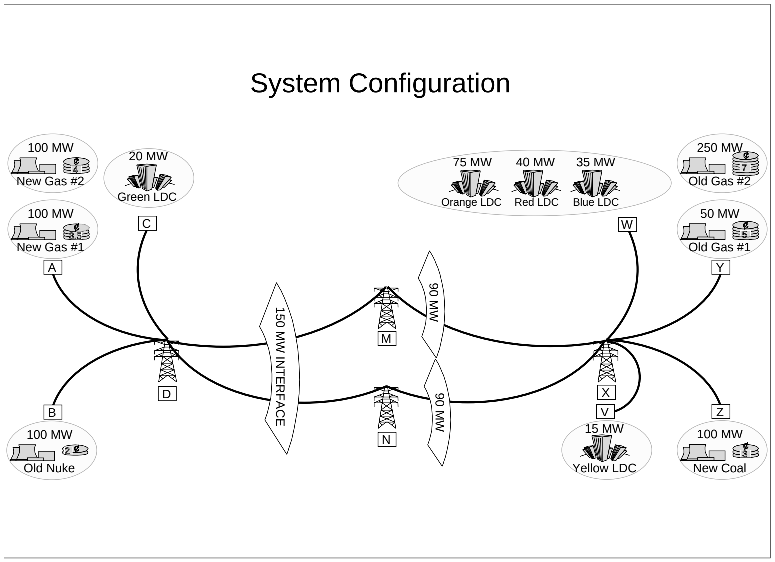
Power Flows and Locational Prices					
	Alternative Cases				
Link Capacity A to B	MW	400	300	200	100
Total Load at B	MW	600	600	600	600
Price at A	cents/kwh	4	3.5	3	2
Price at B	cents/kwh	4	5	6	7
Transmission Price	cents/kwh	0	1.5	3	5
Pool Generation at A	MW	200	150	100	0
Pool Generation at B	MW	200	300	400	500
Blue Bilateral Input at A	MW	100	50	0	0
Red Bilateral Input at A	MW	100	100	100	100

Payments to the system operator are for pool purchases and sales, transmission, and imbalances. The net payments equal the costs of congestion.

Power Flows and Locational Prices					
	Alternative Cases				
Link Capacity A to B	MW	400	300	200	100
Price at A	cents/kwh	4	3.5	3	2
Price at B	cents/kwh	4	5	6	7
Transmission Price	cents/kwh	0	1.5	3	5
Payments to Independent System Operator					
Pool Load at B (400 MW)	cents (x1000)	1,600	2,000	2,400	2,800
Contract Load at B (200 MW)	cents (x1000)	0	0	0	0
Generation at A	cents (x1000)	(800)	(525)	(300)	0
Generation at B	cents (x1000)	(800)	(1,500)	(2,400)	(3,500)
Blue Transmission	cents (x1000)	0	75	0	0
Blue Imbalance at B	cents (x1000)	0	250	600	700
Red Transmission	cents (x1000)	0	150	300	500
Red Imbalance at B	cents (x1000)	0	0	0	0
Net to Independent System Operator	cents (x1000)	0	450	600	500

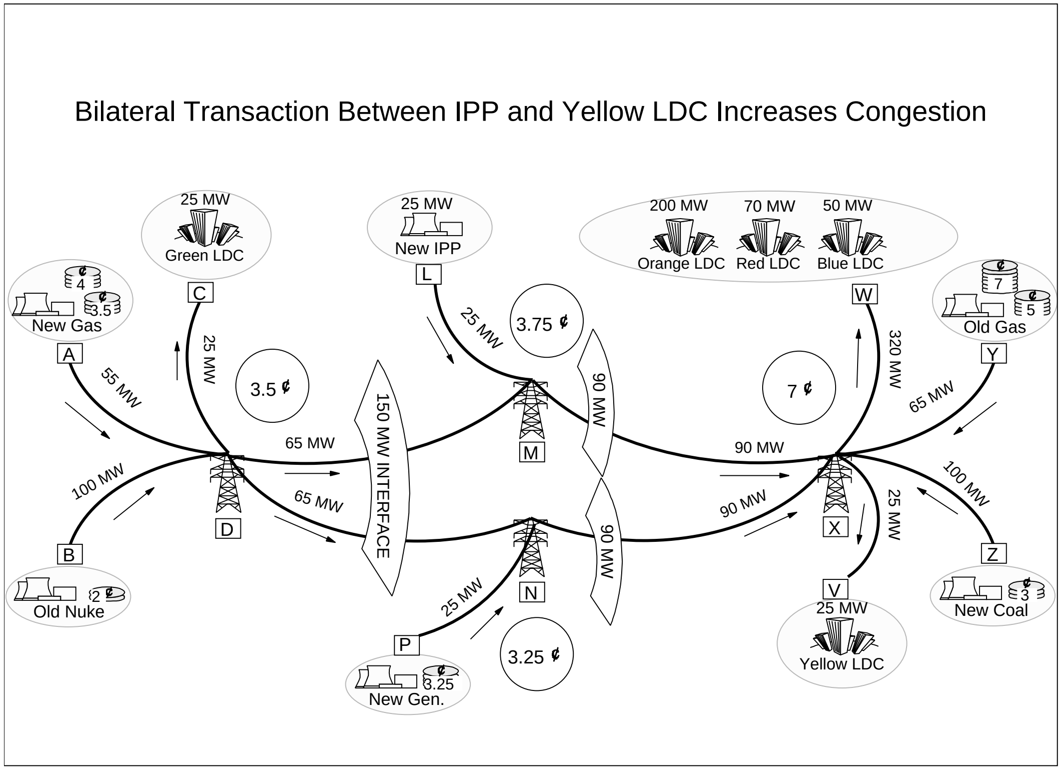
The examples assume a transmission system with the following characteristics:

- Generation available at four locations in the East (Y, Z) and West (A, B).
- Load in the East, consisting of the Yellow LDC at V and the Orange, Red and Blue LDCs at W.
- Load in the West, consisting of a Green LDC at C.
- Interface constraint of 150 MW between bus D and buses M and N.
- Thermal constraints of 90 MW between M and X and between N and X.
- The New Gas and Old Gas generating facilities each consist of two generating units whose marginal costs of production differ.

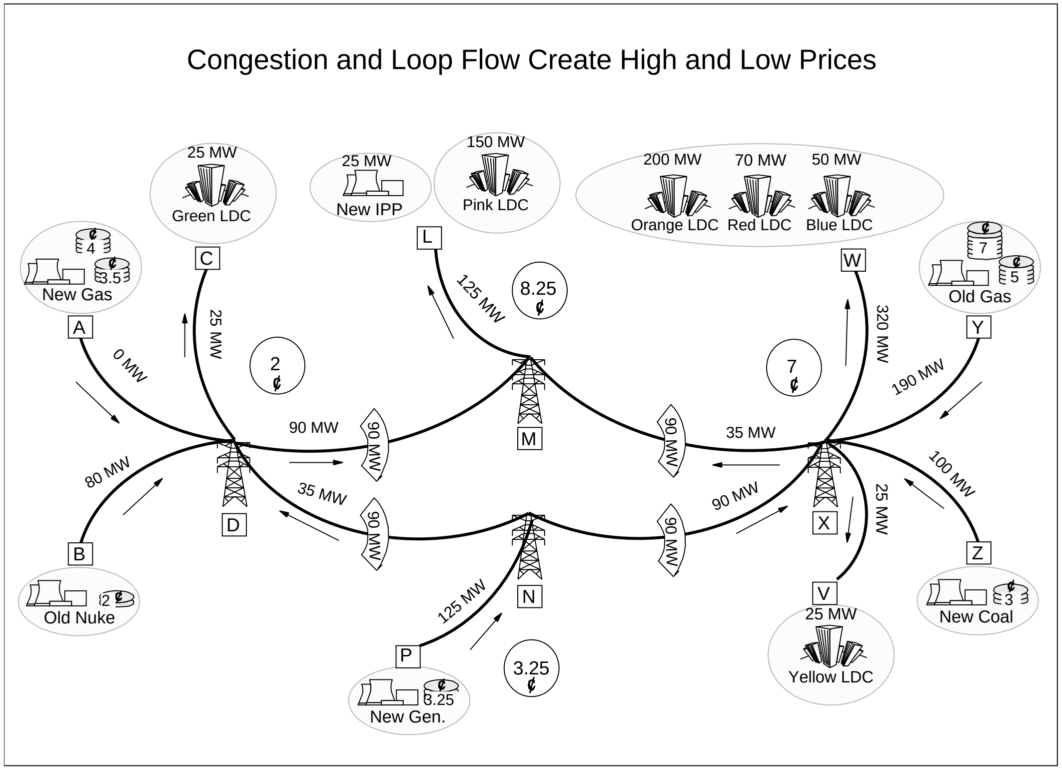


Loads in this figure are illustrative and will vary systematically in each example. For convenience, losses are ignored in all examples.

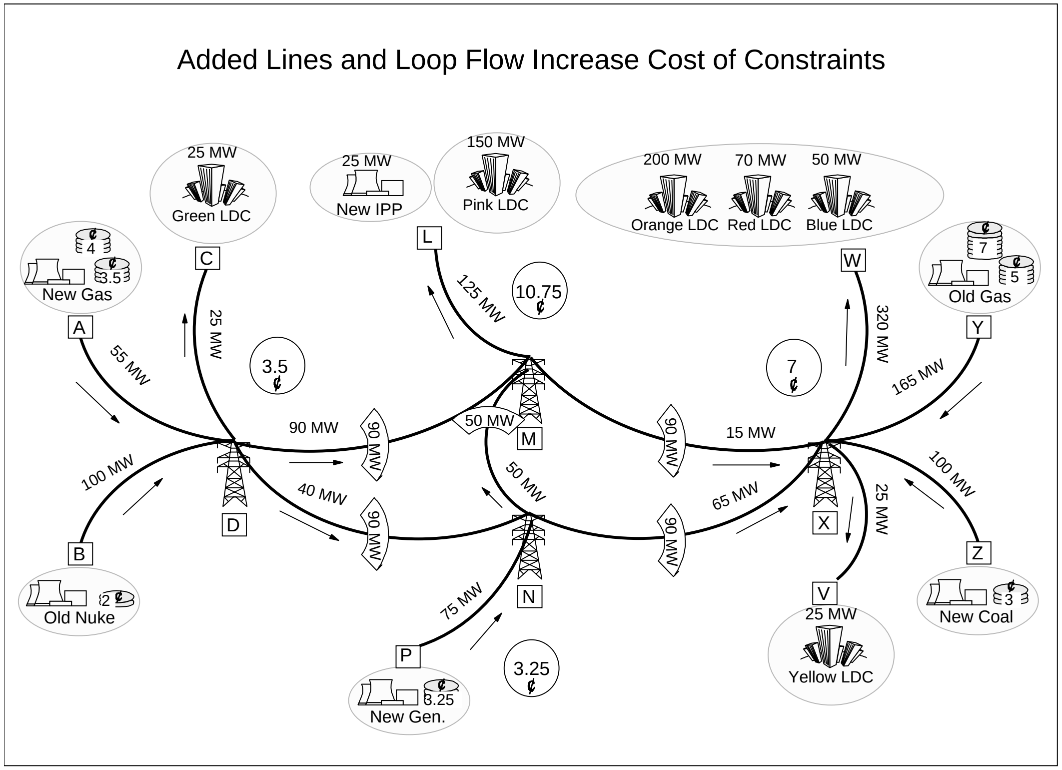
A low cost, large capacity generator becomes available at bus "P." The IPP at bus "L" has bid in a must run plant at 25 MW, having arranged a corresponding sale to the Yellow distribution company at bus "V". Were it not for the IPP sale, more power could be taken from the inexpensive generators at bus "P" and at bus "A". However, because of the effects of loop flow, these plants are constrained in output, and there are different prices applicable at buses "D", "M", "N", and "X".



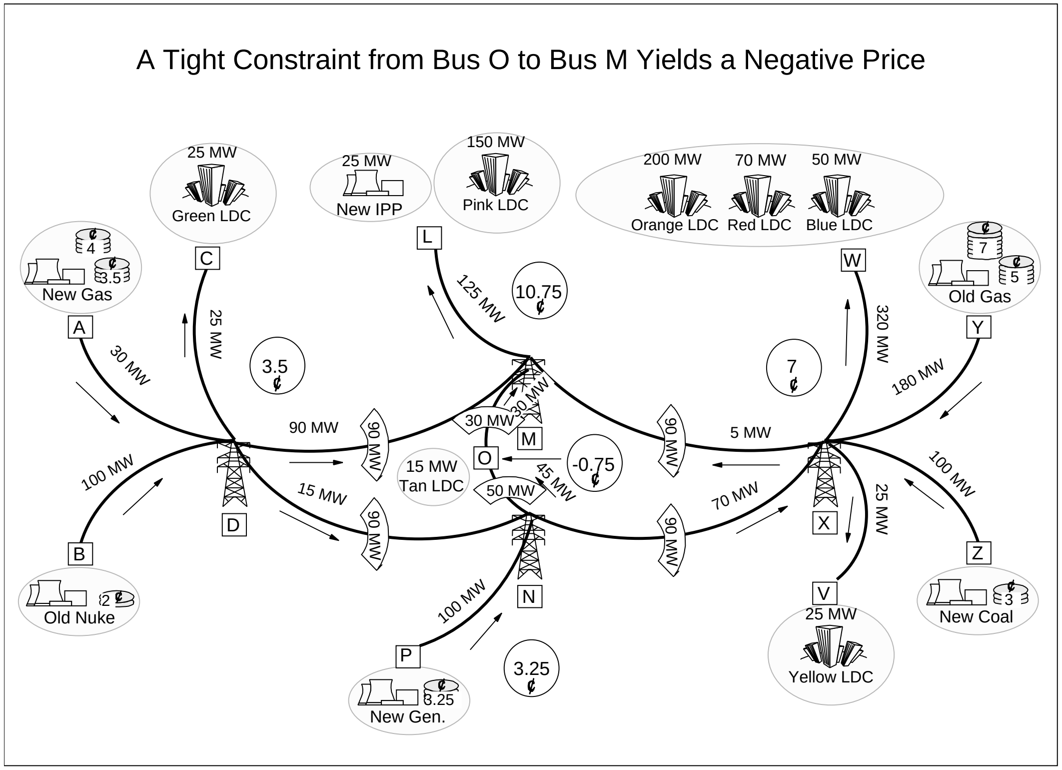
Here every line in the main loop is constrained by a thermal limit of 90 MW, replacing the interface limit. With these constraints, an added load of 150 MW at bus "L" alters the flows for the market equilibrium. In this case, the combined effect of the increased load and the constraints leads to a price of 8.25¢ per kWh at bus "L". This price is higher than the 7¢ marginal running cost of the old gas plant at bus "Y", the most expensive plant in the system.



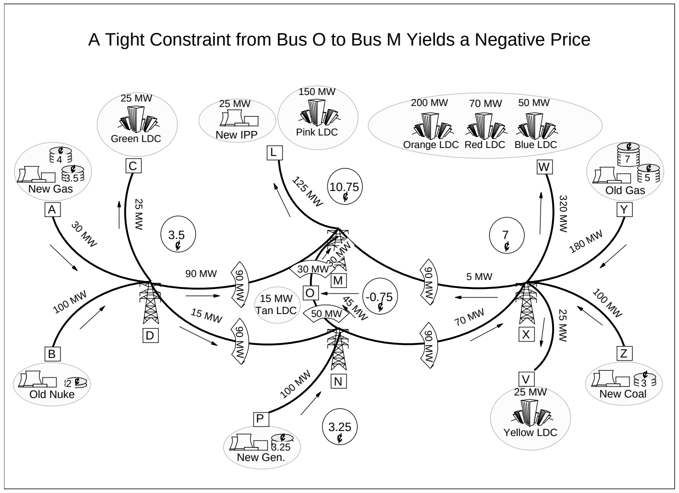
Next a new line has been added to the network, connecting bus "N" to bus "M". This line is assumed to have a thermal limit of 50 MW. The new line adds to the capability of the network in that the new pattern of generation lowers the overall cost of satisfying the same load. The total cost reduces from $20,962.50 to $19,912.50. Although the average cost of power generation fell, the marginal cost of power increased at bus "L", where the price is now 10.75¢ per kWh.



Add a new bus "O" between bus "M" and bus "N", and lower the limit to 30 MW between bus "O" and bus "M". Bus "O" has a small load of 15 MW. The increased load of 15 MW at bus "O" actually lowers the total cost of the dispatch, as reflected in the negative price. Each additional MW of load at bus "O" changes the flows to allow a dispatch that lowers the overall cost of meeting the total load.



The simultaneous set of transmission congestion contracts defines the "Available Transmission Capacity." Consider the example network with two feasible sets of transmission congestion contracts (TCC) for hub at "O".

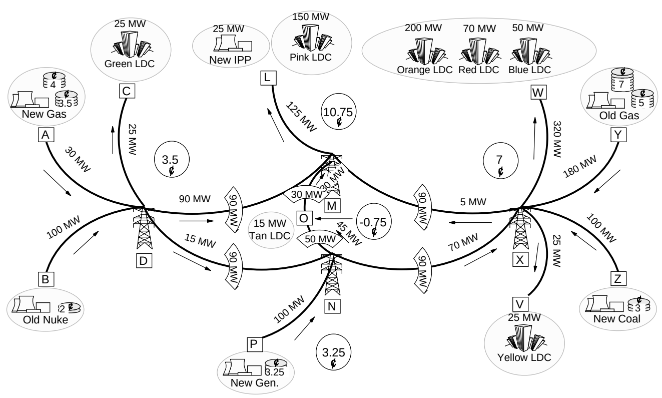


From-To	TCC 1 (MW)	TCC 2 (MW)
"D-O"	180	160
"O-X"	180	160
"M-O"	30	10
"N-O"	30	70

Either set of TCCs would be feasible by itself in this network. However, subsets of the contracts may not be feasible. Hence, the *definition* of available transmission capacity would be as a simultaneously feasible set of contracts.

The congestion costs collected will always be sufficient to meet obligations under transmission congestion contracts. Excess congestion rents, after paying TCC obligations, could be returned under a sharing formula.

A Tight Constraint from Bus O to Bus M Yields a Negative Price



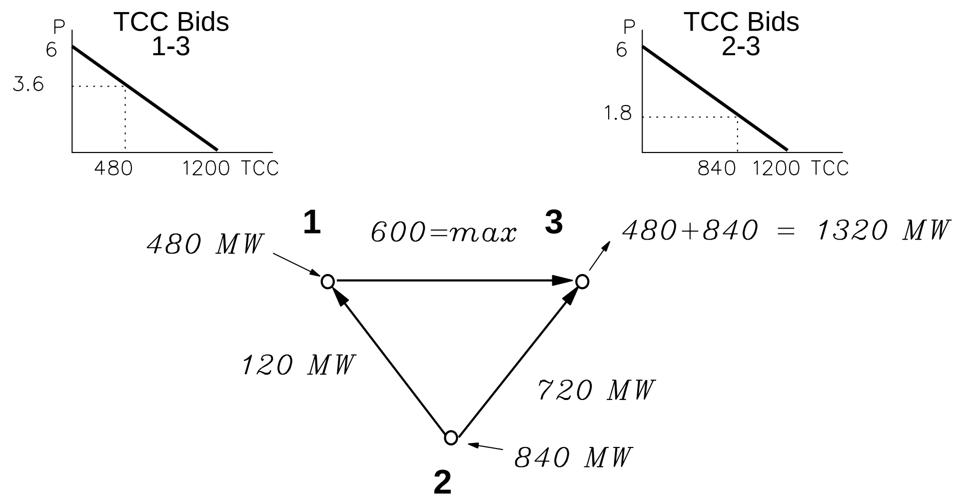
From-To	TCC 1 (MW)	TCC 2 (MW)
"D-O"	180	160
"O-X"	180	160
"M-O"	30	10
"N-O"	30	70

Load at "L"	Bus Prices ¢/kWh					Total Rents $	TCC 1	TCC 2
MW	"D"	"M"	"N"	"O"	"X"			
0	3.50	3.75	3.25	3.50	7.00	6300	6300	5750
50	3.50	5.58	3.25	4.15	7.00	6300	6138	6084
150	3.50	10.75	3.25	-0.75	7.00	10950	1650	1650

Transmission congestion contracts for the grid could be defined and awarded through an open auction. The collective bids would define demand schedules for TCCs. The concurrent auction would respect the transmission system constraints to assure simultaneous feasibility.

Concurrent Auction of Transmission Congestion Contracts

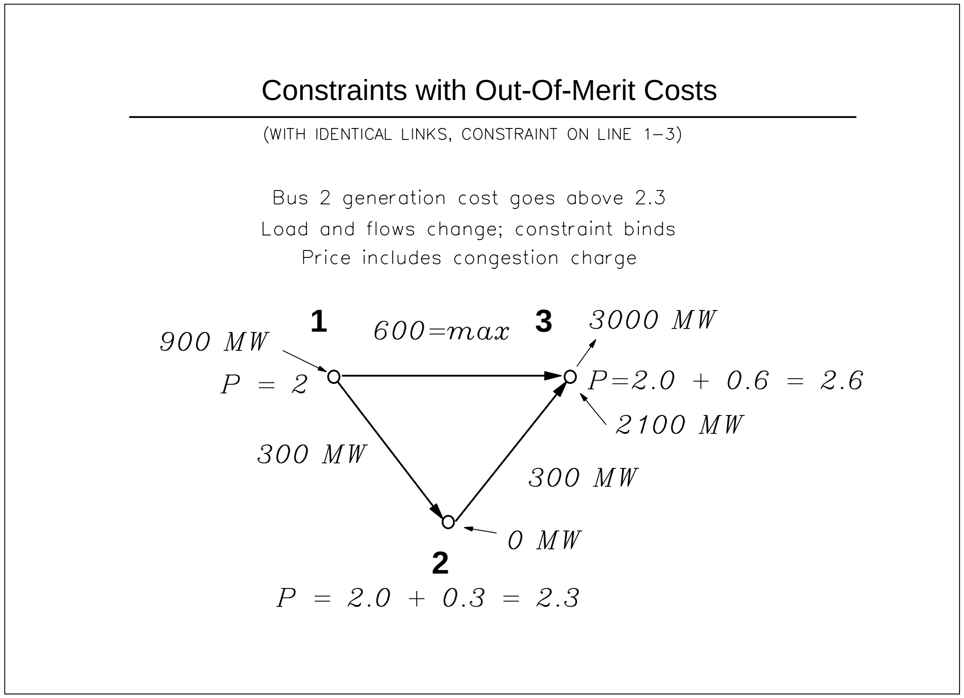
(WITH IDENTICAL LINKS, CONSTRAINT ON LINE 1–3)



TCCs from 1 -> 3 awarded for 480 MW at price 3.6

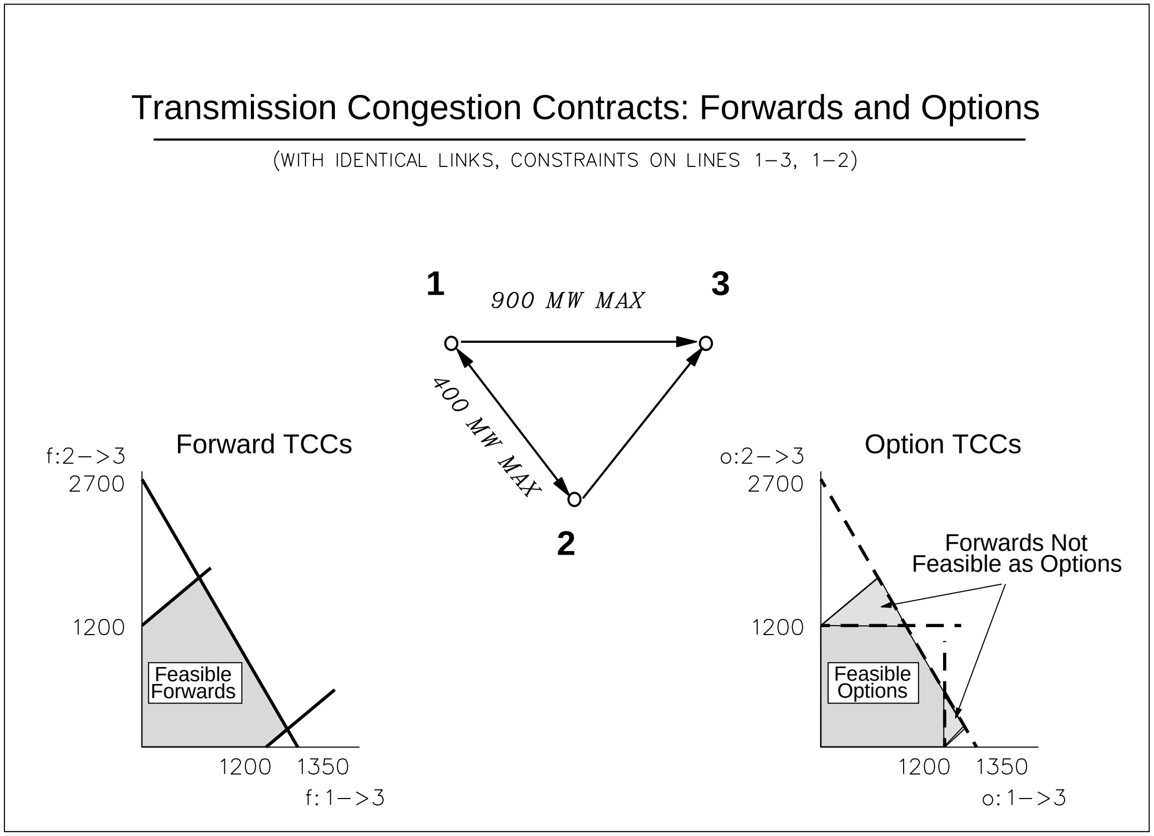
TCCs from 2 -> 3 awarded for 840 MW at price 1.8

With spot locational prices, transmission congestion contracts provide price protection. Even with changing load patterns, the congestion revenues collected by the system operator will be at least enough to cover the obligations for all the TCCs.



System Operator Revenues			
	Quantity	Price	$
Bus 1	900	2	($1,800)
Bus 2	0	2.3	$0
Bus 3	2100	2.6	($5,460)
Bus 3	-3000	2.6	$7,800
TCC 1-3	480	0.6	($288)
TCC 2-3	840	0.3	($252)
Net Total			$0

Option contracts carry no obligation to use the transmission or pay congestion cost. Forward contracts include such obligations. Because of displacement of reverse flows, the capacity for forward contracts is always greater than for option contracts.



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 a Director of LECG, LLC. 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, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, Calpine Corporation, Commonwealth Edison Company, Detroit Edison Company, Duquesne Light Company, Electricity Corporation of New Zealand, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., National Independent Energy Producers, New England Independent System Operator, New England Power Company, New York Independent System Operator, 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. (Related papers can be found on the web at http://ksgwww.harvard.edu/people/whogan).