COORDINATION FOR COMPETITION IN AN ELECTRICITY MARKET

WILLIAM W. HOGAN

Response to an Inquiry Concerning Alternative Power Pooling Institutions
Under the Federal Power Act
Docket No. RM94-20-000

FEDERAL ENERGY REGULATORY COMMISSION
(October 26, 1994)
Docket No. RM94-20-000

March 2, 1995

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EXECUTIVE SUMMARY

Coordination through a well designed pool-based electricity market can be a large part of the solution to the problems of promoting open access and competition. Experience in other countries strongly supports this conclusion and the key elements travel well. Analysis of the underlying conditions of electricity supply highlights the role of effective pooling arrangements in cutting through the complexity of the electricity system and exploiting the benefits of coordination *for* competition.

The "Poolco" model embodies the lessons of best practice found elsewhere and provides a coherent framework for addressing the key elements of efficient pricing, open access, and market choices, all while preserving the necessary requirements for operating reliability. This generic Poolco model has been advanced by public and private utilities in different locations and different circumstances. The broad attraction of the Poolco proposal across the country and in other nations stems in part from the gradual recognition that the Poolco is not a radical proposal. Rather, Poolco recognizes what exists today and what must happen under any system for a competitive electricity market.

Any efficient system for organizing the electricity market should include least-cost dispatch as a centerpiece. To be sure, the least-cost dispatch concentrates only on the short-run and the greater part of the value of a competitive system is to be found in the long-run decisions

that will control contracting and investment. However, least-cost dispatch based on participant bids is the ideal short-run outcome that would appear in a competitive market if it were possible for all the many participants to define the appropriate property rights and conduct all the complex trades in the network. Because of the complexity of these trades and the lack of workable definitions of key physical property rights, the common judgment is that a system operator is needed to coordinate the dispatch, at least for some fraction of the flexible plants. Since the operator must function to provide coordination services, least-cost dispatch provides the natural framework that replicates as close as possible the ideal outcome of the short-term competitive market. The Poolco model accepts and builds on this least-cost dispatch. And working from this starting point, the other features needed for the market can be derived within a consistent framework. The bidding prices and least-cost dispatch provide naturally the level playing field for all market participants, both large and small. There is no special advantage to size in benefitting from dispatch diversity and acquiring backup supplies. These services are available to all on the same basis. The separation of ownership from control guarantees open access to the dispatch and related services to facilitate entry and the pursuit of the forces of competition.

The difficulty in defining property rights, which are so essential for efficient operation of a competitive market, centers on the long-term use of the transmission system. Under current technology, it is not possible to assure physical rights to use the transmission grid. For any physical right to move power from one location to another in a sufficiently complicated network, there is some patterns of loads and dispatch that would foreclose the right. Hence, the network is very unlike the usual model of a single transmission line. Although physical transmission rights cannot be guaranteed, the Poolco least-cost dispatch provides the foundation for a transmission contract that serves essentially the same purpose as a physical right by defining a financial transaction that does not depend on matching physical flows in the actual dispatch. Transmission congestion contracts can be defined for a financial payment equal to the difference in congestion costs between locations. Such a transmission contract would allow a generator to arrange a power contract with a distant customer and be assured of the delivered cost of the power. Through the Poolco dispatch, the system operator would collect congestion payments whenever the system is constrained, and in turn disburse the congestion payments to the holders of the transmission congestion contracts. The Poolco would keep none of the payments, and participants with long-term transmission contracts could fully protect the ability to deliver power at an agreed price, just as if there were physical delivery from the contract source to the contract destination. However, unlike the physical transmission rights, the transmission congestion contracts are well defined, can use the full capacity of the network, and are consistent with actual flows moving according to the least-cost dispatch. Furthermore, the ability to honor the contracts does not depend on the configuration of the inputs and outputs. The transmission congestion contracts provide a workable way to untangle the network and convert short-run opportunity cost prices into long-term transmission arrangements.

The national discussion of the Poolco model has produced a number of questions or concerns about possible failings of the approach that on closer inspection appear to be based on a misunderstanding or misinterpretation of the Poolco design. A brief summary of each suggests the possible source and a clarification of the misunderstanding. Describing what is not sharpens the description of what is included in the Poolco model. The Poolco model does not interfere with the market, it merely adapts the interference that is unavoidable to facilitate open access and competition for all. Participation in the Poolco least-cost dispatch can be voluntary and there is no limitation on the scope of commercial contracts. Of course, physical delivery of power through the network is not optional, and everyone in the market must follow the rules for power dispatch and payment for transmission services. However, within these rules, any contract between any parties in the market can be implemented under the generic Poolco model. For power transactions self-nominated and subject only to transmission charges, any contract can be arranged in a form that is virtually identical to the traditional conceptual model of direct delivery of power between the supplier and the customer. In the case of power bought and sold through the economic dispatch, any contract that supplier and customer could design could be implemented through the device of a contract for differences. The Poolco model provides a simple and efficient framework for implementing the full range of commercial contracts while easing the requirements for the necessary non-discriminatory access to backup power, reference prices and other system services needed to support a competitive electricity market.

The Poolco model does not add barriers or increase the potential for market dominance. Most importantly, the Poolco model does not create nor does it enhance the concentration of ownership of generation. Through open access, the Poolco model removes barriers to entry without erecting any new barriers. Where remaining concentrations of ownership exist, the Poolco provides a framework for dealing with the effects. Where market power exists, Poolco makes the situation better, not worse.

Furthermore, implementation of the Poolco model need not be a cause for bureaucratic delay. Virtually everything that is contained in the Poolco model is in place within the existing utilities or must be created in any event to support comparable access in the competitive market.

The Poolco model is not new and complex so much as new and different. The present industry access and pricing system is both complex and inconsistent with the incentives of the competitive market. By contrast, the Poolco model is built from a consistent model of an efficient competitive market and captures within the economic dispatch the principal and inescapable complexity of the network interactions. "A theory should be a simple as possible, and no simpler." The Poolco model is simpler than the status quo, and may be the simplest model that is consistent with the economics of the industry and the Commission's stated public policy objectives. Importantly, the Poolco model has a theory; it is not a collection of ad hoc band aids for a status quo that cannot be put back together again. The Poolco model does not start with revenue recovery and work backwards along a contract path made up of megawatt miles, leading to inefficient operations and pricing. Rather, the Poolco model starts with efficient operations and pricing, and works forward through a network to revenue recovery under long-term contracts.

The integrated framework of the Poolco model provides the several interconnected features of least-cost dispatch, separation of ownership and control, separation of physical and financial transactions, a framework for transmission pricing, and a framework for long-term transmission contracts to support a competitive market. The pieces fit together into a coherent whole while leaving the maximum degree of commercial flexibility. Regulators would oversee access to the essential facilities and implementation of broader public policies, the Poolco operator would coordinate the dispatch to handle the complicated network interactions, and the electricity market would be free to respond to the forces of competition.

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> "... we must consider whether we are appropriately balancing our dual objectives of promoting coordination and competition."[2]

> "The importance of effective Pooling arrangements in a competitive [Electric Supply Industry] cannot be overstated."[3]

INTRODUCTION

Coordination through a well designed pool-based electricity market can be a large part of the solution to the problems of promoting open access and competition. The Federal Energy Regulatory Commission (FERC), looking ahead to the unfolding restructuring of the electricity

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[1] Thornton Bradshaw Professor of Public Policy and Management, John F. Kennedy School of Government, Harvard University, and Director, Putnam, Hayes & Bartlett, Inc., Cambridge MA. 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 and advice on this and related papers, especially Robert Arnold, John Ballance, Ashley Brown, Jim Bushnell, Doug Foy, Don Garber, Scott Harvey, William Hieronymus, Sally Hunt, Jere Jacobi, Jim Kritikson, Dale Landgren, Amory Lovins, Thomas Parkinson, Howard Pifer, William Reed, Larry Ruff, Susan Pope, Michael Schnitzer, Irwin Stelzer, Steve Stoft, Julie Voeck and Carter Wall. The author is or has been a consultant on electric market reform and transmission issues for British National Grid Company, General Public Utilities Corporation, Duquesne Light Company, Electricity Corporation of New Zealand, National Independent Energy Producers, New York Power Pool, New York Utilities Collaborative, San Diego Gas & Electric Corp., Trans Power of New Zealand, 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.

[2] Federal Energy Regulatory Commission, Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-000, October 26, 1994, p. 2.

[3] J. Moen, "Electric Utility Regulation, Structure and Competition. Experiences from the Norwegian Electric Supply Industry (ESI)," Norwegian Water Resources and Energy Administration, NVE, Oslo, April 1994, p. II-5. Jan Moen is the Norwegian electricity industry regulator.

industry in the United States, anticipates a possible clash between coordination and competition, seen as competing objectives that must be balanced. However, looking back at the creation of a competitive electricity market in Norway, the Norwegian regulator sees no inherent conflict and cites effective pooling arrangements as essential for successful operation of a competitive electricity market. This experience is not unique to Norway, and the key elements travel well. Analysis of the underlying conditions of electricity supply highlights the role of pooling arrangements in avoiding the clashes and exploiting the benefits of coordination *for* competition.

The Commission will read much about the details of the implementation of pool-based competitive electricity markets. There is a certain degree of flexibility in the particulars of implementation, but the core ideas enjoy a coherence that derives from a strong foundation in the basic physics and economics of electricity supply. The purpose of this paper is not to elaborate all the details but rather to explore the core ideas as they fit together to provide a consistent framework for approaching many of the problems that confront the industry and its regulators. The discussion is divided into several parts. First, an outline of the basic principles sets the stage for the analysis that leads to a pool-based market as the natural way to support a competitive electricity industry linking pools, generation competition, customer access to the wholesale market, network interactions, transmission pricing, transmission congestion contracts and the level playing field for all participants in the market. Second, a discussion of some of the misunderstandings about the pool-based market model helps clarify what the proposal is by describing what it is not. Third, a brief discussion of a related problems such as regulation of essential facilities, treatment of market power, and compatible methods for providing customer choice without stranding assets clarifies the relation with a pool-based system that can support complementary approaches to these remaining problems. Finally, subsequent sections cover a illustrations of the principal features of the competitive market, pool operations and transmission access. An appendix develops numerous examples of pricing in a network to demonstrate the problems in electricity networks and the solutions found in the Poolco model. Summary responses to the list of FERC questions follow the appendix.

COORDINATION FOR COMPETITION

A concern with the role of coordination arises naturally from consideration of analogies with other markets where the invisible hand of competition is allowed to operate. In the typical market, explicit coordination of the actions of market participants is feared as a bar to the competitive forces seen as so essential for improved efficiency, both in short run operations and long run innovations. However, in the case of electricity, operational problems arise in the form of network interactions, sometimes referred to as "loop flow," that can greatly complicate the play of competitive forces. Even under the assumption of a workably competitive generation market there remains the challenge of allowing generators to compete through the interaction via the transmission network.

Visible Hand

Contrary to the presumption underlying the extreme version of the invisible hand model for electricity dispatch, the electric system with current technology requires the very visible hand of the system operator to manage the short-term power flows and associated operation of generating plants. The basic coordination functions will always be there, somewhere. A system coordinator or pool is required in support of any electricity market. This insight is available from experience with the operation of competitive electricity markets in other countries. For example, Norway is often mentioned as having a system with a high utilization of bilateral contracts that execute the commercial activities of the market, where over 85% of the power is covered by long-term contracts. However, despite the acknowledged importance of the contract and negotiated business agreements, Norway relies on a pool operation to handle the short-term arrangements that provide the underpinning of the competitive market:

> "The importance of effective Pooling arrangements in a competitive [Electric Supply Industry] cannot be overstated. The Pool provides:
>
> - a source of firm back-up and top-up power to support either generators or suppliers offering long-term contracts to final customers; without access to a Pool firm power could only be offered by generators owning a portfolio of plant and to the extent that firm power is a necessary requirement of consumers the competitiveness of both the generation market and the final supply would be limited;
>
> - a ready market for generators unable to sell their power under contract or wanting a market for spill or excess production;
>
> - a reference price for long or short-term contracts struck outside the Pool which provide participants with price stability not immediately available inside the Pool;
>
> - a reference price to be used in signalling the optimal development of generation and transmission capacity on the system.
>
> In addition, of course, the Pool provides the traditional means by which generation costs can be minimized through merit order operation and the

aggregation of reserve requirements."[4]

Note that Moen, the Norwegian regulator, addresses the short-term efficiency of a better dispatch only as an afterthought. The real value of the pool and the bid-based least-cost dispatch is in providing the various elements that facilitate commercial bilateral contracts and that would be hard to obtain in any other way.

The basic summary of the pool-based system is found in the Commission's characterization of its understanding of the proposals developing in the California discussions. This general "Poolco" model has been advanced in California by two investor owned utilities in San Diego Gas & Electric and Southern California Edison[5]; in the recent proposal by the public power entities in the Southern California Public Power Authority in a variant described as the "Multiple Choice Pool" (McPool)[6]; in Wisconsin by Wisconsin Electric Power[7]; in Maryland by Allegheny Power System and The Potomac Edison Company[8]; and is under active consideration in many other areas of the nation. The FERC summary of the Poolco proposal includes:

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4 J. Moen, "Electric Utility Regulation, Structure and Competition. Experiences from the Norwegian Electric Supply Industry (ESI)," Norwegian Water Resources and Energy Administration, NVE, Oslo, April 1994, p. II-5.

5 San Diego Gas & Electric and Southern California Edison described their proposal in a joint filing with the California Public Utilities Commission, Supplementary Comments of San Diego Gas & Electric Company (U-902-E) and Southern California Edison Company (U 338-E) On Competitive Markets and Appropriate Market Institutions in a Restructured Electric Industry, February 23, 1995.

6 Southern California Public Power Authority, "The Multiple Choice Pool Model (McPOOL)," February 7, 1995.

7 Wisconsin Electric Power Company, "Wisconsin Electric's View of a More Competitive Electric Industry," Investigation On The Commission's Own Motion Into The probable Costs and Benefits of Changing Electric Utility Company Structure and Regulation, PSCW Docket No. 05-EI-114, November 1, 1994.

8 See, Putnam, Hayes and Bartlett Inc., "Electric Power Competition: A Proposal for Maryland," Prepared for Allegheny Power System Inc. and The Potomac Edison Company, January 17, 1995.

..., the poolco would be an independent entity that would not own any (or would own only a limited number of) facilities, but would control the operation of some or all generators, and all transmission facilities, in a region. The poolco would be open to all generators connected to the grid, who would automatically receive any transmission service needed to sell power into the regional pool. In effect, the poolco would be responsible for creating and maintaining a regional spot market for electricity. The spot price in each trading period (perhaps hour-by-hour) would be readily available and made known to all market participants.

Generating resources would be centrally dispatched on an hourly basis by the poolco in much the same way as in current power pools. The principal difference appears to be that generators would be dispatched based on the bid price they submit to the poolco, rather than on their running costs. The poolco would operate a least-cost (in the sense of lowest bid) dispatch that accounts for any transmission constraints in the same manner as an existing power pool or a single utility dispatch center. Generators would be paid the market-clearing price[9] during each hour, as opposed to the bid price that each generator submitted to the poolco.[10] Likewise, distributors would pay the market-clearing price in each hour. Consequently, the poolco would break even in its basic dispatch function, since distributors would pay to the poolco what the generators receive from the poolco.

In effect, the poolco would become the market clearinghouse for the hourly energy market. Under the poolco concept, dispatch benefits are implicitly allocated among sellers and buyers by the spot trading at a market-clearing price. The poolco would have no further role in dividing or allocating benefits. Also the proposed poolco would have no role in long-term energy or capacity markets. Generators and distributors could enter into contracts outside the poolco.

Under San Diego's poolco concept as currently proposed,[11] spot prices would vary from one geographical location to another to reflect

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9 The market-clearing price is the highest bid price of any generator that is selected to provide service to the poolco in an hour. Each successful bidder would receive this price, regardless of whether its bid price was less than the market clearing price.

10 This method of pricing creates an incentive for each generator to bid near its marginal running cost, since it would risk losses if it bids less than its running costs and the poolco selected it to run, and it would risk losses if it bids more than its running costs and the poolco does not select it to run.

11 We understand that both San diego's and Edison's proposals continue to be revised, and that the two proposals may become more similar as details are worked out.

> transmission constraints.[12] This would allow the spot trading to be conducted at a price that reflects the real ability and limitations of the grid to move power from low-cost to high cost areas. The proposal includes opportunity cost pricing for grid congestion, as well as tradable capacity rights.[13]

The attraction of the Poolco proposal to public and private utilities, across the country and in other nations, stems in part from the gradual recognition that the Poolco is not a radical proposal. Rather, Poolco recognizes what exists today and what must happen under any system for a competitive electricity market. After some initial confusion, the continuing participants in the analysis of the electricity market recognize that the characteristics of the electricity system require the continued existence of a system operator. The only issue is the scope of the system operator's functions. At a minimum, the system operator must coordinate the actions of the market participants, to avoid violation of short-term system operating constraints, and provide balancing services that ensure both load following and backup for uncontracted demand. This coordination function exists today within the power pools or the utility control areas. Once it is clear that the coordination and balancing function must continue, a series of three questions arise that define the role of the system operator and the connection to the Poolco proposal.

The balancing functions require that the system operator have operational control over a minimum number of flexible generating plants and loads. The precise minimum number is difficult to define, with views ranging from many to few. However, it may not be necessary to define the number, depending on how we answer three remaining questions about the nature of the services provided by the system operator. For the flexible plants and loads, the balancing

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[12] Under Edison's proposal, in contrast, spot prices would not reflect transmission constraints.

[13] Federal Energy Regulatory Commission, Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, Docket No. RM94-20-000, October 26, 1994, p. 5-7.

function is a dispatch function. The first issue is whether the system operator should dispatch the flexible plants to achieve the lowest possible cost under an economic dispatch:

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

The alternative approach 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. There is no doubt that there are feasible options, such as minimizing the use of the transmission wires, that would preserve reliability and maintain system balance. However, the costs would be high. If we are to find an economic dispatch, then the argument is that the system operator should be able to do so better than anyone else. Although there are minor differences between textbooks in their respective definitions of natural monopoly, the common theme is that a single firm can provide the lowest total cost in serving a particular market. The economics -- the costs -- are essential, with the distinctive characteristic of a natural monopoly being not that there is no alternative to a monopoly, but rather that provision of supply through a monopoly is the lowest-cost solution. The arguments underlying the Poolco proposals stand squarely behind the proposition that economic dispatch is a natural monopoly. It seems that the natural answer is that the operator should be able to consider costs and provide an economic dispatch for some plants and loads, at least those that are part of the flexible components which must exist at some minimum level.

Once the economic dispatch service is available for some plants, access rules must be established to determine who can participate. Hence, the second question about the role of the system operator is:

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

At one end of the policy debate stands the view that the minimum number of flexible plants is a very small fraction of the total. The prediction may be that only the minimum number will participate, or implicit in the argument may be a view that participation in the economic dispatch should be restricted to the smallest number of plants possible. However, the natural extension of open access and the principles of choice would suggest that participation should be voluntary. With only the caveat that a minimum number must be flexible, the principle should be that 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 in the market.

System control is a monopoly and therefore will be under regulation of some form. Its pricing rules are a matter for public oversight. If the operator does consider costs and choose an economic dispatch for the flexible plants, there is an issue in setting the prices that will apply to the associated power flows. And these same prices will play a central role in defining comparable transmission tariffs for those who do not participate in the economic dispatch. Hence, the third question about the role of the system operator is:

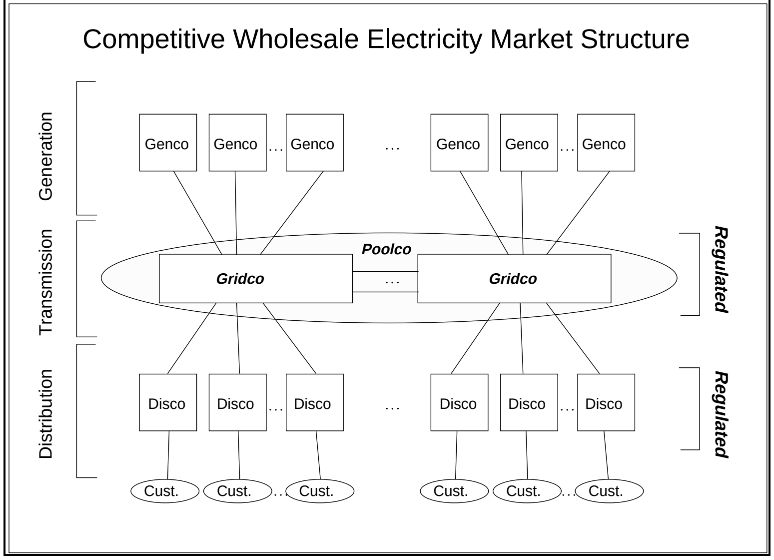
Should the system operator apply marginal cost prices for power provided through the dispatch?

The simplest conceptual approach would be to have an administrative price or penalty for the power obtained through the operator's economic dispatch. However, if set too low, there will be an incentive for participants to rely too much on the supply from the system operator, constituting a subsidy that the operator may not be able to support. Set too high, the administrative price becomes a penalty that provides incentives to avoid the economic dispatch and raise overall system costs. The alternative of marginal cost pricing based on participant bids has an obvious appeal. 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 for all uses of the transmission system.

The three questions are posed to isolate what is reasonably left to be decided under the system variants that might be different than the Poolco model. And if the answers follow the recommendations here -- just say yes -- the system operator will provide an economic dispatch service that is open to anyone who wishes to participate. Pricing will apply marginal cost principles based on the voluntary bids of the participants. And these same prices would apply to all uses of the transmission grid under a comparable, open access transmission tariff. Bilateral contracts would be fully available to meet all other commercial requirements.

The structure of this market could follow many different forms. For the sake of the present discussion, it is useful to describe the various elements and functions in terms of the industry organization suggested in Figure 1. However, as discussed below, it is the division of the functions that matters, not any particular ownership structure. The important point in Figure 1 is to distinguish the Poolco dispatch function as an essential facility with open access requirements just as important as connection to the transmission wires.

Figure 1



This pool-based market provides many advantages that flow from the interaction of the various elements. In particular the pool-based system creates or builds on a few key ideas to exploit coordination for competition within a consistent structure that conforms to the particular operational and economic characteristics of the electricity system. These interconnected pieces include least-cost dispatch, separation of ownership and control, separation of physical and financial transactions, a framework for transmission pricing and a framework for long-term transmission contracts. The connections are outlined here, with each element discussed in greater detail in subsequent sections.

Least-Cost Dispatch

Any efficient system for organizing the electricity market should include least-cost dispatch as a centerpiece. To be sure, the least-cost dispatch concentrates only on the short-run, and although the short-run is important, the greater part of the value of a competitive system is to be found in the long-run decisions that will control location and investment. However as Moen suggested above, the Poolco model builds on least-cost dispatch because it provides a framework for addressing many of the otherwise vexing problems of coordination and balancing to preserve reliability, encompasses a wide variety of ancillary services and still connects with the competitive market.

The least-cost dispatch based on participant bids is the ideal short-run outcome that would appear in a competitive market if it were possible for all the many participants to define the appropriate property rights and conduct all the complex trades in the network. Because of the complexity of these trades and the lack of workable definitions of key physical property rights, the common judgment is that a system operator is needed to coordinate the dispatch, at least for some fraction of the flexible plants. Since the operator must function to provide coordination services, least-cost dispatch provides the natural framework that replicates as close as possible the ideal outcome of the short-term competitive market. The Poolco model accepts and builds on this least-cost dispatch. And working from this starting point, the other features of the market can be derived within a consistent framework. The bidding prices and least-cost dispatch provide naturally the level playing field for all market participants, both large and small. There is no special advantage to size in benefitting from dispatch diversity and acquiring backup supplies. These services are available to all on the same basis. This open access to the dispatch and related services will facilitate entry and the pursuit of the forces of competition.

Separation of Ownership and Control

The Poolco control of the transmission grid and open access to all buyers and sellers in the wholesale market exploits another key idea in the separation of ownership and control of the essential facilities. In most markets there is a natural, but by no means necessary, equation of ownership and control. The owner of the facility typically is able to control its use. In the case of an essential facility such as transmission wires, the concern has been that ownership could be utilized by those with both generation and transmission to control the market. Although this control of transmission use has never been completely true, as witnessed by the continuing loop flow problems in the industry, changing the ownership linkage between generation and transmission has been argued by many as essential for providing true open access to the transmission grid.

The Poolco model takes a different and simpler approach, simpler at least when we recognize the existence and continuing need for the visible hand of the system operator. The Poolco model envisions an independent system operator who controls the balancing functions and flexible dispatch. This independent system operator controls the use of the transmission grid. By taking the control of use of the grid out of the hands of the owners of the wires, Poolco provides a consistent and straightforward mechanism for implementing open access in a complicated network: all market participants can participate in the economic dispatch in the same way and on the same basis. This simple separation of ownership from control could sidestep the need for a formal change of ownership of the Gridco, even though such a change of ownership would also be compatible with the pool-based model. However, with or without a change in ownership, it is essential to remember that under the Poolco model individual owners cannot decide who gets to use which transmission lines. The power flows in the best way available, from sources to uses, to preserve operational reliability while meeting the least-cost test that is consistent with the competitive market.

Separation of Physical and Financial Transactions

Given the Poolco, it is a simple matter to separate physical and financial transactions. In most commodity markets, delivery of the commodity is simple to define and monitor and it is possible and necessary in the early stages of market development to link closely the physical and financial exchange. You pay the farmer for the wheat at the time the bushel is delivered. There is no ambiguity in the definition of the bushel of wheat or the payment. Later, as the market matures, separate financial contracts will arise for wheat futures with only a formalized connection to the cash market for delivery of bushels of wheat. Delivery may never occur, or the quantities delivered may be separate from the protection provided under the futures contract. Over time the market develops separate physical and financial transactions.

The same process would evolve with commodity electricity. However, the Poolco model allows us to anticipate and exploit this separation of physical and financial transactions to solve a difficult problem in the electricity market. In particular, the need for continual balance of a constantly changing load pattern presents great difficulties in defining physical delivery. A Genco may contract with a customer to deliver 100 MWs, but over the course of the day both the generator and the customer may deviate from this contract, producing or taking more or less electricity. For these imbalances, or for any deliveries in the integrated network, it is impossible to say which electricity applied to a particular transaction. The easy direct link between delivery between participants and payment cannot be maintained. To solve this problem in an integrated network, Poolco conveniently skips the primitive step in the commodity market evolution by providing the foundation for separate physical and financial transactions.

The mechanism is through the pairing of simultaneous buys and sells with the Poolco and parallel bilateral contracts for a financial transaction between the parties. If, for example, the Genco delivers 102 MWs to the Poolco and the customer takes 97 MWs, the Poolco in effect buys the 5 MWs imbalance at the spot price. As will be discussed below, the Genco and the customer might have a bilateral contract for differences for the original 100 MWs at a long-term contract price. This separate contract can be arranged independent of the Poolco and has no bearing on the dispatch decisions. However, in this case, the effect would be for the Genco to deliver 100 MWs to the customer at the contract price, *no matter what the spot price*. In addition, the Genco would sell 2 MWs to the Poolco at the spot price and the customer would in effect sell 3 MWs to the Poolco at the same spot price. The imbalances would be priced at the spot price, and the contracts quantities would be covered solely by the negotiated price of the contract. All this occurs automatically, and constantly, because the transactions with the Poolco are at the transparent Poolco price available to all, providing the cash market benchmark that allows separation of the physical and financial transactions.

A Framework for Transmission Pricing

With a least-cost dispatch, there is an immediate and straightforward analysis that identifies the competitive-market opportunity-cost-based prices that should apply for flows in the transmission system. Transmission pricing is one of the most complicated parts of the policy puzzle. The complex interactions in the electric transmission network, with loop flow and the many constraints that may limit transmission use, present significant challenges in the implementation of an open access system. For a pool-based competitive market framework, however, the solution is available from the work of Schweppe et al. in the natural application of market clearing prices.[14]

The ideal competitive market clearing price for power at any location is the marginal cost of meeting the next unit of demand. For a collection of generating plants and loads at a single location, this market clearing marginal cost price is simply the marginal cost of the most expensive plant running at that moment. In a transmission network connecting many locations, there is an analogous marginal cost of power for each location. With least-cost dispatch, this marginal cost is determined by the cheapest way to redispatch the system and meet an additional unit of demand at that location. In the absence of constraints in the transmission system, the marginal cost determined price differs across locations by the marginal cost of power losses in transmission. In the more interesting case when constraints limit the use of the transmission system, the marginal cost contains an additional component that captures the impact of congestion due to the constraint. In either case, however, the marginal cost is easy to define and compute as a byproduct of the least-cost dispatch, as illustrated through several examples in the appendix.

With the marginal cost price of power available at each location, Schweppe identified the marginal cost of transmission between two points distant in the network as the difference in the prices at the two locations. In short, transmission of 1 MW from source to destination is equivalent to selling at the source and buying at the destination at the locational prices. Hence the true short-run opportunity cost of transmission between source and destination is the difference in the locational prices. This insight cuts through the maze of complexity of network interactions, loop flow, security constraints and all the other arcane details of transmission networks. It builds on the foundation of economic dispatch and reduces the problem of finding

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[14] F. C. Schweppe, M. C. Caramanis, R. D. Tabors, R. E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988.

the economically efficient price of transmission use to the determination of the locational based prices that accompany the inputs and outputs of power in the network. And the prices apply no matter how complex the intervening network between destination and sources, with any number of users, and whatever the operating conditions. Just as the least-cost dispatch by the system operator handles all the network operating details, it also produces a solution to the problem of short-term pricing of transmission in a manner consistent with the overall framework of a competitive market.

A Framework for Long-Term Transmission Contracts

A solution for the economically efficient short-run pricing of transmission use based on the Poolco model of least-cost dispatch provides the foundation for a design of long-term transmission arrangements that can support efficient contracts between Gencos and distant customers. The first and most natural approach to long-term transmission access and rights would be to assume that it would be possible to define a physical right to use the transmission grid to move power from certain sources to other destinations. Once a market participant had obtained this physical right, the holder could move power as envisioned or trade the right to allow others to move power from the same sources to the same destinations. This property right would be the natural analogy to capacity rights in other markets, such as for interstate transport of natural gas, and seems necessary to provide the foundations for the essential long-run competition in the market.

Unfortunately, the natural presumption of the existence of such a well-defined physical transmission capacity right confronts three seemingly insurmountable problems. First, assignment of such rights implies control of the use of the physical transmission of power in a way that would reverse the separation of ownership from control that is an essential feature of open access to the transmission network. Second, restricting use of the grid to match the allocation of such rights would either place great demands for constant retrading in a short-run secondary market or would compromise the ability to achieve the least-cost dispatch. To obtain the economic dispatch, the system operator needs control over a sufficient range of flexible plants and control over the full transmission grid. Third, and more arcane, except in the case of a substantial under-allocation of what would seem to be the natural transmission rights, an under-allocation designed to avoid any possibility of confronting any transmission constraints, there is no well-defined physical capacity that can be allocated and assured. Due to the many interactions across locations, the "capacity" of the network is not amenable to any easy definition and the ability to move power between locations cannot be assured. The capacity of the network at any time depends on the configuration of the inputs and outputs.[15]

Although physical transmission rights cannot be guaranteed, the Poolco least-cost dispatch would provide the foundation for a transmission contract that would serve essentially the same purpose as a physical right by defining a financial transaction that would not depend on matching physical flows in the actual dispatch. Transmission congestion contracts could be defined for a financial payment equal to the difference in congestion costs between locations. Such a transmission contract would allow a Genco to arrange a power contract with a distant customer and be assured of the delivered cost of the power. Through the Poolco dispatch, the system operator would collect congestion payments whenever the system was constrained, in turn

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[15] W. W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-242.

disbursing the congestion payments to the holders of the transmission congestion contracts. The Poolco would keep none of the payments, and participants with long-term transmission contracts could fully protect the ability to deliver power at an agreed price, just as if there was the physical delivery from the source to the destination. However, unlike the physical transmission rights, the transmission congestion contracts are well defined, can use the full capacity of the network, and are consistent with actual flows moving according to the least-cost dispatch. Furthermore, the ability to honor the contracts does not depend on the configuration of the inputs and outputs. The transmission congestion contracts would provide a way to untangle the network and convert short-run opportunity cost prices into long-term transmission arrangements.

The Poolco model provides these several interconnected features of least-cost dispatch, separation of ownership and control, separation of physical and financial transactions, a framework for transmission pricing, and a framework for long-term transmission contracts to support a competitive market. The pieces fit together into a coherent whole. Each will be developed further below. This integrated framework under the Poolco model addresses many of the issues inherent in the creation of an open-access, competitive electricity market. To understand this framework, however, it helps to digress briefly and dispose of a few misunderstanding that have arisen about the Poolco model. A number of problems that have been attributed to the Poolco are seen on closer inspection to be either not applicable or, if applicable, independent of the Poolco model.

DISTRACTIONS

The national discussion of the Poolco model has produced a number of questions or concerns about possible failings of the approach that on closer inspection appear to be based on a misunderstanding or misinterpretation of the Poolco design. A brief summary of each suggests the possible source and a clarification of the misunderstanding. Describing what is not sharpens the description of what is included in the Poolco model.

Market Interference

For all whose transactions are organized through the economic dispatch of the system operator, the Poolco formally buys and sells the power. This buy-sell model looks close enough to the experience with natural gas and other industries to raise concerns that the Poolco will have its own commercial interests to consider in choosing which electricity to buy and at what price to sell. After all, it was just the concern with the system gas owned by the interstate pipelines that was at the source of many of the difficulties in developing comparable services and true level playing field in that market. If the system operator is buying and selling as a broker or trader -- taking positions in the market with an anticipation of profit or the risk of loss -- the Poolco model would present similar problems of conflicting incentives and market interference.

Concern with this type market interference is not applicable to Poolco because of the special and limited nature of the formal buying and selling through the economic dispatch. In particular, all transactions with the Poolco are cleared at the same time and at the current market price. The Poolco takes no positions and makes no profit on the transactions through the economic dispatch.[16] The buying and selling may look like the Poolco operator is a trader in the market, but the buying and selling occurs only to simplify the transaction accounting. In

16 For simplicity, this discussion ignores default and credit risk.

principle, it would be possible to match all buyers and sellers, without the Poolco operator standing between as the formal intermediary, with the Poolco charging only market clearing prices for transmission and related services. But this would be an unnecessary recording keeping fiction, with the end result identical to the transaction of the net inputs sold to the Poolco and the net outputs purchased from the Poolco at the current market price. As described in the FERC summary, the Poolco is not another trader; "[i]n effect, the poolco would become the market clearinghouse for the hourly energy market." The Poolco as a clearinghouse simplifies the market accounting and transactions.

Market Limitation

Again because of the formal role of accounting for transactions through the Poolco, it might appear that contracts between buyers and sellers, generators and customers, brokers and aggregators, would be precluded or at least restricted. Only transactions through the Poolco would be allowed, and this would inhibit the intended innovation in the market through development of new products and services that would depend on direct customer access and contracting.

Again this concern is misplaced because of the limited role of the Poolco and the simple accounting process of tracking power in and out of the network. Of course, physical delivery of power through the network is not optional, and everyone in the market must follow the rules for power dispatch and payment for transmission services. However, within these rules, any contract between any parties in the market can be implemented under the generic Poolco model. For power transactions self-nominated and subject only to transmission charges, any contract can be arranged in a form that is virtually identical to the traditional conceptual model of direct delivery of power between the supplier and the customer. In the case of power bought and sold through the economic dispatch, any contract that supplier and customer could design could be implemented through the device of the contract for differences. The Poolco model provides a simple and efficient framework for implementing the full range of commercial contracts while simplifying the requirements for the necessary backup power, reference prices and other system services highlighted above by Moen as so essential to support a competitive electricity market.[17]

Market Dominance

The emergence of a Poolco that covers a large region raises the specter of market dominance. Market participants might control the pool or the bidding process in order to prevent competition and preserve their existing positions. The assertion and fear is that the Poolco would simplify the exercise of market power.

This is an important issue, but the concern is misplaced. At one level, the Poolco removes an important source of market power by providing open access to the grid and the system dispatch. The independence of the system operator is a central feature of the Poolco model, and this independence removes the most obvious and most easily exploited element of vertical integration, thereby reducing market power. However, the Poolco model does not by itself change in any way the concentration of ownership of generators or control over final customers. To the extent that such high concentrations exist, there may be a potential for

[17] W. Hogan, "To Pool or Not to Pool: A Distracting Debate," Public Utilities Fortnightly, January 1, 1995.

exercise of market power under the Poolco model.

Market power issues must be addressed in regional generation markets. No simple design can overcome a fundamental concentration of market power. The new market model for generation needs to recognize concentrations of ownership and provide mechanisms to prevent monopoly pricing through market dominance. However, as discussed below, the new Poolco institution of the competitive market will create alternatives for regulating generation that can prevent monopoly pricing while preserving competitive pricing, both of which will differ from cost-of-service pricing. Most importantly, the Poolco model does not create nor does it enhance the concentration of ownership of generation. The Poolco model removes barriers to entry, through open access, without erecting any new barriers. Where remaining concentrations of ownership exist, the Poolco provides a framework for dealing with the effects. Where market power exists, Poolco makes the situation better, not worse. The Poolco model by itself is not a complete solution to the problem of market power, but the attractions of the Poolco are not reduced by a concern over possible abuses of market concentration.

Bureaucratic Delay

The Poolco model sounds new and different and many fear that it will take too long to implement, thereby delaying the introduction of competitive market forces. This hypothetical concern was not reduced when just such a tactic of delay was the privately conceded and sometimes publicly announced policy of many in the utility industry.

There are three major reasons why this fear of delay may in the end be misplaced. First, the Poolco requires less innovation than appears on first inspection. For instance, the system operators, control functions and other services needed by the Poolco are already in place. They need not be created anew. These people and systems exist within the existing utilities and power pools; the Poolco innovation is the identify these people and functions and have them operate independent of the existing utilities. Surely this step of making the operators independent is necessary and unavoidable. Second, the major innovation of the Poolco is in the matters of pricing and transmission contracts. While new, these problems must be addressed under any system as part of the package of developing and implementing open access and comparable transmission pricing. The Poolco model provides a coherent and consistent approach for such access and pricing. The Poolco model may both simplify and accelerate a task that cannot be avoided, providing the fastest route to comparable transmission pricing that also conforms to the underlying economics of a competitive electricity market.

Third, when coupled with methods for recovery of stranded assets, as discussed further below, the incentives for existing utilities should change from an interest in delay to an interest in early adoption. Implementation of the Poolco model or its equivalent in customer access will likely be a necessary step for the existing utilities to be allowed to participate actively in the deregulated generation and supply markets. Without a Poolco, the regulated utilities may see their markets disappear to new entrants who will operate without the same regulatory constraints. To the extent that the utilities wish to participate in the market, it will be in their interest to implement the Poolco model. The utilities that have offered the Poolco proposals have made the explicit point that the Poolco is the fastest way to a competitive market that also conforms to the other regulatory and reliability obligations that should be met.

Bureaucratic Complexity

The collection of Poolco bidding, economic dispatch, locational-marginal-cost-based prices, transmission congestion contracts and so on appears just too complex. A simpler system would be preferred, and one requiring fewer changes in the status quo.

While the concern is understandable and legitimate, it is important to distinguish between what is truly complex, and what is simply different. The Poolco model is different, at least in its economic and institutional details. At an engineering level, it is much like the current system, designed purposely to capture the ideal design for best practice in the industry. However, the differences in pricing and institutions are not necessarily indications of an increase in complexity. As one industry observer noted, "the people who think the Poolco model is complex are people who think they understand the current system."[18] Yet few people do understand the details of the current system, where a great deal of complexity exists embedded in the operations that are internal to the monopoly utilities or existing power pools. In the open-access, competitive market, these hidden details cannot be hidden for long, as services and pricing rules must be unbundled and made more transparent. For example, anyone who believes that the Poolco pricing rules are too complex should take up the task of explaining how current power pool split-savings pricing systems operate in the presence of system congestion, and then explain how this pricing regime could survive when faced with the pressures of arbitrage by those who can trade around the pool. Explaining how the present system works is at best difficult. An explanation of how to protect the split-savings pricing system from death through arbitrage in a competitive market would deserve a Nobel Prize.

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[18] Anonymous.

The present industry access and pricing system is both complex and inconsistent with the incentives of the competitive market. By contrast, the Poolco model is built from a consistent model of an efficient competitive market and captures within the economic dispatch the principal and inescapable complexity of the network interactions. "A theory should be a simple as possible, and no simpler." The Poolco model is simpler than the status quo, and may be the simplest model that is consistent with the economics of the industry and the Commission's stated public policy objectives.

RELATED ISSUES

There are several related issues in the development of the new industry structure and the associated regulation where the Poolco model changes what can be done, but the Poolco model does not by itself remove the need for other policies. The focus here is on the end state rather than the important transition in creating the new institutions, assigning responsibility for embedded costs, and allocating various assets. This is another topic. In the end state, however, the Poolco model must be compatible with other policies. A brief summary of foreshadows the subsequent discussion.

Regulation of Essential Facilities

The electricity market will not be fully competitive. There will remain an important role for regulation to oversee the operation of monopoly activities and access to essential facilities. For instance, at the state level there will continue to be a responsibility for regulating access to and pricing of distribution wire services.

Wholesale market activities fall under the jurisdiction of the FERC. The Poolco system operator would presumably be subject to FERC oversight to monitor the application of the dispatch and pricing rules, administration of transmission contracts, and the other features of the Poolco model. Regulation would be light handed, with no need for the FERC to address any long-term investments or commitments in power sales.

Gridco expansion and pricing would continue to present a need for regulatory oversight, but the Poolco model would substantially simplify transmission investment decisions. Economies of scale and complex network interactions would continue to create incentives that would not be wholly compatible with decentralized decisions in a market. This need to address network expansion as an integrated problem leads to a continuation of the expected need for the Regional Transmission Groups (RTG). An RTG would be needed to review the operating reliability standards and evaluate the impacts of proposed transmission expansions. However, this evaluation need not extend to a central decision on the need or cost responsibility for transmission expansion. Under the Poolco model, the users of the system who are buying and selling electricity without a complete hedge through transmission congestion contracts will face the short-term market clearing price. In the face of transmission congestion, the locational prices provide the proper incentive for investment in transmission facilities. Investments should be made when justified by the savings in congestion costs. Those who are prepared to make the investment would obtain the associated transmission congestion contracts. The role of the states, the RTG and the FERC, therefore, would be to review requests for transmission expansion, examine the compatibility with the companion request for new transmission contracts, and ensure an open process for all to join in developing combined transmission investments recognizing the interactions in the network. The regulator would be responsible for enforcing a requirement for existing transmission facility owners to support expansions and reinforcements at a traditional regulated cost that recovered the incremental investment, and then to assign the corresponding transmission contracts.

The transmission congestion contracts, once created, would no longer need any special regulation. Although investments in the transmission grid would by lumpy and would require the cooperation of the owners of existing facilities, the transmission congestion contracts would be divisible and freely tradable in a secondary market. This secondary market would provide a ready source of transmission hedges that would serve as an alternative to system expansion. The price of the transmission contracts should never rise above the expected congestion opportunity costs or the cost of incremental expansion of the grid. In this way, the unregulated market for transmission congestion contracts would emulate the broad outlines of the FERC pricing policy. Transmission contracts would be obtained at the lesser of opportunity costs or incremental costs. Holders of existing transmission rights, converted into the appropriate transmission congestion contracts, would pay embedded costs but not opportunity costs. Those using the transmission grid without holding transmission congestion contracts would pay opportunity costs but not any embedded costs other than the costs of any stranded assets that would be collected from all users. Most important of all, the long-term transmission market could be a market, relying as much as possible on the incentives and forces of competition, limiting the role of planning and regulation to address the unavoidable interactions in the transmission grid. Investment decisions would be made at the initiative and with the agreement of those required to bear the cost.

Market Power

To the extent that there is a high concentration of control of generation or load, there will continue to be a potential for an exercise of market power. This potential creates another demand for continued regulatory oversight. An advantage of the Poolco model is the ability to expand the range of options available to address potential problems of market power without compromising other goals in the development of a competitive electric market.

The two ends of the policy spectrum for dealing with market power are regulation and divestiture. At the regulatory end, firms with a high concentration of generation may be subject to a form of continued cost-based regulation designed to prevent any abuse of monopoly power. For the obvious reason, this is an unattractive approach that would be inconsistent with the competitive market. At the other end of the spectrum would be a policy of requiring divestiture of generation into a sufficient number of competing entities. In the U.K., where concentration of generation ownership has produced the expected behavior inconsistent with competitive pricing, the regulator has embraced this divestiture strategy as the principal tool for mitigating the effects of market power. However, the divestiture approach has its own limitations, including what might be the strong objections of the existing utilities who will dispute the existence of market power or argue the inability to exploit what potential power that may exist.

In the middle of the spectrum are many lesser options that could be implemented within the Poolco model and should be explored further. For instance, contracts adopted for a transition period can dramatically alter the incentives of generators with market power. In effect, a long-term power contract at a fixed price transfers the beneficial interest in the plant from the owner to the customer, leaving the generator with the incentives to control costs and maximize the economic use of the plant. This is easy to achieve in the Poolco model and is exactly what happened in the U.K. during the early days of its electricity restructuring. The generators were fully contracted and they behaved like competitors. Only when the generation contracts began to lapse did behavior turn strategic and pricing begin to deviate from the competitive norm.[19] Similar generation contracts could be fashioned in the United States and implemented as contracts for differences, perhaps as part of a larger strategy for recovery of past investment costs.

Absent contracts for the sale of the power, incentive contracts could be structured to insulate the operators of generating plants from the control and interests of the owners of the plants.[20] Generation owners could contract out plant management and bidding, with the incentive payments for the plant geared only to successful operation of the plant in a competitive framework, not to the profits created by strategic behavior that exploited market power. It would be an easy matter for regulators to monitor the terms of such contracts, with the result that the plant operators should perform in the same way as under a divestiture but without the difficulties of actually forcing the sale of the plants.

These examples illustrate the possibility of remedies that might avoid either extreme end of the system. Before even these remedies may be needed, however, further consideration should be given to diagnostics that could reveal abuses of any market power. Again the Poolco model would simplify the regulator's use of such diagnostics to track the performance of the generators. Even if generators have market power, they may not use it, because it would be easy to detect. For instance, it may be possible to design data monitoring schemes that could

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19 R. Green, "Britain's Unregulated Electricity Pool," in M. Einhorn (ed.) From Regulation to Competition: New Frontiers in Electricity Markets, Kluwer Academic Publishers, Boston, 1994, pp. 73-96.

20 This idea was suggested by Michael Schnitzer.

effectively uncover abuses of market power along the following outline. Attention would concentrate on possible market abuses with existing power plants; entry provisions should be sufficient to assure competition with new facilities. For the existing plants, there is a great deal of data that could be used to provide reasonable estimates of the capacity and operating costs of the plants. With this information, and the transparent prices of the Poolco dispatch, exercise of market power to capture monopoly profit would be revealed by three simultaneous conditions:

> **Price Above Operating Costs.** The market price must be high enough to contribute to monopoly profits. If prices are at or below the operating costs of the plant in question, there is no profit, hence no monopoly profit. The plant may not be running, or if dispatched it would have no impact on the market price.
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> **Output Below Capacity.** The exercise of monopoly power in the Poolco market requires restricting output in order to support higher prices. If the plant is running at full capacity, high prices above operating costs may generate large profits, but these profits reflect scarcity and not use of market power. Scarcity prices should be paid and charged to provide the right incentives in the market; but scarcity prices apply only when the applicable plants are offered and running at full capacity.
>
> **Significant Affiliated Output.** The profit from monopoly bidding and pricing is captured on the commonly owned output which enjoys the benefits of the higher prices created by the restriction. Hence the person restricting output must have other output sufficient to demonstrate a higher profit captured because of the use of market power.

These conditions should be easy to monitor with the information available from the Poolco dispatch. If any of these conditions fails to hold, then there is a natural explanation of the market outcome that differs from use of market power. Since the exercise of market power should the concern, not the simple fact of concentration of ownership, this outline of the elements of a possible diagnostic suggests a policy that could be followed before remedies need be applied. This would be a variant of light-handed regulation. The regulator would monitor the Poolco results for existing plants. As long as the three conditions did not exist simultaneously for a significant number of hours a year, bidding behavior would be accepted as consistent with market competition. Otherwise, the search for remedies would be on. Given the nature of the likely remedies, the result might well be that behavior would be competitive and no remedies would be required.

Providing Customer Choice Without Stranding Assets

More than the design of the wholesale market structure, interest in restructuring of the electricity industry centers on alternatives for providing customer choice and the treatment of stranded assets. Customer choice has value as a means to recognize greater diversity of customer needs and to reinforce the pressures of the competitive market. At the same time, offering customer options carries the risk of potentially stranding assets with the danger of subverting the intent of regulatory policy or subverting the intended transition to a more competitive market.

The means to recover any potential stranded assets exist under regulation to the extent that there are truly essential facilities. The simple principle is that otherwise above market costs can be recovered only through control of access to some essential facility. Although FERC will have an important role to play in the policy for dealing with stranded assets, most of the assets at interest fall under state jurisdiction, and the full stranded asset discussion is beyond the scope of this paper. Furthermore, most of the decisions regarding customer access rest in the first instance with jurisdictions other than FERC. As far as the design of the wholesale market is concerned, the principal concern here is to ensure that the system can be made compatible with local choices on customer access and the recovery of stranded assets. The Poolco model allows a great deal of flexibility, and it is possible to design methods for customer access and choice that strand no assets and are compatible with a workable mix of regulatory approaches at the local level.

The usual practice applies the label "retail wheeling" to expansion of competition to include sale of electricity to retail customers. This label appealed to a comfortable fiction that suggested power could be directed from one source to another destination by "wheeling" through the wires of intervening utilities. For a variety of reasons, the traditional retail wheeling approach is an exceptionally bad and misleading model of the actual operation of an electricity market. Ruff has provided an extensive critique under a charge to "Stop Wheeling and Start Dealing."[21] Major obstacles to retail wheeling are in the potential for jurisdictional conflict and uneconomic bypass leaving assets stranded. The traditional retail wheeling model envisions the delivery of power from a particular generating plant to a particular customer, paying a separate charge for the transmission service through the local utility. In the United States, however, this simple act of unbundling the transmission all the way to the customer raises the possibility that the entire transmission rate becomes FERC and not state jurisdictional. The reality of such a change would greatly complicate regulation at the state level, especially during the period of transition to a more competitive market. Even the fear of such a jurisdictional impact could foreclose the regulatory change.

The traditional retail wheeling model carries with it the common, although false, notion that the customer somehow leaves the local utility. And the separation of the transmission charges from other costs creates the incentive and the opportunity for customers to bypass the local utility by "wheeling" power through the utilities wires for only the cost of transmission. To the extent that the local utility charges include significant recovery of sunk costs, the act of

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[21] L. Ruff, "Stop Wheeling and Start Dealing: Resolving the Transmission Dilemma," Electricity Journal, June 1994, pp. 24-43.

bypass threatens to strand the associated assets that gave rise to the costs. Given that many markets have a large potential for stranded assets, there is a real fear that traditional retail wheeling could lead to the financial collapse of many existing utilities. In principle, this bypass threat could be overcome through charges imposed on the wires. However, the retail wheeling model of the customer leaving the utility and the possible loss of state jurisdiction over the wire charges create substantial opposition to the retail wheeling approach and to customer choice. The active support of retail wheeling by others as the prerequisite for immediate lower prices only reinforces the concern. The only way to achieve immediate lower prices under retail wheeling is through bypass of the sunk costs and stranding of assets.

However, the traditional retail wheeling model is not the only way to provide customer choice. *Efficient Direct Access* to the wholesale price is a better and simpler concept that can support customer choice and a competitive market without stranding assets.

Customer choice through Efficient Direct Access builds on the reality of a competitive market with open access and comparability of service.[22] It provides real customer choice through access to the wholesale market consistent with jurisdictional boundaries and incentives for efficient decisions. One way to approach the concept is to start with a simple question: What is required to provide customer access to the wholesale market? This question in turn carries with it the issues of physical access and price.

What is required to provide the customer physical access to the wholesale market? Answer: Nothing. Every customer, large and small, already has access to the physical wholesale market. When anyone flips the switch, the same power comes, retail as well as wholesale.

[22] W. Hogan, "Efficient Direct Access: Comments on the California Blue Book Proposal," The Electricity Journal, Vol. 7, No. 7, September 1994, pp. 30-41.

There is no relevant distinction, and no technical method available to deny access to the power. Hence, all customers are already connected to the physical wholesale market.

Apparently the only issue remaining is to provide customers access to the wholesale market price. Viewed from this perspective, the problem of access is simplified. Only two new ingredients are required to complete direct access to the wholesale market and provide customer choice. The two ingredients are a spot price and a new customer tariff:

- **Arm's Length Spot Price.** The wholesale market will develop a transparent arm's length spot price. It may be through hubs--such as in natural gas--or a pool, or some mixture of a bilateral and a pool-based market. The more efficient the wholesale market, the better, but some price will appear against which buyers and sellers can trade.

- **Time-of-Use Tariff**. All customers remain with the distribution utility under traditional cost-of-service rate principles. However, customers have a time-of-use tariff with the energy component set to the observed arm's length spot price. This approach is related to "net back" pricing principles familiar from other regulatory settings and as advanced by many others (Moskovitz).

With the Poolco model, there is a clearly visible and transparent market clearing price available to all. With time-of-use rates at the distribution level, customers would have real access to the wholesale market. They could enter into contracts with generators, to provide whatever security or flexibility that they were prepared to pay for in the market. The technical step is to employ a contract for differences that keys on the spot-price.

With customer choice available, the obligation to invest in commodity energy should move from the regulated monopoly to a competitive market. Commodity energy investments could be left to the market. Regulated utilities could stop making investments in new long-term energy or generation capacity commitments under cost-of-service regulation. Hence the obligation to serve would be interpreted no more as the obligation to supply but only as the obligation to provide access to the market.

Efficient Direct Access requires only a competitive wholesale market such as that provided by the Poolco model and a modest rate design innovation. This approach to customer choice through direct access to the wholesale market is functionally equivalent to traditional retail wheeling but easier to implement and consistent with many constraints otherwise violated by traditional retail wheeling. Efficient Direct Access:

- **Changes No Jurisdiction.** Customers never leave the local utility. Formally the utility buys from the wholesale market and resells at the spot price. There are no changes in cost-of-service principles or formal entry into the FERC regulated wholesale market.

- **Requires No New Legislation**. State regulatory authorities have long set the time-of-use tariffs. The extension to using the arm's length spot price is important, but it is a difference only in a small detail that should raise no controversy.

- **Strands No Assets**. All customers remain under the cost-of-service tariff. Decisions on rates and cost recovery can proceed as before, independent of the existence of Efficient Direct Access and customer choice.

- **Abandons No Worthy Programs**. Whatever can be done under traditional cost-of-service regulation--limited by the inevitable pressures of a more open wholesale market--can be continued under Efficient Direct Access. Universal service support, investments in energy efficiency, and subsidies for renewable and other environmentally preferred alternatives could be made when justified, and included in the cost of service applied to all customers separate from the time-of-use energy charges.

Efficient Direct Access provides real benefits consistent with the many other goals of the partially competitive and partially regulated electricity market. Efficient Direct Access:

- **Provides Customer Choice.** Customers who wish to make long-term arrangements for contracts with generators have full freedom through the mechanism of contracts for differences, which conform to the reality of the electricity market.

- **Reduces Regulatory Demands**. Central planning for all commodity resource procurement can move to the decentralized decisions of the competitive market.

- **Supports Efficient Investment**. Since payment for sunk costs or other mandated programs is independent of the source of power or the arrangements under long-term contracts, the incentives support efficient investment in new facilities and services for commodity electricity.

- **Gives Utilities an Exit Strategy**. Since there is no need to delay Efficient Direct Access to allow for recovery of sunk costs, regulated utilities can immediately stop investment in new regulated generation commitments, redefining the obligation to serve as the obligation to deliver.

With the Poolco model available to provide open access in the wholesale market, and Efficient Direct Access as a means for providing customer choice, the basic elements would exist for consistent regulatory policies at the state and federal level that would promote the transition to a competitive market and allow for recovery of stranded assets. The remaining issues would be to deal with stranded assets that might be legitimately recovered from wholesale customers, which FERC could regulate through some variant of transmission access charges.

THE FUNCTIONS OF THE ELECTRICITY MARKET

The wholesale electricity market, like any well-functioning commodity market, will include diverse commercial and financial arrangements, including contracts of various types and duration, vertical integration where allowed, joint ventures, short-term trading and so forth. At the core of these commercial arrangements will be a spot market in which physical electricity is priced and traded. This electricity spot market will be technically complex but invisible to most consumers, just as the technically complex wholesale markets in petroleum and government securities are invisible to most buyers of petroleum and banking services.[23]

A spot market will develop for any commodity and it is not the usual focus of policy interest. However, the special characteristics of electricity increase the importance of the spot market in designing a framework to support competition. A spot market in electricity has two principal functions.

- **Maintain Efficient Short-Term Operations or Dispatch.** A spot market coordinates short-term operations of separately owned entities to assure that demand is met economically and reliably given the production facilities actually available on the day, largely independent of longer-term contract arrangements.

- **Facilitate Longer-Term Contracting and Competitive Entry.** A spot market reduces the risks of contracting by allowing contracting parties to buy and sell "overs and unders" to meet their obligations at least cost/highest profits, thereby facilitating entry by undiversified competitors, each of which can compete in the specific activity it does best without needing to be a self-contained, full-service producer.

Discussions of electricity spot markets usually focus on the first of these two objectives, maintaining efficient and reliable operations or dispatch. This focus is understandable, given the traditional central control of system operations and the difficulty or even impossibility of designing a spot market that will mimic the operations of a technically oriented dispatch

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[23] D. Garber, W. Hogan, L. Ruff, "An Efficient Electricity Market: Using a Pool to Support *Real* Competition," The Electricity Journal, Vol. 7, No. 7, September 1994, pp. 48-60.

process. But it is not the primary purpose of a spot market to improve or duplicate the dispatch of given plants with given cost characteristics meeting given demand *in the short run*; rather, it is to allow market forces to determine the amount, mix and costs characteristics of generating plants, and the level and shape of demand, *in the long run*. A well-designed spot market and associated dispatch process will maintain or even improve short-run efficiency and reliability, albeit probably with more price-induced load management and less reserve capacity than is traditional. But even if a spot market appears to reduce short-run dispatch efficiency to some extent, this can be a small price to pay for the benefits of competition in the longer run, where the largest benefits are expected.

Contracts and the Spot Market

Most money flows in the industry will be determined by contracts rather than by spot market prices directly. One of the principal functions of a spot market is to facilitate contracting between producers and consumers, either directly or through middlemen of various kinds. A spot market allows contracting parties to buy and sell incremental amounts of physical product in the market, so that their bilateral contract does not have to try to perfectly match their individual physical operations. In a fully efficient market the parties to a contract may not even trade physical product with one another at all, but act independently in the spot market, with monetary payments between them based on the difference between the spot market price and a contractually defined price. Such "contracts for differences" can take many different forms, providing a flexible vehicle for allocating market and other risks any way contracting parties agree upon.

The commercial substance of the contracts that will prevail in a mature electricity market cannot and need not be predicted with certainty now, although it is certain that the allocation of risks and rewards will be different in a competitive electricity market than in centrally planned monopoly systems. It may be that, apart from the long-term contracts necessary to define the equity risks of long-term investments, most commercial contracts in a competitive electricity industry will be for relatively short terms of a few months to a few years. Such contracts will allow generators to manage their maintenance and cash flow, retailers to set their tariffs and negotiate contracts with customers, industrial customers to plan their operations and budgets and so forth, but will leave long-term energy market risk on generators -- where it probably belongs.

Because many parties will find contracts useful for managing their short- and medium-term operations and cash flows, on any given day much of the demand in the electricity market will be covered by contracts, so that spot market prices may determine only a small fraction of the money flows between consumers and generators. This does not make the spot market any less important or its price signals any weaker. Even with a high level of contracting, the spot market will determine the price expectations against which future contracts will be written, will facilitate contracting and entry and will maintain efficient operations by, among other things, providing strong incentives for incremental generation and load management when demand threatens to exceed supply. When spot prices increase to high levels, even a fully contracted generator has strong incentives to produce up to and beyond its contracted amount and even a fully contracted buyer has strong incentives to reduce its demand and sell its contracted but unused energy into the spot market.

A high level of contracting is important for spot market operations because it allows the spot price to fluctuate as widely as necessary to accomplish the critical coordination and market-clearing roles without exposing producers and consumers to large fluctuations in revenues and costs. Spot prices can and should vary widely and rapidly; they are high at some times, perhaps increasing by factors of several hundred during emergency conditions; and they are low at other times, perhaps even negative when inflexible generating plants are competing to avoid shut-down costs. These extreme price signals should be regarded largely as internal technical devices the industry uses to manage itself, much like a central bank's overnight interest rate, which can soar to annual rates of hundreds of percent -- for one day. Extreme fluctuations in spot market prices simply make explicit the equally extreme but mostly hidden measures a monopoly utility uses to deal with the same technical situations. Because spot prices may apply to little of the product that is actually traded at any time, these fluctuations may have little commercial significance to many customers, while providing opportunities for those who have the technical capability and commercial interest to operate in the wholesale spot market.

The Role of Dispatch in the Spot Market

An electricity spot market can work much like any other wholesale market in which buyers and sellers make offers, determine the prices at which supply equals demand and trade the product at those prices. Some special market arrangements are needed to deal with the special characteristics of electricity; but both the special characteristics of electricity and the market arrangements differ only in degree from those in other functioning commodity markets.

The most obvious special feature of electricity is the need for an integrated transmission grid. But centralized facilities for handling the physical product exist in many commodity markets. An electricity grid differs from port facilities, airports and stock exchanges only in the size of the capital investment and in the extreme degree of natural monopoly involved. Grid access and pricing must be regulated to assure nondiscriminatory treatment of all traders.

The more unusual and less appreciated aspect of electricity markets is the need for a centralized trading process. Because electrical energy cannot be economically stored, supply must equal demand virtually instantaneously everywhere on an interconnected system. Pricing energy to clear the market at all times means, strictly speaking, that a different price must be computed every minute or less and, when transmission losses or constraints are important, at different locations on the grid.

Least-cost dispatch is the competitive market equilibrium. The least-cost dispatch satisfies the "law of one price" and the "no arbitrage" condition of the competitive equilibrium. Convergence of a fully decentralized market to a competitive equilibrium depends on ease of trading and well-defined property rights. Neither condition holds in the electricity system. The characteristics of electricity coupled with poorly defined property rights create a natural monopoly in dispatch.

Natural monopoly is an economic concept. Although there are minor differences between textbooks in their respective definitions of natural monopoly, the common theme is that a single firm can provide the lowest total cost in serving a particular market. The economics -- the costs -- are essential, and without specifying the cost structure there would be no foundation for asserting a natural monopoly condition. There is no theory of "natural physical monopoly," and with appropriate restrictions virtually any market could be served in a number of ways that would involve more than one firm. The distinctive characteristic of a natural monopoly is not that there is no alternative to a monopoly, but rather that provision through a monopoly is the lowest-cost solution. The electricity system has special characteristics with important engineering and commercial implications that lead to a natural monopoly condition in dispatch:

- **Cost Diversity.** The short-term cost of operating existing power plants exhibits great heterogeneity across plant types and locations. There are always substantial gains from trade by using low-cost plants that are available to substitute for higher-cost plants.

- **Load Uncertainty.** Load conditions change substantially over the day and season. Variations in load are difficult to predict and change differently at different locations.

- **Complex Control Requirements.** Operating conditions require close monitoring and control on very short time horizons. For many important decisions, operating conditions must anticipate emergency contingencies. These constraints can and often do limit the flexibility to select the running levels of individual power plants.

- **Network Interactions.** The interconnected network under current technology creates strong interactions across locations. Every power plant and load affects all others. The interactions with system constraints can be large and differ substantially by location.

This combination of factors greatly complicates operation of a short-run bilateral market. It is difficult to specify and use decentralized information that would allow decentralized trades to approach the efficient short-run solution. These problems historically motivated the development of electricity power pools.

Operating such a system of decentralized, interacting, minute-by-minute markets without any central coordination is still and probably always will be impractical; hence it is necessary to continue relying on a monopoly dispatcher to provide the services necessary to match supply to demand instantaneously and across electrically separated locations. But it is practical to create a spot market that matches supply to demand and computes market-clearing prices for, say, each half-hour within a relatively unconstrained area on the grid, allowing the competitive market to deal with most of the problem and leaving the monopoly dispatcher to deal only with changes applying to a short period, say the hour or half-hour.[24]

Although a half-hour is a long time on an electricity system, it is still too short a period to expect a market to clear efficiently through decentralized information exchange and bilateral negotiation. Instead, it is necessary to do what is done in many other markets: establish a central process that collects buy and sell offers (including each offerer's reservation prices), determines market-clearing prices consistent with these offers and reservation prices, notifies the successful offerers, facilitates delivery of the physical product and settles payments among the traders.

Traditional dispatch is a form of market dispatch, with trading based on engineering estimates of incremental costs. By adding software to handle buy and sell offers from independent traders, determine a least-cost combination of trades and the associated market-clearing prices and settle payments among the traders, the dispatch process can be extended to

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[24] The period to be covered by the central dispatcher depends on the strength and complexity of the dispatch interactions over time. The physics dictate a need for last minute control. A half-hour may be a convenient period. Unit commitment decisions might call for a sequence of market balances coordinated by the central dispatcher over the day and hour, as in the United Kingdom and Norway. There are significant differences in the lead times applied in the New York and New England Power Pools. However, choices beyond a month could be left to the decentralized decisions of the market. The selection of the best time frame for coverage under the central dispatch is an issue to be addressed.

support a commercially oriented marketplace. The resulting integrated dispatch and market process will then play two important roles:

- **Operate the Competitive Spot Market.** The dispatcher and market operator determines market-clearing quantities and prices for each half-hour, based on buy and sell offers from the market participants. This process will determine most of the energy and some of the money flows in the spot market -- most of the money flows in the system will be determined by contracts.

- **Provide Monopoly System Services.** The dispatcher and market operator uses the market-determined supplies to meet the market-determined demands in each half-hour as far as possible, but then acts as a monopoly buyer of the incremental energy and ancillary services -- reactive power, spinning reserve and so forth -- needed to respond to changing conditions within the market period. The dispatcher covers its costs with charges no system user can escape, such as an uplift on the spot market price of energy.

Commercial transactions in the competitive electricity market develop principally through bilateral agreements between buyers and sellers. Contracts for long-term electricity supply, price protection and other competitive services contain any terms and conditions acceptable to the parties and feasible within the limitations inherent in the interconnected electric system. Under the Poolco model, the short-term electricity market addresses the few necessary constraints and technical issues by coordinating system operations and power plant dispatch. The system pricing and access rules permit the maximum degree of customer flexibility and choice. The same pool-based rules define a comparable, open-access transmission tariff. With rare exception, generators enjoy free choice to participate in the pool-based dispatch or manage their own generating plant operations under the transmission tariff. Customers, brokers and aggregators enjoy free choice to make long-term arrangements with any supplier or rely solely on access to the short-term market. The Poolco market supports any feasible bilateral transactions and provides everyone with additional options that resolve difficult problems such as obtaining backup supplies, transmission rights or other technical services.

ILLUSTRATION OF MARKET OPERATIONS

In illustrating the operation of the market, it is natural to distinguish between the short-run operations managed by the Poolco and long-run decisions that include investment and contracting. The system is much simpler in the very short run when it is possible to give meaningful definition to concepts such as opportunity cost. Furthermore, the long run is just a succession of short runs. In ideal competitive markets, without economies of scale and other complications, there is a natural connection between long run and short run that, for example, equates short- and long-run marginal costs in equilibrium. This handy simplification from competitive market theory is assumed, often implicitly, in proposals for the electricity market much in the way it is implicit in proposals for incremental pricing of transmission. However, due to economies of scale in transmission, this handy condition of short- and long-run equilibrium at the margin is not valid in the case of electricity and it may be poor even as an approximation. Close attention to the connection between short- and long-run decisions, therefore, isolates unique features of the electricity market.

Short-Run Electricity Market

The short-run electricity market is relatively simple. In the short run, locational decisions have been made and power plants, the transmission grid, and distribution lines are all in place. Customers and generators are connected and the work of buyers, sellers, brokers and other service entities is complete. The only decisions that remain concern the delivery of power, which in the short-run is truly a commodity product.

On the electrical scale, much can happen in a half-hour and the services provided by the system include many details of dynamic frequency control and emergency response to contingencies. Due to transaction costs, if nothing else, it would be inefficient to unbundle all of these services and many are covered as average costs in the overhead of the system. How far unbundling should go is an empirical question. For example, real power should be identified and its marginal cost recognized, but should this extend to reactive power and voltage control as well? Or to spinning reserve required for emergency supplies? For the sake of the present discussion, the focus is on real power -- reactive power may also be unbundled, but assume that further unbundling would go beyond the point of diminishing returns in the short-run market.[25]

On a human scale, over the half-hour the market operates competitively to move real power from generators to customers. Generators have a marginal cost of generating real power from each plant, and customers have different quantities of demand depending on the price at that half-hour. With these conditions in a fully decentralized market, with no information costs, customers and generators would search and trade until an equilibrium developed at the market price where supply and demand balance.

This short-term market result is illustrated in Figure 2. The collection of generator costs stack up to define the generation "merit order," from least to most expensive. This merit

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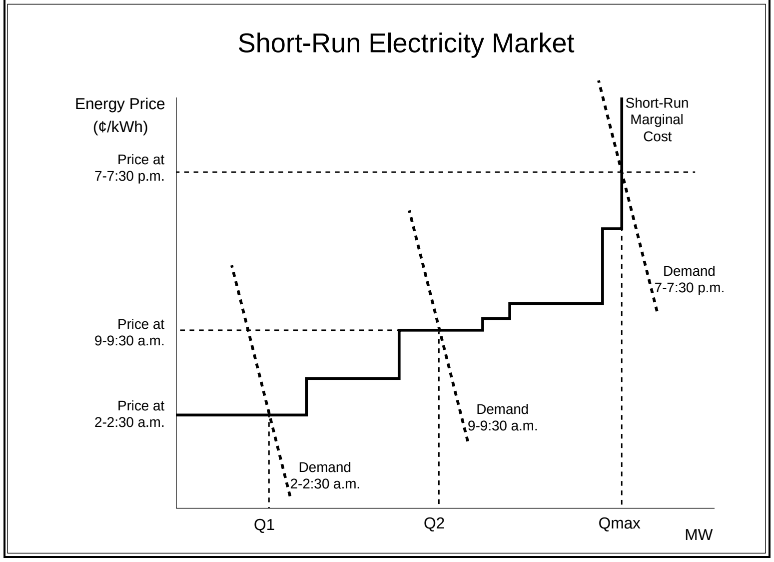
[25] W. Hogan, "Markets in Real Electric Networks Require Reactive Prices," Energy Journal, Vol. 14, No. 3, 1993, pp. 171-200. B. Ring, G. Read, G. Drayton, "Optimal Pricing for Reserve Electricity Generation Capacity," Proceedings of the 29th Annual Conference of the Operational Research Society of New Zealand, Auckland, New Zealand, August 1993.

order defines the short-run marginal-cost curve that governs power supply. Similarly, customers have demands that are sensitive to price, and higher prices produce lower demands. As illustrated simply in the figure, the same supply curve is assumed to apply throughout the day, but three different periods have been selected to show different levels of customer demand. In the early morning, there is little demand and the market equilibrium price settles at the marginal running cost of the cheapest generators. Later in the morning, demand increases and so does the equilibrium price. At this time, every customer actually consuming power pays the market-clearing price and every generator running is paid this same price. For the generators, the differences between the market price and their individual marginal costs are the short-run profits that make a contribution to recovery of capital.

Figure 2



At the peak period in the evening, the equilibrium price is very high, with all capacity in use. Here the dispatchable demand is setting the market price above the marginal cost of even the last, most-expensive generator, and all generators earn a short-run profit. The equilibrium price still measures the opportunity cost, but at the peak period the marginal opportunity is not to generate more power but rather to forgo that last increment of demand.

This description of the equilibrium economics of a decentralized short-run market could apply to any product with many producers and many consumers. The special complication in the case of electricity arises because the technology does not permit the many leisurely offers, acceptances and trades that are implicit in the search for an equilibrium in the decentralized market model. On the electrical time scale, all those within half-hour dynamics precludes sole-reliance unilateral or bilateral decisions by the participants in the market. Preserving electrical stability and achieving efficiency within the half-hour requires some form of centralized, or at least closely coordinated, dispatch of supply and demand.

This complication presents no insurmountable difficulties, but it does differentiate electricity from other products. This problem has always existed, and the traditional solution has been to operate the system with a close approximation of centralized control and least-cost dispatch. Generators and customers do not act unilaterally; they provide information to the dispatcher(s) to be used in a decision process that will determine which plants will run at any given half-hour. Power pools, especially tight power pools in the United States, provide the model for achieving the most efficient dispatch given the short-run marginal costs of power supply. Although dispatchable demand is not always included, there is nothing conceptually or technically difficult about this extension.[26] The central dispatcher controls operation of the system to achieve the efficient match of supply and demand.

In principle -- and now in practice in the United Kingdom, Norway and elsewhere -- this central dispatch can be made compatible with the market outcome. The fundamental principle to exploit here is that for the same load, the least-cost dispatch and the competitive-

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[26] Demand could be dispatched or, with appropriate technology, customers could respond to real-time pricing without explicit bids. Real-time pricing goes further than what is necessary for competition and efficient dispatch. For a discussion of real-time pricing, see F. C. Schweppe, M. C. Caramanis, R. D. Tabors, R. E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988.

market dispatch are the same. The principal difference between the traditional power pool and the market solution is the price charged to the customer. In the traditional power pool model, customers pay and generators receive average cost, at least on average. Marginal cost implicitly determines the least-cost dispatch, but customers and generators pay do not include the marginal cost. Of course, this reliance on average-cost pricing is not necessary. This is apparent from the current practice in the U. K. where the power market operates in a manner that is essentially consistent with Figure 2, but transactions take place at marginal rather than average cost.[27]

An important distinction between the traditional central dispatch and the decentralized market view is found in the source of the marginal cost information for the generator supply curve. Traditionally the cost data come from engineering estimates of the energy cost of generating power from a given plant at a given time. However, relying on these engineering estimates is problematic in the market model since the true opportunity costs may include other features, such as the different levels of maintenance, that would not be captured in the fuel cost. Replacing of the generator's engineering estimates, which report only incremental fuel cost, with the generator's market bids is the natural alternative. Each bid defines the minimum acceptable price that the generator will accept to run the plant in the given half-hour. And these bids serve as the substitute to guide the dispatch.

As long as the generator receives the market-clearing price, and as long as there are enough competitors so that each generator assumes that it will not be providing the marginal plant, the optimal bid for each generator is the true marginal cost. To bid more would only

[27] The United Kingdom market includes other features that cause the price to deviate from pure marginal cost, but the essential element is to determine the half-hourly equilibrium marginal cost, which is known as the system marginal price (SMP).

lessen the chance of being dispatched, but not change the price received. To bid less would create the risk of running and being paid less than the cost of generation for that plant.[28] Hence, with enough competitors and no collusion, the short-run central dispatch market model can elicit bids from buyers and sellers. The dispatcher can treat these bids as the supply and demand curves of Figure 2, and determine the balance that maximizes benefits for producers and consumers at the market equilibrium price. Hence, in the short run electricity is a commodity, freely flowing into the transmission grid from selected generators and out of the grid to the willing customers. Every half-hour, customers pay and generators receive the short-run marginal-cost (SRMC) price for the total quantity of energy supplied in that half-hour. Everyone pays or receives the true opportunity cost in the short run. Payments follow in a settlements process with a single dispatch and single price that is simple by comparison with the settlements required under the multiple dispatches and multiple costs of traditional split-savings systems.

Transmission Congestion

This short-run market model is easy enough and workably approximated in the existing systems in the United Kingdom, New Zealand, Norway and so on. It could be readily adopted in tight power pools in the United States and elsewhere. However, this model implicitly relies on a critical assumption that all power is generated and consumed at the same location. In reality, generating plants and customers are connected through a free-flowing grid of transmission and distribution lines. The use of this transmission grid affects the short-run market model as summarized in Figure 2 on supply and demand.

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[28] This "incentive compatibility" property of the dispatch auction is not strictly true for those bidders who have a significant chance of defining the marginal price, but if the margin is small the distortion will also be small.

In the short-run, transmission too is relatively simple. The grid has been built and everyone is connected with no more than certain engineering requirements to meet minimum technical standards. In this short-run world, transmission reduces to nothing more than putting power into one part of the grid and taking it out at another. Power flow is determined by physical laws, but a focus on the flows, whether on a fictional contract path or on more elaborate allocation methods, is a distraction. The simpler model of input somewhere and output somewhere else captures the necessary reality. In this simple model, transmission complicates the short-run market through the introduction of losses and possible congestion costs.

Transmission of power over wires encounters resistance, and resistance creates losses. Hence the marginal cost of delivering power to different locations differs at least by the marginal effect on losses in the system. However, with a few exceptions, the marginal losses on high-voltage transmission grids are relatively small, amounting to only a few percent of the cost of delivered power, and incorporating these losses does not require a major change in the theory or practice of competitive market implementation. Economic dispatch would take account of losses, and the market equilibrium price could be adjusted accordingly. Technically this would yield slightly different marginal costs and slightly different prices, depending on location, but the basic market model and its operation in the short-run would be preserved.[29]

Transmission congestion is another matter entirely. Limitations in the transmission grid in the short run may constrain long-distance movement of power and thereby impose a higher marginal cost in certain locations. In the simplest case, consider the generators in Figure 2 with the supply curve separated into low-cost and high-cost groups connected by a single transmission

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[29] In the United Kingdom, losses are ignored in setting prices and included in an average cost added to all consumption. In New Zealand and Norway, losses are determined and priced for each location.

line. For sake of discussion, assume all the customers are located in the high-cost region. Hence power will flow over the transmission line from the low-cost to the high-cost region. If this line has a limit, then in periods of high demand not all the power that could be generated in the low-cost region can be used, and some of the cheap plants are "constrained off." In this case, the demand is met by higher-cost plants that, absent the constraint, would not run, but due to transmission congestion are now "constrained on." The marginal cost in the two regions differs because of transmission congestion. The marginal cost of power in the low-cost region is no greater than the cost of the cheapest constrained-off plant -- otherwise the plant would run. Similarly, the marginal cost in the high-cost region is no less than the cost of the most expensive constrained-on plant -- otherwise the plant would not be in use. The difference between these two costs, net of marginal losses, is the congestion rental.

This congested-induced marginal cost difference can be as large as the cost of the generation in the unconstrained case. If a cheap coal plant is constrained off and an oil plant that costs more than twice as much to run is constrained on, the difference in marginal costs by region is greater than the cost of energy at the coal plant. This result does not depend in any way on the use of a simple case with a single line and two regions. In a real network the interactions are more complicated -- with loop flow and multiple contingencies confronting thermal limits on lines or voltage limits on buses -- but the point is the same. It is easy to construct examples where congestion in the transmission grid leads to marginal costs that differ by more than 100 percent across different locations.[30]

If there is transmission congestion, therefore, the short-run market model and

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[30] W. Hogan, "Markets in Real Electric Networks Require Reactive Prices," Energy Journal, Vol. 14, No. 3, 1993, pp. 171-200.

determination of marginal costs must include the effects of the constraints. This extension presents no difficulty, in principle. The only impact is that the market now consists of a set of prices, one for each location. Economic dispatch will still be the least-cost equilibrium. Generators will still bid as before, with the bid understood to be the minimum acceptable price at their location. Customers will bid also, with dispatchable demand and the bid setting the maximum price that will be paid at each customer's location. The economic dispatch process will produce the corresponding prices at each location, incorporating the combined effect of generation, losses and congestion.[31] In terms of their own supply and demand, everyone sees a single price, which is the SRMC price of power at their location. If a transmission price is necessary, the natural definition of transmission is supplying power at one location and using it at another, with the corresponding transmission price as the difference between the prices at the two locations.[32]

This short-run competitive market with bidding and centralized dispatch is consistent with least-cost dispatch. The locational prices define the true and full opportunity cost in the short run. Each generator and each customer sees a single price for the half-hour, and the prices vary over half-hours to reflect changing supply and demand conditions. All the complexities of the power supply grid and network interactions are subsumed under the economic dispatch and calculation of the locational SRMC prices. These are the only prices needed to provide efficient

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[31] F. C. Schweppe, M. C. Caramanis, R. D. Tabors, R.E. Bohn, Spot Pricing of Electricity, Kluwer Academic Publishers, Norwell, MA, 1988. W. W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-242.

[32] Locational prices reflecting short-run generation, losses and congestion are determined in the "regulation" spot market in Norway. See J. Moen, "Electric Utility Regulation, Structure and Competition. Experiences from the Norwegian Electric Supply Industry (ESI)," Norwegian Water Resources and Energy Administration, NVE, Oslo, April 1994. A similar approach is part of the proposed transmission pricing regime for New Zealand as described in Trans Power New Zealand "Transmission Pricing 1993," Wellington, New Zealand, February 1993.

incentives, and payments for short-term energy are the only payments required to cover costs in the short run. The administrative overhead of the Poolco could be covered by rents on losses or, if necessary, a negligible markup applied to all power. The dispatch and settlements process are handled by Poolco, with regulatory oversight to guarantee comparable service through open access to the pool. Something like this system is necessary, and a pool operation is the natural mechanism:

> "The process of defining the comparability standard will dominate the electric transmission service debate just as it did in the case of natural gas. And for many reasons having to do with backup, balancing and so on, a natural resolution of this debate will be to give all eligible producers and customers equal access to a tight power pool, with the pool operating to provide economic dispatch."[33]

Long-Run Market Contracts

With changing supply and demand conditions, generators and customers will see fluctuations in short-run prices. When demand is high, more expensive generation will be employed, raising the equilibrium market prices. When transmission constraints bind, congestion costs will change prices at different locations.

Even without transmission congestion constraints, the spot market price can be volatile. In the United Kingdom, the "system marginal price" for generators, as shown in Figure 3, is calculated only in terms of the unconstrained dispatch. The figure shows the volatility in average monthly prices. The changes within a day or over the month have been greater, sometimes an order of magnitude greater. This volatility in prices presents its own risks for both generators

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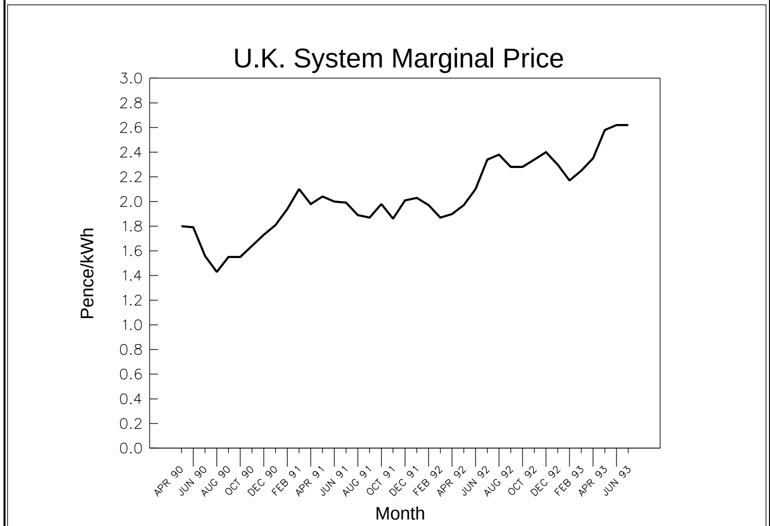
[33] L. E. Ruff, "Competitive Electricity Markets: Economic Logic and Practical Implementation," International Association for Energy Economics, 15th Annual International Conference, Tours, France, May 1992 (Revised June 1992).

and customers, and there will be a natural interest in long-term mechanisms to mitigate or share this risk. The choice in the market is for long-term contracts.

Figure 3



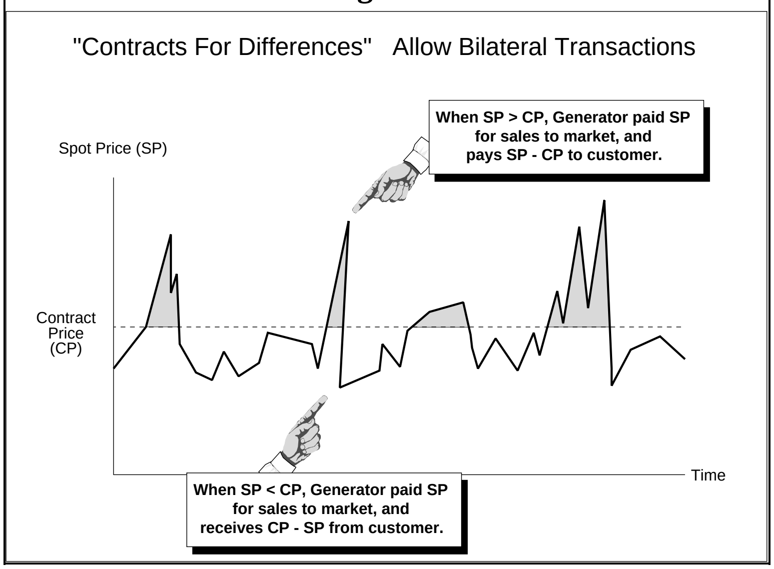
Source: U.K. Office of Electricity Regulation, Pool Price Statement, July 1993

Traditionally, and in many other markets, the notion of a long-term contract carries with it the assumption that customers and generators can make an agreement to trade a certain amount of power at a certain price. The implicit assumption is that a specific generator will run to satisfy the demand of a specific customer. To the extent that the customer's needs change, the customer might sell the contract in a secondary market and so, too, for the generator. Efficient operation of the secondary market would guarantee equilibrium and everyone would face the true opportunity cost at the margin.

However, this notion of specific performance stands at odds with the operation of the short-run market for electricity. To achieve an efficient economic dispatch in the short-run, the dispatcher must have freedom in responding to the bids to decide which plants run and which are idle, independent of the provisions of long-term contracts. And with the complex network interactions, it is impossible to identify which generator is serving which customer. All generation is providing power into the grid, and all customers are taking power out of the grid. There are no bilateral transactions and there is no way to operate a secondary market in the actual deliveries of power. It is not even in the interest of the generators or the customers to restrict the dispatch and forgo the benefits of the most economic use of the available generation. The short-term dispatch decisions are made independent of and without any recognition of any long-term contracts. In this way, electricity is not like other commodities.

This dictate of the physical laws governing power flow on the transmission grid does not preclude long-term contracts, but it does change the essential character of the contracts. Rather than controlling the dispatch and the short-run market, long-term contracts focus on the problem of price volatility and provide a price hedge, not by managing the flow of power but by managing the flow of money. The short-run prices provide the right incentives for generation and consumption, but create a need to hedge the price changes. Recognizing the operation of the short-run market, there is an economic equivalent of the long-run contract for power that does not require any specific plant to run for any specific customer.

Figure 4



Consider the case of no transmission congestion first. In this circumstance, except for the small effect of losses, it is possible to treat all production and consumption as occurring at the same location. Here the natural arrangement is to contract for differences against the equilibrium price in the market. As illustrated in Figure 4, a customer and a generator agree on an average contract price for a fixed quantity, say 100 MW at five cents. On the half-hour, if the pool price is six cents, the customer buys power from the pool at six cents and the generators sells power for six cents. Under the contract, the generator owes the customer one cent for each of the 100 MW over the half-hour. In the opposite case, with the pool price at three cents, the customer pays three cents to the Poolco, which in turn pays three cents to the generator, but now the customer owes the generator two cents for each of the 100 MW over the half-hour.

In effect, the generator and the customer have a long-term contract for 100 MW at five cents. The contract requires no direct interaction with the Poolco other than for the continuing short-run market transactions. But through the interaction with the Poolco, the situation is even better than with a long-run contract between a specific generator and a specific customer. For now if the customer demand is above or below 100 MW, there is a ready and an automatic secondary market, namely the pool, where extra power is purchased or sold at the pool price. Similarly for the generator, there is an automatic market for surplus power or backup supplies without the cost and problems of a large number of repeated short-run bilateral negotiations with other generators. And if the customer really consumes 100 MW, and the generator really produces the 100 MW, the economics guarantee that the average price is still five cents. Furthermore, with the contract fixed at 100 MW, rather than the amount actually produced or consumed, the long-run average price is guaranteed without disturbing any of the short-run incentives at the margin. Hence, the long-run contract is compatible with the short-run market.

The price of the generation contract would depend on the agreed upon reference price and other terms and conditions. Generators and customers might agree on dead zones, different up-side and down-side price commitments or anything else that could be negotiated in a free market to reflect the circumstances and risk preferences of the parties. Whether generators pay customers, or vice versa, depends on the terms. However, the Poolco does not need to take any notice of the contracts or have any knowledge of the terms. Just such contracts have emerged in the United Kingdom market to provide price hedges against fluctuations in the pool price.

In the presence of transmission congestion, the generation contract is necessary but not sufficient to provide the necessary long-term price hedge. A bilateral arrangement between a customer and a generator can capture the effect of aggregate movements in the market, when the single market price is up or the single market price is down. However, transmission congestion can produce significant movements in price that are different depending on location. If the customer is located far from the generator, transmission congestion might confront the customer with a high locational price and leave the generator with a low locational price. Now the generator alone cannot provide the natural back-to-back hedge on fluctuations of the short-run market price. Something more is needed.

Transmission congestion in the short-run market creates another related and significant problem for the Poolco. In the presence of congestion, revenues collected from customers will substantially exceed the payments to generators. The difference is the congestion rent that accrues because of constraints in the transmission grid. At a minimum, this congestion rent revenue itself will be a highly volatile source of payment to the Poolco. At worse, if the Poolco keeps the congestion revenue, incentives arise to manipulate dispatch and prevent grid expansion in order to generate even greater congestion rentals. The Poolco is a natural monopoly and could distort both dispatch and expansion. If the Poolco receives the benefits from congestion rentals, this incentive would work contrary to the goal of an efficient, competitive electricity market.

The convenient solution to both problems -- providing a price hedge against locational congestion differentials and removing the adverse incentive for Poolco -- is to redistribute the congestion revenue through a system of long-run transmission contracts operating in parallel with the long-run generation contracts. Just as with generation, it is not possible to operate an efficient short-run market that includes transmission of specific power to specific customers. However, just as with generation, it is possible to arrange a transmission contract that provides compensation for differences in prices, in this case for differences in the congestion costs between different locations across the network.

It is possible to define point-to-point transmission congestion contracts for compensation that make payments to the right holders in the event of constrained transmission in the grid. These point-to-point price protection transmission contracts defined in alternative equivalent ways, with various advantages for implementation and interpretation. For example:

- **Difference in Congestion Costs**. Receive the difference in congestion costs between two buses for a fixed quantity of power.

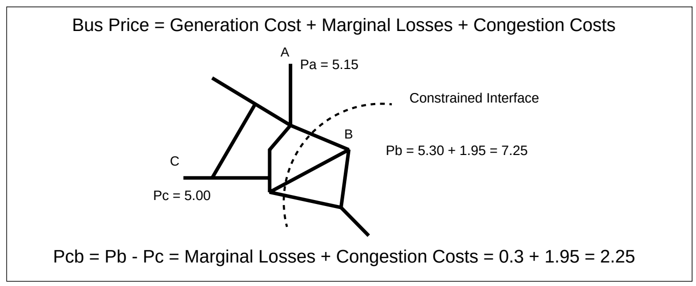
- **Purchase at a Distant Location**. Purchase a fixed quantity of power at one location but pay the price applicable at a distant location.

- **Dispatch with No Congestion Payment**. Inject and remove a fixed quantity of power without any congestion payment.

The total quantity of these contracts can be defined for a given configuration of the network. A particular pattern of flows in the network cannot be guaranteed, due to the effects of changing load patterns and the complex network interactions through loop flow. Hence, physical rights for moving power cannot be assured. However, the congestion rental or purchase rights, as defined here, in effect deal with assured compensation that produces the same economic effect as do assured flows. These transmission congestion contracts can be guaranteed for any pattern of loads in the network. In a real system, the associated flows under the transmission congestion contracts would respect all the constraints in the grid, including contingency constraints for thermal limits on lines and voltage limits at buses.

Figure 5

NETWORK TRANSMISSION CONGESTION CONTRACTS



- 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.

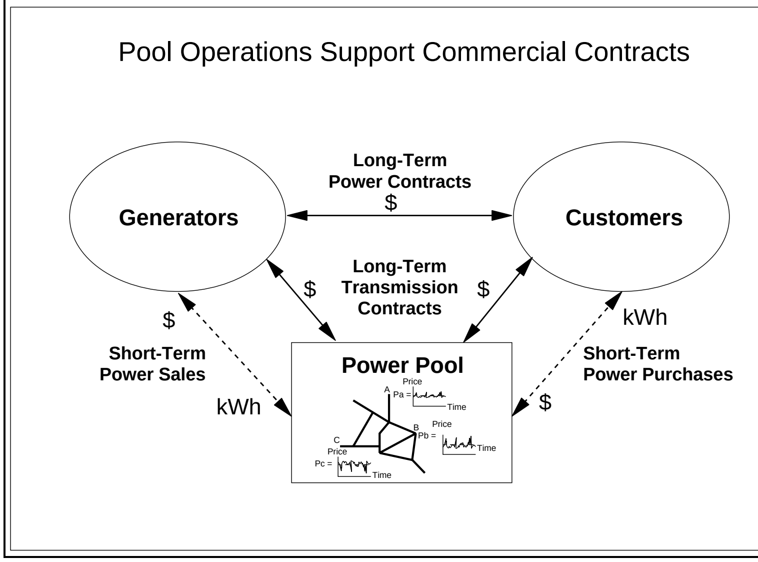
The transmission right would exist for a particular quantity between two locations. For example, suppose that the generator in the example above operated at location C in Figure 5, and had a contract for 100 MW with a customer at location B. Without any constraints, the difference in prices might be a few percent, say 5 cents at C and 5.3 cents at B. The difference would be the marginal cost of losses, and the generator could promise the customer power at 5.3 cents per kilowatt-hour. When the system becomes congested, as it is in the figure, the efficient price might jump to 7.25 cents at location B, reflecting a congestion cost of 1.95 cents.

The generator in this case might have obtained a transmission contract for 100 MW between the generator's location at C and the customer's location at B. The right provided by the contract would not be for a specific movement of power, but rather for payment of the congestion rental. Hence, if a transmission constraint caused prices to rise to 7.25 cents at the customer's location, but remain at five cents at the generator's location, the 2.25 cent difference would be the cost of losses at 0.3 cents and the congestion rental of 1.95 cents. The customer would pay the Poolco 7.25 cents for the power. The Poolco would in turn pay the generator five cents for the power supplied in the short-run market. As the holder of the transmission contract, the generator would receive 1.95 cents for each of the 100 MW covered under the transmission contract. This revenue would allow the generator to pay the difference under the generation contract so that the net cost to the customer is 5.3 cents as agreed upon in the bilateral power contract. Without the transmission contract, the generator would have no revenue to compensate the customer for the difference in the prices at their two locations. The transmission contract completes the package.

The point-to-point congestion contracts can be provided by the pool and allow protection of new investment in generation and transmission. The pool takes no risk in offering these transmission congestion contracts because the revenue collected from users paying at short-run marginal cost is always great enough to honor the obligations under the congestion contracts.

When only the single generator and customer are involved, this sequence of exchanges under the two types of contracts may seem unnecessary. However, in a real network with many participants the process is far less obvious, but the net result is the same. Short-run incentives at the margin follow the incentives of short-run opportunity costs, and long-run contracts operate to provide price hedges against specific quantities. The structure of this market with contracts is illustrated in Figure 6. The Poolco operates in the short-run market to provide economic dispatch. It collects and pays according to the short-run marginal price at each location and distributes the congestion rentals to the holders of transmission congestion contracts. Generators and customers make separate bilateral arrangements for generation contracts. Unlike with the generation contracts, the Poolco's participation in the transmission contracts is necessary because of the network interactions that make it impossible to link specific customers paying congestion costs with specific customer receiving congestion compensation. In the aggregate the total congestion payments received by the Poolco will fund the congestion payment obligations under the transmission contracts, but the congestion prices paid and received will be highly variable and load dependent. Only the Poolco will have the necessary information, but the information will be readily available, embedded in all the pool's locational prices.[34]

Figure 6



If the pool transmission congestion contracts have been fully allocated, then the Poolco will be simply a conduit for the distribution of the congestion rentals. The Poolco will no longer have an incentive to increase congestion rentals, because any increase would flow only to the holders of the transmission congestion contracts, not to the Poolco. The problem of supervising the Poolco and Gridco monopolies would be greatly reduced. And through a combination of

[34] W. W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-242. These transmission congestion contracts define directional price differences that guarantee protection from changes in congestion rentals. Additional congestion payments from the grid to congestion contract holders may be necessary to pass through all the congestion rents inherent in short-run, locational, marginal-cost prices. See the appendix in the present paper for further examples.

generation and transmission contracts, participants in the electricity market can arrange price hedges that could provide the economic equivalent of a long-term contract for specific power delivered to a specific customer.

Poolco and Contract Flexibility

The pool-based market operation is fundamentally a technical device to facilitate bilateral contracts negotiated and administered totally independent of the Poolco. Because the pool provides and prices system services and incremental physical energy on an efficient, nondiscriminatory basis without even knowing about bilateral contracts, market participants can enter into any kind of bilateral commercial contracts they choose and can then meet their contract obligations flexibly and economically.

Gencos, customers and, perhaps, power merchants could enter into bilateral contracts specifying the prices and other conditions under which the seller would sell and the buyer would buy defined amounts of electricity at defined times and places. Such contracts would be used to guarantee prices for periods of, say, one year, to accommodate annual budget and weather cycles, planned maintenance schedules and so forth. Shorter-term (e.g., two-week) contracts would also be used to adjust contract positions to actual conditions as they develop. For example, a customer whose load evolved differently than expected earlier in the year, or a Genco whose generating capacity was temporarily less than it contracted to provide, could always satisfy its needs and obligations by buying and selling physical energy in the pool -- that is the great advantage of the pool -- but may want short-term contracts to protect against pool price risk.

The pool would allow last-minute adjustments by any entity who needs more (less) physical energy than it could produce or had contracted for. The ability to buy and sell such quantities at a common, efficient spot price at the time and location of the physical transaction is essential to maintain efficient short-run operations of the system, to reduce the risks involved in longer-term contracting and to facilitate contracting by exposing a common reference price.

A pool-based market allows great commercial flexibility in bilateral contracting and individual operations even though -- or, more accurately, because -- physical electricity is sold to and purchased from the spot market or pool. As a mechanical matter, however, the contracts must take the form of contracts for differences that specify payments between the parties based on pool prices.

The existence of a pool does nothing to limit the flexibility of any Genco or customer to operate as it chooses individually or as it has contracted to operate. The Poolco's dispatch and pricing rules would provide the flexibility for any Genco to operate whenever it wants to (subject to system-dependent technical limits) simply by providing a sufficiently low minimum-energy price bid or declaring itself "must run." In some variants the same outcome would be implemented through Genco self-nominations that would be treated as must-run dispatch. A Genco choosing to operate in this way will be passing up the opportunity to meet its contract obligations more cheaply by buying from the pool when the pool price is less than the Genco's incremental energy cost; but any Genco which wants to operate in such a manner would be able to do so. Hence, with the exception of some minimum number of flexible plants needed to manage the system at the margin, participation in the pool dispatch would be voluntary. For a Genco which would declare plants as being required to run, thereby forgoing the benefits to itself of pool participation, the pool purchase and sale arrangements would reduce to an accounting convenience to track deliveries and charge for imbalances.[35] The market participants would retain the maximum flexibility that would be possible, consistent with reliable operation of the system.

Long-Term Market Investment

Within the contract environment of the competitive electricity market, new investment occurs principally in generating plants, customer facilities and transmission expansions. In each case, corresponding contract-right opportunities appear that can be used to hedge the price uncertainty inherent in the operation of the competitive short-run market.

In the case of investment in new generating plants or consuming facilities, the process is straightforward. Under the competitive assumption, no single generator or customer is a large part of the market, there are no significant economies of scale and no barriers to entry. Generators or customers can connect to the transmission grid at any point subject only to technical requirements defining the physical standards for hookup. If they choose, new customers or new Gencos have the option of relying solely on the short-run market, buying and selling power at the locational price determined as part of the half-hourly dispatch. The Poolco itself makes no guarantees as to the price at the location. It only guarantees open access to the pool at a price consistent with the equilibrium market. The investor takes all the business risk of generating or consuming power at an acceptable price.

If the generator or customer wants price certainty, then new generation contracts can be struck between a willing buyer and a willing seller, possibly through the intermediation of the

[35] Under least-cost dispatch, running at a short-run loss would increase the total cost of operations in the system. With market-based pricing, there could be a redistribution of economic rents among the other market participants. However, the "must-run" Genco would bear the net increase in the total cost in the system.

aggregators and brokers. The complexity and reach of these contracts is limited only by the needs of the market. Typically, we expect a new generator to look for a customer who wants a price hedge, and the generator defers investing in new plant until sufficient long-term contracts with customers can be arranged. The generation contracts can be with one or more customers and may involve a mix of fixed charges coupled with the obligations to compensate for price differences relative to the pool price. But the customer and generator will ultimately buy and sell power at their location at the half-hourly price.

If either party expects significant transmission congestion, then a transmission congestion contract would be indicated. If transmission congestion contracts are for sale between the two points, then a contract can be obtained from the holder(s) of existing transmission congestion contracts. Or new investment by the Gridco can create new transmission congestion contracts. In the case of transmission investment, economies of scale and network interactions loom large, unlike the case assumed for generation. Hence, because of economies of scale it is expected that for any given transmission investment there will be a material change in the pool prices through reduced congestion rentals. In addition, the network interactions will create many potential beneficiaries.

These facts typically will require that any transmission expansion be organized by a consortium of transmission investors who negotiate a long-term contract that allocates the fixed cost of the investment and the corresponding allocation of new transmission congestion contracts. The Gridco, as a regulated monopoly, builds the lines in exchange for a payment that covers the capital cost and a regulated return. The Gridco does not make transmission investments without long-run contracts signed by willing customers who will pay the fixed costs and recover any future congestion revenues. The Poolco participates in the process only to verify that the newly created transmission congestion contracts are feasible and consistent with the obligation to preserve the existing set of congestion contracts on the existing grid. Unlike in the traditional definition of transmission transfer capacity, which can be ambiguous, there is a direct test to determine the feasibility of any new transmission congestion contracts for compensation, while protecting the existing transmission congestion contracts, and the test is independent of the actual loads.[36] Hence, incremental investments in the grid are possible anywhere without requiring that everyone connected to the grid participate in the negotiations or agree to the allocation of the new transmission congestion contracts.

This structure and its key elements -- access to essential facilities including the wires and pool dispatch, use of short-run marginal-cost pricing and reliance on long-term contracts to provide economic hedges rather than specific performance -- are not far from actual operations or proposed reforms in other systems. This competitive market is the essence of the design of the current U. K. system, with the notable difference of the lack of locational short-run prices.[37] Locational prices are applied in Chile and New Zealand with an explicit treatment of losses and implicit use of congestion costs. Norway applies both losses and congestion costs. Transmission congestion contracts to hedge against locational cost differentials appear in several pooling proposals.

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[36] The test is that the net loads implicit in the congestion contracts are feasible in the absence of any other loads on the system. See W. W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-242.

[37] S. Littlechild, "Competition, Monopoly and Regulation in the Electricity Industry," U.K. Office of Electricity Regulation, June 1993. U.K. Office of Electricity Regulation, "Pool Price Statement," Birmingham, England, July 1993. The United Kingdom design is plagued by incentive problems created in unusual and unnecessary features of the calculation of market prices coupled with too few generators to ensure competition.

APPENDIX

Competitive Electricity Market Pricing

Introduction

Examples of pricing in networks illustrate the issues and the use of least-cost dispatch with accompanying transmission congestion contracts under the Poolco model. Pricing in a competitive electricity market is at marginal cost. The many potential suppliers compete to meet demand, bidding energy supplies into the pool. The dispatchers at Poolco choose the least-cost combination of generation or demand reductions to balance the system. This optimal dispatch determines the market clearing prices. All consumers pay this price into the pool and all generators in turn are paid this price for the energy supplied.

Inherently, energy pricing and transmission pricing are intimately connected. The FERC has outlined objectives for transmission pricing that would be compatible with a competitive market.[38] A series of examples of pricing in the competitive electricity market model illustrates the determination of prices under economic dispatch in a network and relates transmission constraints to congestion rentals that lead to different prices at different locations. These fundamentals provide the building blocks for an energy and transmission pricing system that addresses the several requirements of the FERC outline.

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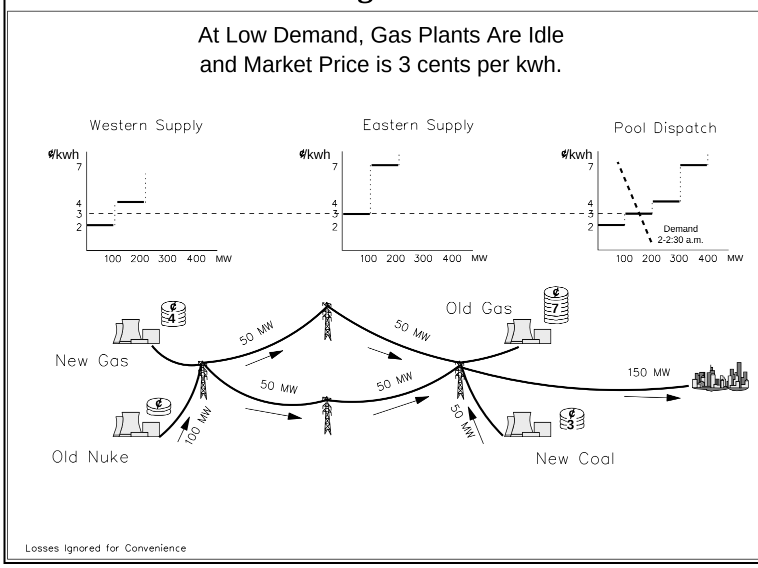
[38] Federal Energy Regulatory Commission, "Transmission Pricing Issues," Staff Discussion Paper, Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Washington, DC, June 1993, pp. 7-8.

Economic Dispatch

Consider the simple market model in Figure 7, which will serve as the starting point for a set of succeeding examples. In this market there is one load center, a city in the east, supplied by generators located far away in the west, connected by transmission lines, and by local generators who are in the same region as the city customers. The plants in the west consist of an "Old Nuke" which can produce energy for a marginal cost of 2 ¢/kWh and a "New Gas" plant that has an operating cost of 4 ¢/kWh. These two plants each have a capacity of 100 MW, and are connected to the transmission grid which can take their power to the market in the east.

The competing suppliers in the east are a "New Coal" plant with operating costs of 3 ¢/kWh and an "Old Gas" plant that is expensive to use with a marginal cost of 7 ¢/kWh. Again these eastern plants are assumed to have a capacity of 100 MW. The two plants in the west define the "Western Supply" curve, and the two plants in the east define the corresponding "Eastern Supply" curve. These supply curves could represent either engineering estimates of the operating costs or bids from the many owners of the plants who offer to generate power in the competitive market. For simplicity, we ignore transmission losses and assume that the same supply curves apply at all hours of the day.

Figure 7



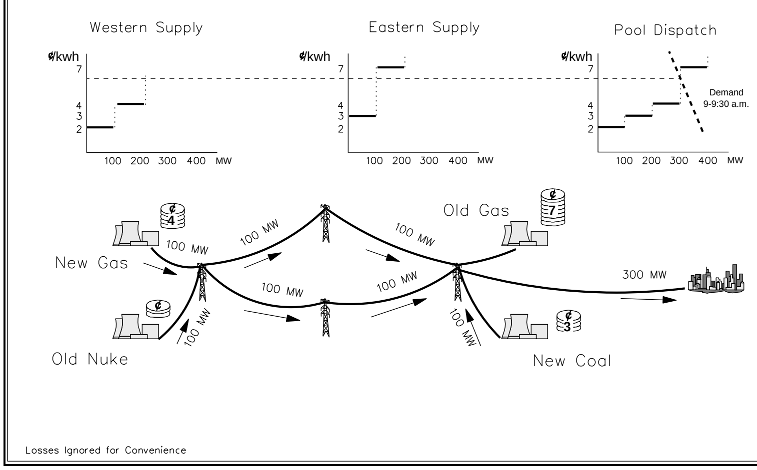
Under low demand conditions, as shown in Figure 7 for the early hours of the morning, the supply curves from the two regions define an aggregate market supply curve that the Poolco dispatchers can balance with the customer demands. The aggregate market supply curve stacks up the various generating plants from cheapest to most expensive. The Poolco dispatchers choose the optimal combination of plants to run to meet the demand at this hour. In Figure 7, the result is to provide 150 MW. The inexpensive Old Nuke plant generates its full 100 MW of capacity, and the New Coal plant provides another 50 MW. The New Coal plant is the marginal plant in this case, and sets the market price at 3 ¢/kWh for this hour. Hence the customers in the city pay 3 ¢/kWh for all 150 MW. The New Coal plant receives 3 ¢/kWh for its output, and this price just covers its running cost. The Old Nuke also receives 3 ¢/kWh for all its 100 MW of output. After deducting the 2 ¢/kWh running cost, this leaves a 1 ¢/kWh contribution towards capital costs and profits for Old Nuke owners.

In this low demand case, and ignoring losses, there is no additional opportunity cost for transmission. The 100 MW flows over the parallel paths of the transmission grid. But there is no constraint on transmission and, therefore, no opportunity cost. Hence the price of power is the same in the east and in the west. In the short run, there is no charge for use of the transmission system.

If demand increases, say at the start of the business day, Poolco must move higher up on the dispatch curve. For example, consider the conditions defined in Figure 8. This hour presents the same supply conditions, but a higher demand. Now the Poolco dispatchers must look to more expensive generation to meet the load. The Old Nuke continues to run at capacity, the New Coal plant moves up to its full capacity, and the New Gas plant in the west also comes on at full capacity. The New Gas plant in the west is the most expensive plant running, with a marginal cost of 4 ¢/kWh. However, this operating cost cannot define the market price because at this price demand would exceed the available supply, and Poolco must protect the system by maintaining a constant balance of supply and demand.

Figure 8

At Morning Demand, New Gas Plant is Dispatched and Market Price is 6 cents per kwh.



In this case, the result is to turn to those customers who have set a limit on how much they are willing to pay for electric energy at that hour. This short-run demand bidding defines the demand curve which allows Poolco to raise the price and reduce consumption until supply and demand are in balance. In Figure 8 this new balance occurs at the point where the market price of electricity is set at 6 ¢/kWh. Once again, the customers who actually use the electricity pay this 6 ¢/kWh for the full 300 MW of load at that hour. All the generators who sell power receive the same 6 ¢/kWh, which leads to operating margins of 2 ¢/kWh for New Gas, 3 ¢/kWh for New Coal, and 4 ¢/kWh for Old Nuke.

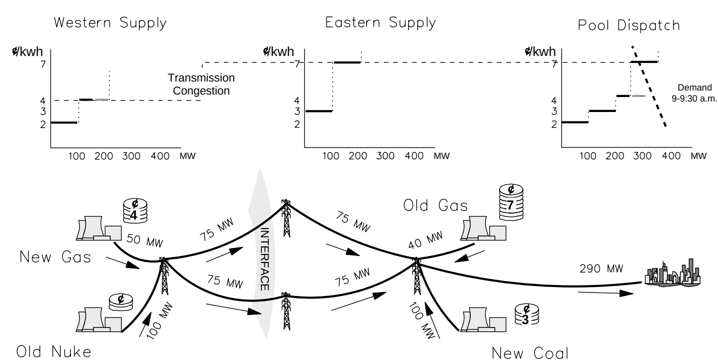
Once again, the Poolco dispatch in Figure 8 depends on excess capacity in the transmission system. The plants in the western region are running at full capacity, and the full 200 MW of power moves along the parallel paths over the grid to join with New Coal to meet the demand in the east. There is a single market price of 6 ¢/kWh, and there is no charge for transmission other than for losses, which are ignored here for convenience in the example.

Transmission Constraints

With the plants running at full capacity, there might be a transmission constraint. To illustrate the impact of a possible transmission limit, suppose for sake of discussion that there is an "interface" constraint between west and east. According to this constraint, no more than 150 MW of power can flow over the interface.

Figure 9

Morning Demand & Transmission Interface Constraint Yield Congestion;
Market Price is 7 cents in the East and 4 cents in the West.



Transmission Constraint Creates 3 cent Congestion Rental.

Losses Ignored for Convenience

As shown in Figure 9, this transmission constraint has a significant impact on both the dispatch and market prices based on short-run marginal costs. In Figure 9 the level of demand from the city in the east is assumed to be the same as in the case of Figure 8. However, now the Poolco dispatcher faces a different aggregate market supply curve. In effect, only half of the New Gas output can be moved to the east. To meet the demand, it will be necessary to simultaneously turn off part of the New Gas output and substitute the more expensive Old Gas generation which is available in the East. This new dispatch increases the market price in the east to 7 ¢/kWh and necessarily induces a further reduction in demand, say to a total of 290 MW. The New Coal and Old Gas plants receive this full price of 7 ¢/kWh for their 140 MW, which provides a 4 ¢/kWh operating margin or short-run profit for New Coal and allows Old Gas to cover its operating costs.

In the western region, however, a different situation prevails. The transmission interface constraint has idled part of the output of the New Gas plant. Clearly the market price in the west can be no more than the operating cost of the plant. Likewise, since the plant is running at partial output, the market price can be no less than the operating cost of 4 ¢/kWh. This is the price paid to New Gas and Old Nuke, which covers New Gas operating costs and provides Old Nuke an operating margin of 2 ¢/kWh.

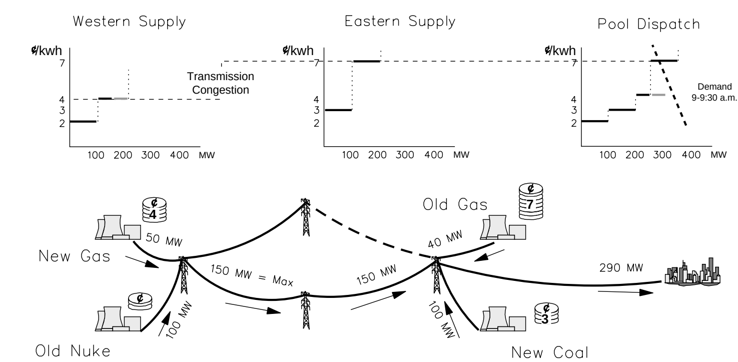
The 3 ¢/kWh difference between the market price in the east and the market price in the west is the opportunity cost of the transmission congestion. In effect, ignoring losses, the marginal cost of transmission between west and east is 3 ¢/kWh, and this is the price paid implicitly through the transactions with Poolco. Electricity worth 4 ¢/kWh in the western region becomes worth 7 ¢/kWh when it reaches the eastern region.

The transmission "interface" constraint is a convenient shorthand for a more complicated situation handled by the Poolco dispatchers. The interface limit depends on a number of conditions, and can change with changing loads. Typically it is not the case that there is a 75 MW limit on one or both of the parallel lines through which power is flowing in the grid. In normal operation, it may well be that the transmission lines could individually handle much more flow, say 150 MW each or twice the actual use. At most normal times, the lines may be far from any physical limit. However, the Poolco dispatchers must protect against contingencies--rare events that may disrupt operation of the grid. In the event of these contingencies, there will not be time enough to start up new generators or completely reconfigure the dispatch of the system. The power flow through the grid will reconfigure immediately according to the underlying physical laws. Hence, generation and load in normal times must be configured, and priced, so that in the event of the contingency the system will remain secure.

For instance, suppose that the thermal capacity of the transmission lines is 150 MW, but the Poolco dispatchers must protect against the loss of a northern transmission line. In this circumstance, the actual power flows may follow Figure 9, with 75 MW on each line, but the Poolco dispatchers must dispatch in anticipation of the conditions in Figure 10. Here the northern line is out, and in this event the flow on the southern line would hit the assumed 150 MW thermal limit. This contingency event may never occur, but in anticipation of the event, and to protect the system, Poolco must dispatch according to Figure 10 even though the flows are as in Figure 9. In either case, the transmission constraint restricts the dispatch and changes the market prices. The price is 4 ¢/kWh in the west and 7 ¢/kWh in the east, with the 3 ¢/kWh differential being the congestion-induced opportunity cost of transmission. This "congestion rental" defines the competitive market price of transmission.

Figure 10

Transmission Constraint May Be A Contingency Limit,
Here Protecting Against Loss of Northern Line.

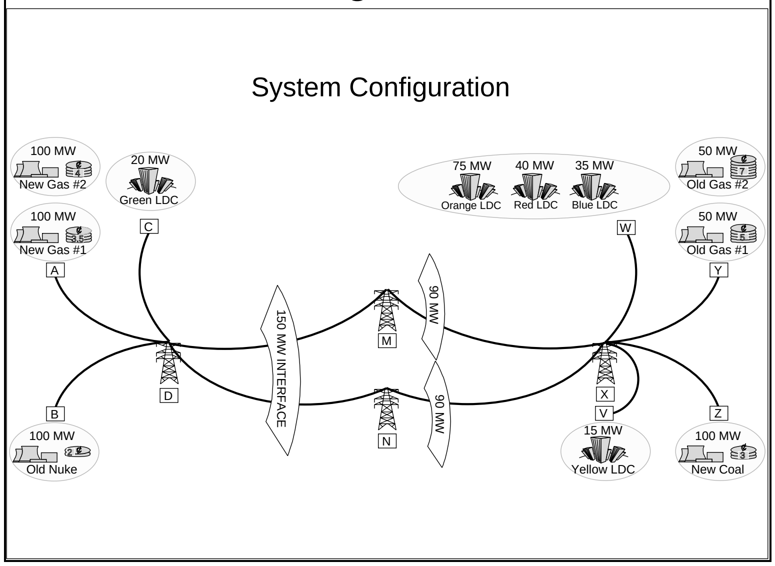


Contingency Constraint Still Creates 3 cent Congestion Rental.

Losses Ignored for Convenience

Buying and selling power at the competitive market prices, or charging for transmission at the equivalent price differential provides incentives for using the grid efficiently. If some user wanted to move power from east to west, the transmission price would be negative, and such "transmission" would in effect relieve the constraint. The transmission price is "distance- and location-sensitive," with distance measured in electrical rather than geographical units. And the competitive market prices arise naturally as a by-product of the optimal dispatch managed by Poolco.

Figure 11



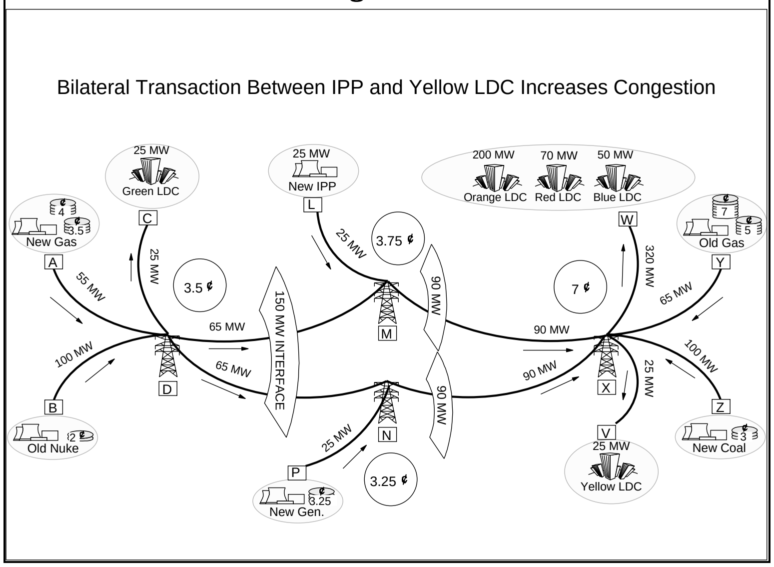
The simplified networks in Figure 7 through Figure 10 illustrate the economics of least-cost dispatch and locational prices. However, these networks by design avoid the complications of loop flow that can be so important in determining prices and creating the difficulties with physical transmission rights. The extension of these examples and the basic pricing properties to more complicated networks includes the possibility of inputs and load around loops in the system. Here assume a transmission system as before but with the basic available generations and loads as shown in Figure 11. These generators define a basic supply configuration with quantities and prices, coupled with the associated loads, and all 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 Figure 11 are illustrative and will vary systematically in each example. For convenience, losses are ignored in all examples.

Figure 12

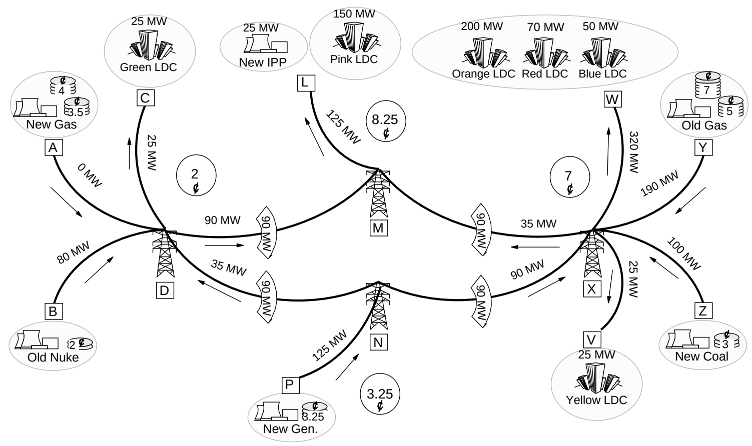


The first example to introduce the effect of loop flow involves a new sources of supply at a location on the loop. Here a low cost, large capacity generator becomes available in Figure 12 at bus "P." An IPP at bus "L" has bid in a must run plant at 25 MW, having arranged a corresponding sale to the Yellow 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".

In a further example the constraints are modified to replace the interface limit with limits on the flows on individual lines. Here every line in the main loop is constrained by a thermal limit of 90 MW, replacing the interface limit. With these constraints in Figure 13, 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 illustrates that it is possible to have market clearing prices at some locations that are higher than the 7¢ marginal running cost of the old gas plant at bus "Y", the most expensive plant in the system. The interaction of the network constraints is such that with a reduction of load at bus "L" it would be possible to reduce out put of the most expensive plant by even more, and make up the difference with cheaper sources of supply, causing the high price for load at bus "L".

Figure 13

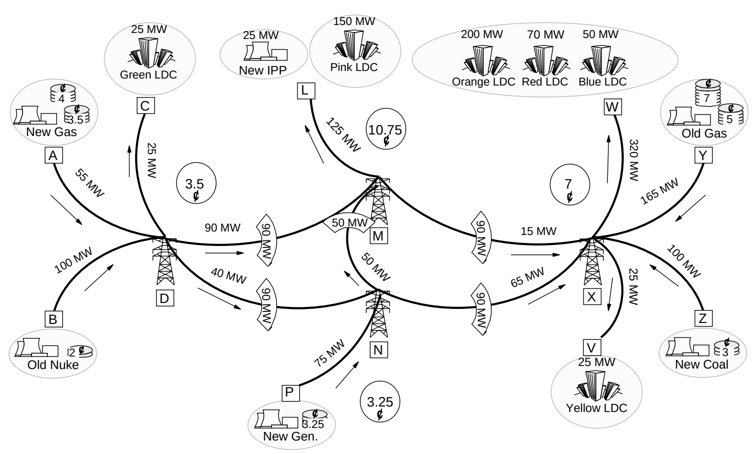
Congestion and Loop Flow Create High and Low Prices



Changing the network further adds new loops and even more examples of the effect on prices and dispatch caused by the network interactions. In this case, a new line has been added to the network in Figure 14, 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

Figure 14

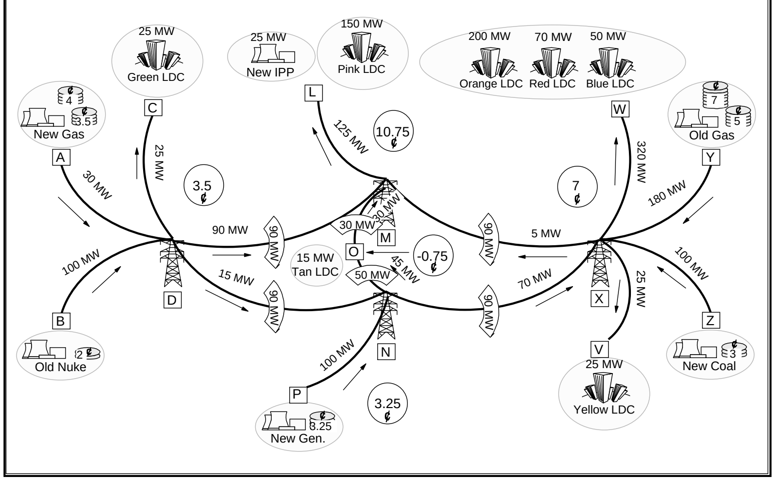
Added Lines and Loop Flow Increase Cost of Constraints



generation lowers the overall cost of satisfying the same load. The total cost reduces from $20,962.50 in Figure 13 to $19,912.50 in Figure 14. 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. The new loop provides more options, but it also interacts with other constraints in the system. This set of interactions is the cause of the high price as it appears at bus "L".

Figure 15

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



As a final example that confirms the sometimes counterintuitive nature of least-cost dispatch and market equilibrium prices, add a new bus "O" between bus "M" and bus "N" in Figure 15, 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 optimal solution would be to pay customers at "O" to accept dump power, thereby relieving congestion elsewhere and providing benefits to the overall system. In the extreme, load at bus "O" is so important that without any load at bus "us "O" and with the 30 MW limit between "O" and "P", there is no feasible dispatch. This final example, therefore, illustrates and summarizes the types of interactions that can develop in a network with loop flow. Power can flow from high price nodes to low price nodes. The competitive market clearing price, equivalent to the marginal costs for the least-cost dispatch, can include simultaneously at different locations prices higher than the cost of the most expensive generation and lower than the cost of the cheapest generation source.

Transmission Congestion Contracts

The congestion rental received by Poolco provides the key to defining property rights in the transmission grid. In the face of transmission constraints, prices will be more volatile and it will not be possible for a generator to provide guaranteed price stability in the form of a long-term contract with a customer. Furthermore, customers and generators will have an incentive to expand the grid only if they recognize and believe that after making an investment in the grid there will be some protection against any future congestions costs. A simple way to define the property right and provide this guarantee is to assign the congestion rental not to Poolco but to the holder of the transmission congestion contract. In the transmission constrained cases of Figure 9 or Figure 10, the congestion contracts for a total 150 MW of power might have been held by customers in the city, or by generators in the west. In either case, this right is defined only as the right to collect the congestion rental. The generators and customers would not control the use of the grid. Poolco would determine the efficient pattern of use through economic dispatch. Poolco would collect the congestion payments from the actual users of the grid and pay them in turn to the holders of the transmission congestion contracts.

With this definition of transmission congestion contracts, it is an easy matter for generators at Old Nuke and New Gas to arrange long-term contracts that provide price stability for customers in the city. For example, the owners of Old Nuke may have acquired power contracts for 100 MW, and signed long-term contracts that guaranteed to provide power delivered to the city at a price of 5 ¢/kWh. In the case of low demand as in Figure 7, the short-run price is only 3 ¢/kWh, which customers pay and generators receive through Poolco. Separate from Poolco, the customers pay Old Nuke the difference of 2 ¢/kWh owed under the contracts. If demand shifts to the higher case in Figure 8, the market price is 6 ¢/kWh, and again the customers pay and generators receive this short-run price through Poolco. In this event, the generators separately pay the customers the difference of 1 ¢/kWh required under the long-term contract.

When transmission constraints bind as in Figure 9 or Figure 10, the price paid by the customers to Poolco is 7 ¢/kWh, and the price received by the generators from Poolco is 4 ¢/kWh. If the generators own the transmission congestion contracts, then Poolco pays the generators an additional 3 ¢/kWh which allows the generators in turn to pay the customers the 2 ¢/kWh difference agreed to by contract. The owners of Old Nuke are always making an operating margin of 3 ¢/kWh, and the customers are always receiving the equivalent of 5 ¢/kWh electricity. Likewise, if the customers own the transmission congestion contracts, the customers receive the 3 ¢/kWh from Poolco and in turn pay 1 ¢/kWh to the generators. Again the owners of Old Nuke are always making an operating margin of 3 ¢/kWh, and the customers are always receiving the equivalent of 5 ¢/kWh electricity. Furthermore, in either case Poolco ends up with no transmission congestion rentals; Poolco serves only to pass through the congestion costs from the actual users of the grid to the holders of the property rights in the economic interest of the transmission grid.

This system of transmission congestion contracts and property payments back and forth may seem unnecessary and cumbersome in the case of the simple system of Figure 7 through Figure 10. After all, couldn't the Poolco dispatchers in effect assign the generation from Old Nuke to the long-term customers in the city? In principle, this specific performance model--assigning particular generation to particular users--is possible in this simple case, but it does not generalize into the more complicated reality of an interconnected grid with many different sites of load and generation, real and reactive power, thermal and voltage limits, and multiple contingencies. The examples in Figure 12 through Figure 15 illustrate the difficulties attendant to the network interactions. It is impossible in a real system to meaningfully assign any particular sources and destination of electricity, and attempts to do so can only serve to compromise the efficiency objective of maintaining an optimal dispatch which may require only partial use of plants in constrained regions, violating the assumptions of specific performance. However, the payments of congestion rentals from Poolco to the holders of point-to-point transmission congestion contracts do generalize to the more complicated case, and allow optimal dispatch for efficiency while accommodating long-run contracts for price differences and congestion rentals, contracts that provide both stability and the essential protection of investment in the network.

Transmission Congestion Contracts in a Network

These examples of efficient pricing and transmission congestion contracts extend beyond the case of two locations to the general case of a network with the complications of electricity system operation and prices at many locations. Electric energy pricing in a pool with economic dispatch is closely connected with transmission pricing. With multiple participants in a pool the efficient choice is to price power at the short-run marginal cost at each location. With such efficient pricing, transmission use pricing appears automatically in pool pricing: the differences between locational prices are the opportunity cost prices for transmission. At a minimum, locational prices would reflect differences in marginal losses. To the extent that there is congestion in the transmission grid, locational prices would also differ by the cost of congestion induced by "out-of-merit" generation. All users pay or are paid by the pool at these short-run prices. Through these prices the pool would collect congestion rentals.

Changing prices at locations would create an interest in transmission congestion contracts that would protect those who invest in the grid. Because of the effects of network interactions, it is not possible to guarantee simultaneously both specific performance--particular plants operating for particular customers--and constrained economic dispatch. If specific plants must be run for specific customers, then the system operators do not have the freedom to provide the least-cost dispatch. If the operators provide the least-cost dispatch, then constraints may preclude using specific plants and require alternative plants to run.

However, it is possible to define point-to-point transmission congestion contracts that make payments to the right holders in the event of constrained transmission in the grid.[39] These point-to-point price protection transmission contracts defined in alternative equivalent ways, with various advantages for implementation and interpretation. For example:

- **Difference in Congestion Costs**. Receive the difference in congestion costs between two buses for a fixed quantity of

[39] The focus here is on the congestion costs. This approach treats losses as operating costs to be paid by the users of the grid without a hedge against changes in the loss component of the price. It is possible to define analogous transmission contracts that protect the holder from changes in marginal losses. The modification is that the quantity of the transmission contract application differs for input and output to account for the amount of marginal loss in the associated transmission contract flows.

power.

- **Purchase at a Distant Location**. Purchase a fixed quantity of power at one location but pay the price applicable at a distant location.

- **Dispatch with No Congestion Payment**. Inject and remove a fixed quantity of power without any congestion payment.

The total quantity of these transmission congestion contracts can be defined for a given configuration of the network, and the congestion contracts guaranteed for any pattern of loads in the network. In a real system, the transmission congestion contracts would respect all the constraints in the grid, including contingency constraints for thermal limits on lines and voltage limits at buses.

The point-to-point congestion contracts can be provided by the pool and allow protection of new investment in generation and transmission. The pool takes no risk in offering these transmission congestion contracts because the revenue collected from users paying at short-run marginal cost is always great enough to honor the obligations under the congestion contracts. Under certain circumstances, the revenues collected by the grid will be greater than the obligations on the point-to-point congestion contracts, and there will be "excess congestion rentals." For example, if there are no point-to-point contracts assigned, then none of the congestion rental would be paid out under such contracts. In the more interesting cases, if point-to-point congestion contracts are assigned up to the limit of some transmission constraint, it is possible that some other network constraint will be binding in the actual dispatch. In these cases, there will be more than enough revenues to honor the rental or purchase rights, and the pool will face the added task of allocating the excess congestion rentals.

The natural assignment of any excess rentals is to those who are paying the fixed charges. There is no single rule for allocating the rights to the excess congestion rentals. The rule examined here is to share the revenues according to the share of the fixed charges. Hence, the owners of the grid who commit to pay the fixed charges have access to two types of well defined and tradeable transmission congestion contracts: the point-to-point rental contract and a share in any excess congestion rentals.

Contract Network Examples

For purposes of further illustration, consider the case of a three bus network with identical lines and identical thermal limits on each line. A three bus network is the minimum case needed to observe the network interaction effects of loop flow. Here we use the DC-Load approximation for real power only, and ignore contingency constraints. Reactive power and contingency constraints can be included without changing any of the fundamental points examined here.[40]

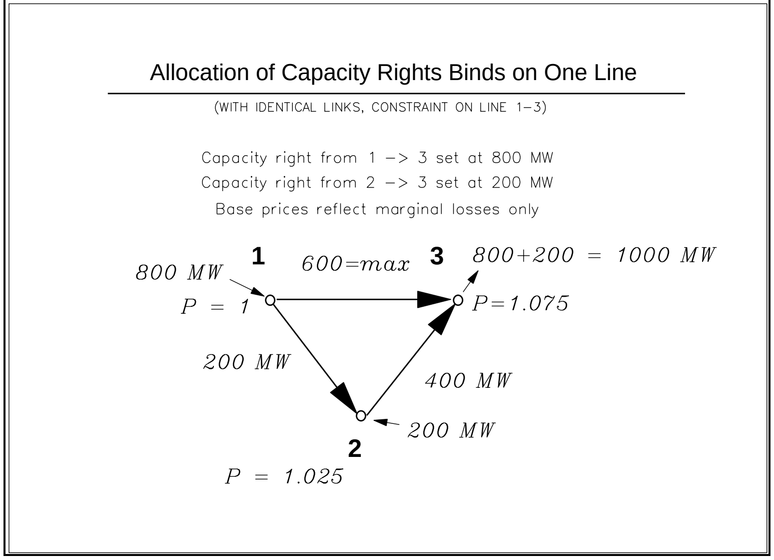
An alternative base case model and an allocation of congestion contracts are shown in Figure 16. Here we assume that the desired transmission congestion contracts are for 800 MW from bus 1 to bus 3, and 200 MW from bus 2 to bus 3. Or, an equivalent definition is that the customer at bus 3 has the contract to purchase 800 MW at bus 1 and 200 MW at bus 2. The simultaneous allocation of these contracts is feasible, but it does hit the thermal transmission constraint of 600 MW on the line between bus 1 and bus 3.

In Figure 16 the prices calculated for this dispatch are shown relative to the price at

[40] W. W. Hogan, "Contract Networks for Electric Power Transmission," Journal of Regulatory Economics, Vol. 4, No. 3, September 1992, pp. 211-242.

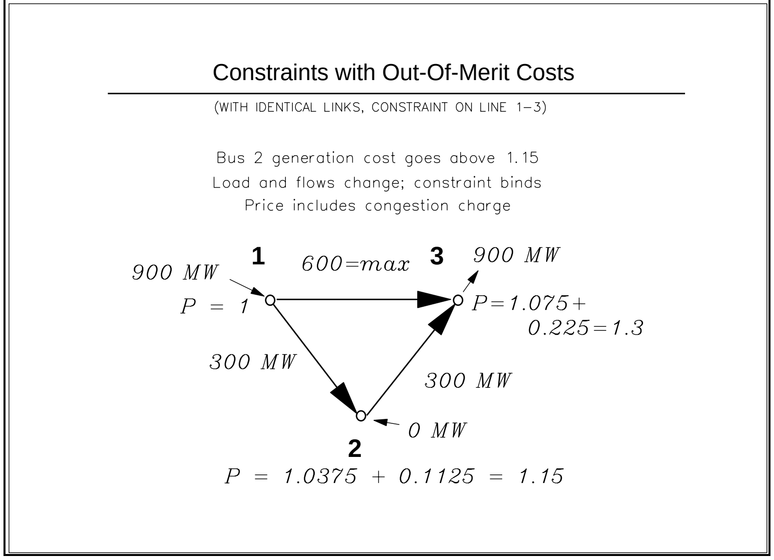
bus 1. In this instance there is no congestion and the prices cover only the cost of generation at bus 1 and the marginal cost of losses. In this simplified case, the equilibrium required is that the marginal losses are linear in the flow on any link and are the same along any parallel path. Hence the marginal loss of one additional megawatt from bus 1 to bus 3 is 0.075, whether by the path 1→3 or via 1→2→3. There is no additional congestion cost, and hence there is no payment from the pool under the congestion rental contracts. Equivalently, the customers at bus 3 buy their 800 MW from bus 1 and 200 MW from bus 2, just as specified in the transmission congestion contracts.

Figure 16



Of course, a change in the economics of generation could induce transmission congestion with the associated differences in prices across locations. In Figure 16, it was economic to generate power at bus 2 and the actual economic dispatch is the same as the dispatch with simultaneous use of the allocated congestion contracts. In Figure 17, the assumed conditions change with an increase in the running cost of power at bus 2 and the need to use expensive generation at bus 3. If the gross load at bus 3 is still 1000 MW, then part of the load must be met with local generation, which costs 1.3, including a congestion rental of 0.225. At this price for bus 3 and with these loads and flows, the price at bus 2 is determined by the equilibrium conditions of optimal economic dispatch. The easiest way to verify the equilibrium prices is to assume that an additional 2 MW of power could be supplied at bus 2. This would allow a reduction of 1 MW at bus 1 and an increase of 1 MW delivered to bus 3 that could displace the expensive generation at bus 3. The flow from 1→2 would reduce by 1 MW, with a corresponding 1 MW increase along 2→3. The flow along 1→3 would still be at the limit of 600 MW, and total losses would be the same. Hence the net savings would be 1 unit at bus 1 and 1.3 units at bus 3, for a total of 2.3 units. This implies a price for the incremental generation of 2 MW at bus 2 of 2.3÷2 = 1.15, which is the equilibrium price. Along with the marginal losses, this total opportunity-cost price implies a bus 2 congestion price of 0.1125.

Figure 17



By assumption, the cost of the generating plant at bus 2 is above 1.15, so the plant does not run. Now all the power transmitted is generated at bus 1, and only 900 MW can be transmitted. The thermal constraint of 600 MW on the line between bus 1 and bus 3 is binding. All the users of the grid pay or are paid these prices for the actual dispatch. In addition, the holders of the point-to-point transmission congestion contracts receive payments from the pool operators.

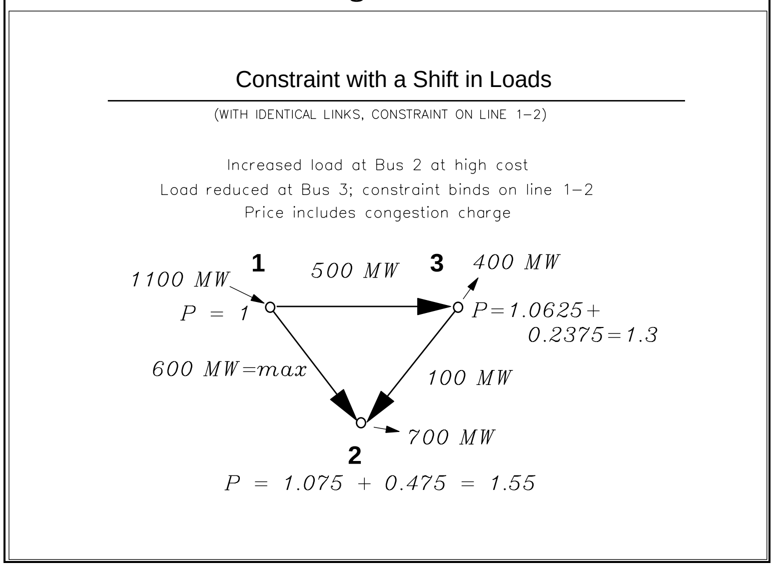
The resulting payments are shown in Table I. Hence the owner of the 800 MW contract from bus 1 is paid the congestion rental difference from bus 1 to bus 3 of 0.225 for the full 800 MW, requiring a payment from the pool of 180. Likewise, the owner of the 200 MW contract is paid the difference in the congestion rental between bus 3 and bus 2, or 0.1125, for the full 200 MW contract and a payment of 22.5. Both users actually buy power from the pool at bus 3 for the price of 1.3. For the customer with the 800 MW contract to purchase at bus 1, the payment of 180 is the total value of the congestion price differential between bus 1 and bus 3. And for the customer with the contract for 200 MW at bus 2, the payment of 22.5 is the total value of the congestion price differential between bus 1 and bus 2.

By purchasing 200 MW at bus 3 at a price of 1.3 and then applying the transmission congestion payment of 22.5, the holder of the 200 MW transmission contract can in effect purchase 200 MW at the price at bus 2 and pay only the marginal losses to move the power to bus 3. Although the actual dispatch is different than the simultaneous allocation of congestion contracts, the payments to the congestion contract holders provide the guarantee in effect that the congestion contract holders can purchase power at the price of power at another location. This holds true even if no power was actually generated at that location, as here for bus 2. Furthermore, specific performance to actually generate and transmit the 800 MW and 200 MW according to the congestion contracts would not be feasible under this economic dispatch. Only by foregoing the advantages of the economic dispatch, and increasing total costs, could the specific plants be used for specific customers. The transmission congestion contracts guarantee the economic value of the transmission, but do not determine the actual flows.

Table I: Congestion with Out-Of-Merit Costs						
Congestion Contracts	Q (MW)	Congestion Price Difference	Direct Receipts	Excess Share	Excess Rentals	Net Receipts
1->3	800	0.225	180	80.00%	0	180
2->3	200	0.1125	22.5	20.00%	0	22.5
Total			202.5		0	202.5

The example in Figure 17 finds the pool dispatcher collecting congestion rentals from the actual users and paying the same rentals to the owners of transmission congestion contracts. Because the same transmission constraint limits both the actual dispatch and the initial allocation of transmission congestion contracts, there are no excess congestion rentals. All the congestion revenue collected is required to compensate the holders of the point-to-point transmission congestion contracts.

Figure 18



An alternative case is shown in Figure 18. In this case the economics of load and dispatch have changed significantly. Power still costs 1.3 at bus 3, but now the net load is reduced to 400 MW. There is a big net load at bus 2, and the equilibrium power cost there is at 1.55. The relatively cheap generation at bus 1 is used at the level of 1100 MW, which causes a shift in the flows.

Now the dispatcher has no problem with a thermal limit on the line between bus 1 and bus 3, but the line between bus 1 and bus 2 has reached a similar thermal limit at 600 MW. This transmission constraint induces the indicated bus prices and congestion rentals.

Again the pool pays or is paid the short-run prices for power at each of the locations. And again the pool makes payments to the holders of the point-to-point transmission congestion contracts. The summary of the various payments appears in Table II. For the customer with the contract for 800 MW between bus 1 and bus 3, the congestion differential is 0.2375 and the total payment from the pool is 190. This allows the contract holder to purchase 800 MW at bus 3--with some of that power necessarily generated by plants located at bus 3--pay the price of 1.3, and after netting out the payment of 190 from the pool, effectively purchase the 800 MW at bus 1 and pay only marginal losses to move the power to bus 3.

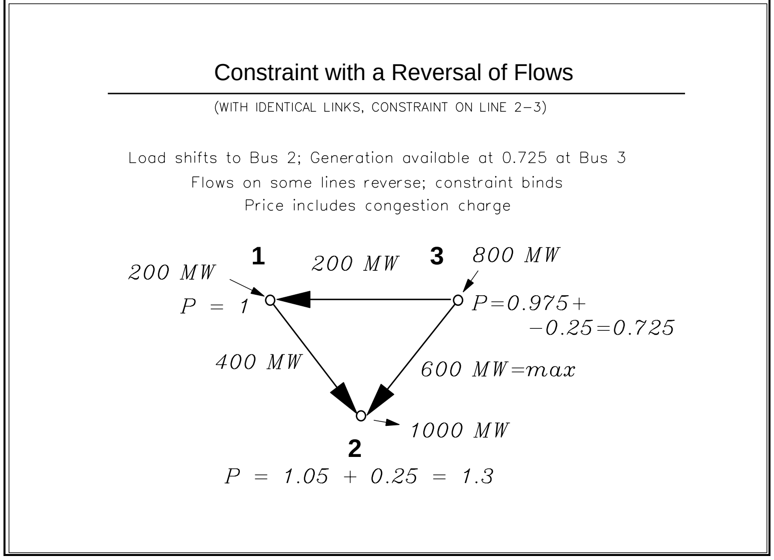
Similarly, the customer with the contract for 200 MW from bus 2 to bus 3 can purchase 200 MW at bus 3 at the price of 1.3. However, this price is lower than the price at bus 2, and the difference in congestion rentals is now negative, at -0.2375. Under the terms of the point-to point contract, this customer must make an added payment of 47.5 to the pool. When coupled with the purchase of 200 MW at bus 3, this is equivalent to purchasing 200 MW at bus 2 at 1.55 and then moving to bus 3 paying only the marginal losses (in this case the marginal losses also would be negative between bus 2 and bus 3). The final effect is as promised under the transmission contract of the customer at bus 3 to purchase 200 MW at bus 2.

Table II: Constraint with a Shift in Loads						
Congestion Contracts	Q (MW)	Congestion Price Difference	Direct Receipts	Excess Share	Excess Rentals	Net Receipts
1->3	800	0.2375	190	80.00%	228	418
2->3	200	-0.2375	-47.5	20.00%	57	9.5
Total			142.5		285	427.5

In this case of a shift in loads, with a new transmission constraint binding, the pool can make all the necessary payments to the holders of the point-to-point transmission congestion contracts, but the payments out amount to only 190 - 47.5 = 142.5. However, the total for the congestion rentals paid by the users of the grid is 700*0.475 + 400*0.2375 = 427.5. There remain excess congestion rentals of 285. Assuming that the fixed charge payments are proportional to the transmission congestion contracts, one way to dispose of these excess congestion rentals would be to pay them out to the transmission congestion contract holders in the ratio of 80 to 20. Hence the transmission contract holder from bus 1 would receive an additional payment of 228, for total receipts of 418. Likewise, the transmission contract holder from bus 2 would receive 57 from the excess congestion rentals for total receipts of 9.5.

In Figure 18 there is a shift in load and economics, and one of the transmission contract holders, for power from bus 2, is required to make addition congestion payments to the pool. With enough of a change in the loads and transmission flows, it is possible that everyone with a transmission contract holds them in the reverse direction, and in this case the payments under the sharing of excess congestion rentals take on added importance. For example, consider the conditions depicted in Figure 19. Here the economics of the dispatch and load have changed even more dramatically compared to the initial allocation of transmission congestion contracts. Now there is low price at bus 3 and a net input of 800 MW, and the higher price is at bus 2 with a net load of 1000 MW. The flows on the links from bus 3 are now reversed.

Figure 19



The prices at the buses include a positive congestion component at bus 2 and a negative congestion impact at bus 3, all relative to bus 1. Once again, the users of the grid pay or are paid according to these short-run marginal cost prices. The pool collects the payments and, in turn, makes the necessary payments to the holders of the transmission congestion contracts. In this case, both the customers with congestion contracts to bus 1 and those with contracts to bus 2 face negative congestion rent differentials. Hence the customer with congestion contracts of 800 MW from bus 1 sees a differential of -0.25, and makes a total additional payment to the pool of 200. With the purchase of 800 MW at bus 3 at the price of 0.725, these combined payments are equivalent to a purchase of 800 MW at bus 1 and then moving to bus 3 at the cost of marginal losses.

For the customer with a 200 MW contract to bus 2, the congestion price difference is -0.5, and the direct payment to the pool is 100. These payments from the contract holders to the pool add to the total congestion rentals collected by the pool from the actual users of the grid, who pay -800*(-0.25) + 1000*0.25 = 450. In all, as summarized in Table III, there are 750 units of excess congestion rentals. As before, these congestion rentals could be distributed according to the share in the fixed cost allocation. In the present example, this would provide a payment of 600 to the customer with transmission congestion contracts of 800 MW from bus 1, for net receipts of 400; and 150 for the customer with contracts of 200 MW at bus 2, for net receipts of 50.

Table III: Constraint with a Reversal in Loads

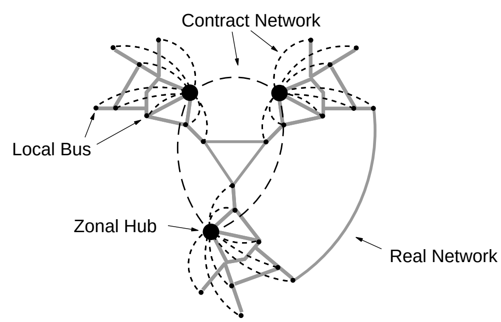
Congestion Contracts	Q (MW)	Congestion Price Difference	Direct Receipts	Excess Share	Excess Rentals	Net Receipts
1->3	800	-0.25	-200	80.00%	600	400
2->3	200	-0.5	-100	20.00%	150	50
Total			-300		750	450

In all cases, the net effect of economic dispatch, marginal cost pricing, and assignment of transmission congestion contracts is to collect congestion costs from the actual users of the grid and pay the congestion costs to those who bear the burden of the fixed charges. The transmission congestion contracts based on price differences compromise two forms. First, point-to-point transmission congestion contracts can be offered which provide the economic equivalent of a customer at one location always having the effective contract to buy delivered power at the cost at a distant location plus the marginal losses. Second, to the extent that there are excess congestion rentals, these rentals can be distributed according to some agreed formula. In aggregate, the congestion rentals paid are always adequate to honor the point-to-point transmission congestion contracts, and sometimes there can be additional rents that could be dispersed according to a sharing formula. In some instances, the congestion payments under the point-to-point contracts can be negative, but only when the economics of the dispatch have switched to provide the contract holder, who has access to cheap generation, the money from an operating margin through the pool dispatch that can fund the congestion payments. The transmission congestion contract is analogous to a futures contract which provides a perfect hedge for the cash market in transmission. The pool dispatcher and operator of the settlements system is taking no financial risk in providing these price guarantees, and the actual dispatch is not constrained by the transmission congestion contracts. The dispatcher always has the freedom to provide the most economical generation possible given the current costs, bids, and system constraints.

Figure 20

Contract Network Connects with Real Network

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



The three bus and three line example is the minimum network needed to illustrate the effects of loop flow and the impact of locational prices in a network. The results for the three link loop can be quite different than those found for a single transmission line or a radial connection. Analogies built on the case of a single line can be misleading. However, the analysis of the three bus case extends to more complicated networks, with one additional and important amendment. In the three bus case, it may be easy to fall into the trap of assuming that transmission congestion contracts are connected with individual lines between buses, since there is no difference in the geography of point-to-point definitions when every bus is connected to every other by a direct line. In a more complicated network, the transmission congestion contracts can be defined quite separately from the map of the individual lines. As shown in Figure 20, for example, the contract network must anchor to the same locations, but the point-to-point contracts can follow a very different geography. Market hubs can arise and be included, with the contract connections in the network following a configuration convenient for contracting and trading. The separation of the physical and the financial flows allows this flexibility with the congestion revenues always sufficient to cover the obligations under transmission congestion contracts, no matter what the resulting pattern that appears in the least-cost dispatch.

To illustrate this conclusion for a more general network, consider again the example network in Figure 15. For this example, consider the extreme case where the market has elected to use bus "O" as the market hub, with transmission congestion contracts all defined relative to this hub. Generators may have the contracts to get to the market at "O". Customers may have similar contracts to get from the market at "O" to their own locations. The individual transmission congestion contracts may embody flows which would never be individually feasible, especially given the limits on the lines connecting "O" and the unusual conditions in this extreme case. As long as the collective flows under the contracts would be feasible, however, the congestion costs collected will always be sufficient to meet obligations under transmission congestion contracts, even in this extreme case.

Here Table IV offers with two feasible sets of transmission congestion contracts (TCCs) for a hub at "O". If the only inputs and outputs in the system consisted of those with

TCC 1 at 180 MWs in at "D", 30 MWs in at "M", 30 MWs in at "N", 60 MWs out at "O" and 180 MWs out at "X", the flows would be feasible even though the individual contracts appear to require flows that are not feasible. Similarly for TCC 2. With these feasible transmission congestion contracts, alternative dispatch cases illustrate the impact of the changing congestion payments.

Table IV: Transmission Contract Allocations		
From-To	TCC 1 (MW)	TCC 2 (MW)
"D-O"	180	160
"O-X"	180	160
"M-O"	30	10
"N-O"	30	70

The results summarized in Table V capture the outcomes for economic dispatch with the only change being three different assumptions about the load at bus "L" in Figure 15, ranging from 0 MW to 150 MWs, with all other conditions the same. The table shows the corresponding prices at key buses, ignoring losses, and the associated collection of congestion rents. These rents are compared in turn with the obligations under the point-to-point contracts of the two sets of transmission congestion contracts. In the case of no load at "L", the congestion payments amount to $6300. Under the TCC 1 the obligation is also $6300; under TCC 2 the point-to-point obligation is $5750, leaving an excess of congestion payments to be disbursed through a sharing formula.

Table V: Transmission Congestion Payments								
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

As the load at bus "L" increases, dispatch reconfigures and prices change. Power flows are different than in the transmission congestion contracts. However, in every case and for each set of TCCs, the congestion rentals equal or exceed the obligations under the point-to-point contracts. The transmission congestion contracts can always be honored, no matter what the pattern of load. In some instances, there will be excess congestion rentals to disburse, but transmission congestion contract holders will always be able to hedge power contracts without requiring physical transmission rights and without compromising the least-cost dispatch.

COMMISSION SUMMARY QUESTIONS

Question 1: a. What alternative power pooling institutions might be beneficial? b. What are the strengths and weaknesses of these alternatives? c. What special transmission pricing needs, if any, would such alternative pooling institutions have? d. What specific benefits would an alternative bring that are not available today? e. What specific benefits of existing pools would be lost? f. What, if any, benefits would alternative power pooling institutions provide compared to bilateral trading? g. How would alternative power pooling institutions differ from a regime of bilateral trading?

The Poolco model for a competitive electricity market, as outlined above, will provide a consistent economic, regulatory and business framework for the development of competitive wholesale markets. The Poolco model: (i) Establishes an open and transparent spot price of electricity; (ii) Provides efficient economic dispatch of electricity demand and supply; (iii) Provides truly comparable open access to the transmission grid at cost- based rates that reflect opportunity costs; (iv) Accommodates bilateral contracts and provides least cost balancing of generation and load covered by bilateral contracts; (v) Maintains current reliability standards; (vi)

Is compatible with many alternative retail competition and pricing policies.

Question 2: a. Do any current Commission policies impede the formation of beneficial alternative power pooling institutions? b. What changes in our existing policies, if any, including pricing policies, are needed to encourage pools that facilitate competitive bulk power markets?

The Poolco competitive electricity market is compatible with the Commission's basic policy. The formation of pool-based competitive electricity markets could be facilitated by adoption of policies that explicitly endorse market-based pricing of electric power, short-term transmission service and transmission rights within competitive open access power markets as envisioned in the Poolco system. The differences with existing systems appear in these details but not in the broad goals enunciated by the Commission.

Question 3: a. In discussing any alternative power pooling institution, please address how the adequacy of generation and transmission services would be ensured, (e.g.: maintenance of adequate generation and transmission reserves and construction of needed generating and transmission capacity)? b. How would reliability be ensured? (e.g.: control of transmission systems, voltage support, reactive power, loop flow, load following, backup services and other control area services).

The Poolco model outlined above preserves operating reliability standards through the economic dispatch implemented by the system operator. The change in pricing rules provides the incentives for appropriate investment in generation and transmission facilities.

Question 4: a. What are the conditions required for alternative power pooling institutions to be beneficial (e.g.: a minimum number of sellers or buyers, a minimum geographic size, maximum market share for any seller or buyer, open membership, appropriate governance rules? b. Should participation by generators in the alternative pool's area be voluntary or mandatory?

The minimum conditions required for the Poolco model are, as today, that the control system be sufficiently extensive and well developed to permit the independent system operator to monitor electrical conditions within the pool area and that the independent system operator have control of sufficient resources (generation; dispatchable demand; and transmission assets, such as capacitors) to maintain system reliability. The precise minimum degree of flexibility is not likely to be constraining, even though participation in the pool dispatch should be voluntary. With consistent pricing as outlined above, the natural incentive will be for voluntary participation.

Question 5: Do alternative power pooling institutions have the potential to help resolve or minimize stranded cost issues? If so, how?

The Poolco model by itself does not resolve the stranded asset cost issues. However, the Poolco model is compatible with workable approaches such as Efficient Direct Access for dealing with customer access and recovery of embedded costs.

Question 6: a. How would specific alternative power pooling institutions be regulated? b. In particular, can these institutions be designed to fit easily into the existing Federal-State regulatory structure so as to avoid duplicating the regulation of pool functions?

The actual Poolco operations would not require intrusive regulation. For the wholesale market, FERC presumably would have oversight responsibility. Through Efficient Direct Access, a bright line can be maintained between the bulk of state and federal jurisdictional responsibility.

Question 7: a. What are the merits of proposals to restructure the electric power industry along functional lines such as the genco-gridco-disco delineation? b. Should the Commission be prepared to proceed with poolco-type proposals in advance of any functional utility restructuring efforts, or should the Commission refuse to act on poolco-type proposals unless the functional restructuring occurs simultaneously? c. Does such a restructuring have merit even if an alternative power pooling arrangement is not adopted? d. Would such a restructuring facilitate the development of a more competitive bulk power market in a way that the current institutional structure of the electric power industry cannot?

Development of a pool-based competitive generation market may lead to many related changes in the structure of the electric power industry. However, it is not necessary to delay the implementation of a pool-based market to await this restructuring except for the necessary establishment of the independence of the system operator. Separation of ownership from control of use makes formal restructuring less necessary or urgent.

Question 8: In addition to the proposal mentioned in the preceding question, are there other alternative institutional structures for the electric power industry that warrant the Commission's consideration in this Inquiry?

Understanding the details of the Poolco model and working out the new pricing and access rules sets an ambitious agenda. These issues can be considered in conjunction with other matters, such as the role of RTGs, but the focus should remain on the pooling arrangements.

Question 9: a. What are the strengths and weaknesses of today's power pool? We are particularly interested in concrete examples related to existing power pools. b. Should the Commission consider changing any existing power pool practices or policies to facilitate competitive bulk power markets?

Existing power pools integrate the complex issues in economic dispatch and reliability. These strength should be preserved. The principal weaknesses are in pricing and investment rules that are incompatible with a competitive market and access provisions which are closed and discriminatory. The Poolco model described above addresses these weaknesses without compromising the strengths.

Question 10: a. Would changes to existing power pools be preferable to creating new pooling institutions? b. Is an RTG an appropriate institution to become a power pool? c. Or should the RTG's transmission planning function be kept separate from the pool's generation market-clearing function?

There is no general answer to these questions. In some instances it may be easier to adapt than create. It may be that the planning functions of the RTG and the operating functions of Poolco could be managed by one or related institutions.

Question 11: a. Can a pool provide advantages to its members without unduly preferring members to non-members? b. How should pool members relate to non-members in an open access market? c. Are any improvements in information availability necessary for existing pools or alternative pooling institutions to be more beneficial? d. What reciprocity conditions are appropriate between pool members and non-members? e. How would a state policy of retail access affect pool membership conditions and retail access affect pool membership conditions and reciprocity obligations? f. What if retail access were available in only some states in the pool?

Yes. The essence of the comparable transmission tariff defined by Poolco prices is that members of the pool are buying and selling to the dispatch and nonmembers are paying the transmission tariff, but at the market equilibrium there is no discrimination. And since participation in the pool dispatch can be voluntary with efficient economic incentives, there is no need for special provisions, reciprocity requirements or other barriers to the market.

Question 12: How should the Commission's recently announced policy concerning comparability of transmission services be implemented with respect to alternative power pooling institutions and/or existing power pools?

Any competitive generation market with efficient prices and a truly non-discriminatory, comparable open access transmission service must be a functional equivalent to the Poolco model. The dispatch and transmission pricing rules of the Poolco model conform to the underlying physics and economics of the electricity system. Pricing and access rules that are not equivalent to the Poolco model must sacrifice economic efficiency, comparability, or both.

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