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NATIONAL ENERGY STRATEGY

Technical Annex 3

Electricity Transmission Access

A series of technical papers developed to support the National Energy Strategy
First Edition
1991/1992

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Executive Summary

Increased access to electricity transmission lines for sellers and buyers of wholesale power could encourage competition in the industry, lower electricity costs, and enhance environmental quality. The generation sector of the industry has recently become more competitive, with much of the new capacity ordered in the 1980's supplied by nonutility generators. However, achievement of the economic benefits potentially available through increased competition in generation of electricity could be constrained by the absence of adequate access to transmission. Calls for more open transmission have increased for this reason and because price differentials among utilities have caused wholesale buyers that cannot satisfy all of their own generating needs to seek alternative suppliers of electric power.

Complex questions of economics, equity, and reliability are embedded not just in the concept of transmission access, but also in the issues surrounding access—such as pricing, dispute resolution, joint ownership of lines, and planning for future additions to transmission capacity. Utilities' obligations under State laws and regulation add an additional layer of complexity. The purpose of this analysis is to explore these issues and suggest appropriate Federal options.

Transmission of electricity has the characteristics of a natural monopoly. This is in contrast to electricity generation, where competition is an economic alternative to exclusive reliance on local utilities constructing generating units. Owners of transmission systems can deny access to those who wish to make economic sales or purchases. A transmission owner with market power could do this to protect his wholesale sales from competition.

While increased transmission access for wholesale sellers and buyers of electricity can enhance efficiency by opening the wholesale generation market to more competition, it is not clear that access for retail customers would produce any additional economic gains. Moreover, there could be a significant strain on system reliability if all retail customers were allowed unlimited access. Increased wholesale access will not degrade reliability, provided access increases at a rate that does not outpace the technical capabilities of control systems and that allows system control centers to remain in control of system operation.

Three options for Federal action on transmission are considered. The first is to allow the present pattern of case-by-case determination of transmission access policy to continue. The second is to examine existing laws for authorities that could be used to expand wholesale transmission access while making the terms and conditions governing that access more predictable and orderly. Both these options would ideally involve rulemaking on transmission access, pricing, contracting, and capacity-expansion planning to define more clearly "just and reasonable" utility policies that are consistent with systemwide efficiency and reliability and with utilities' obligations under State law and regulation. The third option is to enact new Federal legislation which, among other things, could create an obligation for utilities to provide transmission service for wholesale customers.

1. Introduction

Purpose of This Paper

The electricity industry today is changing rapidly. These changes are creating pressures for new operational procedures and policies. One such pressure is for increased access to the transmission system by various categories of sellers and buyers. Prominent among the many reasons cited by proponents of increased transmission access are the emergence of increased competition in the electricity generation sector, reduced capacity surplus in many regions, difficulty in siting new generating facilities in some regions, and the increase in geographic size of regional electricity markets, made possible by the development of regional high-capacity transmission grids.

The purpose of this paper is to explore, first, the principal issues raised by calls for new transmission access policies and, second, the possible Federal policy options that might address these concerns. The remainder of this introduction is intended to give the reader the background necessary to appreciate the later discussion of issues and options.

Increased Competition and Transmission Access

Electricity is delivered to end-use customers by local monopolies, as it has been since the industry began in the early 1880's. From the earliest days of the industry until the late 1960's, economies of scale in construction and operation of new generating units caused prices of utility-provided generation to decrease steadily. As electricity production costs bottomed out and started to rise in the late 1960's, the question of whether generation of electricity is in fact a natural monopoly was raised more and more frequently.

Greater visibility and controversy for the industry began with the cost and price increases that first occurred in the 1970's. These industry-wide cost increases had many causes. Fuel prices rose, most notably with the oil embargoes of the 1970's. The price of natural gas also rose, in response to the partial wellhead-price deregulation of the late 1970's. Coal prices rose, due in part to labor settlements that allowed wage increases in excess of inflation.

In addition, the inflation that started in the early 1970's and peaked about 1980–81 drove financing costs up. New environmental and regulatory requirements increased both fuel and capital costs. The costs of nuclear powerplants under construction at the time of the Three Mile Island accident, for example, rose to levels several times higher than originally projected. Finally, new economies of scale in generating electricity were hard to achieve in the 1970's, substantially reducing or eliminating the decades-long trend of reductions in costs when new plants came into service and allowed service to be expanded at reduced unit costs.

This maturity of the electricity generation system called into question the economic rationale for the traditional assumption that new plants should be built only by local utilities. The rising costs of the 1970's prompted much closer and more contentious regulatory oversight than utilities had experienced previously. The cost increases, together with the recession following the 1979 oil embargo, left many utilities with excess capacity that regulators were reluctant to include in the rate base. One consequence of the increased oversight has been a decade of regulatory decisions that, according to industrial credit rating services, many analysts, and the testimony of many utility executives, have made utilities reluctant to invest capital in new generating units because they fear they may not fully recover their costs.

Concurrently, the Public Utility Regulatory Policies Act of 1978 (PURPA) created a new class of electricity generating entities known as qualifying facilities (QF's). To be a QF under PURPA, a generator must either cogenerate electricity and steam or use a waste or renewable resource for at least 75 percent of its primary fuel. To promote this type of generation, PURPA freed these generators from much of the rate base and other financial regulation that utilities face—for example, the

Public Utility Holding Company Act of 1935. QF's were also given a guaranteed market. Electric utilities are required by PURPA to purchase electric energy offered by QF's at a price equal to the purchasing utility's avoided cost, rather than at the QF's cost of service. Efficient QF's can thus earn potentially large profits by selling power to electric utilities. Further consideration of PURPA and a discussion of proposed changes to the act can be found in a separate technical annex.

The most visible results of PURPA and the regulatory climate of the last decade are the emergence of new entrants in the wholesale generation sector of the industry and competition between the new entrants and traditional utilities for the opportunity to meet new electricity demand.

While most of these new entrants are QF's, recently another class of new entrants, independent power producers (IPP's), has appeared.[1] The use of competitive bidding mechanisms has emerged in approximately 20 States as the preferred method of choosing which sources of new power are least expensive, partly as a result of the abundance of QF's responding to administratively determined avoided-cost prices for QF power in some areas. In several areas of the United States, much of the recent growth in demand for electricity has been met mostly by QF's and recently by some IPP's, rather than by traditional utility construction, as utility proposals or avoided-cost projections have been underbid by QF's or IPP's.

The term "transmission access" refers to the ability of a seller or buyer of power to use high-voltage transmission lines owned by one or more utilities to purchase or deliver electricity to markets distant from the point of generation. Transmission access issues have been debated in the electric utility industry for many years. The emergence of competition in wholesale power markets, however, has given the subject new importance.

Many of the new suppliers in the wholesale electricity generation market have called on the Federal Government or State governments to institute transmission access policies that would enable suppliers to locate generating units where they would be most economical, taking into account environmental and other siting constraints. Significant cost differences among utilities have motivated wholesale purchasers, notably public power utilities with little generating capacity of their own, to seek transmission access that would enable them to purchase power that is less expensive than power supplied by their local utility. Other entities, such as the National Governor's Association, have taken notice of the inability to transmit the surplus power from some areas to areas that need additional sources of power.

Advocates of increased transmission access argue that local utilities, through their control of transmission lines, may reduce competition and increase their own profits at the Nation's economic expense. Many utilities disagree, suggesting that they are already allowing considerable transmission access and that to do more could harm the reliability of the system and increase the likelihood of blackouts. They also argue that because competitive bidding has been vigorous, and because wholesale buyers have locally available alternatives to purchases from distant utilities (such as self-generation, conservation, or continued purchase from the local utility), more transmission access is not needed. They point out that, in conjunction with the traditional obligation of the utility to serve, transmission access could cause inequities such as "stranded investment"—that is, investment in generating equipment that was built in part to serve customers that now seek other suppliers. These and associated issues are explored in detail in the body of this paper.

Changes in the Industry

In the early decades of this century, the electric power industry was predominantly local in nature. Each local utility served the immediate area, usually with a city of some size at its core. Gradually, as cities grew, larger utilities formed from mergers and eventually served several cities. However, the degree of interconnection between utilities was weak by today's standards, and each utility depended mostly on its own generation sources, usually located close to load centers.

Since the 1920's, however, utilities have become more strongly interconnected over large regions. Generating plants became larger and were located farther from load centers as the technology developed for longer transmission lines of higher voltage. Utilities recognized the economic benefits of interconnection, in particular because interconnection could increase system reliability at lower cost than could building more generating facilities. A possible shutdown of a local generating unit can be backed up by the generating capacity of neighboring utilities instead of by building additional units locally.

New transmission technologies eventually allowed the use of much larger lines—230-kilovolt (kV), 345-kV, 500-kV, and finally 765-kV lines. Each of these can carry correspondingly more power per construction dollar, and can do so with greater efficiency than the smaller lines. In the United States, 345-kV lines were first built commercially in the early 1950's; 500-kV lines in the mid 1960's; and 765-kV lines in the late 1960's. About 1,000 circuit-miles of extra-high-voltage lines (230 kV and up) existed in the United States in 1950. By 1987, approximately 130,000 circuit-miles of these lines were in use, and now great amounts of electricity can travel up to a thousand miles in many parts of the Nation.

Transmission is now regional, rather than local, in scale. Just four large, interconnected grids cover the continental United States and the highly populated areas of Canada. The coordination of electricity interchanges is managed by about 150 "control areas," many of which are multistate power pools dispatching the generating units of several utilities.

Because the industry's transmission network is now often regional in scale, large amounts of power can often be transmitted long distances; without this capability, there would be fewer calls for increased transmission access. However, wheeling (that is, the transfer of power by a utility that is neither the generator nor the ultimate purchaser of the power) does not necessarily entail the transmittal of power over long distances. A wheeling transaction could and often does involve a buyer and seller within close proximity of one another.

Institutional Structures and Transmission Issues

Construction and transmission access decisions, siting approvals, and regulatory oversight all have effects that extend over large regions. However, these decisions are often made by local or State bodies, or by local utilities. Thus the potential for decisions to be made in the interest of the locality exists, and this interest may conflict with broader regional or national interests. Regional or national economic efficiency may suffer.

Some voluntary regional bodies do exist. Some are power pools that use central dispatching systems to ensure the lowest short-run production cost and that, in some cases, help coordinate future construction decisions. There is also the North American Electric Reliability Council and its nine regional reliability councils, which take steps to ensure the reliability of electricity service. However, these groups were not formed to facilitate the most efficient use of regional transmission facilities and have not tried to do so.

Yet, many parties are calling for changes in transmission policies. For instance, the National Governor's Association 1987 report, *Moving Power*, states:

> Even when a transmission project would clearly generate net total benefits, regulatory or institutional factors affecting the distribution of those benefits can result in at least one affected group concluding that the line is "uneconomic" or undesirable. In short, *the way the utility industry is organized and regulated* can create a disparity between the total economic value of a project (including its social costs and benefits), and its "accounting value" which reflects whether, and by whom those benefits can be realized. [italics added]

Moving Power then concludes (in part):

> The task force also found that, by and large, long range planning (by both states and utilities) focuses on and is driven by generating capacity needs. This focus seems to result from an institutional and regulatory framework which promotes consideration of needs within rather than between utility systems. *In particular, the fact that transmission lines are generally developed and owned by the utility within whose service territory they reside, but will be used by non-owners as part of the whole system, creates*

> *economic and regulatory disincentives to the optimal development of the transmission grid.*
>
> Larger-scale transmission projects, which better reflect the needs of the overall system rather than its individual components, *may only be achievable if regulatory requirements actually promote greater inter-utility coordination and cooperation on transmission development.* [italics added]

Considering the status and diversity of interests represented by the National Governor's Association, these are strongly stated findings. The next section lays the groundwork for a further discussion of the issues and potential policy options.

Notes

1. As yet, relatively few IPP projects have been undertaken. The success of the future IPP industry will depend upon whether the Public Utility Holding Company Act is amended to reduce regulatory barriers now faced by IPP's. For more detail, see the technical annex on options to amend the Public Utility Holding Company Act.

2. Barriers to Increased Wholesale Transmission

Implications of Lack of Transmission Access

Electricity transmission is a textbook case of a natural monopoly. Natural monopolies are characterized by decreasing unit costs over the entire extent of the relevant market and are normally characterized by relatively large fixed investments.[1] When a natural monopoly exists, society's total costs for providing the service in question are minimized when a single facility is built, rather than having several providers each build duplicative and more expensive (per unit of service) facilities. In the case of transmission lines, society's total expense is reduced if one set of lines is built, with the large economies of scale achievable in transmission service, rather than two or more sets of less efficient, more expensive (per unit of energy shipped) lines.[2] Furthermore, there are environmental benefits in minimizing the number of transmission lines. For these reasons, it has been both efficient and traditional to grant only one entity the right to build transmission capacity in any particular jurisdiction. In some cases, which can be identified by the application of modern antitrust analysis, that entity thereby acquires significant monopoly power in the market for transmission services.

All firms strive to maximize profitability. A utility monopolist can be expected to utilize its monopolistic position to maximize its profitability. A monopolist maximizes profits by reducing the output of the good in question or the amount of service provided, thereby raising its price. In the utility industry, that would mean constructing less transmission capacity than is optimal for society's overall benefit while also charging too high a price for the use of existing lines. A simple numerical example of how a utility might do this, and in so doing prevent an economical project from being built, is provided in Appendix A.

The electric utility industry exhibits a high degree of vertical integration; that is, virtually all owners of transmission lines in the industry also own generating capacity. This introduces the possibility that firms could use their control of transmission facilities to reduce competition in wholesale markets, particularly when firms are restricted in the price they can charge for transmission. For instance, a utility might want to submit a bid to sell power in a competitive procurement. It therefore might want to block potential competitors from access to this market. Alternatively, a utility might want to protect its existing wholesale sales by restricting transmission access to competition from alternative suppliers.

Finally, to retain market share, utilities want low rates. Utilities are regulated, and it is important for them to have good relations with their ratepayers and regulators. Thus, they might also use their transmission facilities first to minimize their retail rates, even if in the long term this might prevent power transfers through the system at lower regional costs.

Owners of transmission lines object to contentions that they abuse their monopoly position and argue that expanded transmission access would cause inequities and reliability problems. These owners have made the following generic arguments:

- Reliability of service will suffer because control will be more difficult when more users or providers of generating capacity can make demands on the transmission grid.

- With regard to "captive" wholesale buyers who wish access to other sources of supply, both stranded investment and "prodigal son" issues are raised.

  The stranded investment argument arises when the local utility has constructed generating capacity to serve its customers but then finds that some wholesale customers want to leave the system, thus requiring stockholders or other customers to pay for these investments.

  The "prodigal son" issue arises when a wholesale customer has left its traditional electric utility supplier for a source offering lower cost and then, when costs on the other system become higher, returns and again demands service as a right from the local utility. Here the utility may not have adequate capacity or may have to increase rates to other customers to meet the returning demand. Allowing wholesale customers to move on and off a utility's system generally would make the already difficult job of load forecasting even more difficult.

- If transmission access is made mandatory rather than voluntary, then either courts or governments might have to decide which entities should have access and under what terms and conditions that access should be provided.

- Some have urged *retail* transmission access. If retail access were allowed, however, the stranded investment and prodigal son issues would be far more difficult to manage than if access were limited to wholesale customers; the same applies to the planning and forecasting problem. Reliability problems would be much more likely, given the much larger number of independent users of a system that requires a high degree of coordination among all participants.

  System accounting would become more complex under retail access. Because of the numerous potential buyers, dispatch centers and utilities would have to ensure that blocks of power are matched with the correct customers. Because the number of sellers within a control area also could become quite numerous, the accounting could become even more burdensome.

- Because transmission lines are paid by and built for the utility's customers, it would be inequitable, it is argued, to allow other users to have priority for the use of the lines.

Most of these issues are addressed in later chapters. In this chapter, though, with its focus on market barriers, we examine next the arguments of some utilities that lack of *mandatory* transmission access does not create economic inefficiencies.

Does Lack of Transmission Access Cause Economic Inefficiencies in the Electricity Industry?

A typical argument presented by owners of transmission lines is as follows:

> Transmission owners do not abuse their monopoly power. Instead, their policy of voluntary access is working well, resulting in increased wholesale trade. Competition in new wholesale markets is substantial; therefore transmission access appears not to be a barrier for new entrants such as independent power producers (IPP's) and qualifying facilities (QF's). Furthermore, power purchasers may have alternatives to transmission access for meeting their energy needs.

Four points to consider in evaluating this argument are presented below.

Contention: IPP's and QF's are thriving. Therefore, expanded transmission access for IPP's and QF's would not produce additional benefits.

Most competitive procurements have been oversubscribed by a factor of 5 to 10. However, some of the winners in these procurements have been unable to build their plants because of the lack of transmission service. For example, in Virginia Power's 1988 solicitation, four of the winning bidders, located in West Virginia, could not obtain transmission service.[3] Other, more efficient competitors might have entered this and other bidding contests had they been assured of access at reasonable rates.

Transmission service would also enable QF's or IPP's to sell to several utilities. Thus they could build larger plants and take advantage of economies of scale, thereby lowering the cost per kilowatt of new generating capacity over a larger area.

Increased access would also enable utilities in areas where siting new powerplants is very difficult or expensive to purchase power from remotely sited plants at lower costs.

Another type of potential entrant in the generation market, a "merchant IPP," could also be prevented or discouraged by lack of transmission access. A merchant IPP is a company that owns generation but sells only part of its power under long-term contract, reserving the remainder to sell on the spot market as economy power. There are no merchant IPP's today, but some argue that such IPP's could perform useful functions in wholesale power markets by simultaneously providing price signals for potential builders about when to build new generating capacity and shifting some of the "demand risk" of building new plants from buyers to sellers of power. The existence of merchant IPP's could increase transmission reliability difficulties if power flows for spot-market sales are not carefully controlled. However, according to a recent study by the Office of Technology Assessment,[4] there are no institutional, engineering, or economic reasons why satisfactory arrangements with control centers and reliability councils cannot be reached to ensure reliability.

Thus, the multitude of bidders responding to competitive procurements does not mean that lack of transmission access is not inhibiting more vigorous competition. The issue is whether expanding transmission access would cause bidding programs to be even more successful in terms of lower prices and higher quality bidders.

Contention: An entity requesting access has alternatives that largely prevent the transmission owner from exercising monopoly power.

The argument here is that a wholesale buyer can build its own plant, invest in energy efficiency, or in some cases use another firm's transmission facilities, and thus circumvent any attempt to exercise market power by denying transmission access on reasonable terms. While this argument may have some merit, increased access is nevertheless important for at least three reasons.

First, while alternatives exist, they may not be least-cost alternatives. This is why buyers request access. Modern antitrust analysis will correctly detect significant monopoly power when differences in economic cost are substantial. The cost of a new plant, especially for a small utility, may be higher than the market price of electricity that can be acquired through the best use of transmission lines. Cost-effective conservation resources may be limited or uncertain. In short, the fact that some alternatives exist does not prove that market power is absent any more than the mere ownership of transmission facilities proves that it is present. The existence of alternatives does not prevent economic inefficiencies from occurring as a result of the exercise of market power.

Second, where significant market power exists, to argue that the presence of imperfect alternatives negates the need for action to prevent the exercise of that power is to argue that monopolies should not be regulated. By analogy, industrial users of electricity can in many cases shift from electricity to oil-based or gas-based technologies, and homeowners can use gas or oil instead of electricity for heat; however, few policymakers would argue that these alternatives warrant deregulation of electric retail service.

Third, while it is important for the wholesale buyer to have a number of alternative supply sources, it is also important that a utility seller not be able to restrict the buyer's choices. An ability to restrict access to markets is likely to be used by a seller to its own advantage. If this is not the seller's intention, the seller should have little interest in maintaining an ability to restrict access in the first place.

Contention: Voluntary access is working.

The argument that transmission access is not a barrier to efficient electricity transactions is often based on the premise that the significant increase in coordination sales between utilities in the last two decades demonstrates that access is given liberally to those who desire it.

The volume of short-term wholesale electricity transactions between utilities has increased substantially in the past two decades. An increase in transfer capacity, excess generating capacity at some utilities, and increased disparity in production costs among utilities, due in part to increases in the cost of oil relative to coal for much of the past 17 years, have all contributed to this trend. The amount of electricity being sold in power pools, also considered wholesale trade, also has increased because of these factors.

In most spot-market, or economy, transactions, an owner of transmission lines will lose revenues if a potential sale, perhaps between two utilities on either side of the transmission-owning utility, does not take place. Consequently, a transmission owner with excess capacity has a short-term incentive to accommodate economically beneficial trades. In addition, transmission owners in power pools typically allow other pool members to use their lines in exchange for the substantial economic benefits generated by the pool. A 1981 report by the Federal Energy Regulatory Commission (FERC), *Power Pooling in the United States,* found that only 1 to 2 percent of possible short-term savings were not achieved at that time, indicating that most opportunities to displace units with higher operating costs with units with lower operating costs were taken. However, a nationwide gain of 1 to 2 percent in short-term savings is equivalent to more than $1 billion annually.

Two issues must be considered here. First, while it is true that many efficient short-term trades are consummated in today's "spot market" for economy energy, the market itself is imperfect. Individual transactions are priced at widely different prices because FERC sometimes allows split-savings pricing for economy transactions. This pricing practice has arguably improved the utilization of existing generation assets and heretofore has been an appropriate part of FERC's policy. However, it may become an impediment to the development of more efficient arrangements because different sellers could face significantly different prices for similar transmission service, thus distorting the delivered cost of power.

Second, it is important to distinguish between transmission access for short-term trade and transmission access for long-term trade. In the long term, the issue is whether long-term access is available on reasonable enough terms and under reasonable enough conditions to allow a distant competing generator to provide service to local utility systems.

For potential long-term transmission agreements, an economically rational transmission owner would examine a range of issues, including the revenue stream those requesting access might provide; the possibility of brokering power at a markup greater than allowed transmission rates; the revenues to be derived from using the transmission for his own uses (for example, selling power from his own generating units); and how best to minimize his own retail rates. The rational decision sometimes will be to deny long-term access or to charge high transmission rates that would discourage construction of competing new generating units.

Thus, the large gains in short-term wholesale electricity transactions do not mean that the exercise of monopoly power over transmission lines cannot result in economic inefficiencies for long-term trade.

Contention: Many groups are calling for increased access for the wrong reasons.

The American Public Power Association, the National Rural Electric Cooperative Association, the National Independent Energy Producers, the National Coal Council, and many others are calling for increased transmission access. It is difficult to conclude that voluntary access is working well when so many potential transmission users assert that access is inadequate.

Some of the demands for opening the Nation's transmission system are undoubtedly self-serving. These users want service at low embedded-cost rates and seek transmission access to avoid the sunk capital costs of generating units, shifting these costs onto other users. Many of the proposals, however, would entail acceptance of higher incremental-cost rates and cannot be summarily dismissed as self-serving and contrary to the public interest.

Discussion

On the whole, it seems unlikely that the voluntary access policies in place today will provide sufficient and economical transmission access for wholesale sellers and wholesale buyers of electricity—especially those needing long-term contracts. However, some promising incremental changes have begun to occur in the industry recently. The more prominent of these are discussed below.

Recent Transmission Access Agreements

Few utilities grant long-term open access to all entities that request it. In some recent FERC cases, however, some utilities have agreed to provide transmission access, generally as a condition for FERC approval of a utility proposal or action (for example, a merger or proposal to sell power at market-based rates). Several of the more important cases, both completed and pending, are discussed in some detail in Appendix B and are briefly summarized here.

Turlock and Modesto

In 1988, FERC approved transmission agreements between Pacific Gas & Electric Company (PG&E) and two of its captive wholesale customers: the Turlock and Modesto Irrigation Districts. In both cases, the Commission approved a 20-year regulatory bargain whereby the wholesale customer would receive certain firm transmission and power services at embedded cost-based prices while PG&E would be authorized to charge "market-based" prices for certain coordination services. The Commission approved PG&E's request for market-based pricing because it judged that the company had sufficiently mitigated its market power, in general, by its offer of cost-based services and, in particular, by its transmission commitments.

Neither agreement allows the captive customer to resell reserved transmission service, and in both cases the transmission service is provided between specific receipt and delivery points. Both these features restrict the market activities of the wholesale customers and help to insulate PG&E from competitive pressures that might otherwise be exerted against it.

PSI Energy

In 1990, FERC approved a proposal by PSI Energy (formerly Public Service Company of Indiana) to sell up to 450 megawatts of long-term, firm power at market-based rates in exchange for a commitment by PSI to open its transmission grid. FERC approved PSI's program on the basis, first, that PSI is not a dominant firm in its region and consequently lacks market power over generation and, second, that PSI derives no market power from its transmission assets because of its commitment to provide open-access transmission service to all utilities, IPP's, and QF's.

FERC required PSI to back up its obligation to provide transmission service by agreeing to suspend its market-based power pricing should FERC receive and uphold a third-party complaint about the lack of timely transmission service.

PacifiCorp-Utah Power & Light Merger

FERC conditioned its approval of the merger of PacifiCorp and Utah Power & Light on the company's acceptance of an absolute obligation, over the long term, to provide firm transmission service to any power producer, not including QF's, at cost-based rates.

FERC's conditions were accepted by the two companies and the merger was consummated in 1989. In so doing, the company agreed to place its coordination transactions at risk. This aspect of FERC's conditions is viewed as particularly onerous by many companies in the industry. Whether it is burdensome in practice remains to be seen. In any case, such a commitment satisfies the Federal interest in ensuring that efficient interstate electricity transactions are not unnecessarily impeded by utilities or local authorities. However, this "Utah condition" is not the only means of doing this.

Wisconsin Power & Light Transmission Tariff

In 1990, FERC accepted a transmission tariff under which Wisconsin Power & Light Company (WP&L) effectively became an open-access provider of transmission services. No regulatory bargain was involved at the Federal level. The Wisconsin Public Service Commission, however, established a policy that required its jurisdictional utilities to implement joint transmission planning and to file transmission service tariffs.

This State policy raises the possibility of joint Federal-State partnerships to establish adequate transmission access. FERC has authority over transmission rates, but cannot (except in a few unlikely circumstances) order nondiscriminatory access. Here, the State, which has no authority over the pricing of transmission service, is in essence ordering access. If Wisconsin's action passes judicial scrutiny, the groundwork for possible Federal-State cooperation will have been laid.

Under the tariff, WP&L will provide both firm and nonfirm transmission service to any utility, including QF's and IPP's, from existing facilities at embedded-cost rates. If new facilities are needed, WP&L will provide service under separate, negotiated agreements approved by FERC. Although the tariff does not specify the transmission price to be charged if new facilities must be built, it must ultimately be "just and reasonable" under the Federal Power Act. Thus far, FERC has required a cost basis for the price of firm transmission service under this standard.

The WP&L tariff allows transmission between flexible receipt and delivery points, but does not allow the service to be resold. The flexibility offered to customers by the first condition is somewhat offset by the restrictiveness of the second.

Pending Cases

Several cases are pending at FERC, including the Western Systems Power Pool extension and the Southern California Edison-San Diego Gas & Electric merger. These cases suggest that the trend toward voluntary offers of transmission service is continuing. Issues related to mergers, market power in nonfirm transmission pricing, and FERC's authority to order transmission under Section 207 of the Federal Power Act are also raised by these cases.

FERC actions in these pending cases will substantially affect the evolution of transmission policy. The current strategy at FERC appears to rely on case-specific developments. No generic action on access or pricing has yet been proposed or announced by FERC; thus it is not yet clear where the Commission intends its case-specific actions to lead or what principles will guide its actions in future cases. As discussed below, there would appear to be significant benefits from the development and articulation of a more general transmission policy.

Notes

1. See Alfred E. Kahn, *The Economics of Regulation,* Vol. II, p. 119.

2. See *Report of the Federal Energy Regulatory Commission Transmission Task Force,* Table 2–5, p. 47, for cost per kilowatthour of transmitting power over different sized lines.

3. After these projects were canceled, Virginia Power and American Electric Power reached agreement on the construction of new extra-high-voltage transmission lines that will make it possible for projects in this part of West Virginia to sell power into Virginia starting in the mid-1990's.

4. Congress of the United States, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Considerations for Increased Competition,* May 1989.

3. Pricing and Related Terms for Transmission Access

The Relationship Between Pricing and Monopoly Power

As noted in Chapter 2, the critical transmission issue facing the industry is how to deal with the potential exercise of market power by some owners of transmission facilities. In this regard, both price and priority of use are crucial to determining whether access to transmission lines is in fact meaningful to an independent power producer, qualifying facility, or other wholesale seller. If the price of service for a long-term contract is not specified with a reasonable degree of certainty, a prospective wholesale seller cannot know if a candidate powerplant is economically feasible, especially because in many cases the seller would have no transmission alternative. If the service is not firm (or is firm for only a part of the contract), the seller would not know if it could always get its power to market.

The National Independent Energy Producers, which represents nonutility generators, states the issue in greater detail:

> In specific competitive situations, utilities which own and control transmission facilities may exercise market power over competitors if they:
>
> - Make transmission access available to affiliates while denying access to competitors
> - Deny transmission access to favor competing proposed rate-based plants
> - Refuse to make public transmission capacity or availability information
> - Delay signing letters of intent to provide wheeling service to suppliers which prevents those suppliers from meeting bidding deadlines or other bidding requirements
> - Make access available to all, but impose prices, terms or conditions on transmission service for nonaffiliated entities that make projects unfeasible or uneconomic.[1]

Of these five points, the first two relate to how a transmission owner could block competition in generation markets (addressed in Chapter 1); the third and fourth points indicate how a transmission owner might indirectly avoid providing access; and the last addresses the focus of this chapter, namely the relationship of pricing and the use of market power.

What examples are there of transmission owners actually using their market power? Few cases of outright refusal to either wheel or otherwise provide service exist. The most celebrated is the two-decade-old *Otter Tail* case, in which a utility that denied access was penalized on antitrust grounds.[2] The more recent cases described below illustrate the difficulty of separating access from pricing issues. Specifically, these cases demonstrate how the utility owning the lines can use pricing and prioritization to limit use of transmission lines by wholesale buyers or sellers of power.

1. The Geneva, Illinois, municipal electric system in 1986 exercised its contractual right to drop its local supplier, Commonwealth Edison, and obtain only transmission services from Edison, upon 1 year's notice. However, Geneva was unable to arrange for access at a transmission price that would make it economical to purchase power from its new supplier. In a 1986 decision, the Federal Energy Regulatory Commission (FERC) found:

> By the terms of the agreement, Edison was to enable any of its wholesale customers to pursue alternative power supply options under reasonable parameters. *Implicit in such an arrangement must be an agreement that transmission service will be priced reasonably relative to existing services being provided by the utility.*[3] [italics added]

FERC noted that Edison proposed a rate approximately four times the price that had been quoted to Geneva during its evaluation of suppliers. The FERC decision continued:

> Whatever ultimate findings the Commission might make with regard to the merit of Edison's pricing structure or, conversely, its anti-competitive effects, we know at this point that the filing will immediately subject Geneva to an observable prejudice or

> disadvantage in the power supply market that will not be remedied through later refunds. [4]

2. In the Northeast Utilities (NU)/Public Service of New Hampshire merger case currently before FERC, similar issues are raised by the Vermont Public Service Board, a wholesale purchaser of electric power:

> ...*NU's policy that a customer in need of transmission service receive such service only under terms dictated by NU—the largest electric utility in New England and often the only utility with the facilities to provide such transmission—and receive such service only on the condition that the customer does not challenge the terms of service* [before FERC or the courts]—is patently unreasonable and renders inadequate much of the essential interstate service available in New England....
>
> Under the terms of [contractual conditions] the customer is obligated, for the life of its transmission agreement, *to pay all, or a pro rata portion, of the costs of new construction or modification of transmission facilities which NU determines are [required],* whenever NU makes that determination..... *NU's practice ... holds potential transmission customers hostage* to indeterminate future charges as a condition of service.... *[T]his practice is unduly discriminatory in that NU's sales customers, particularly its native load, are apparently not subject to this condition for continued service, although continued service to them may also "contribute to the need for such new or modified facilities."*[5] [italics added]

NU's view is quite different:

> Vermont complains that NU's transmission service practices are discriminatory in two respects. First, NU's long-term transmission service contracts disclaim any obligations "to construct or modify its transmission facilities" to ensure continuation of the transmission service. If new or modified transmission facilities are required in order to continue the service, the transmission service customer has the option of either contributing to the costs of these facilities or discontinuing the service. Second, *NU currently follows the practice of not committing to provide transmission service to another utility where to do so would interfere with NU's ability to use its transmission system to make off-system sales from its generation capacity to reduce the cost of service to NU's native load customers, and to sell the output of its own generation to its own native load customers.*[6] [italics added]

This dispute raises a key issue. NU, quite reasonably from its viewpoint, wants to minimize its own customers' rates (and maximize shareholder returns) and therefore will give its own uses priority over the uses of others, including those who seek firm service contracts. If a transmission user with a long-term contract to use the lines wants to continue using them for firm service, it must pay some or all of the costs of expanding the capacity of the lines.

3. The Wisconsin Public Service Commission, in a recent order, addressed similar issues when it stated:

> The monopoly control of "bottleneck" facilities has also permitted the owning utilities to allocate the benefits of the transmission system optimally for their own ratepayers without consideration of statewide least-cost planning, or statewide efficiency of use. Allocation on this basis is unlikely to be equitable or to provide the statewide efficiency for which the system is being planned and built.[7]

It should be noted, of course, that even policies designed to maximize statewide efficiency (or to minimize statewide average rates) may reduce efficiency on a regional or national basis. Individual State commissions cannot be expected to applaud policies that have the potential to raise their constituents' rates in the service of broader efficiency goals.

An important corollary issue is whether a utility must sacrifice its own short-term sales in order to provide long-term access. Such a policy might require the user to pay for any upgrades needed to accommodate use of the transmission system in the near term, when the user is brought on line. Under this policy, a utility also would charge a reasonable (perhaps embedded-cost) rate for the use of lines that do not need upgrading, but would then treat the user as an existing part of the system. If the "reasonable rate" went up over time, it would go up the same amount as for other system users, including retail customers, and thus all would share on a *pro rata* basis in the costs of system upgrades needed to provide continued service.

Would this kind of policy cause losses to the transmission-owning utility by making it forgo economic transactions? This type of policy would cause a utility to forgo economy transactions only if the utility could not provide upgrades needed to serve all users in a timely manner. Then, a choice would have to be made for priority of use.

PacifiCorp (in its merger with Utah Power & Light) and PSI Energy (in its recently approved market sales program) both agreed that firm transmission will have priority over nonfirm uses of the grid, even those that might otherwise benefit native-load customers. This priority applies equally to expansion planning and operational uses of the grid. The fact that some members of the industry can arrange to operate their grids under rules of priority that apply equally to the industry and its customers suggests that problems of priority of use are not viewed uniformly across the industry and may be particularly difficult to solve.

The question of whether utilities could reasonably be expected to provide needed upgrades is discussed further below.

Transmission Pricing in the Absence of Market Power

The reasoning thus far is that in cases where transmission owners have significant market power over firm transmission service, their conduct must be constrained by regulation. Ensuring that transmission services are priced in an economically sound fashion and provided under reasonable contractual conditions while improving the access conditions in the industry is a significant challenge for FERC and other interested parties at present. Economically sound pricing of transmission services promotes good decisionmaking in the generation and transmission sectors of the industry by promoting trades that are economically efficient and discouraging trades that are not.

A report issued by the National Regulatory Research Institute (NRRI) finds that marginal-cost pricing for transmission would tend to promote good decisionmaking and would be more appropriate than embedded-cost pricing.[8] In this view, long-term incremental-cost pricing will give the correct signals about real resource costs to users of long-term firm transmission service.

Similarly, short-term marginal-cost prices will give correct price signals to users of nonfirm transmission service, where short-term marginal costs include a measure of congestion costs if transmission facilities are constrained in the short term. The NRRI concept of short-term marginal costs corresponds closely to that advocated by the so-called MIT group, which favors a form of spot-market pricing for short-term, nonfirm transmission service.[9]

As the NRRI report points out, not only is it important to get the prices for individual transmission services right, but it is also critical for the overall functioning of the market that customers have a viable choice between firm and nonfirm services. In that way, when the spot price of transmission rises because of congestion, customers who do not wish to pay the resulting higher prices for nonfirm service will be able to subscribe to firm service instead. The spot market, then, will provide signals that affect the demand for firm transmission service, which, if the service is priced at expansion costs, will signal that additional transmission capacity is needed.

The report of the FERC Transmission Task Force took this reasoning a step further and addressed the possibility of so-called "vintaged pricing" in which, among other things, native-load customers and off-system customers would be treated differently. This concept involves native-load users paying embedded costs for the transmission service that they receive bundled together with generation service. With this concept, off-system customers would pay incremental costs for firm service and each customer would in addition pay the incremental cost of the grid at the time the long-term, firm transmission contract is initially negotiated and approved.

Former FERC Commissioner Stalon has carefully examined four alternative pricing regimes for long-term, firm transmission service involving various combinations of policies concerning incremental versus embedded-cost pricing, and whether or not vintage pricing is permitted for off-system users.[10] All of Stalon's alternatives have embedded-cost pricing for the native load. He concludes that, of the four alternatives considered, incremental-cost pricing for all off-system users would best promote the Nation's economic efficiency objective.

He points out, however, that embedded-cost pricing is familiar to regulators and is politically attractive. In addition, discriminating among off-system users with vintage pricing can also be politically attractive to regulators and can be thought of as a form of "grandfathering," an acceptable regulatory practice in many instances. Consequently, while the efficient choice in Stalon's view is nondiscriminatory incremental-cost pricing, he expects that a less efficient embedded-cost standard or a vintaging standard is likely to be adopted. Given the importance of making efficient use of the Nation's energy resources, a politically driven standard could be extremely costly.

These pricing issues are complicated matters that may require several years to sort out completely. The sorting-out process could be accelerated if FERC were to move forward with a rulemaking process concerned with transmission issues related to access, pricing, contracting, and capacity expansion planning. In the meantime, the industry has proposed some interesting approaches that FERC has found to be just and reasonable. PSI Energy's program, described in more detail in Appendix B, involves embedded-cost pricing for service from existing assets and incremental-cost pricing when new facilities must be built. PSI Energy and FERC were able to move forward on PSI's basic proposal by acknowledging that PSI's calculation of incremental costs, if and when new facilities are needed, must meet the Commission's "just and reasonable" standard. The Wisconsin Power & Light (WP&L) transmission tariff envisions a similar regulatory solution to the need for new facilities.

The WP&L transmission tariff is also an example of an industry-sponsored approach for dealing with one aspect of the quality-of-service issue. It permits systemwide transmission service as opposed to point-to-point service. Systemwide transmission was also a feature of the Gulf States Utilities settlement with Sam Rayburn Cooperative. PSI Energy's recently approved program does not have systemwide access, but does allow receipt and delivery points to be adjusted if the buyer agrees to pay any incremental costs. These examples suggest that the industry is capable of addressing the quality-of-service issue in productive and innovative ways.

Another aspect of service quality of interest to transmission customers is whether firm transmission service can be resold. In the PacifiCorp-Utah Power & Light merger, FERC required that customers be allowed to resell firm transmission service. In this instance, reselling was seen as one way of checking the merged company's market power over nonfirm transmission—a flexibly priced service. Similarly, PSI Energy also allows transmission service to be resold, although the market power issue does not arise to the same degree in this case because PSI offered to cap nonfirm prices at cost. The Large Public Power Council, an association of transmission-owning municipal utilities, has called for reselling in its transmission reform proposal. In contrast, the WP&L transmission tariff does not allow reselling, although this restriction is tempered by the systemwide character of the service in the first instance. These industry-sponsored initiatives suggest that reselling can be dealt with in the context of current institutions.

The recent regulatory experience strongly suggests that FERC has adequate authority to deal with pricing and other terms and conditions of transmission service, including such issues as whether to allow reselling and whether systemwide or point-to-point service is appropriate. The unanswered question is whether FERC can address the transmission owner's obligation to serve within its current authority—a topic discussed below.

Will Adequate Transmission Capacity Be Provided?

In this section, we return to the issue of whether it is reasonable to expect a utility to provide adequate capacity at reasonable prices over time for both existing and potential transmission users. The reader will recall that some utilities have recently accepted such a proposition in cases before FERC. Three factors affect the capacity expansion issue: (1) the ease of building new lines, (2) new technologies for upgrading existing lines, and (3) a historical perspective.

Regarding new lines, the FERC Transmission Task Force found that in the 1980's, more than 29,000 circuit-miles of extra-high-voltage transmission lines were built while only about 100 circuit-miles were on the "troubled line" list published by the North American Electric Reliability Council. There is no question that the public is increasingly aware of environmental issues, and that this awareness makes it more difficult and expensive to build new lines. The FERC Transmission Task Force concluded, however, that "the barriers to building new transmission lines do not seem formidable when viewed from a national perspective. Some difficulties may exist in densely populated regions, however." The fact that several new intrastate and interstate 500-kilovolt lines have been proposed in the East in the last several months suggests that the industry believes that environmentally sensitive, carefully planned lines can still be constructed. It remains to be seen whether these lines can actually be constructed. Problems in siting transmission lines may well increase as concern about the health effects of electromagnetic fields increases.

As for existing transmission lines, new technological improvements, collectively known as Flexible AC Transmission Systems (FACTS), could significantly increase the capability of existing transmission lines if used on a widespread basis.

For example, an April 1990 General Electric publication, *Systems Innovations*, presented the results of a study of an application of one of the FACTS technologies, a thyristor-controlled series capacitor. Under present conditions, a certain critical transmission corridor is capable of transmitting 5,000 megawatts while withstanding the loss of a 500-kilovolt line. However, with the addition of the FACTS technology, the interface is capable of transferring an additional 1,200 megawatts, or 6,200 megawatts in all. The Electric Power Research Institute (EPRI) has found that application of several different FACTS technologies on a particular transmission corridor of 5,000 megawatts can almost double the power-carrying capacity.

EPRI gives several other examples of how this and other FACTS technologies, some of which are still a few years away from commercialization, can increase transmission capacity on existing lines. Combined with data demonstrating the number of new lines built in the 1980's, FACTS suggests that needed capacity increases can be provided.

From a historical perspective, utilities have been able to provide transmission for the needs of their native-load customers without apparent exception. For most of the post-World War II period, electricity demand was growing at about 7 percent yearly, much higher than the average national growth rate today of about 2 to 3 percent. Given their historical success, it does not seem unrealistic that utilities could meet a requirement for transmission service that includes some new firm users, provided that the utility is given adequate time to build or upgrade capacity. However, simply imposing the obligation to provide this service without ensuring adequate returns from doing so puts captive-customer rates at risk and creates incentives for delay. However, given an adequate amount of time to add capacity, an economic pricing regime, and contract terms that set reasonable service priorities, there should be no reason to sacrifice future national efficiency.

Notes

1. W. Harrison Wellford and Nancy H. Sutley, "Our Views on Transmission Policy," *Public Utilities Fortnightly*, July 19, 1990, pp. 35–36.

2. See Douglas G. Green, "The Antitrust Laws and Transmission Access in The Electric Utility Industry: An Outline of Basic Principles," presented at the Annual Meeting of the American Bar Association, August 1990, pp. 32–34.

3. FERC Docket No. ER86–76.

4. *Op. cit.*

5. Motion of the Vermont Department of Public Service and Vermont Public Service Board to Amend Complaint and for Partial Summary Judgement, FERC Docket No. EL90–13–000, March 19, 1990, pp. 3–4.

6. Answer of Northeast Utilities Service Company to Amended Complaint, FERC Docket No. EL90–13–000, April 18, 1990, p. 9.

7. Wisconsin Public Service Commission Order in Advance Plan 5 (Docket 05–EP–5).

8. See Kevin Kelly, J. Stephen Henderson, and Peter A. Nagler, *Some Economic Principles for Pricing Wheeled Power*, National Regulatory Research Institute Report 87–7, August 1987.

9. The "MIT group" has written extensively on spot transmission pricing; for example, see Roger E. Bohn, Michael C. Caramanis, and Fred C. Schweppe, "Optimal Pricing in Electrical Networks over Space and Time," in *The Rand Journal of Economics* 15 (Autumn 1984): 360–376.

10. See Charles G. Stalon, "A Pricing Regime to Achieve Economic Efficiency and Equity in the Provision of Transmission Services," Presentation to Keystone II Project on Transmission, Keystone, Colorado, March 1990.

4. Reliability, Dispute Resolution, and Planning

Reliability Is Crucial

The importance of the transmission system's reliability cannot be overemphasized. Reliability here means the ability to ensure that power is delivered to customers and that power outages are infrequent. The costs of large-scale, extended outages (for example, the blackouts in the Northeast in 1965 and in New York City in 1977) can be great. An accumulation of smaller outages also imposes significant costs.

There have been debates over what constitutes an adequate level of reliability in the electricity industry. The industry's typical standard for planning purposes has been that there should only be 1 day in 10 years during which electricity would not be available due to insufficient generation. This rare outage would be caused by a lack of adequate generating capacity, lack of adequate interconnection to import power, or some combination of the two. (Not included would be outages caused by acts of nature, such as tornadoes, hurricanes, or violent thunderstorms; these outages affect distribution lines more often than larger transmission lines and are generally localized in nature.)

Given the costs of new generating and transmission capacity, some commenters have wondered if a somewhat less stringent standard, perhaps 1 day in 5 years, might not be more cost-effective. Alternatively, some utilities are beginning to experiment with "product differentiation," offering different degrees of reliability to customers at different rates. Some large users have the ability to reduce operations or to generate power with backup equipment, and so could accept interruptible rates that entail an occasional loss of service; others require continual high-quality electricity service to avoid large economic losses.

This analysis will not attempt to assess what constitutes a cost-effective level of reliability. It will simply assume that whatever the appropriate level is, an increase in transmission access ought not to change the level.

Assuming the control and operation of the transmission system stays exactly as it is today, how might transmission access decrease reliability? One must understand the nature of electricity transmission to appreciate the technical issues associated with increased transmission access.

Electricity does not flow along a defined, predictable path from the generator to the ultimate end-user. Instead, it flows along multiple paths. This means that contractually prescribed transmission paths are largely a fiction because bulk power transactions simultaneously affect many lines in a transmission network. The actual division of power over the various lines depends on the loadings on those lines and can vary widely over time. The summation of the flow over the various paths can cause an effect known as loop flow. Thus, a power transaction between two utilities often will affect the transmission system of other utilities that are not parties to the transaction.

Therefore, little insight into the power transfer capability of a utility is gained by evaluating the available capacity on a single transmission circuit. What needs to be determined is the amount of power that can be safely carried by the portion of the network under consideration.

The amount of power that can be transferred between parts of the network is also subject to reliability constraints. Reliable system operation requires that there be some excess capacity in the system to handle contingencies—loss of a generator or transmission line. System loading will generally be kept below a limit that is expected to be safe for at least a 30-minute period if any single component is lost.[1] Thus, one or more circuits will intentionally be loaded at less than full capacity so that the system can respond to contingencies.

Coordination of power flows is handled by the previously mentioned control areas. Currently, there are about 150 control areas within the lower 48 States and interconnected southern Canada. Each control area is responsible for matching generation (plus purchases from other control areas, minus sales to other control areas) with load. To accurately match generation and load, automatic control of generation is required within the area and each area controller must know about scheduled power flows into, out of, or across the region and must be able to plan for them. Unscheduled flows could cause economic harm (for example, by forcing the use of less economic plants than would have been used if the flow had been properly scheduled) and in the extreme could cause loss of service because of changes in system conditions such as line overloading or undervoltage.

In addition to possible problems caused by unscheduled power flows through control areas, area controllers must also be able to control emergencies by being able, at a minimum, to turn generating facilities—including qualifying facilities (QF's) and independent power producers (IPP's)—on or off or otherwise disconnect them from the system. Being able to dispatch generating facilities to a greater or lesser extent also can improve system stability. Utilities generally will not sign contracts with QF's and IPP's unless they meet minimum reliability standards such as a willingness to be disconnected in emergencies. In the last few years, the ability to dispatch has become either a requirement or a major nonprice factor in competitive bidding for power.

The challenges posed to transmission area controllers by greater numbers of QF's and IPP's are in principle not much different from those posed by the tremendous expansion of the system over the past several decades. Loop flows could increase, but utilities have heretofore managed either to ignore or to reach voluntary agreements on loop flows, and pertinent new accounting methods and technologies are being examined. New equipment, new software, and new training procedures might all be needed. However, given adequate time to adjust, and without a very large increase in the number of entities seeking transmission access, there seems to be no reason why increased transmission access should cause decreased reliability. This is the conclusion of both the Office of Technology Assessment (in *Electric Power Wheeling and Dealing,* May 1989) and of the Large Public Power Council (LPPC), a group of publicly owned utilities, most of whom own large transmission systems. For instance, the March 15, 1990, LPPC Transmission Access Task Force paper states:

> Additional supplier and wholesale customer access can be provided *without jeopardizing reliability....*
>
> LPPC's transmission policy supports increased access to suppliers and wholesale customers and LPPC believes this can be accomplished without jeopardizing reliability. However, it is imperative that certain actions be taken by the industry to ensure that these new players will not jeopardize reliability. [italics added]

The LPPC paper then lists a number of such actions. These would include the enforcement of technical requirements so that new generating and transmission equipment conforms with utility standards. The ability of new suppliers and wholesale customers to be dispatched or curtailed must be compatible with economic and emergency use of existing utility generating systems. Operational control of the network must be retained by utilities and power pools because, to protect the transmission system, they ultimately have the responsibility and physical ability to control transactions between nonutility suppliers and wholesale customers with no generating capacity.

Dispute Resolution and Planning Procedures

Wholesale trade and interregional transfers may continue to increase, thereby creating a need for new or upgraded lines within and between geographic regions. As more new entrants press for access, there will inevitably be disagreement about how much capacity might be available, for what timeframe, at what cost to the existing system, and at what prices. The result will be an increasing need for ways to resolve disputes and for closely related new planning procedures.

Dispute Resolution

As we have seen, maintaining reliability in a regime of more open access means that the network will have to accommodate a larger number of buyers and sellers. A larger number of participants creates more opportunities for disputes over access and the terms of access. If these disputes cannot be settled in a timely manner, system operation and hence reliability could suffer as multiple parties stake claims for a limited amount of transmission capacity.

Hence, the inevitable disagreements regarding the amount of available transmission system capacity must be resolved by some entity. These could include regulators, groups whose primary qualification is technical knowledge about how the grid operates, or as a last resort the courts (arguably the least qualified to interpret technical issues).

Given the surge of interest in increased access to the grid, and given the precarious balance between monopoly ownership of the grid and potential antitrust difficulties if those who desire to use the grid cannot get access, there may be significant reason to worry that courts might in the end be the arbiter of terms and conditions of access. This worry should be shared not just by utilities, which would have to live with the decisions of the courts, but also by others interested in maximizing economic efficiency.[2] Although it goes without saying that the arbiter of such disputes must be neutral, an arbiter without adequate technical knowledge could make decisions that unnecessarily cause significant economic harm.

The extent to which the Federal Energy Regulatory Commission (FERC) might be able to encourage access and associated terms and conditions is explored in Chapter 6 of this analysis. However, several proposals for voluntary dispute resolution have been made recently. For instance, a group of proposals with some common characteristics include those of the National Rural Electric Cooperative Association, the Consumer Energy Council of America (CECA), and the Large Public Power Council.

The LPPC proposal would allow investor-owned and publicly owned utilities and QF's and IPP's to join a voluntary association that would utilize the talents of people intimately familiar with the grid to resolve transmission access disputes. Members would be bound by the decision of the arbitration panel. The LPPC sees this voluntary method as far superior to relying on the courts and points to other voluntary industry organizations, such as the Institute for Nuclear Power Operations and the North American Electric Reliability Council and its regional councils, as precedents for its proposal.

CECA recently released a new study, *Transmission Planning, Siting and Certification in the 1990s: Problems, Prospects and Policies,* which calls for the creation of an arbiter to "resolve impasses among the states in planning, siting or certifying multistate transmission lines." CECA's large advisory committee for this study included the executives of several investor-owned electric utilities as well as representatives from most other groups interested in the electricity industry, including regulators, public utilities, environmentalists, consumer bodies, and government officials.

The CECA proposal would attack a problem different from but related to the problem addressed by the LPPC proposal. The LPPC proposal would referee issues related to the terms and conditions of access, while the CECA concept would attempt to deal with the closely related issue of how to ensure that the transmission capacity needed to implement greater access and transfers of power will be built. It would do so by providing a forum for resolving disagreements of planning and siting of new lines in the context of binding arbitration. CECA's arbitration mechanism would be established as part of an agreement among States to form Regional Transmission Planning and Certification Coordination Boards (RCB's), the full purpose of which is explained below. If binding arbitration within an RCB agreement or as a result of other agreements among States did not occur, CECA recommends a Federal "court of last resort," created by new legislation, in which the burden of proof would be on the complainant, whether the complainant was proposing or opposing a proposed new line.

Another important factor in siting transmission lines is the clear and growing public concern about the possible health effects of electric and magnetic fields (EMF's). The CECA proposal calls for a vigorous Federal research effort into EMF effects, to resolve uncertainties about the possible health impacts of these fields. CECA also suggests establishment of an international clearinghouse to compile and disseminate research, with costs shared between the government and private sectors. Finally, the RCB's would be a useful forum through which States could adopt uniform standards for dealing with EMF emissions.

Planning

Planning and dispute resolution are closely related because new planning procedures could remove or mitigate the need for dispute resolution by enabling transmission "have nots" to become transmission "haves."

At the outset, it is useful to consider mergers as a particular type of solution that may help to facilitate planning, although mergers are not planning tools in themselves. Mergers may be important because they could help reduce one disincentive to economic provision of transmission: the balkanization of ownership that allows a transmission owner to block highly beneficial transmission capacity that must go through several utility territories. Thus certain mergers could help remove bottlenecks, in that a merger could "internalize" the net economic benefits from wholesale transactions within one system.

Clearly, however, mergers can have the opposite effect. For example, in the merger of PacifiCorp and Utah Power & Light, FERC was concerned that the merger would decrease the number of competing corporate transmission corridors in the western Rocky Mountain area from two to one, thereby harming those in need of transmission and decreasing economic efficiency. It was for this reason that FERC conditioned its approval of the merger on, among other things, firm transmission access for wholesale buyers and IPP sellers.

New planning possibilities can be characterized as falling in four areas: statewide planning, regional regulation and planning, joint ownership of transmission lines, and FERC activities. FERC activities in this context are not strictly planning measures. They are included here, however, because they can have effects on efficiency similar to some of the other measures proposed. These activities could include continuation of the present policy of conditioning mergers and utility power sales at market-based rates on transmission access as well as exploration of potentially existing but unused powers in the Federal Power Act.

Statewide planning can also help solve the balkanization issue, in the sense that any bottlenecks *internal* to the State would presumably be removed to maximize efficiency gains within the State for those entities with rights to use the transmission grid. In most cases, one would expect for this reason alone that statewide planning with a goal of maximizing efficiency would likely be better than not having statewide planning. In this context, statewide planning means having the regulators provide incentives for jurisdictional utilities to conduct joint resource planning. It does not mean having regulators do the actual system planning. Regulators would maintain their traditional role of reviewing and approving utility resource plans.

Whether statewide planning would solve the economic inefficiencies that would exist because a wholesale seller, such as an IPP, might not be able to sell into markets other than its host utility would depend on several factors. States do not have authority to set prices for transmission services, and their power to order wheeling appears to be quite limited. FERC normally asserts jurisdiction over wholesale transactions even when all the utilities involved are within a single State. FERC's rationale, which has been supported by the U.S. Supreme Court, is that any power transaction involving at least one utility interconnected with a utility in another State, or with a utility that has an interstate connection, constitutes an interstate power flow. Because of the highly interconnected nature of the electricity system, nearly all wholesale transactions meet this criteria and thus are subject to FERC's jurisdiction.[3]

Yet, State regulators have powers of persuasion that are relevant, even if explicit authorities are lacking. It is therefore possible that statewide planning could include "voluntary" provisions for statewide wheeling at reasonable cost for wholesale sellers without previous rights to use the system, if the State regulators want such a policy and potential legal obstacles are resolved.

A test case of this approach is already under way in Wisconsin. As noted in Chapter 2, in 1989, the Wisconsin Public Service Commission issued an order calling for establishment of a statewide transmission system based on single-system integrated planning and operated pursuant to long-term joint use and cost-sharing agreements.[4] The order also requires transmission-owning utilities to file wheeling tariffs with FERC. The Wisconsin Commission's view is that efficiency gains will result from providing all of the State's utilities, public and private, the opportunity to jointly take part in the planning, operation, and ownership of a statewide transmission system. All but one of Wisconsin's major investor-owned utilities are currently challenging provisions of the order before State court and FERC.

An important issue regarding statewide planning is whether such planning could increase *intra*state efficiency but harm, or at least not help, *inter*state efficiency. Suppose that construction or upgrade of a certain line within a certain State would allow two in-State utilities to minimize their joint costs of production, considering only the resources within the State. Suppose also that still greater efficiency would result if the utilities build or upgrade a different, *inter*state line and share the benefits with several out-of-State utilities. In this case, the statewide plan would conflict with efficient cost minimization, and could even prevent cost minimization, because once the line is built or upgraded the utilities would be much less likely to build the second, interstate line.

Alternatively, suppose that the most economic potential market for an IPP is in a neighboring State, but that the only utilities to which it could sell its output under a given statewide plan, other than its local utility, are other in-State utilities. Here, the State, through its plan, has helped the IPP and promoted efficient use of energy by broadening the IPP's potential market. But the absence of regional planning has prevented the most economic use of this resource.

Regional planning and regulation potentially could achieve some of the multistate benefits that could elude statewide planning. For instance, if such planning and regulation were effective, bottlenecks that affect efficiency across several States, not just one, could be dealt with. IPP's and other wholesale sellers could have access to a larger market, and purchasing utilities could have access to a greater number of sellers. Regional planning could resolve the possible difficulty posed by statewide planning whereby a transmission or generation project that maximizes efficiency within one State might impede an even more efficient solution.

Regional planning, however, also could cause inefficiencies. If it becomes simply a burdensome regulatory hurdle on top of existing regulation in several States, it could hinder the already difficult process of getting needed facilities built. However, if it provides a process that not only helps achieve regional efficiencies, but also reduces the regulatory hurdles faced by these economical new projects, then regional planning or regulation would be beneficial. CECA's recent proposal to establish RCB's to coordinate the planning, siting, and certification of new lines seems to promise movement in this direction. In addition to encouraging regional planning, the RCB's would simultaneously offer a mechanism for dispute resolution.

Another proposal that could achieve regional efficiencies is that of former Commissioner Susan F. Tierney of the Massachusetts Department of Public Utilities. Her proposal to create a formal marketplace for generation within the New England Power Pool (NEPOOL) has four principal features:

- All utility or nonutility projects inside or outside NEPOOL that pass a market test would become "Pool Planned Units."
- All such units would be eligible for the access and transmission pricing terms currently available under the NEPOOL agreement (for example, pool transmission facility rates, which do not vary with distance).
- The current embedded-cost transmission rates would be replaced with marginal-cost rates based upon the full costs of building new transmission facilities.
- The revenues from these new rates (applied to all new wheeling contracts) would provide a fund to pay the full costs of all new bulk power transmission facilities in the region.

Joint ownership of transmission lines would allow transmission "have nots" (who today are often wholesale buyers) to have greater access to potential markets. A policy of greater joint ownership would certainly help those who would be new members of the transmission owners' "club," and in that way would enhance competition significantly.

However, joint ownership probably would give only limited help to entities that do not become joint owners. For example, a wholesale buyer who for one reason or another does not or cannot become a joint owner of transmission capacity would be helped only to the extent that the additional owners would provide the potential for competition among transmission sellers. Wholesale sellers would be helped by joint ownership either by becoming joint owners or by being able, through greater numbers of transmission owners, to access markets that were formerly closed to them.

Turning from actions that can be taken at State or regional levels to actions at the Federal level, there are two types of possibilities for increasing transmission access, although both are not strictly planning procedures. These options are (1) continuation of FERC's policy requiring transmission access as a *quid pro quo* for approval of particular utility proposals that might not be "just and reasonable" or otherwise legal without transmission access to mitigate market power and (2) a reexamination of FERC powers under Sections 205, 206, and 207 of the Federal Power Act.

Continuation of FERC's case-by-case, *quid pro quo* policy, as in several mergers and proposals to sell power at market-based rates, will inevitably be a slow process. While this approach has the virtue of increasing understanding of the effects of departure from traditional ways of doing business, it may not lead naturally to the development of a coherent and workable framework. Development of a comprehensive policy, possibly including legal reform, would be desirable and would have the advantage of avoiding the creation of a patchwork of different and possibly conflicting approaches. Continuation of the current case-by-case approach is likely to create a patchwork that depends on which utilities come before FERC with requests that motivate FERC to require transmission access as a *quid pro quo*, on the specific facts in each such case, and on the details of each such decision. In addition, uncertainty regarding case-specific outcomes may inhibit companies from coming to FERC with mergers and other proposals that would themselves enhance efficiency.

The common theme of the five nongeneric approaches above—mergers; the three State or regional ideas for statewide planning, regional planning, and joint ownership; and the continuation of FERC's present policies—is that each can contribute something to decreasing the transmission owner's ability to exercise market power by increasing transmission access, but each represents only part of a comprehensive solution.

Looking further out in time, a more comprehensive policy would establish a less balkanized regulatory solution to a problem that itself is partly caused by industry balkanization. FERC could move in this direction by initiating a rulemaking process on transmission access, pricing, contracting, and capacity expansion planning, taking into account the importance of avoiding conflicts between laws and obligations at the State and Federal levels. There may be unused powers in the Federal Power Act that FERC could use to increase transmission access in a more broadly applicable manner. Alternatively, there might be ways in which State authorities, with their ability to influence utilities to offer transmission access, could be combined with FERC authorities to establish prices and terms for the use of transmission lines. These concepts are explored further in Chapter 6.

Notes

1. John A. Casazza, "Understanding the Transmission Access and Wheeling Problem," *Public Utilities Fortnightly,* October 31, 1985, pp. 35–42.

2. See Richard J. Pierce, Jr., "Who Will Mandate Access to Transmission: FERC or the Courts?" in *Public Utilities Fortnightly,* March 29, 1990.

3. See Robert E. Burns, "Legal Impediments to Power Transfers," in *Non-Technical Impediments to Power Transfers* (National Regulatory Research Institute, Kevin Kelly, ed.), September 1987, p. 74.

4. See George R. Edgar, "Wisconsin Lines," in *Public Power,* July-August 1989.

5. Which Entities Should Have Access?

As noted in earlier chapters, three types of firms want a greater degree of access to the integrated transmission system. These are: wholesale sellers (utilities, qualifying facilities, and independent power producers); wholesale buyers (generally utilities that want to purchase all or part of their needs from other parties); and retail users (generally large industrial customers).

To judge the appropriateness of greater access for each of these groups, *economic efficiency*, *equity*, and *reliability* criteria are discussed.

Economic Efficiency

Four effects related to economic efficiency should be considered. Two of these are large and positive, leading to gains in efficiency, and two are relatively small, possibly leading to losses in efficiency.

Potential Economic Efficiency Gains in Wholesale Transactions

As discussed in Chapters 1 and 2, transmission access for wholesale *sellers* of power will most likely lead to a more efficient electricity generation market. This is the first type of gain in economic efficiency. Wholesale sellers would include utilities with excess capacity that have been unable to get their power to buyers as well as new facilities that have demonstrated in competitive bids that they are among the least expensive options available.

Potential efficiency gains also can result from access for wholesale *buyers*. The possibility of losing wholesale customers would arguably make utilities more cost-conscious and more flexible with respect to rate design and service by enhancing market discipline, which currently exists only to the extent that large customers might be able to self-generate. Today, wholesale power markets generally (with the exception of sales to "captive" wholesale customers) involve neighboring or nearby utilities selling firm or economy power to one another or participating in a power pool. Such markets are active, especially in times of excess capacity, but it is also true that such wholesale markets would likely be significantly more competitive if many "captive" wholesale buyers, in most cases purchasing from the local utility in whose service area they are located, were actively purchasing on the open market.

This analysis does not attempt to determine how many wholesale buyers are needed within a region to create a workable, competitive market. However, to the extent that increased access facilitates an expansion in the number of wholesale customers purchasing on the open market, there is reason to believe that, over time, wholesale power might be substantially more cost-efficient. For these efficiencies to be realized, however, open transmission access would be required.

These efficiencies would come about because utilities would have to compete more strenuously not only to retain their own (no longer captive) wholesale customers, but also to expand their sales to other wholesale buyers. The likely result would be substantial cost reductions such as those seen in highly competitive industries where there are no captive customers. Utilities would have new incentives to conduct their business more efficiently. Regulators would be able to observe which utilities are able to sell power at the lowest cost, an impetus to lower costs at all utilities.

Sometimes this potential cost reduction is referred to as the gain to be had from "pencil sharpening," for example, by reducing the costs of one's operation. In fact, the gains may be more substantial.

In the short term, a utility with excess generating capacity could offer a "discount rate" to retain a wholesale customer, much as utilities with excess capacity have offered discount rates to large industrial customers during the 1980's. However, over time only those utilities that could build or acquire new sources of power at low cost would expand their base of wholesale customers. Thus, if a utility designed a power-purchase auction poorly or did not minimize the cost of new powerplants, it would sell less power and would therefore build less. The same would be true of a utility that fails to build plants economically.

Would these same efficiency gains also be present if retail buyers, in addition to wholesale buyers, have access for purchases on the open market? Although the answer cannot be known with certainty, it seems unlikely that much added efficiency would be gained. Presumably, over time, the ability of wholesale buyers to choose among many wholesale sellers would weed out the less efficient builders and operators. Most utilities would have reduced costs in other ways in response to the increase in competition. Access for wholesale sellers such as qualifying facilities and independent power producers should bring the most efficient nonutility generators to market. Thus, the added benefits of retail transmission access are likely to be small.

Potential Economic Efficiency Losses in Wholesale Purchasing

Transmission access will not always engender improved efficiency. Some transactions may "wheel money" rather than wheel power. This phenomenon occurs when the transaction is motivated by differences in average, embedded-cost rates between utilities rather than differences in marginal production costs. An individual utility may experience a sharp increase in its average cost of service following incorporation of an expensive new generating plant into its rate base. The near-term increase is exacerbated by the "front-end loading" of the capital cost of new plants. Wholesale buyers will naturally seek to purchase power from a neighboring utility with lower embedded-cost rates. However, if the two utilities are members of a centrally dispatched power pool, the composition of plants actually producing the power might remain unchanged, even though there has been a change in contractual arrangements. If there is no physical change in plant dispatch within a region, there are no savings in aggregate regional production costs. Thus, there is no efficiency benefit.

Alternatively, in a few cases costs could actually increase. For example, suppose the new seller sells firm power, based mostly on older coal plants, at a total price of $0.05 per kilowatthour, but at a short-term marginal production cost of $0.03 per kilowatthour. Suppose the previous seller's price was $0.07 per kilowatthour, but with short-term marginal production costs of $0.023 per kilowatthour. In this example, economic efficiency is harmed because short-term costs have increased from $0.023 to $0.03 per kilowatthour. (The fixed costs, reflected in the $0.05 and $0.07 per kilowatthour total costs, are sunk—already spent—and so do not enter a calculation of economic efficiency today.) Whether such inefficiencies occur depends in part on Federal Energy Regulatory Commission power-pricing rules.

A special subcase of the generic problem of "wheeling money instead of power" would involve public power-generating plants. Often, these plants are built with low-interest Federal loans, and their owners have no obligation to pay income taxes. Both of these cost reductions, everything else equal, give public power projects a cost advantage over plants built by other entities, even taking into account the deferral of income tax payments and other tax incentives for investor-owned utilities. Currently, some public power builders have excess capacity. The potential economic efficiency problem might come about if a public power utility were to appear to be lower in cost than an investor-owned utility for a power sale only because of the Federal subsidies available to public power utilities. There would be an efficiency gain if the short-term costs of the public power utility were lower than those of the investor-owned utility. However, if the lower total costs of the public power entity disguised the fact that it had higher short-term costs, economic efficiency would be harmed.

Even though there may be some cases where efficiency could decrease in the manner described, the net impact of transmission access for wholesale buyers on efficiency is likely to be quite positive.

The second possible type of efficiency loss has to do with the "prodigal son" issue, and again the potential efficiency loss is small relative to the potential efficiency gain. In the utility context, a "prodigal son" is a wholesale customer that deals with other suppliers when lower price alternatives are available, but then seeks to return to its original supplier, at embedded-cost rates, when those alternatives disappear. If the utility has an obligation to provide power to the prodigal son, it might be required to build new plants on short notice when the prodigal son returns. Any generating resource that cannot be constructed in a short time period—such as coal and nuclear technologies—could not be considered, even if it might have been the most economical with a longer planning horizon.

Ways to deal with cases where new wholesale transactions might increase short-term costs need to be investigated. Regulators need to examine pricing policies carefully to ensure that they do not facilitate inefficiencies in regional dispatch. If, as we expect, regulators can find such solutions, then the possibility of these limited efficiency losses could be minimized, while the potential efficiency gains indicated above could be achieved.

Equity Issues

The equity question arises most prominently with both the stranded investment and the prodigal son issues.

Stranded Investment

Suppose a utility has built generating capacity to serve not just its retail customers, but also a long-time wholesale customer located entirely within its service area. For each of these classes of customers, the utility has the legal obligation to provide the amount of power requested. The utility therefore builds enough capacity to serve both.

Suppose then that the wholesale customer finds, in a time of general excess capacity such as occurred in the 1980's, that it can get wholesale power at a lower cost elsewhere, most likely in the form of a multiyear contract. If the buyer then leaves its original supplier, that supplier is left with excess capacity—capacity that must be paid for by remaining (mostly retail) customers or by shareholders, or marketed through off-system sales. If the original supplying utility had known the buyer was going to "leave the system," it would not have built this capacity. The excess capacity caused by the decision of the buyer to leave the system is called "stranded investment." While stranded investment occurs in unregulated industries as well, and can be thought of as an inducement to make good investment decisions, the utility's obligation to serve means an obligation to invest and thus creates an equity issue not faced by unregulated firms.

Rate reform could reduce the incentive for wholesale customers to leave the system. Traditional utility ratemaking exacerbates the rate differentials resulting from the incorporation of costly new generating capacity into the rate base because it is heavily front-loaded, that is, the plant's capital cost is loaded more heavily onto its earlier years of operation. (State commissions somewhat moderated front-loading during the 1980's by using rate phase-ins. Phase-ins lessened the degree of front-loading, but rarely eliminated it.)

Prodigal Sons

Suppose that the wholesale buyer in the above example finds another seller and signs a firm 7-year contract with that seller. However, during the 7 years the amount of excess capacity in the area diminishes to the point that few utilities, including both the original seller and the new seller (with the 7-year contract), have much excess capacity. When the contract expires, the wholesale purchaser cannot find a new arrangement to its liking. It might then go back to the original utility in whose service territory it is located, and demand that it be provided power at a (presumably) low-embedded-cost wholesale rate.

The original selling utility asserts that it has no capacity to sell on a firm basis because its reserve capacity is low. Notwithstanding the logic of this argument, utilities fear that political pressure on State and Federal regulators would enable the wholesale buyer, the returning "prodigal son," to force the original seller to sell power at embedded-cost wholesale rates. In turn, the selling utility would have to embark on a crash construction program or purchase costly firm power on the open market to meet its obligation to serve all its customers, including the prodigal son. In all likelihood, the cost of the construction or purchase program would not be fully compensated by the embedded-cost rates paid by the returning wholesale buyer. Once again, the extra costs—here, the difference between the embedded-cost rate paid by the prodigal and the extra costs the utility must spend to satisfy its service obligation—would be borne largely by the retail customers or the shareholders. A policy that would allow a prodigal utility to return to its original supplier at rates that would impose increased costs on others is considered by most parties to be inequitable.

Efficiency issues are at stake as well. The ability of a wholesale customer to return to its host utility and receive embedded-cost service, for example, may encourage excessive risk-taking by the customer, since the customer knows that it has a "safety net" if its supply plans do not turn out well. Risk-taking of this sort by wholesale customers may facilitate insufficient risk-taking on the part of utilities that will be discouraged from undertaking long-lead-time projects with more risk in favor of projects with low risk and short lead times, even though the latter projects may be less efficient.

Potential Solutions

Two observations emerge from this discussion. First, of the entities seeking transmission access, only wholesale *sellers* do not necessarily cause stranded investment or prodigal son equity difficulties (that is, sales to utilities conducting power auctions do not create such problems). Second, transmission access for wholesale buyers should emphasize development of equitable resolution of the stranded investment and prodigal son issues.

Two trends seem likely to reduce the importance of the stranded investment problem over time. First, as generation services become more competitive, price differentials among utilities are likely to become smaller. These smaller differentials, in turn, will reduce the incentive for wholesale customers to seek off-system supplies. Second, most utilities can be expected to have less excess capacity within a few years as demand continues to grow. Generally, if a selling utility has little excess capacity today, the stranded investment problem will be diminished to an extent. The selling utility might even have no objection to losing the customer if that would allow the utility to avoid building a plant. Under these circumstances, a wholesale purchaser might be able to leave without penalty.

Ameliorative strategies are available to deal with the prodigal son problem. For example, the prodigal could return if it were willing to pay the *incremental* costs it imposes on the selling system. Alternatively, if there were enough transmission access to allow the prodigal to choose from a large number of potential suppliers, there would be no need to require the original seller to supply power on anything but a voluntary basis, because there would be a competitive market for wholesale power.

Finally, it may be possible in contracts between wholesale buyers and sellers to establish a system of "exit" and "entrance" fees that could provide a market solution to the stranded investment and prodigal son problems.

Reliability Impacts

As discussed previously, reliability would be affected by the number of new players, the frequency of their transactions, the degree of central control required or allowed for such transactions, and the institutional arrangements worked out to accommodate more open access. The 1989 Office of Technology Assessment report, *Electric Power Wheeling and Dealing,* found that the transmission system could accommodate greater competition. However, it also found that:

> The greatest challenge will be to maintain the coordination of the bulk power system as an integrated whole when many different entities are involved.... *Rapid change will entail the greatest risk*.... If implemented unwisely, competition easily could result in higher costs and *lower reliability* because crucial functions such as economic dispatch would not work as effectively. [italics added]

Some analysts have noted that the roughly 30,000 megawatts provided by qualifying facilities (QF's) entering service in the 1980's do not seem to have adversely affected reliability, in the sense of increasing the possibility of blackouts. They conclude from this that transmission access will not cause reliability problems, and they note that several electric utilities have testified to that effect.

There are several reasons for the lack of adverse impact. One appears to be contractual conditions; for example, QF's must meet certain reliability criteria. Another reason is probably that, in most sections of the country, the amount of QF capacity is still relatively small and utilities and power pools have had the time to adjust to the newcomers in their midst. A third is that many or most QF transactions take place within one control area and involve scheduled sales to the control area operator; they do not require wheeling through another utility's system. Finally, many bidding auctions for new power sources implicitly or explicitly take into account the location impacts of proposed generating facilities on the transmission system.

In the future, greater transmission access may mean more transfers between control areas, involving transactions where one or more parties to the transaction will not themselves be control-area utilities. This could mean, absent explicit agreements between the control areas and the new entities, and absent continued adherence to North American Electric Reliability Council operational criteria, that unscheduled power transfers could take place, possibly upsetting the operation of the grid. While there is no obvious reason why such agreements could not be forged, it is important to note that these agreements must be reached or mandated in order to maintain reliability.

In summary, it seems clear that to maintain high standards of reliability—standards crucial not just to minimizing costs, but also to ensuring against blackouts with great economic consequence—any opening up of the transmission grid to new users should proceed at a measured pace. This would give transmission owners and controllers adequate time to develop the capability to deal with the issues that would be raised by the presence of new users without jeopardizing reliability in any sense.

Conclusions

In summary, increased access for wholesale sellers and buyers can lead to long-term efficiency gains.

Access for wholesale buyers raises equity issues. If these issues can be resolved, there is promise of significant economic gain. Reliability issues would not be overly difficult if reasonable agreements between control area and non-control area entities can be reached.

With retail access, equity problems are far more difficult than with wholesale access. The reliability issues are much more difficult because of the huge number of potential retail buyers that could want access. Efficiency gains would be questionable, except perhaps for the largest of retail buyers willing to pay appropriate entry and exit fees. Given the crucial need to maintain the reliability of the transmission system and the unexplored cost accounting problems, retail access is not a recommended policy at this time.

6. Transmission Policy Options

This chapter discusses options for transmission policy. These options are considered at the level of a national energy strategy; that is, we treat only broad issues that can command the attention of the Administration and perhaps the Congress, and leave to regulators the resolution of the many issues that will surely arise as broad policy is implemented. Because we are concerned with government policy, an important option not considered here is that of industry forming a voluntary association to solve transmission disputes without government action.

As the previous chapters have indicated, much is changing in the electric power industry. These changes are occurring for many reasons, and the theme running throughout these reasons is efficiency and competition. Many now believe that greater access to transmission can make the wholesale market for electricity more competitive.

Some observers of the industry believe that, absent significant progress toward a greater degree of nondiscriminatory access, lawsuits calling for access to transmission may be brought and be successful. In essence, this would put the terms of access and use in the hands of juries and judges. Many industry observers contend that juries and judges would be unlikely to design efficient terms and conditions for transmission access and use. This task is better left to those with a solid technical understanding of the transmission system. Thus the worst outcome for increased transmission access might be a series of court decisions not solidly grounded in engineering and economics.

If this kind of outcome is to be avoided, progress should be made through government policy leadership. The options below encompass three broad approaches to increasing nondiscriminatory wholesale transmission access.

The Case-by-Case Approach

Option 1: Continue the present case-by-case approach at the Federal level and at the State and regional levels (including voluntary proposals for access and use).

Even without any generic regulatory or legislative action, many incremental changes are occurring. At the State and regional level, there are Wisconsin's statewide plan and the proposal for equalizing New England Power Pool (NEPOOL) terms and conditions for wholesale sellers to enable independent power producers (IPP's) and qualifying facilities (QF's) to wheel power across several utilities for the same rates as NEPOOL member utilities.

There are various other proposals for regional action. These would include the proposals of the Large Public Power Council, the National Rural Electric Cooperative Association, and the Consumer Energy Council of America, and other proposals that cover a wide range of issues, from regional planning and regulation to dispute resolution (for siting of transmission lines or for deciding terms and conditions for access).

At the Federal level, the Federal Energy Regulatory Commission (FERC) has made it clear that transmission access is a key concern in providing a remedy for the anti-competitive effects of proposed mergers and market-based pricing proposals. FERC has indicated that utilities that desire market pricing for generation sales must be willing to allow other entities to use their transmission systems under nondiscriminatory conditions.

In the recent Terra Comfort, PSI Energy, and Entergy Services cases, FERC indicated that a utility that owns transmission lines that could be used by competitors and that wants to sell power to an adjoining utility at *market* rates (as opposed to traditional, embedded-cost rates) will be much more likely to obtain FERC approval if, at the time competition for a sale takes place, it makes transmission capacity available to potential competitors. Such an offer would demonstrate that the utility has mitigated its market power over competitors (that is, the power to prevent them from competing by denying them use of transmission facilities). Having made such an offer at reasonable transmission rates, the utility could make a credible claim that a market rate for its power sales is a competitive rate. Without allowing others to use its transmission lines, a lack of sellers might be an indication not of lack of interest in selling power, the reasoning goes, but of inability of potential competitors to secure necessary transmission service.

As mentioned, in some cases FERC has required utilities to commit to building or upgrading capacity for those requiring firm transmission service and, after a length of time deemed appropriate to secure added capacity, provide firm service to others before they can use the system for their own economy transactions. FERC has justified this condition on the ground that it encourages utilities to construct needed transmission. Insofar as generic transmission policy is considered, this approach is problematic. First, it depends on a utility wanting something unusual, such as a merger approval, from FERC before access can be achieved. Second, it may be inefficient. An efficient approach would always assign the highest transmission priority to the trade of greatest value, but the FERC approach could halt coordination trades, including those of higher value, to meet the firm transmission needs of others. This happens when transmission cannot be expanded to meet the needs of others because legitimate environmental or other obstacles prevent transmission expansion.

Third, this approach raises fairness concerns and the potential for conflict with State regulators because the utility's retail customers typically must pay for these transmission lines in the absence of wholesale trades by other users. Frequently, the extra capacity on these lines was installed to permit economy transactions that lower retail rates. It may be unfair for others to have first call on the use of these assets while retail ratepayers have the ultimate liability to cover their costs, depending on the price at which access is provided.

If FERC had clear authority to order wholesale transmission access, as provided in options 2 and 3, this "condition" approach would be unnecessary. FERC would be better able to achieve uniformity of result and to coordinate its efforts with those of State regulators.

Despite the considerable amount of case-by-case change, it is not clear whether the movement toward increased transmission access is being or will be reasonably coordinated. Partly because of the patchwork character of the various efforts, progress may be slow under option 1 and perhaps eventually incomplete. The "patchwork problem" could be mitigated considerably, however, if FERC were to develop general policies toward transmission access and pricing, most naturally through the rulemaking process.

As an example of the patchwork problem, consider that analyses of market power in electric bulk power markets and its effect on competition are conducted by the FERC staff, the Department of Justice, State commission staffs, State attorneys general, and the antitrust courts, among others. The analyses often yield conflicting results, creating tension among these agencies. Results differ in part because of differences in analytical approach. Significant differences between the FERC staff's approach to the analysis of market power in the electricity industry and the approach followed in modern antitrust analysis has been a source of concern to some observers. Progress under option 1 would be enhanced if FERC were explicitly to strive for greater uniformity of approach, perhaps by adopting the analytical approach used by the antitrust courts to evaluate mergers in other sectors. Inconsistent Federal and State policies for transmission access, pricing, contracting, and capacity planning are also a problem. Greater consistency among case-specific decisions could be ensured by FERC's adoption of general policies.

Pros and Cons of Option 1

Pros

- Requires no new FERC authority.
- Allows gradual evolution of new mechanisms and institutions for an industry in transition.

Cons

- May take a long time to achieve the benefits of increased competition in generation; indeed, such benefits may never be realized.

- Will result in inconsistent and uneven evolution of access around the country.
- May be overtaken by events if court decisions result in inefficient outcomes.
- May discourage utilities from bringing efficiency-enhancing proposals before FERC because of aggressive pursuit of the *quid pro quo* approach, with results that vary from case to case.

Potentially Available Authorities

Option 2: Explore present law for potentially unused or underused authorities, including antitrust law. Encourage FERC to explore maximum use of authority under the Federal Power Act to establish an affirmative policy of moving the Nation's transmission systems toward open access for wholesale entities.

There are at least three areas where existing law might be examined to see the extent to which greater amounts of nondiscriminatory access might be granted to wholesale buyers and sellers:

- Antitrust law
- Sections 205 and 206 of the Federal Power Act (regarding undue discrimination)
- Section 207 of the Federal Power Act (regarding State petitions to FERC concerning inadequate transmission service).

Antitrust Law

The *Otter Tail* case, decided by the U.S. Supreme Court in 1973, established that electric utilities are subject to antitrust law. If a violation of antitrust law occurs, in this case in the denial of use of available transmission facilities under particular circumstances, then courts may compel wheeling as a remedy for the violation.

Antitrust law, however, appears to have some deficiencies as a remedy for correcting abuses of monopoly power in transmission access and use. First, there may be no antitrust violation if a line is fully used by the owner. Second, antitrust law as applied to utilities may have no provision for expanding capacity. The combination of these two characteristics of antitrust provisions produces different results from those in FERC's PacifiCorp-Utah Power & Light merger decision, which was accepted by the utilities in that case. The decision called for expansion of transmission capacity if necessary, within a reasonable timeframe, to accommodate firm transmission service to other users, including wholesale purchasers and IPP's.

Is it possible that antitrust law, applied to the unique technical and economic landscape that now exists in the electricity industry, would be sufficient to achieve economic efficiency in wholesale power markets? Although utilities expand transmission capacity for their own use, will they do so for others? If they expand their capacity by minimal amounts, without offering to build enough capacity for others when they build for themselves, they will not have enough capacity to offer to others. Could this in some sense be interpreted as an antitrust violation? Alternatively, if a utility does not have enough capacity for an entity desiring it, and refuses to expand capacity, would this in itself be an antitrust violation? Or must there be a regulatory obligation to serve the wholesale market, which exists apart from antitrust law?

Undue Discrimination: Sections 205 and 206 of the Federal Power Act

Section 205 of the Federal Power Act requires that utility transmission rates subject to FERC jurisdiction not be unduly preferential to any entity, nor subject any entity to any undue prejudice or disadvantage. Section 206 requires that whenever FERC finds undue preference or discrimination in any rate, contract, practice, or regulation under its jurisdiction, it must determine and enforce a nondiscriminatory rate, contract, practice, or regulation. Together, these two sections appear to offer promise for providing increased transmission access to achieve greater economic efficiency.

Consider, for example, an 11-year-old case involving Section 205 and 206 powers. In 1979, the D.C. Circuit Court upheld a FERC decision—the *Central Iowa* case. In this case, several utilities had formed a power pool. A power pool's proposed methods for accounting for interpool sales are in essence rates for wholesale sales, so they require FERC approval. In this case, FERC found that the proposed rates were unduly discriminatory because some utilities were excluded from the pool without good reason and were therefore subject to higher transmission rates than pool members.

In 1979, there were no QF's or IPP's. Can the *Central Iowa* reasoning now be applied to IPP's, or can similar logic be applied to wholesale purchases and sales? Consider two theoretical examples.

Example 1

Utilities A and D are members of a multistate power pool, and an IPP is located within A's service area. Both are competing in an auction to sell power to utility D. Utility A, as a member of the power pool, will pay "postage stamp" rates of 3 mills per kilowatthour for transmission to D. The IPP, not a member of the pool, would have to pay a wheeling charge to utilities A, B, C, and possibly D, amounting to 9 mills per kilowatthour.

Question: Is it undue discrimination to have these two competitors, Utility A and the IPP, pay such different rates for transmission if the units are similarly situated and would essentially use the same transmission capacity? The IPP might have significantly lower generating costs and might clearly be more efficient, but could lose the bid to A because of the difference in transmission costs.

The question can be put another way: Is there a cost basis for charging different transmission tariffs for Utility A and the IPP? Is this basis reflected in the tariffs?

Example 2

Captive municipal utility M is located inside Utility A's service area. Utility M needs power, and utility A is willing to wheel power at nondiscriminatory rates. Utility D (a member of the same power pool as A) and utility E (just beyond D, but not a member of the pool) both want to sell to M. Utility E's price is significantly lower than D's. Utility D, however, pays the low postage stamp transmission rate, while E, not a member of the pool, must pay each intervening utility a separate rate, as in the first example, and therefore loses the sale.

Again, the question is: Does E face undue price discrimination? What is the cost justification for different transmission rates?

Avoiding Undue Discrimination

There are several ways for possible undue price discrimination to occur in rates that FERC must approve. The suboption here is for FERC to closely examine such rates to determine whether changes in the electricity industry may have rendered discriminatory transmission pricing practices that in the past may have been reasonable.

Complementary Federal and State Jurisdiction: Section 207 of the Federal Power Act

Section 207 of the Federal Power Act states that if FERC, upon complaint of a State regulatory commission and after notice and opportunity for a hearing, finds that any interstate service of a public utility is inadequate, it shall determine and order the proper or adequate service.

On its face, the authorities of Section 207 appear to be strong. However, because the ability of FERC to order increased transmission access to improve efficiency is apparently limited by Sections 211 and 212, the strength of Section 207 to improve transmission access is uncertain. A Section 207 case is now before FERC, so a decision, likely to be appealed, may be forthcoming. This decision ultimately should tell us much about FERC's Section 207 powers in this area.

To prevent the owner of a monopoly from exercising monopoly power, two authorities are required: an ability to establish an obligation to serve and an ability to regulate the rates, terms, and conditions of service. One without the other is inadequate. For instance, if a utility must serve a customer but can charge what it desires, it can exercise monopoly power. If rates are regulated but the utility can choose not to serve particular customers, again it can exercise monopoly power.

It is generally believed that, under current authority, FERC cannot order utilities to serve the transmission needs of others, except in very limited circumstances. However, if State regulators have, in essence, the power to require utilities within their States to serve transmission needs, this authority, exercised in coordination with FERC's authority to approve transmission rates, terms, and conditions, could be used to substantially increase transmission access. Thus, as alluded to in the earlier discussion of the Wisconsin Public Service Commission's order to Wisconsin utilities to file open-access transmission tariffs with FERC, the existing bifurcated powers between State and Federal regulators could be used cooperatively to expand transmission access.

Regardless of State regulatory authority, FERC, under this and the previous suboption, would explore its Section 205, 206, and 207 powers and also work with States to examine the extent to which complementary Federal and State authorities might be used to increase transmission access and provide greater economic efficiency. FERC's powers under Sections 205 and 206 may prove to be the more promising basis for these efforts because FERC has such a strong statutory mandate to remedy undue discrimination.

To develop general policies on transmission access, pricing, and contracting, and to address complicated issues of reliability, economic efficiency, and expansion planning that will arise as the grid becomes more heavily used, FERC may find it necessary to develop its technical expertise. The additional staff expense should be small compared to the potential improvements in power markets.

Pros and Cons of Option 2

Pros

- Requires no new legislation.

- More likely than option 1, even with the development of general policies toward transmission access and pricing, to result in consistent national policy and foster a meaningful increase in competition in generation.

- Would relieve FERC from the need to rely on imposition of undesirable conditions to achieve policy objectives.

Cons

- FERC may not have sufficient existing authority to implement an efficient open-access policy.

- FERC actions would likely be appealed; uncertainty would be created and decisions might be overturned; several years may be needed to gauge the effectiveness of this option.

- State authorities to establish a utility obligation to provide interstate transmission service might be limited, hindering an effective Federal-State partnership.

New Legislation

Option 3: Develop new legislation that would give FERC explicit authority to require open-access transmission for wholesale entities when it is in the public interest to do so.

The prior options may fail to provide adequate, nondiscriminatory transmission access. Another option is to create an explicit Federal obligation for transmission owners to provide wholesale transmission service to eligible sellers and buyers. FERC would enforce this obligation. Such enforcement would complement existing FERC powers to regulate transmission pricing, thus ensuring that both authorities needed to adequately address the exercise of monopoly power—the obligation to serve and the ability to regulate prices—are unified in one regulatory agency. Adoption of this option would of course require FERC to develop detailed policy principles for regulating transmission access and pricing.

Pros and Cons of Option 3

Pros

- Would permit FERC to develop a consistent national policy to maximize the benefits of competition in generation.

- Would relieve FERC of the need to rely on imposition of undesirable conditions to achieve policy objectives.

Cons

- Would require new legislation, prospects for which are unclear.
- Could result in inappropriate legislation, especially if the experience with the current case-by-case approach is an insufficient basis for designing appropriate legislation.
- Might be interpreted by States as a kind of Federal preemption, unless or until it is determined that States themselves are unable or unwilling to establish a utility obligation to provide regional wholesale transmission service.

7. Cost-Benefit Analysis

The costs and benefits of more open transmission access are difficult to quantify. However, to be responsive to an Economic Policy Council request to examine whether costs or benefits are greater for each National Energy Strategy option, in this chapter we present crude estimates of the minimum likely benefit of more open transmission access and the maximum likely cost of such a policy. The actual benefit could be much greater than the minimum, and the actual cost may well be much less than the maximum; the purpose of the calculation is merely to see if benefit exceeds cost, however approximate our estimation of each of these quantities may be.

Introduction

Several types of benefits could result from increased transmission access. The benefits of greatest concern here are economic, both short term and long term. The short-term benefits are improved use of existing generating resources. The long-term benefits include the operational cost-cutting measures that occur when a vertically integrated industry experiences more competition. Additional long-term benefits include the efficiency gained through acquisition of new generating units. These would include economies in the newly emerging generating sector (qualifying facilities and independent power producers) as well as among traditional utilities.

The efficiencies for new generating units would come about as more efficient plants displace less efficient competitors. With or without competitive bidding, benefits would come from displacement of higher cost local plants that would have been built in the absence of transmission access by lower cost plants built elsewhere.

There are other benefits of transmission access. Due to siting constraints in many areas, it is increasingly difficult to construct new electricity generating plants. Depending on assumptions, some 200 to 275 gigawatts of new capacity will be needed by 2010. Without transmission access, many utilities face unnecessarily high costs to locate powerplants in their service areas. With transmission access, power can be moved from locations where siting is easier and cheaper. This benefit can be thought of as a special case of the long-term efficiencies in acquisition of new resources noted above. Here the gains would be from avoiding alternatives that by their very nature would be more expensive, even if efficiently constructed.

Finally, there are benefits to the Nation from flexibility in plant siting, flexibility in fuel choice, and flexibility in response to energy emergencies. Transmission can, for example, be used to facilitate switching from oil to other fuels in those relatively few areas that still rely on oil-generated electricity to a significant degree. The benefits here would come from two sources. Primarily, increased transmission access would allow displacement of remaining oil-fired generation. As a secondary effect, if transmission access lowers electricity prices, it could facilitate displacement of oil used elsewhere in the economy, including industrial processes, personal transportation, and space heating in the industrial, commercial, and residential sectors.

Benefits

Short-Term Benefits

To estimate the short-term benefits of transmission access, one can use recent studies of improved economic dispatch procedures. In particular, the Indiana Economic Dispatch Study (*Decision Focus*, 1989) is a representative analysis.

The State of Indiana is already engaged in substantial interutility trade, including a formalized brokerage system. To examine the potential for further gains, a State task force commissioned a study. The results estimated potential annual production cost savings in the range of $13 million to $37 million, with an expected value of $24 million. This is a small number relative to the State's 1988 annual electricity revenues of about $4 billion.[1] Suppose that roughly half the expected savings, or $12 million, could be realized under improved transmission access. This result can be scaled to a national level. Proportional scaling assumes that these benefits are achievable everywhere to the same degree. In some regions, where pooling arrangements are strong, this may not be true. In other regions, greater savings may be obtained, especially if displacement of more expensive oil is possible. Indiana accounts for about 2.8 percent of U.S. electricity sales; if equal savings were achievable proportionally, the result at a national level would be annual savings of $432 million from 1991 through 2000.[2] The net present value of these savings is $2.654 billion.[3] For comparison, a 1981 Federal Energy Regulatory Commission study of power pooling estimated additional benefits of coordination at 1 to 2 percent of national electric revenues. This corresponds to $1.44 to $2.88 billion annually. While our lower estimate contains an implicit assumption (without corroboration) that much of this potential has already been captured in the 1980's, this may not be the case.

Long-Term Benefits

Long-term efficiency gains from transmission access include cost-cutting measures and savings in resource acquisition. We will first examine cost-cutting efficiencies.

Transmission access will increase competitive pressures in the utility sector. A typical response of any industry to increased competition is increased productivity. This is often accomplished by reducing staff and overhead. Suppose all productivity improvements were accomplished by reducing staff. According to the Edison Electric Institute (EEI) *Statistical Yearbook of the Electric Utility Industry / 1988* (p. 99), the investor-owned segment of the industry employed 513,742 people in 1988. The publicly owned sector represents one-third of the industry, estimated by sales, but proportionately less by employment. Let us assume the publicly owned sector adds another 20 percent to the EEI figure. This would make total industry employment approximately 615,000. The EEI data show an employment decline of 16,000 from the peak level of 1986. We assume that an additional decline of 5 percent, or about 31,000, is a reasonable response to competitive pressure. We will conservatively attribute roughly half the decline, or 15,000 jobs, to transmission access. (This workforce reduction can be achieved largely through attrition.) In support of the assertion that this estimate is conservative, we would note that several utilities have cut employment by more than 5 percent in the last 2 years.

The estimated cost decrease from eliminating 15,000 jobs over a 10-year period is based on the assumption that the full cost (including benefits) per position is $100,000 per year. We assume that these reductions are spread evenly over the decade. The first year's savings are $150 million, and savings grow by that amount each year. The present value of that stream is $4.354 billion.

This is, admittedly, a crude estimate of productivity gains. Gains could also be achieved by improving heat rates and capacity factors, and by more aggressively lowering fuel expenses through improved acquisition practices. Many of these improvements could require addition, not depletion, of staff and would, of course, be made only if the operating cost savings outweighed the extra staffing cost. Our calculation of staff reductions then can be considered a surrogate for such larger savings.

A second long-term benefit comes from proportionately greater reliance on lower cost powerplant builders and sites. This can occur either under traditional utility supply or under a competitive bidding scenario.

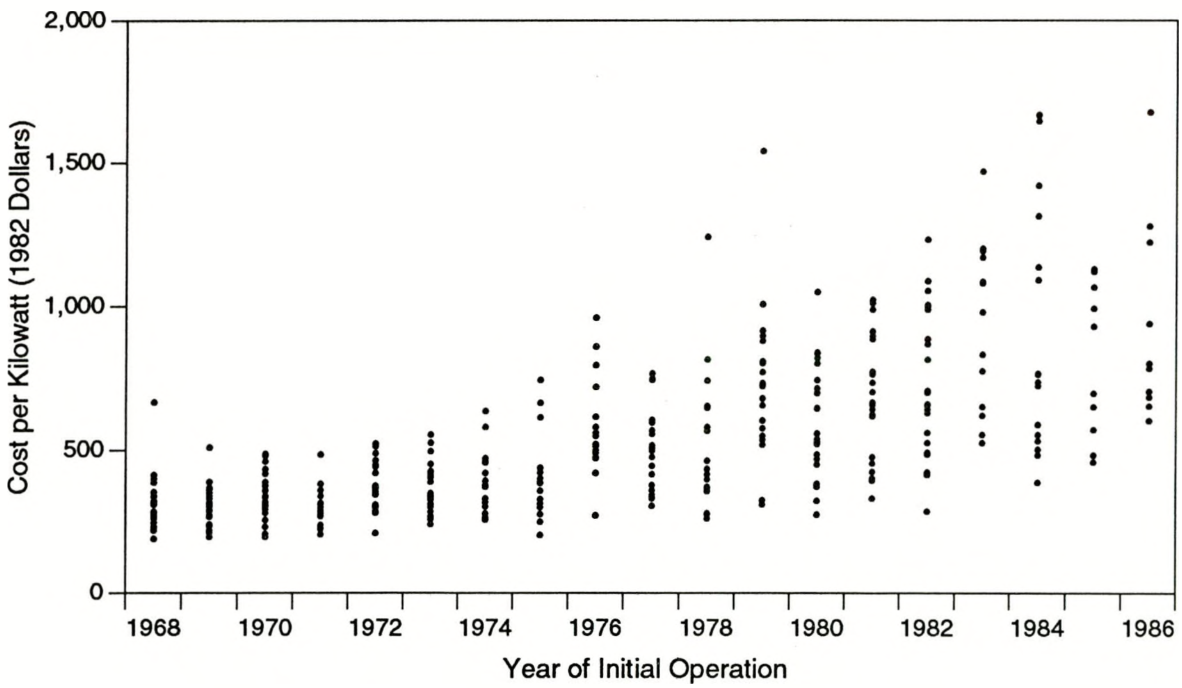
An important example of the effect of transmission access on long-term costs in the unregulated sector comes from the recent experience of Virginia Power in attempting to purchase capacity from out of State. A very efficient project was canceled, after being selected by Virginia Power in its 1988 solicitation, because the project could not obtain transmission into Virginia. Estimated cost savings for this project compared to the alternative choice made by the utility were approximately $70 per kilowatt-year starting in 1994.[4] The capacity associated with this project represented 15 percent of the total capacity selected by the utility in the solicitation.

On the regulated side, benefits can be estimated by examining the distribution of construction costs for new coal plants built in the 1980's. The standard deviation of construction cost has typically been one-third of the average value (Utility Data Institute, 1989). A typical estimate of the cost per kilowatt of new coal-fired capacity today is about $1,200 without capitalized interest and $1,500 with capitalized interest. If broader markets were available through transmission access, the high-cost end of this cost distribution is apt to be eliminated. The benefit can then be estimated by truncating the high-cost end of the cost distribution.

For the purpose of this analysis, let us assume that, with transmission access, more efficient builders would construct plants or plants would be built in better locations so as to displace higher cost plants that would have been built locally by the local utility. From the data above, saving 25 percent of the cost of the plant with the highest cost seems reasonably achievable. Figure 1 shows the cost distribution of new coal plants from 1976 through 1986. In most years, the plant with the highest cost was 2.5 to 3 times more expensive than the plant with the lowest cost. Cost differences of this magnitude, often in the same parts of the United States, imply that cost savings of the magnitude discussed here are justified by the historical record. Suppose the higher cost plants, at $2,000 per kilowatt, could be replaced by plants that cost only $1,500 per kilowatt, a savings of $500 per kilowatt. The annualized equivalent of $500 per kilowatt is roughly $50 per kilowatt-year. Under standard ratemaking treatment, the present value of future revenue requirements is approximately 1.6 times the rate base, thus establishing an annuitized value that includes overheads of roughly $80 per kilowatt-year.

For this exercise, we assume conservatively that 15 percent of the total market for new capacity can achieve this saving through a policy of increased transmission access. (This is also the percentage of Virginia Power's needs lost in the cancellation of one plant due to lack of access.) The Current Policy Base for the National Energy Strategy (September 1990) projects capacity additions of 54 gigawatts of coal capacity and 20 gigawatts of renewables in the 1990–2000 period. These largely capital-intensive technologies are the market that

Figure 1. Capital Costs of Coal Units
(1968–1986)



Source: Utility Data Institute, *Construction Costs, U.S. Steam Electric Plants, 1966–1986*, October 1987.

would potentially be most affected by transmission access. This results in an estimate of $83 million per year starting in 1990 and increasing by that amount every year until 2000. The net present value of that stream is $2.416 billion.

Another potential benefit from any competition enhanced by transmission access, which we have not attempted to quantify, is that of technological innovation. Recent experience with heightened competition in other sectors of the economy suggests that introducing competition in areas long subject to cost-of-service regulation results in unanticipated technological and organizational innovations, with major economic benefits for consumers.[5]

It is reasonable to assume that open access could hasten development and use of technical improvements in electricity transmission. Chapter 3 mentions the technological improvements currently being developed by the Electric Power Research Institute. In some cases, these technologies could double the transfer capability of a transmission corridor. Greater demand on the existing transmission network coupled with the difficulty in siting new lines in some cases should create a powerful incentive for owners of transmission systems and builders of transmission technologies to find and implement innovative ways to upgrade the power-transfer capability of the existing network.

Costs

The basic costs of increased transmission access would be either decreased reliability of the bulk-power transmission network or increased mitigation costs to maintain reliability. The proposition that reliability would decrease if transmission access increases significantly without adequate mitigation has been discussed in the professional literature.[6]

The concern with reliability arises from the complexity of coordination among large numbers of control centers. When disturbances occur on the transmission network, the coordinated response of more than one control center is often required to maintain system security. The power grid of the United States and lower Canada has about 150 control centers. The computational, communication, and human complexities of real-time coordination among these control centers are the sources of difficulty in confining and limiting the impact of transmission disruptions.

As the Office of Technology Assessment study and the Large Public Power Council proposal (discussed in Chapter 4) indicate, the reliability of transmission can be maintained as access increases, provided the process proceeds in an orderly manner and that control area requirements are strictly followed and maintained. There will be increased software development and hardware costs, as well as manpower and training costs. These costs are difficult to quantify, but they are unlikely to be of the order of magnitude of the benefits. One approach is to make a rough estimate of the costs associated with reduced reliability of the transmission system and treat these costs as a proxy for the real costs of administrative adjustments required to ensure reliability as access increases.

Estimating the costs of power outages is a complicated problem that involves both engineering and economics. We used the limited literature on this subject to estimate the transmission-related cost of unserved energy. The estimate has two parts: the amount of energy unserved due to transmission system outages and the costs of outages to consumers. Using these figures, we place a dollar value on the cost of unserved energy.

To estimate the amount of unserved energy due to transmission outages, we rely on statistical data reported in a comprehensive national study administered by the Department of Energy in response to the requirements of Section 209 of the Public Utilities Regulatory Policy Act of 1978. In particular, we use data summarized in "Analysis of Bulk Power System Failures and Review of Utility Security and Restoration Procedures."[7] Although the data reported here cover only the 1967–79 period, it is not unreasonable to extrapolate them, because there appears to be no particular time trend in the occurrence of outages over the period covered.

The amount of energy unserved due to transmission outages is the product of (1) the average number of outages per year due to the transmission system, (2) the average duration, in hours per transmission outage, and (3) the average load lost per transmission outage. The averages are (1) 45.3 outages per year, (2) 5.6 hours per outage, and (3) 177 megawatts lost per outage. The product of these factors is 44.9 million kilowatthours lost annually due to transmission system failures.

The economic literature on the value of service reliability is summarized in a special issue of *The Energy Journal* (v. 9, 1988) devoted to this subject. Conventional studies of this type develop separate estimates for residential and nonresidential customers. The value estimated for residential customers is approximately $4 per kilowatthour.[8] For nonresidential customers, the value estimated is about $7 per kilowatthour.[9] If we assume that the amount of interrupted load corresponds to annual sales, then roughly one-third of the interrupted load will be residential and two-thirds will be nonresidential. This proportion will result in a weighted average outage cost of about $6 per kilowatthour.

The transmission outage cost, then, is the product of the unserved energy (44.9 million kilowatts per year) and its consumer value ($6 per kilowatthour), or about $270 million per year.

This estimate can be interpreted as an upper bound on the costs of transmission access under several scenarios. A worst-case scenario would be one in which consumers incurred an additional $270 million in outage costs due to decreased reliability.

Our cost estimate is based on the reasonable assumption that current outage costs would no more than double due to increased transmission access. About half or more of the outages reported in the source document are related to weather or other factors that would be relatively unaffected by system disturbances that might be caused by increased transmission access. Thus, to assume a $270 million increase in outage costs is to assume implicitly that outages caused by degraded system reliability would increase by at least a factor of four.

Alternatively, we can think of this estimate as an upper bound on the mitigation costs required to maintain current reliability levels. These mitigation costs would include research and development, software development, incremental hardware, additional manpower, and manpower training.

Summary

It must be reemphasized that our analysis has attempted to maximize potential costs and minimize potential benefits. We have not quantified all benefits of more open access. The potential for decreased reliability or the cost of mitigating that potential may well be overstated.

Let us now compare the costs and benefits over the 1991–2000 period. All estimates are in 1990 dollars, with future estimates discounted at a 10-percent real discounted rate.

We assume that the short-term benefits persist over the entire 10-year period. The present value of these benefits is $2.654 billion. The long-term cost-cutting benefit is estimated at $4.354 billion. The long-term construction-efficiency benefit is assumed to grow over the 10-year period. We assume it begins at $83.25 million per year and increases by that amount every year as the market for new capacity grows. The present value of this growing stream is $2.416 billion. The sum of the three benefits is $9.424 billion.

The reliability cost (either direct or its mitigation equivalent) is assumed to be constant at its maximum over the whole period. The present value of $270 million per year for 10 years is $1.659 billion.

The benefit-cost ratio we estimate for transmission access, therefore, is 5.68 (9.424 divided by 1.659).

This benefit-cost ratio applies to a sudden, substantial, and national increase in transmission access. If access and its attendant competition come about more slowly or one region at a time, both cost and benefits would be correspondingly lower. However, in this model we would still expect benefits to exceed costs, and we would not expect the ratio to change.

Notes

1. Energy Information Administration, *Electric Power Annual 1988*, 1990, p. 42.

2. *Ibid.*, p. 40.

3. All NPV calculations in this report use a 10-percent real discount rate.

4. Testimony of Larry W. Ellis, Virginia Electric and Power Company, before the State Corporation Commission of Virginia, 1989, Case No. PUE 89051.

5. An example would be the long-distance telephone industry. In the 1970's, it was predicted that easier entry would have little effect because entrants would have to rely on small-scale, inexpensive microwave technology, as opposed to fiber optics, which is economical only at very high volumes. However, the cost of fiber optics has fallen faster than anticipated, largely because of greater than expected demand for it from new entrants, so that entrants have found it economical to build extensive fiber optic networks. This illustrates the creative ability of new entrants and the ability of competitive markets to make the most of new technologies and unfilled market niches.

6. See F. Wu and A. Montecelli, "Analytical Tools for Power System Restoration: Conceptual Design," in *IEEE Transactions on Power Systems*, v. 3, no. 1 (1988): 10–16. It is also prominent in industry study groups (see Electric Power Research Institute, *Proceedings: Power System Operations-Research Needs and Priorities*, EPRI EL–6659, 1990).

7. See Chapter 5 of *The National Electric Reliability Study: Technical Study Reports*, DOE/EP 0005, April, 1981.

8. See M. Doane, R. Hartman, and C. Woo, *Households' Perceived Value of Service Reliability: An Analysis of Contingent Valuation Data*, pp. 135–149.

9. See C. Woo and K. Train, *The Cost of Electric Power Interruptions to Commercial Firms*, pp. 161–172.

APPENDICES

APPENDIX A

Profiting From Constrained Capacity: A Simple Example

A monopolist, like economic actors in fully competitive markets, will attempt to maximize profits. Textbook economics, derived from many real-world examples, indicates that a monopolist will maximize profits by selling less of a good or service at a higher price than would occur in a fully competitive market. Economic efficiency is then harmed because fewer economic transactions take place under the monopoly.

Some may dispute whether a monopoly owner and seller of transmission services acts as a traditional monopolist. The argument seems to be that if there is an opportunity to make an economic transaction, the transaction will take place, and the only argument is over who gets the rents. This may be the case in a short-term period of days or months, where the worst outcome for the monopolist would be excess capacity going unused and a profit opportunity being missed, and where the transaction costs of achieving the efficient outcome are small. Thus a power pool with central dispatch may not exercise market power in its day-to-day operations.

To examine this argument as it applies in the long term to the independent power industry, let us posit a utility that is centrally located with regard to a number of inexpensive fuel sources (for example, a southwestern utility for gas and a midwestern utility for coal). Potential independent power producers (IPP's) or qualifying facilities (QF's) would likely find it economically attractive to build inside this service area and sell power, over two decades or more, to several potential buyers through a combination of long-term and shorter contracts. To do this, they would need to know that transmission services would be available at reasonably predictable rates from the host utility.

Let us assume that five such potential sellers exist, each 100 megawatts in size, and that their minimum selling costs are 6.2, 6.4, 6.6, 6.8, and 7.0 cents per kilowatthour, respectively. Several buyers willing to pay 7.35 cents per kilowatthour are at various locations just outside the service area. The embedded cost of transmission services is 0.3 cents per kilowatthour, this embedded cost is greater than the short-term marginal costs of transmission incurred, and the host utility can make 500 megawatts of transmission available with some minimal difficulty. Our final assumption is that the utility may have some degree of flexibility in pricing its transmission services, either because of relaxed regulation allowing such flexibility or for other reasons.

In a fully efficient market, any of the five IPP's and QF's could build its plant and sell its power because the cost of the most expensive plant, plus the cost of transmission, would be 7.3 cents, less than the 7.35 cents that the buyers are willing to pay. The host utility receives no economic gain from the sale of transmission beyond the normal profit built into embedded-cost rates.

Suppose the utility, seeing that the IPP's and QF's are not able to build new transmission lines themselves, holds out for 0.6 cents per kilowatthour for transmission services. Let us assume, for the sake of argument, that the host utility points to a number of technical difficulties that, while not expensive or difficult to solve, allow the utility to delay reaching agreements with the IPP's and QF's for some time. Let us also assume that, to avoid losing contracts, the IPP's and QF's eventually agree to the 0.6-cent wheeling charge. Only the first three will be able to make a deal (the fourth, with a selling cost of 6.8 cents, plus the 0.6-cent transmission adder, can sell power at a total cost of 7.4 cents, which is above the 7.35-cent offer).

In this case, only three of the five economic IPP's and QF's are built and sell power. The utility receives 0.3 cents per kilowatthour in economic rents. While the utility loses only the small amount of normal profit in the 0.3-cent wheeling charge it does not recover from the lost sales of transmission services, the 6.8- and 7.0-cent IPP's and QF's will more than make up this amount in the large gain in rents on transmission sales to the three remaining sellers.

Thus, a monopoly owner of transmission services could increase profits by restricting output and increasing prices for the monopolized service. These actions lead to fewer economic transactions, with a loss to the Nation of economic efficiency.

APPENDIX B

Recent and Pending FERC Transmission Decisions

This appendix describes some recent and pending Federal Energy Regulatory Commission (FERC) decisions regarding innovative transmission proposals offered by the industry, and some transmission conditions ordered by the Commission. In addition, a few of the more important pending transmission cases are listed.

Transmission Commitments for Market-Based Pricing

Turlock-Modesto

In 1988, FERC approved two transmission agreements between Pacific Gas & Electric Company (PG&E) and two of its captive wholesale customers: the Turlock and Modesto Irrigation Districts.[1] Both cases are 20-year regulatory bargains in which the wholesale customer receives certain services, notably firm transmission service, at cost-based prices while PG&E is authorized to charge "market-based" prices for certain coordination services. FERC concluded that market-based pricing is appropriate because PG&E had sufficiently mitigated its market power by its offer of cost-based services in general and its transmission commitments in particular.

In the Turlock agreement, PG&E agreed to provide three services at cost-based rates: (a) partial-requirements generating service that Turlock may request initially, (b) firm, reserved transmission service to four specific receipt points, and (c) contract firm power service that acts as a safety valve for Turlock to return to PG&E's system in the event that Turlock's suppliers cannot perform. All other power and transmission services are voluntary and flexibly priced. FERC based its finding that PG&E lacked market power over Turlock on the grounds that:

- Reserved transmission service can be used for all types of transactions, including short-term coordination trades.
- PG&E is obligated to provide additional reserved transmission service, upon request, at embedded-cost prices if capacity is available and at incremental cost prices if capacity must be built.
- Turlock can return to PG&E for contract firm power service in the future and thereby has a safety net.

The Modesto agreement is similar to that struck by Turlock, except that the contract firm power safety net is missing and Modesto is not restricted to selecting among four specific delivery points as was Turlock. The safety net is replaced in the Modesto contract by the following, showing that PG&E lacks market power:

- Evidence that Modesto had arranged for sufficient reserved transmission, along with purchased and owned generation services, to cover its requirements for the first 3 years of the agreement
- A FERC requirement that PG&E would lose its flexible pricing authority in the event that Modesto cannot meet its requirements because of an inability to obtain reserved transmission service from PG&E.

Neither agreement allows the captive customer to resell reserved transmission service. In both cases, the transmission service is provided between specified receipt and delivery points that can be rearranged upon negotiation. Both of these features somewhat restrict the market activities of the wholesale customers and help to insulate PG&E from competitive pressures that might otherwise be exerted by them.

PSI Energy

In 1990, FERC approved a proposal by PSI Energy (formerly Public Service Company of Indiana) to sell up to 450 megawatts of long-term, firm power at market-based rates in exchange for a commitment by PSI to open its transmission grid. FERC approved PSI's program on the basis, first, that PSI is not a dominant firm and consequently lacks market power over generation and, second, that PSI derives no market power from its transmission assets due its commitment to provide open-access transmission service to all utilities, independent power producers, and qualifying facilities.

PSI owns several low-cost coal plants that are designed for base-load service but will be underutilized in the future. PSI intends to sell its base-load capacity to a utility that can fully utilize it and build new peaking facilities for itself. Such a trade enhances the economic efficiency of all the parties; however, it would most likely not be economically attractive for PSI if PSI were required to sell its power at cost-based rates—likely to be much lower than the prevailing market price. PSI intends to keep the plants used to produce the market-priced power in the rate base of Indiana consumers and to more than compensate Indiana ratepayers by sharing the profits from the sales. This portion of the regulatory bargain will be overseen by the Indiana Utility Regulatory Commission.

To gain Federal approval of its plan, PSI included strong transmission commitments intended to demonstrate to FERC that PSI lacks market power over its proposed power sales. These commitments include the following

- PSI will provide long-term firm transmission service to any utility at cost-based prices (embedded-cost prices if existing capacity is used and incremental-cost prices if new capacity must be added).
- PSI will provide nonfirm transmission service at rates capped by embedded costs.
- For planning and operational purposes, all firm transmission service will have priority over nonfirm service, even that which would otherwise benefit native-load customers.
- PSI has agreed to provide transmission service between specific points of receipt and delivery, and to allow changes in these points if the customer pays for any additional costs.
- Firm transmission service may be resold or reassigned, with the new utility receiving the service paying for any additional costs imposed by the changes in receipt and delivery points.

FERC required PSI to back up its obligation to provide transmission service by agreeing to suspend its market-based pricing authority for power if a third party complains about the lack of timely transmission service and the Commission subsequently upholds the complaint. In addition, FERC will receive certain reports from PSI on the status of both the midwestern power market and PSI's transmission program that will assist FERC in any future review of the program.

PSI's open-access transmission program is likely to be an important factor in the development of a competitive power market in the Midwest for several years. The most obvious weakness of PSI's commitments is its limited duration. PSI asked FERC for market-based pricing authority until 1997 and also asked that its transmission-building obligation be similarly limited. After 1997, PSI's obligation to upgrade the transfer capability of its grid will be limited to new investment needed to accommodate rearrangements of levels of service that were existing or requested at the end of 1996. Whether this restriction will become important or will be overtaken by events is difficult to judge now.

Transmission Conditions for Mergers

PacifiCorp-Utah Power & Light Merger

Each of the previous three agreements is a regulatory bargain in which FERC has granted market-based pricing in exchange for transmission commitments sufficiently strong to mitigate the market power likely to be wielded in the particular circumstances. FERC has opportunities to reshape the regulatory bargain in other ways that promote the public interest. One such instance was the merger between Utah Power & Light Company and PacifiCorp. In that case, FERC conditioned its approval of the merger on the company's acceptance of an absolute obligation over the long term to provide firm transmission service to any utility, not including qualifying facilities, at cost-based rates.

FERC based its decision on the record in the case that showed that Utah Power & Light had exhibited a history of denying transmission service to utilities in the Northwest and Rocky Mountain regions who wished to sell inexpensive power into lucrative markets in the Southwest. Instead, Utah Power & Light would buy the cheap power for itself and resell it into these markets at a markup. This purchase and resell activity was more profitable than providing wheeling service. The profits were mostly credited to Utah Power & Light's retail ratepayers and served to keep rates in Utah low. FERC concluded that the merger would strengthen the company's ability to use its transmission assets in such anti-competitive ways and could therefore foreclose a significant amount of interstate trade between the Northwest and Southwest regions.

To address these anti-competitive concerns, FERC fashioned two sets of transmission conditions:

- **Transition Period** (First 5 years). The merged company was required to identify remaining transmission capacity (after setting aside capacity needed for native load) and to allocate it as follows: 20 percent to transmission-dependent utilities, 30 percent to unaffiliated entities to the north and east of the company, and 50 percent to any company, including the merged company itself.

- **Long-Term Obligation to Serve.** The merged company must provide firm wholesale transmission service at cost-based prices to any utility requesting it. FERC required the company to back up this commitment with an agreement to reduce its own coordination trade to whatever extent is necessary should the company not be able to meet this obligation within 5 years of a request.

FERC also required that customers be able to resell or reassign firm transmission service. As in the Turlock, Modesto, and PSI cases, PacifiCorp will provide point-to-point transmission service, with the customer responsible for paying the cost of any upgrades due to receipt point or delivery point changes.

FERC's conditions were accepted by the two companies and the merger was consummated in 1989. In doing so, the company agreed to the condition that PacifiCorp must reduce its own coordination trade if such action is needed to accommodate a firm transmission request. As discussed in Chapter 6, this condition is problematic.

Open Transmission Access With No Federal Quid Pro Quo

Wisconsin Power & Light Transmission Tariff

In 1990, FERC accepted a transmission tariff under which Wisconsin Power & Light Company (WP&L) effectively became an open-access provider of transmission services. No regulatory bargain was involved at the Federal level. Instead, the bargain, if any, may reflect circumstances in Wisconsin. In 1989, the Wisconsin Public Service Commission expressed a strong interest in statewide joint use or joint planning of the transmission grid as part of the a biennial regulatory review of integrated resource planning within the State. As part of its interest in transmission, the Wisconsin Public Service Commission required Wisconsin utilities to file transmission tariffs at FERC within 1 year. The WP&L initiative may be the utility's response to the State Commission's directive. Alternatively, the tariff may be a way for WP&L to compete in a developing regional market for transmission service.

In any case, the WP&L transmission tariff, called T–2, applies to all utilities, including qualifying facilities and independent power producers, outside of its service territory.[2] Under the tariff, WP&L will provide both firm and nonfirm transmission service at embedded-cost rates from existing facilities. If new facilities are needed, WP&L will provide service under separate, negotiated agreements approved by FERC. Although the T–2 tariff does not specify the transmission price to be charged if new facilities must be built, it must ultimately be "just and reasonable" under the Federal Power Act. Thus far, FERC has required a cost basis for the price of firm transmission service under this standard.

The WP&L tariff is distinguished by the company's offer to provide transmission service between generalized interfaces that separate adjoining utilities, instead of between specific receipt and delivery points as in each of the aforementioned cases. The additional flexibility allowed by such arrangements may be an important feature of the tariff to some market participants. The most restrictive feature of the tariff is the inability of a customer to resell transmission service. The inflexibility due to this restriction is offset to some extent by WP&L's concept of service between generalized interfaces.

Pending Cases

In all, since 1988 FERC has dealt with five specific regulatory cases that have increased the availability of transmission service in parts of the Midwest and West. Several cases are pending at the Commission, suggesting that this trend is continuing. A few of the more important cases are listed below.

- **Western Systems Power Pool.** FERC has ordered the pool to develop a method for mitigating the market power of the pool members or else lose the pricing flexibility that they seek for nonfirm transmission service, in particular.

- **Southern California Edison-San Diego Gas & Electric Merger.** This merger is under consideration. It involves the offer of certain transmission commitments by the merging companies.

- **Northeast Utilities-Public Service Company of New Hampshire.** This is another merger involving transmission commitments, with the added feature that the merger is intended to bring Public Service of New Hampshire out of bankruptcy.

- **Kansas City Power & Light-Kansas Gas & Electric Merger.** This is a hostile takeover that involves transmission commitments.

- **Northeast Utilities-United Illuminating Company Nonfirm Transmission Pricing.** FERC has set for hearing the issue of whether opportunity cost pricing for nonfirm transmission service is appropriate in the presence of market power on the part of the transmission incumbent.

- **Vermont Commission Section 207 Complaint.** The Vermont Commission, as part of its intervention in the Northeast Utilities-Public Service of New Hampshire merger case, has complained that the transmission service received by Vermont utilities from Northeast Utilities is inadequate and has asked FERC for relief under little-used Section 207 of the Federal Power Act.

Notes

1. See Pacific Gas & Electric Company's agreement with Turlock (42 FERC ¶ 61,406, rehearing 43 FERC ¶ 61,403) and Pacific Gas & Electric Company's agreement with Modesto (44 FERC ¶ 61,010, rehearing 45 FERC ¶ 61,061).

2. A separate tariff, T–1, is available to utilities within WP&L's service territory and provides for transmission services under similar prices, terms, and conditions.