NRRI-87-7

SOME ECONOMIC PRINCIPLES FOR PRICING WHEELED POWER

Kevin Kelly
Associate Director

J. Stephen Henderson
Senior Institute Economist

Peter A. Nagler
Mark Eifert
Graduate Research Associates

THE NATIONAL REGULATORY RESEARCH INSTITUTE
1080 Carmack Road
Columbus, Ohio 43210

August 1987

This report was prepared by The National Regulatory Research Institute (NRRI) with funding provided by participating member commissions of the National Association of Regulatory Utility Commissioners (NARUC). The views and opinions of the authors do not necessarily state or reflect the views, opinions, or policies of the NRRI, the NARUC, or NARUC member commissions.

EXECUTIVE SUMMARY

Electric power is said to be wheeled when the transmission lines of one or more utilities are used to transport electric energy from a seller of power to a buyer. The best way to price the wheeling service depends on one's pricing objective and the environment within which the objective is pursued. This study examines the best way to price wheeling so as to encourage good decisions about the use and expansion of electric power transmission networks.

The current setting of laws, regulations, and other limitations placed on utilities, regulators, and wheeling customers somewhat constrains ratemaking from achieving this goal. Conditions appear to be changing, however, so that the best wheeling pricing policy in the current setting may not serve well in the future. For example, the best policy depends on whether or not utilities are required to wheel and on whether cost-based rates are required or market-based rates are permitted for wheeling service.

A Test of Good Decision-Making

Despite the changing environment, there is a test for whether wheeling rates encourage good decision-making, which always applies. We call this test the equalization of marginal costs across the grid. Under any set of laws, regulations, or institutional arrangements, the best wheeling prices are those that reduce the difference in electricity costs between any pair of electricity producers to the incremental cost of moving power between them, or less. The power then flows in an interconnected network of transmission lines in the same way as it would with economic dispatch of all generating units in the network. This occurs if there are no other, nonprice impediments to wheeling; this issue is discussed in a forthcoming NRRI companion report on non-technical impediments to power transfers.

Where differences in production costs between utilities exceed interutility transmission costs, there are gains to be derived from a power transfer. When wheeling is needed to complete the transaction, good wheeling decisions are those with incremental benefits greater than the incremental costs for all members of the network. Several pricing rules can promote good decisions about wheeling. They differ according to how the gains from trade are shared among the parties.

The current policy debate about changing the legal, regulatory, or institutional environment governing power transfers is motivated partly by a desire to facilitate beneficial trading and partly by a desire to assign a greater share of existing gains to particular parties. Arguments for particular wheeling policies are sometimes based on some notion of fairness, but often do not encourage good decisions about transmission system use and expansion. The approach suggested to policy makers in this study is to look among the pricing policies that can equalize marginal costs across the grid and choose the one that seems fairest. The study examines cost-based wheeling prices, as well as rates higher than costs, that encourage good wheeling decisions.

Wheeling Costs

For the purpose of applying the marginal cost equalization test, the relevant costs are the incremental costs imposed on the wheeling utility by the wheeling transaction. The costs of wheeling are the costs of operating, and sometimes expanding, a network of electric power transmission lines.

In an electric power transmission network, there are many pathways from generating stations to load centers. While this has the advantage of redundancy, power typically flows over multiple paths in a wheeling transaction. The cost of wheeling, then, is the sum of the costs of the incremental power flows over all paths in the network.

A wheeling utility is in some sense a passive participant in the transaction. The selling utility increases its power generation while the buyer backs off its own generation or increases its load, and the power flows over all available transmission lines connecting them. To transmit the electric power, the utilities that own these lines, other than the buyer and seller, do not need to take any action of the sort that, say, gas transmission companies do as they actively pump gas through particular pipelines in their systems.

Wheeling is not costless, however, to a company that carries the power. At a minimum, a wheeling utility must know and compensate for the effect of the extra load on the reliability of its service. In an interconnected network, utilities must synchronize their generating units, match local generation to local loads, and provide for local correction of power factors. Each of these activities may require some additional expenditure as the volume of power transfers among utilities grows. The wheeler also incurs the administrative costs of metering flows and billing the wheeling customer for services.

More importantly, a wheeler experiences changes in operating costs and other short-run costs. If its transmission capability is strained, a wheeler may need to expand its transmission capacity to satisfy the needs of wheeling customers. Then wheeling imposes long-run costs on the wheeler.

Short-run wheeling costs consist principally of changes in the fuel costs of electricity generation and opportunity costs that represent the value of alternate uses of lines used to capacity. Fuel costs can increase as generation increases, mostly to make up for energy lost in transmission. Fuel costs can also change as new generating units come on line and as the economic dispatch of generating units changes. Of these costs, those associated with transmission line and transformer energy losses are usually by far the most significant. In practice, these line losses are often accounted for by having the seller supply the wheeler with more energy than the wheeler delivers to the buyer. But such in-kind payment may not accurately reflect the change in the wheeler's fuel costs.

The wheeler's fuel costs may either increase or decrease depending on whether the power wheeled flows in the same direction as, or counter to, the native load on the wheeler's transmission lines. Counterflow reduces line losses and yields fuel cost savings. The cost of incremental line losses depends not only on the direction of native load, but also on its level. Wheeling power on a heavily loaded line causes more energy loss than wheeling the same amount of power on a lightly loaded line. Depending on the cost of fuel, the changes in fuel cost per kilowatt-hour can range from fractions of a mill to a cent or more.

Other short-run costs include opportunity costs and some (typically negligible in practice) increased physical depreciation of the transmission system, as well as the administrative and other transaction costs previously mentioned. Opportunity costs rise as transmission load rises to the level of transmission capacity. Transmission lines can have multiple uses, such as facilitating economic dispatch over a large area and permitting utilities to share reserve generating capacity. If wheeling restricts other uses of transmission lines, including use by other wheeling customers, it imposes a cost on either the wheeling utility or other wheeling customers because of lost opportunities for fuel cost savings or generation capacity cost savings.

In the long-term, wheeling may cause the wheeler to increase transmission capacity. Adding new transmission lines not only can reduce the opportunity costs on a heavily loaded system, but also can reduce line losses and save fuel. Indeed, new lines may be justified solely on the basis of the fuel savings even when existing transmission capacity is not fully utilized.

The maximum wheeling load depends on which lines are used and the direction of power flow. The north-to-south wheeling capability of a utility is likely to differ from its west-to-east capability, and hence the cost of increasing system wheeling capacity can differ by direction too. The cost of increasing transmission capability also depends on the options open to the wheeler for increasing the level of power transfers. The existing transmission system's maximum load may be set by any of several conditions: the physical limits of the transmission lines to carry power without undue physical deterioration, the need to maintain a relatively constant voltage along the lines, the need to maintain a stable synchronization of generating units, and the need to maintain a transmission capacity reserve margin on certain lines to assure an appropriate level of electric service reliability.

Transmission limitations related to voltage support and system stability can often be overcome by adding equipment that compensates for the voltage and stability effects of additional power transfers. Compensation equipment costs typically range from one to ten million dollars per hundred miles of extra-high-voltage (EHV) transmission line. Physical limits on transmission line voltage and current can be overcome by improving an existing line, adding a second circuit to a single-circuit line, or constructing a new transmission facility. New facilities typically cost between 20 and 80 million dollars per hundred miles of EHV line.

This information comes from an NRRI survey of all state regulatory commissions in the Spring of 1986. It asked for the current construction cost of new overhead, alternating current (AC) transmission lines of 115 kilovolts (kV) and above. The responses were used to estimate new line costs for various regions of the country as a function of design voltage, line length, number of circuits, type of supporting structure, and the terrain and population density traversed by the line. A cost function was estimated with regression analysis from a sample of 148 lines recently constructed or currently under construction. The resulting regional cost estimates are displayed in figure ES-1 for typical single-circuit transmission lines, 50 miles long, for various voltage levels. The lines are typical in the sense that likely characteristics of supporting structure, terrain, and population density are incorporated in the cost estimate for each voltage level. The figure shows, for example, that a 50-mile long, single circuit, 765-kV line constructed in the South Central region is estimated to cost $650 thousand per mile in 1985 dollars. The estimates in the figure are expected values, about which there is some statistical uncertainty. The step-like design of figure ES-1 shows how costs per mile of line vary by voltage and region.

These results were combined with somewhat weaker results (based on only 109 reported lines) relating line capacity to voltage. The combined data indicate that the cost of new capacity varies inversely with voltage, from about $1000 per megawatt-mile at 115 kV to about $150 per megawatt-mile at 765 kV.

Cost-Based Prices

Wheeling prices that encourage good bulk power supply decisions are related to wheeling costs. Either of two concepts of cost, the short-run marginal cost of transmission or its long-run incremental cost, could be the basis of prices that equalize marginal bulk power supply costs across the grid. Bulk power supply costs are the combined costs of the generation and transmission systems of an interconnected network. As mentioned, short-run transmission costs are mostly line losses and the opportunity costs of a congested system. With no congestion, the short-run marginal cost of bulk power supply is mostly fuel costs. This cost varies throughout the network. At any point, it is the sum of the fuel cost of generating electricity plus the fuel cost of transmitting electricity to that point. Bulk power supply costs are minimized in the short-run, if there are no transmission constraints, by dispatching a set of generating units to meet a set of loads at minimum network fuel cost. Long-run transmission costs consist principally of the cost of expanding transmission capacity plus line losses adjusted for fuel savings. The long-run bulk power supply cost also varies from point to point. At any point, it is the cost of delivering electricity to that point after all beneficial opportunities for building new generation and transmission capacity--those that lower aggregate electricity costs--have been exploited.

Setting wheeling prices equal to short-run transmission costs encourages customers to make decisions that equalize short-run bulk power supply costs throughout an interconnected network. Such a price is the cost

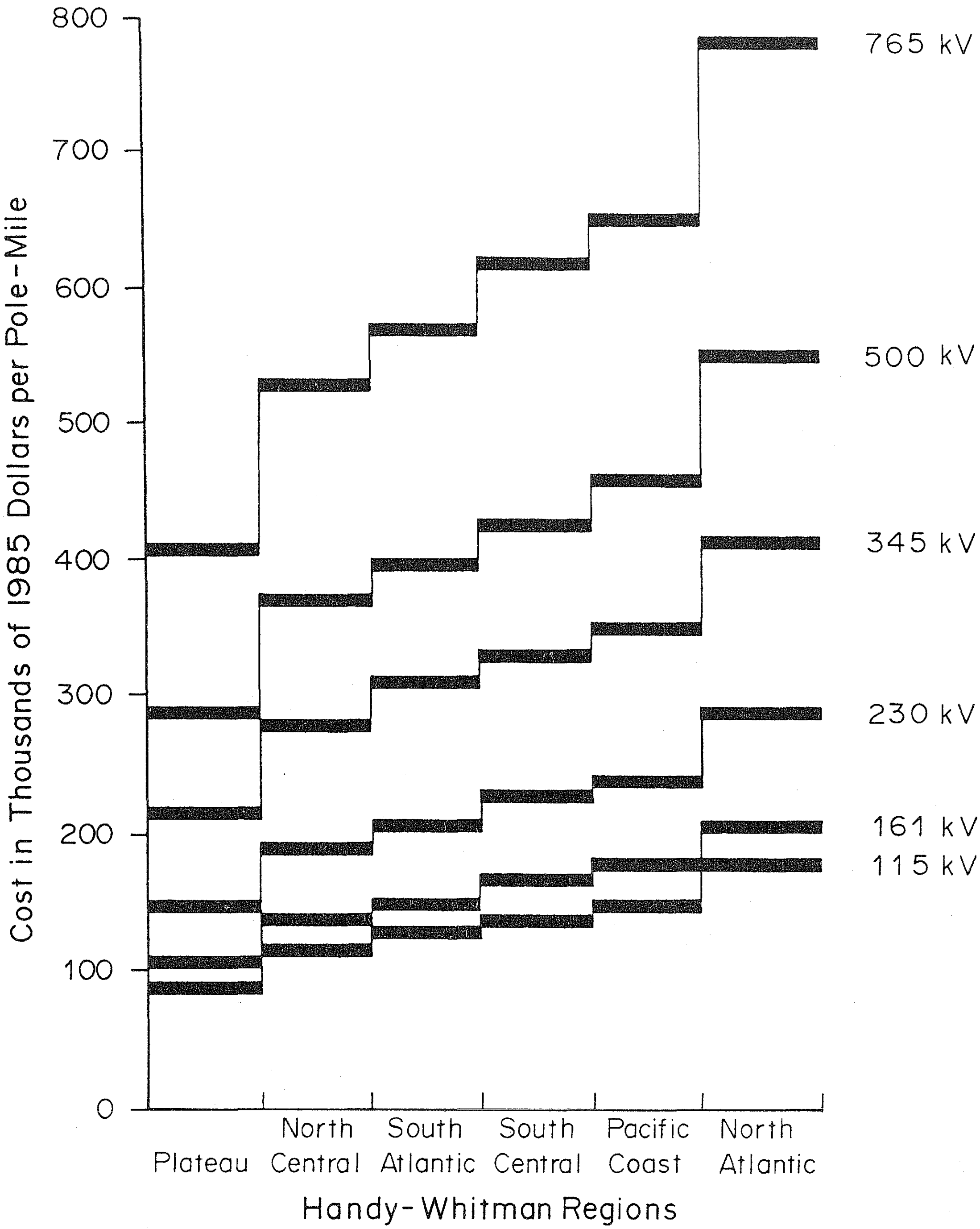


Fig. ES-1 Estimated construction costs per mile for typical single-circuit transmission lines, 50 miles long, by U.S. region and voltage. (Source: regression analysis of NRRI survey data.) Note: the analysis yields estimated costs for all line types whether or not they exist; no 765-kV lines exist on the Pacific Coast, for example.

of moving an increment of energy between two points in the network. A wheeling customer who receives more value than this price from the transaction is encouraged to wheel because his benefit exceeds his cost, the price. A price below this cost encourages too much wheeling or wheeling over too great a distance. A higher price unnecessarily restricts the amount or distance of wheeling. The result in either case is that bulk power customers make poor choices about the amount of power to wheel and the radius of the area for seeking trading partners.

When transmission capacity is used up, the price contains a congestion charge component reflecting the opportunity cost of the capacity. This acts to ration the use of this capacity to those who place the highest value on it. Those customers who can obtain greater energy cost savings from wheeling, and hence are willing to pay a higher congestion charge, receive the wheeling service. Others opt for less costly energy supply alternatives.

Under this system of pricing at short-run cost, the electricity costs (system lambdas) of all utilities in a network tend toward a common value. The energy cost difference between any pair of companies is at most the cost of energy delivery.

In the long run, the total incremental cost of electric bulk power supply includes not only fuel (and other expenses) but also the cost of replacing or expanding generation and transmission capacity. Wheeling customers are themselves utilities--perhaps including municipalities, cooperatives, cogenerators and other industrial customers--that are considering constructing their own generating units, purchasing power from contiguous neighbors, constructing their own transmission lines, switching to alternate fuels, and installing major electricity-consuming equipment, as well as importing energy through the wheeling utility. In order to make good decisions about least cost energy supply, these customers need to know the cost of wheeling over the long-term--in this case, perhaps over several decades.

In theory at least, setting wheeling prices equal to short-run wheeling costs also equalizes long-run electric bulk power supply costs across the grid. This is because, in a system that is expanded optimally over time, the time-average value of short-run costs, which fluctuate with congestion, would equal the long-run cost. As a result, short-run prices in principle should encourage not only good short-term energy supply decisions by wheeling customers, but also should encourage good long-term investment decisions by these customers.

In practice, pricing at short-run costs has a limited ability to do this. While in theory a customer might anticipate correctly that fluctuations in short-run prices average out to the long-run price, in reality this is difficult because he would undoubtedly give undue weight to the current overutilized or underutilized state of the network. Further, he may be averse to the financial risk of the possibly high and uncertain future prices needed to maintain an uninterrupted supply. A customer may find, also, that the added transaction costs of continually competing for transmission capacity in a short-term interruptible market are high enough to affect his investment decisions. Further, the transmission system may not be optimally configured over time, so that the time-average of short-run costs is not equal to the long-run cost after all. As a result, setting price equal to short-run wheeling cost may not achieve the equalization of long-run bulk power supply costs across the grid.

Prices set equal to long-run transmission costs, on the other hand, do tend to equalize long-run bulk power supply costs across the grid. They correctly signal to customers the long-run incremental cost of wheeling over several transmission expansion cycles during which congestion charges, not a part of long-run costs, would rise and fall several times. As a result, wheeling prices based on long-run costs encourage customers to compare correctly the total costs of various long-term energy supply alternatives and hence to make good investment decisions and long-term contractual commitments. Prices equal to long-run costs have the disadvantage, however, that they are too high during periods of excess transmission capacity, discouraging beneficial power trades at these times. Conversely, these prices may not be high enough to limit demand to available capacity during peak periods.

To summarize, prices equal to short-run costs encourage wheeling customers to make good short-run wheeling decisions that tend to equalize energy costs throughout the network, but such prices can distort customers' long-term decisions about such long-term commitments as constructing their own generating units, signing long-term firm power supply contracts, or constructing their own transmission lines. Prices equal to long-run costs encourage good long-run investment decisions of this sort, but can distort good decision-making about the optimum near-term use of network generation and transmission facilities for minimizing energy costs.

Best Pricing Policy

From these considerations, the best practical cost-based pricing policy appears to be to divide the wheeling market, setting price equal to short-run cost for customers seeking energy economy and also for customers willing to risk price variation in hope of greater gain, and setting price equal to long-run cost for customers facing major investment decisions and long-term power supply decisions. Customers would decide for themselves into which category they fall on the basis of the service reliability level they require. Firm service would be priced at long-run cost, interruptible service would be priced at short-run cost, and customers would have the option of selecting either type of service.

Most wheeling customers seeking temporary economy energy would choose interruptible service. So might many customers that need replacement generation capacity for a few months during which they expect no congestion on the wheeler's transmission system; during times of wheeling capacity shortage, such customers would probably choose firm service. Most customers who require wheeling over several decades, perhaps as an alternative to constructing their own generating facilities, would almost certainly choose firm service. Customers needing wheeling service of intermediate firmness and duration would choose between these two types of service on the basis of their own self-interest.

Interruptible wheeling customers curtail their own service as they decide not to pay the temporarily high congestion charge. A customer who subscribes to interruptible service and pays the short-run cost at all times would not actually be interrupted. Over time, such a customer would pay about the same as firm service subscribers, since the time-average of short-run costs would be about equal to long-run cost if the system is expanded optimally. Interruptible customers who allow themselves to be interrupted at peak times avoid paying the high peak price. They pay a lower average price and receive a lower quality of service. Under optimal system expansion, wheeling capacity would not be constructed ahead of time to avoid interrupting service to those who pay short-run costs. If the congestion charge component of the short-run price frequently rises above the level of long-run capacity cost, new construction then is appropriate. On the other hand, capacity must be planned and constructed to meet the needs of firm wheeling customers for uninterrupted service.

Sharing the Gains

Several issues stand in the way of implementing this pricing policy. All relate to how the gains from trade are shared. One issue is whether to have a regulatory revenue requirement for wheeling service, which would alter wheeling prices so that wheeling revenues equal some portion of the undepreciated booked costs of the transmission system plus average line losses. Clearly, such a requirement constrains good decision-making. At today's costs, it requires utilities to wheel at a price below long-run cost, which not only creates inappropriately low price signals to wheeling customers, but also yields a negative share of the economic gains to the wheeler. The case for applying a revenue requirement to power transfers among companies may be weaker than the case for having such a requirement for retail service within a franchised service area. It may be desirable to phase-out the wheeling service revenue requirement over time. Just as correct wheeling prices encourage good investment decisions by wheeling customers, correct wheeling profits encourage good investment decisions by wheelers. The normal profits that accompany marginal cost pricing motivate the wheeler to expand wheeling capacity. These profits should be distinguished from the monopoly profits that are created when a wheeler intentionally restricts capacity.

There are other power transfer policies that give a positive share of the gains from trade to the companies transmitting power, while still equating marginal costs across the grid. One is for the transmitting company to buy the power and resell it, thus capturing a share of the gains both as a buyer and a seller. This practice, an alternative to wheeling, is commonly used in the industry today for economy energy transfers. It is, of course, preferred by the transmitting utilities to wheeling at prices constrained by a revenue requirement. Utilities would be more encouraged to wheel if the wheeling price could be set in a pricing formula as some fraction of the difference between the buyer's and seller's electricity production costs. Some wheeling arrangements for economy interchange are priced at 10 to 15 percent of the fuel cost savings, for example. In practice, both of these policies, buy-sell and formula pricing, can ultimately equalize costs. To do so requires either multiple transactions or that prices be continually adjusted to reflect the changing production costs of the ultimate seller and buyer. The transaction costs of either activity could deter a buyer-seller pair from equalizing marginal costs. If so, these approaches would not promote good decision-making quite as effectively as wheeling at cost-based prices. But they may be useful for equalizing marginal costs in some industry environments.

Wheelers would receive the largest share of the gains from trade if they could auction transmission capacity to the highest bidder and keep the proceeds. Pricing by auction helps to equalize marginal costs, and recent industry proposals and regulatory experiments suggest that auctions may be an acceptable policy option. Of all the policies examined, this one would require the most regulatory oversight to limit monopoly profits.

Flexible pricing, familiar in the natural gas area, could be a useful regulatory tool for pricing wheeling service also. Wheeling prices would be flexible in a range above and below long-run incremental wheeling cost. As price exceeds long-run cost, regulators could gauge the need for new transmission facilities. Wheeling utilities would receive some share of the gains from trade, and long-run bulk power supply costs would be largely equalized. Cost equalization is also encouraged by regional power pools and power brokers that facilitate trading. Trading is promoted in such arrangements by reciprocal agreements that members wheel for one another at cost. Depending on pool rules, either long-run or short-run costs may be equalized; brokers tend to equalize short-run costs.

Policy makers have a choice of pricing policies that can equalize marginal bulk power supply costs, though some may be more effective than others. The choice depends in part on society's wishes about who should benefit from new power trading opportunities, as expressed in the institutional setting of laws and regulations. Making policy to eliminate regional cost differences is complicated by rules regarding preferential access to subsidized power sources, cogeneration power supply, loss of requirements customer loads and possibly industrial customer loads, along with the related issues of stranded investment and residual service obligations. These issues are treated in more depth in a follow-on NRRI report on non-technical impediments to power transfers. They are mentioned here because appropriate pricing policy for wheeling interacts with these broader policy concerns about the nation's bulk power supply networks. The approach in this study is to determine wheeling prices that encourage good decisions about network use and expansion. These prices would be offered indiscriminately to those whom policy makers allow to have access to wheeling services.

Practical Pricing Measures

Regardless of the wheeling pricing policy, some practical aspects of determining costs and designing rates must be considered. Especially because of loop flows, the calculation of cost-based wheeling prices is complicated and almost certainly requires computerized load flow models. Techniques and models are available to determine these parallel flows and line losses, but are more familiar perhaps to large utilities and the regional reliability councils than to smaller companies and regulatory agencies.

Responsive pricing is the best, but most complicated, way of implementing a pricing system based on short-run costs. To determine the congestion charge component of the short-run cost with responsive pricing, an observer (or computer) monitors the transmission system and posts a price reflecting the cost of the current system congestion. (An experiment to test the feasibility of responsive pricing is underway in the state of New York.) In lieu of responsive pricing, an auction of wheeling capacity would yield a price that contains the correct congestion component. If a congestion charge is not feasible (perhaps because it is not allowed by regulatory statutes), the long-run incremental capacity cost of transmission facilities would be a useful approximation.

The incremental capacity cost is the cost of expanding wheeling capacity by some increment divided by the size of the increment. The U.S. Department of Energy's Energy Information Administration is developing a national data base on transmission line costs and transfer capabilities, which will be very useful for calculating capacity costs. Long-run cost is proportional to the length of a transmission line, suggesting that firm service prices ought to have a distance dimension such as dollars per megawatt-mile.

Apart from responsive pricing or frequent auctions, rates or tariffs must be set ahead of time. Such pre-set prices must reflect the costs expected during the period the rates are to be in effect. A time-of-use rate design, and also a rate design with separate energy and demand components, would result in prices that reflect costs more accurately. These features of rate design are familiar from retail ratemaking.

As mentioned, where loop flows are involved in wheeling, the total cost of wheeling is the sum of the costs over all paths. Similarly, the total charge for wheeling would be the sum of the charges for all loops. The unit cost of wheeling, stated on the basis of dollars per megawatt-hour, is the weighted average of the unit costs on all loops, where the weights are the fractions of the total power wheeled that flows along each path. Using weighted averages permits one to calculate a single value for the cost of wheeling through a utility in terms of the costs along its many transmission lines. The cost of wheeling through a large region, it follows, is the weighted average of the costs for each of the utilities in that region.

Wheeling Policy

Pricing policy for the wheeling of electricity is best viewed within the context of how to use and expand optimally the nation's bulk power supply systems. An institutional difficulty is that pricing policy is largely under federal control while system expansion policy is under state control. This suggests that more federal-state cooperation is advisable, perhaps through a joint board of federal and state regulators, to fashion a coherent wheeling policy.

Wheeling is one of several kinds of interutility transactions that can reduce the aggregate cost of delivering electricity to widely dispersed customers. Toward this end, all such transactions, including wheeling, should be priced so as to promote the equalization of both short-run and long-run marginal costs across the grid because, in such a condition, aggregate total supply costs are minimized. Such an equalization requires prices that are not distorted by embedded-cost revenue requirements, preference power allocations, cogeneration pricing rules, or arrangements that ignore loop flows through unaffiliated transmission systems. Prices based on incremental costs accomplish the equalization. Important implementation issues remain, but should not obscure the basic point that, in order to promote marginal electricity cost equalization across the grid and thereby supply the nation's electricity at least cost, the movement of power must itself be priced at marginal cost.

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

PART III
WHEELING PRICES

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF FIGURES (continued)

LIST OF FIGURES (continued)

LIST OF TABLES

LIST OF TABLES (continued)

FOREWORD

The answer to the question of how rates are set for wheeling electric power is an empirical one and, while perhaps not routine in determination, is at least discoverable. A much tougher question is the subject of this study and that is, What does economic theory say is the best way to price wheeled power? This, therefore, was a multi-year study begun in the fall of 1985. Several avenues of inquiry were pursued with varying degrees of fruitfulness. The way was largely uncharted, and throughout there was a premium on original work. The resulting report is intended to be a notable contribution to consideration of this important regulatory issue.

Douglas N. Jones
Director
Columbus, Ohio
July 17, 1987

ACKNOWLEDGEMENTS

The authors wish to thank especially Stephen Sebo, Professor of Electrical Engineering at The Ohio State University, for carefully and critically reviewing the technical portions of this report. He suggested numerous improvements and offered much helpful advice. Any technical deficiencies that may remain, however, are those of the authors.

The report also benefited from the many comments of those who volunteered to read a draft of the report completed in May 1987: Kedron Hendrick and Charles Falcone of the American Electric Power Service Corporation, Daniel Lewis, Lawrence Bruneel, and Lawrence Hobart of the American Public Power Association, John Casazza of Casazza, Schultz & Associates, John Procario of the Cincinnati Gas and Electric Company, Mario Villar of the Florida Power and Light Company, Sara Brumbaugh of the Florida Public Service Commission, Lockie MacGregor of the Michigan Public Service Commission, Narayan Rau of the National Energy Board (Canada), Peter Blair of the Office of Technology Assessment, Ross Pultz of the Ohio Office of the Consumers' Counsel, Ron Handlin of the Pacific Power & Light Company, Vikram Budhraja of the Southern California Edison Company, George Mentrup and Francis Davis of the Texas Public Utility Commission, Jerry Mendl of the Wisconsin Public Service Commission, and Dennis Ray of the Wisconsin Public Utility Institute. We appreciate their many helpful suggestions and incorporated most in the report. Unfortunately, space constraints prevented us from elaborating on all the topics suggested to us. Understandably, most commenters did not have time to read the entire report; our acknowledgement of their help implies neither that they overlooked its remaining flaws nor that they agree with its policy conclusions.

Jeffrey Shih, formerly with NRRI and now with Battelle Memorial Institute, provided invaluable assistance in the early stages of this study. The authors would also like to thank Mr. Colin Wright of the North American Electric Reliability Council and Mr. Eric Engdahl of the American Electric Power Service Corporation for providing some of the information in appendix D. We also gratefully acknowledge the help of the many state regulatory commission staff members who supplied data on the costs of new transmission lines. During the course of the study, several secretaries worked diligently to make this report ready for publication; the main contributors were Patricia Brower, Karen Flesch, Kay Nixon, Karen Myers, and Wendy Windle. We are very grateful for their fine work.

CHAPTER 1

INTRODUCTION

Today it is a commonly held belief that electric utilities are not trading in electric power to the full extent that is technically feasible. Among the difficulties cited are the unwillingness of low-cost producers of electricity to sell at a price attractive to the buyer and the unwillingness of high-cost producers to buy low-cost power from other systems because this would result in additional unused native generating capacity. Besides these difficulties, a major difficulty frequently cited for lack of trading is that buyers and sellers are usually not directly interconnected but must rely on one or more intervening utilities to transmit, or "wheel," the power between buyer and seller.

These intervening utilities are often reluctant to wheel. Numerous reasons for such reluctance are advanced, including the following. The intervening utilities' transmission systems were designed to move power from native generators to native loads, not primarily to move power across their systems. Such movement may require additional costly equipment to correct for the effects of wheeling power. Wheeling can reduce the reliability of the wheeling system by using up transmission capacity available for emergency needs. In some cases, sustained wheeling may require the construction of additional transmission capacity in the wheeling utilities' systems. Reluctance to wheel is also a reflection of a reluctance to impose secondary effects on the wheeling utilities' neighboring systems, as all interconnected utilities are affected to some degree by the movement of electric power through the grid. Further, a utility that wants to sell its own excess power may be reluctant to wheel the power of a lower cost competitive seller. Also, a utility may be reluctant to wheel low-cost power to another buyer when that utility would prefer to buy the power itself.

Utilities that do wheel often want to charge a seemingly high price for the wheeling service. This may be either to cover the full costs imposed by wheeling or to gather a large share of the profits available because of the cost differential between buyer and seller. The result of a high wheeling charge, however, is to remove much of the incentive for buyer and seller to engage in a wholesale transaction at all.

If it is indeed the case that more trading of electric power among electric utility companies is technically feasible, such technically feasible trades will occur only if the buyer's avoided cost of power is greater than the selling price plus the wheeling price. That is, the technically feasible trade must also be economically feasible. Usually the buyer's avoided cost is fairly easy to determine, and the selling price is set by the Federal Energy Regulatory Commission (FERC). While the FERC claims the authority to set rates for wheeling, in practice prices often result from negotiations among the parties. The result is wheeling prices that are not likely to be established according to any one pricing principle, and these prices are not likely to result in the economically optimum level of power trades.

Purpose of the Report

State utility commissioners, in particular the members of the NARUC Committee on Electricity, are interested in the basic principles that ought to apply to the pricing of wheeling service. Prices can be based on a variety of principles, depending on one's view of the goals of pricing, such as fairness, encouraging conservation, promoting power transfers, opening or restricting access to subsidized generation, and so on. The primary purpose of this report is to set out methods for setting wheeling prices so as to encourage good decision-making by wheelers, buyers, and sellers of wholesale electric power. That is, prices should be at such a level that all power trades occur for which the benefits to all parties exceed the costs to all parties, and no trades occur for which this is not true.

The pricing practices that result from the application of this principle depend on the environment. While benefits in the aggregate may exceed costs in the aggregate for all parties, the distribution of benefits and costs among the parties depends on laws, regulations, agreements, and conventions. Different pricing rules result from application of the good decision-making principle in different environments. It is not possible to develop pricing rules for all conceivable circumstances, so this report deals with two distinct cases: one in which the appropriate regulatory agency has full authority to order wheeling and so to set cost-based wheeling rates, and another in which that agency can set rates but has no authority to order a utility to wheel power.

Useful application of a good pricing priciple can be made only with some understanding of transmission systems, and a secondary purpose of this report is to help develop some such understanding. Most published materials on transmission technology are either complex mathematical treatments intended for practicing engineers or overly simplified representations of the technology intended for the general public, which do not provide enough detailed information to form the basis for pricing policy discussions. What is needed is an intermediate level treatment directed toward intellegent professionals, often without engineering training, who must make judgements about these complex technical matters. This report is intended to meet this need. While it omits many topics important to power engineers, it attempts to present most of the technical information needed for a wheeling policy discussion in simple language and in a coherent manner.

Organization of the Report

The intent is to develop some economic concepts about how wheeling service ought to be priced. The approach is first to present information about existing transmission systems sufficient to develop a basic understanding of the engineering aspects of a typical system. This is the subject of part I. It covers the components of the transmission network and the technical requirements for interconnecting companies and wheeling power between interconnected companies. Part I also contains a discussion of the technical limits to wheeling and the steps for removing these limits. Some knowledge of the technology of wheeling and of wheeling limits is necessary for understanding the costs borne by the wheeler in providing service.

Part II examines these costs. Wheeling costs include the costs of certain actions for balancing generation and loads, possibly new equipment costs for system control, and metering and billing costs. The amount of power lost along the wheeler's transmission lines may increase. There may also be costs imposed by the wheeler's reduced opportunity to use the transmission system for its own power trading. These costs relate to the use of existing transmission capacity. Additional costs would be incurred, of course, if existing transmission capacity must be expanded to accommodate long-term wheeling while maintaining a constant standard of reliability. Understanding wheeling costs is a prerequisite for a discussion of wheeling rates.

Wheeling ratemaking is taken up in part III. If prices are to be based on costs (instead of, say, the value of the wheeling service), cost-based pricing must be enforced either by a competitive market or a regulatory agency. A competitive market would force prices to the level of marginal costs. A regulatory agency may set prices on the basis of either marginal or embedded costs. Where good decision-making is the objective of pricing, some sort of marginal cost pricing rule is expected to be superior. Part III develops the concept of marginal cost equalization across the grid as a test of the appropriateness of various pricing methods. A commission can prescribe cost-based prices only if utilities agree to wheel or are required to wheel. A pricing mechanism based on the value of service could be useful for encouraging power exchanges in cases where authority to order wheeling is absent. The resulting wheeling price would depend on the value of the wheeling transaction. The transaction's value (to the three parties, excluding any costs and benefits to others) is the buyer's avoided cost less the seller's and wheelers' costs less allowance for the cost of transmission. Part III also considers several non-cost-related influences on wheeling prices, such as allowing wheeling utilities to charge a price above marginal cost so as to provide a positive incentive both to wheel and to plan expansion of transmission capacity for the future wheeling needs of the region.

The report concludes with a discussion of various issues that surround the wheeling pricing policy question. It also contains six appendices intended to provide background information. A glossary of terms used in the power industry that relate to wheeling is contained in appendix A; other appendices contain a primer on basic electric circuitry, a discussion of the evolution of transmission systems, a description of the current situation with regard to bulk power transfers, a discussion of certain cost statistics, and discussion of what is known about how wheeling prices are set at present.

PART I

WHEELING TECHNOLOGY

CHAPTER 2

WHEELING FACILITIES AND OPERATIONS

Power is said to be wheeled when one or more utilities allow their transmission lines to be used to transport electric energy from a selling utility to a buying utility. This chapter is intended to provide a policy analyst with an understanding of the electric power transmission facilities in the existing U.S. electric system, with emphasis on how these facilities are operated to wheel electric power, and thus it serves to introduce the discussion of operating costs in part II. It also leads into chapter 3, which covers the major technical limitations to wheeling capability and how these can be overcome; this in turn introduces the part II discussion of capital costs.

The level of understanding to be developed here is that sufficient to allow the analyst to read and comprehend later chapters on the costs and pricing of wheeling service. Of course, this falls far short of training the reader as an electrical engineer, and no mathematical description of power flows is given. However, chapters 2 and 3 together go well beyond the simple representation of the transmission system as a wire connecting generator and load.

For the reader unfamiliar with electrical engineering concepts and terms, it would be best to start with appendices B and C, then read the chapters straight through because concepts and terms introduced in early sections are used and developed in later sections. Necessary basic concepts about electric circuits are introduced in appendix B. These include terminology and units, and also include an introduction to the concepts of reactance and reactive power. Appendix C contains a brief review of transmission history, which serves both to develop a sense of how systems have grown and to introduce some of the electric power transmission terminology used in discussions of wheeling.

A Transmission System Model

Because wheeling takes place over existing transmission systems, wheeling discussions inevitably become discussions of transmission systems. Further, pricing the wheeling service on the basis of costs requires an understanding of transmission costs, for which an understanding of the components of a transmission system is essential.

An electric utility can be idealized, as shown in figure 2-1, as made up of a generating unit, two substations, a transmission line, and a distribution system. The generating unit is usually a steam-driven or water-driven electric generator, which converts the energy of motion into electrical energy. The voltage of the generator output is usually in the range of 13 to 26 kV. The substation near the generator raises the generator voltage to the high level needed to send power without undue losses over the transmission line to the distribution system. At the interface between the line and the distribution system, another substation reduces the voltage to a level appropriate for distribution.

A slightly less idealistic model of an electric utility is shown in figure 2-2. A utility typically has more than one generating unit at a single location, or generating station, and has more than one generating station in its system. At each station the generating units are connected to a high voltage transmission line by means of a substation.

With modern generator design, it is efficient and economical to create three-phase electric power with the generator. Transmission lines then require three conductors to carry the three phases from the generator, and a fourth conductor may be required for the combined return flow to the generator. The three return flows of each phase tend to cancel one another out, resulting in little or no net return current in the fourth line. In fact, the main reason that use of three phases is economical is that the fourth conductor can often be dispensed with: the earth itself provides the fourth electrical pathway if one is required. Hence in figure 2-2 each interconnection between components of the system is illustrated with three conductors, indicating that three-phase supply of electrical power occurs.

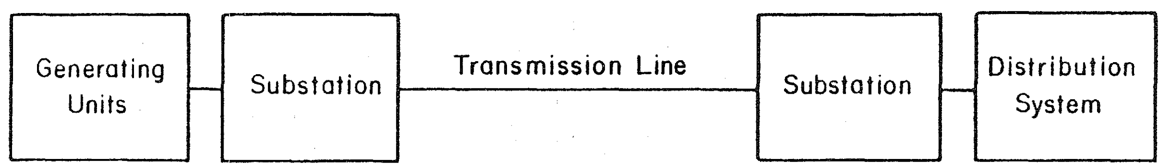


Fig. 2-1 An idealized model of an electric utility

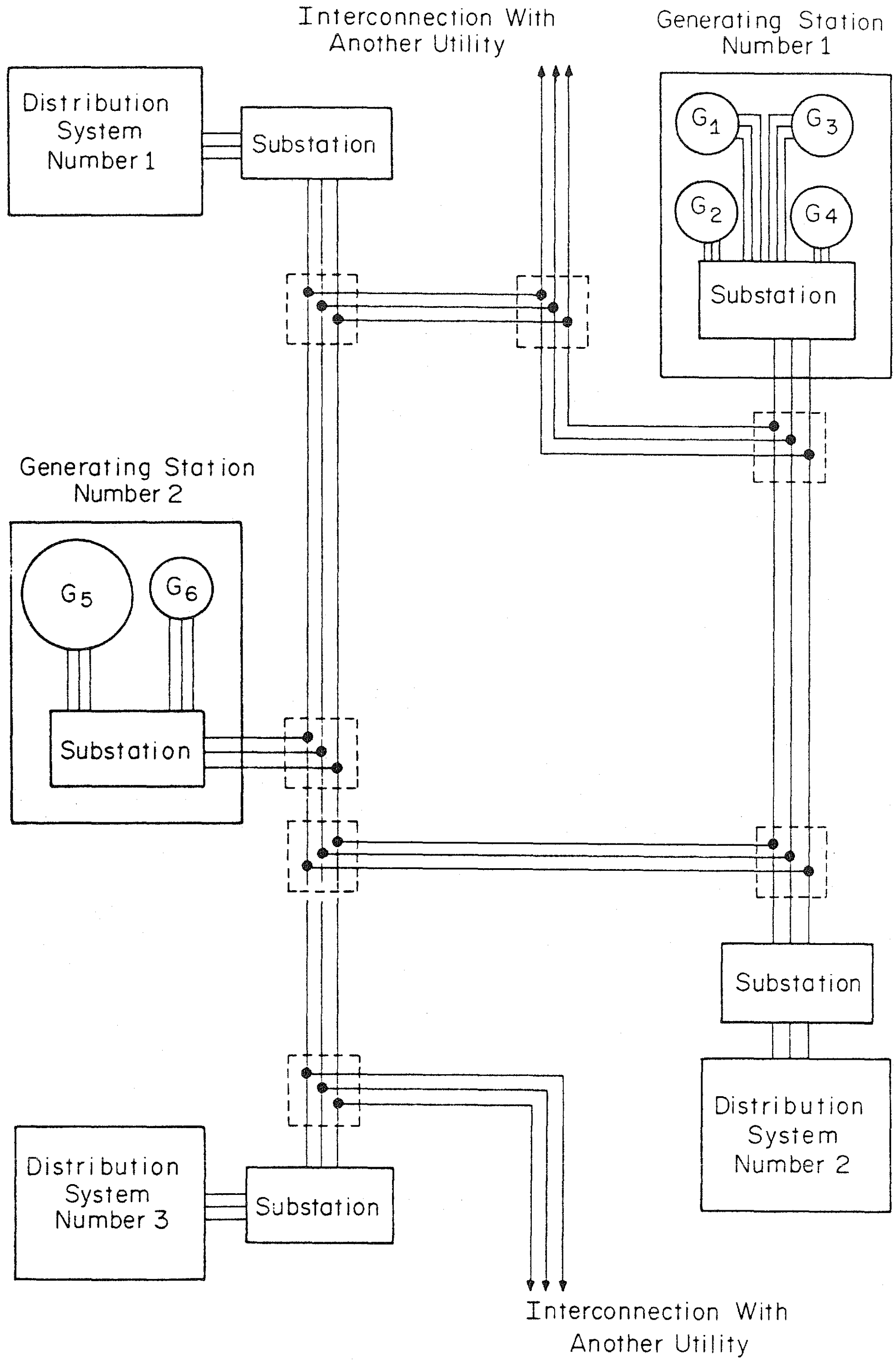


Fig. 2-2 A more realistic model of an electric utility, showing a transmission system with three-phase power

A utility usually has many local distribution systems; three are shown in figure 2-2. A distribution system typically serves a population or industrial center and consists of lower voltage power lines for moving smaller amounts of electricity intermediate distances and still lower voltage distribution lines for moving power short distances.

There is no sharp distinction between transmission and distribution voltages. Primary distribution voltage is typically 12 to 14 kV or, more recently, 25 to 35 kV, while secondary distribution lines run from the primary system onto the small customer's premises at voltages below 0.5 kV (500 volts). Lines of 230 kV and above are always called transmission lines. In many cases, however, as utilities grew and the amounts, voltages, and distances of power flows increased, yesterday's transmission lines became part of today's distribution system. As a result, lines in the voltage range of 69 kV to 161 kV may be classified as part of the transmission system by one company and part of the subtransmission (or even distribution) system by another. The term "subtransmission" can refer to different voltage ranges in different companies.

A transformer is always required to connect lines of different voltages (see appendix C). It may be a stand-alone transformer or a transformer that is part of a substation.

Figure 2-2 illustrates the concept of networking in a simple way. It would be possible to have generating station number 1 serve only, say, distribution system number 2, and to have generating station 2 serve only distribution systems 1 and 3. This would be the case if the transmission lines represented horizontally in the figure did not exist. But these horizontal lines make the system more reliable in that one generating station can serve to back up another. Then, a smaller system generating reserve capacity can provide the same reliability level as the two isolated stations each with more reserves. Further, there is not simply one large transmission line linking the left and right hand sides of the figure, but two. The second line makes the transmission system a "network" in that, if any major transmission line is out of service, each distribution system is still connected to both generating stations along some network path.

Also shown in figure 2-2 are interconnections with two other utilities. These interconnections may be available primarily to enhance reliability, so that the utility pictured can obtain power from a neighbor if one of its major generating units goes down. However, the two other utilities may want to exchange power by having the pictured utility wheel the power across its system. Whether it does wheel depends, at least in part, on the effects on service to its own distribution systems.

A still more realistic model of a large utility than that shown in figure 2-2 would include transmission lines at various voltage levels (345 kV and 500 kV, perhaps 765 kV) interconnected at substations, along with the subtransmission system, its various voltages, and the required transformers. The figure would then depict a more elaborate and reliable interconnected network. But figure 2-2 is an adequate model for our purposes. Let us look more closely at the lines and substations shown in the figure.

Overhead Transmission Lines

Transmission lines may be overhead, underground, or underwater. Overhead lines are used wherever possible because of the high cost of transmission by the other two means.

The principal components of an overhead transmission line are the right-of-way, that is, the land along which the line is located; supporting structures (poles or towers) for supporting the conductors aloft; the conductors themselves, which carry electricity; insulators, which are in direct contact with the conductors, supporting them while preventing electricity from flowing through the main supporting structures into the ground; and shield wires, conductors that are strung above the power conductors to shield them from lightning. These components are illustrated in figure 2-3 for a simple AC line. Each of these components contributes significantly to transmission line cost, and each is described briefly as follows.

Right-of-Way

The right-of-way is the land along which the transmission line is located. It may be owned or leased by the company. Typically, the right-of-way route is chosen on the basis of minimum cost, modified by such factors as the line voltage, real estate values, environmental/ecological constraints and effects, aesthetics, socioeconomic considerations, the

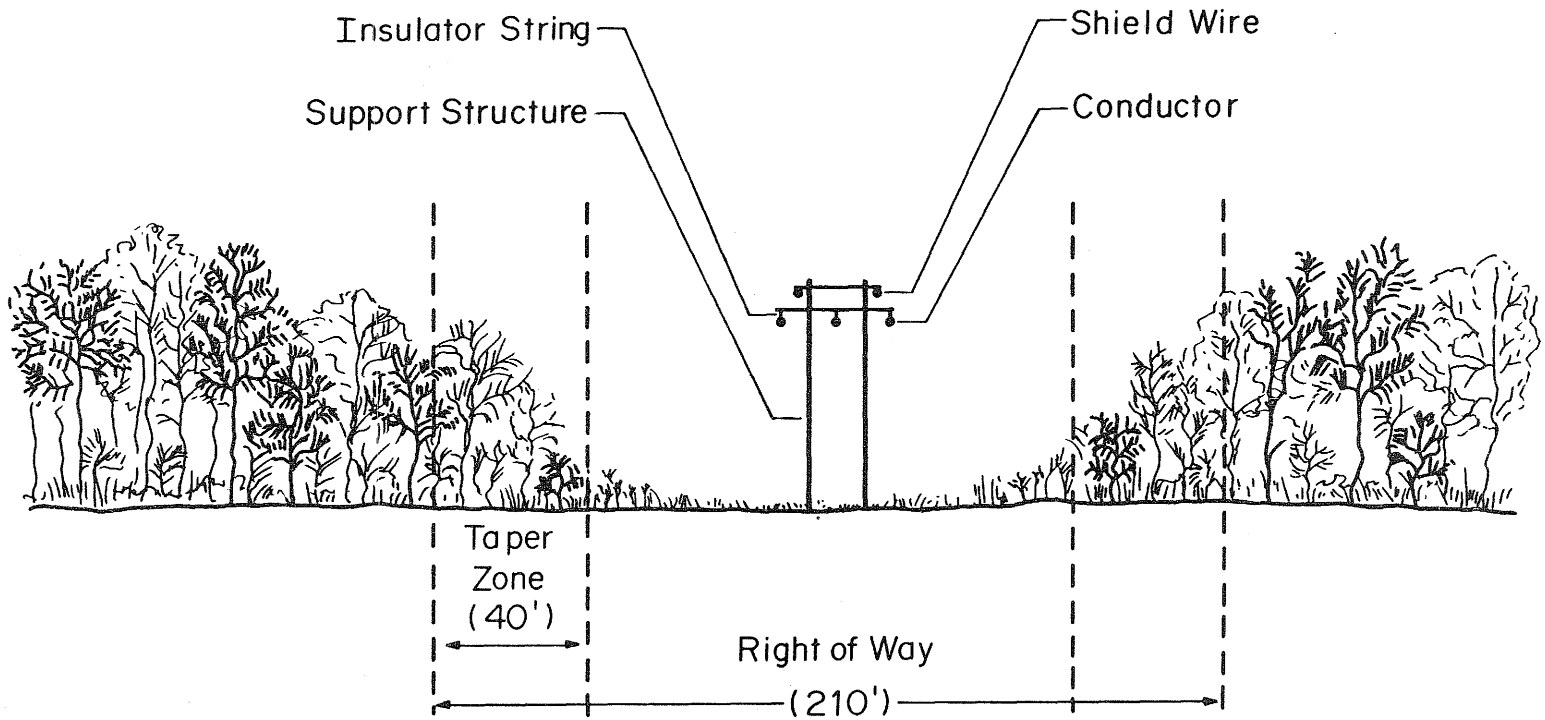


Fig. 2-3 Cross-sectional view of a simple 138-kV AC transmission line and right of way, illustrating the principal components

location of political units and bodies of water, the ruggedness of the terrain, and the character of the land. Choice of route may also be influenced by plans for future generating stations, substations, and new lines. The right-of-way must be kept clear of trees, tall bushes, or any other objects that could form an electrical pathway between the conductor and the ground. It is not necessary for such objects to touch the conductor to cause a problem. Any object touching the ground and coming within a few feet of the line may act as a kind of lightning rod with respect to high-voltage conductors. The right-of-way in figure 2-3 is 210 feet wide with a 40-foot zone on either side for selective thinning of trees and brush to achieve a taper.

Supporting Structures

Wooden and prestressed concrete poles are commonly used to suspend transmission line conductors, especially for lower voltages. For higher voltage transmission, steel towers are now common, and aluminum towers are sometimes used to reduce weight and hence construction costs. The design of towers varies depending on the number and arrangement of conductors, the terrain, the tower material, and the forces that the tower must withstand. The distance between towers is also affected by these factors. Important forces are the weight of the conductors themselves and of any ice that may build up on them, as well as the force of wind.

Conductors

Overhead conductors are bare metal cables that conduct electricity. A typical conductor consists of dozens of strands of aluminum wire wrapped around a steel core. Aluminum conducts electricity well and is much cheaper than copper. The steel core provides strength and the aluminum is of relatively light weight.

At least three conductors are needed for AC transmission to accommodate a three-phase supply. Moreover, to alleviate the corona problem (appendix C) at voltages above 230 kV, each phase may be carried by two, three, or even four conductors of equal size, supported near one another at the end of a string of insulators. These smaller "bundled conductors" take the place of each single large conductor carrying three-phase power. Because they form part of the same electrical pathway, that is, they act as one big conductor, no insulation is needed to separate electrically the individual conductors in any one bundle. A simple line carrying only one three-phase circuit, with or without bundled conductors, is called a single-circuit line.

When increased transmission capacity is needed between two locations, economies can often be achieved by using a single (presumably wider) right-of-way for two separate transmission lines. However, if the supporting structures are designed to handle it, further economies can be achieved by stringing the new line as a second set of conductors on a single set of poles or towers. Such a composite system is called a double-circuit transmission line. It requires at least six conductors to carry power in two separate AC circuits, each with three-phase supply. As in the case of single-circuit lines, more conductors are needed above 230 kV because each of the six electrical pathways is made up of bundled conductors to avoid corona problems. A drawback of double-circuit lines is lower system reliability; one accident can affect two circuits.

Figure 2-4 illustrates three of the many possible variations in tower and pole design and conductor configuration.

Insulators

Without electrical insulation, power would flow from the conductors directly through the metal towers into the ground. A problem with most candidate insulating materials is that they are not strong enough to withstand the weight of the conductor without breaking, especially when these are laden with ice and whipped around by strong winds. One of the best trade-offs in insulating ability and strength has been found to be a chain (or "string") of specially shaped, interconnected porcelain pieces, called suspension insulators. The length of the string depends on several factors, including the voltage of the line and the magnitude and frequency of any expected voltage surges on the line. A significant fraction of the new insulation installed is made of nonceramic materials, mostly fiberglass.

The conductors may be supported by a vertical string of insulators, as

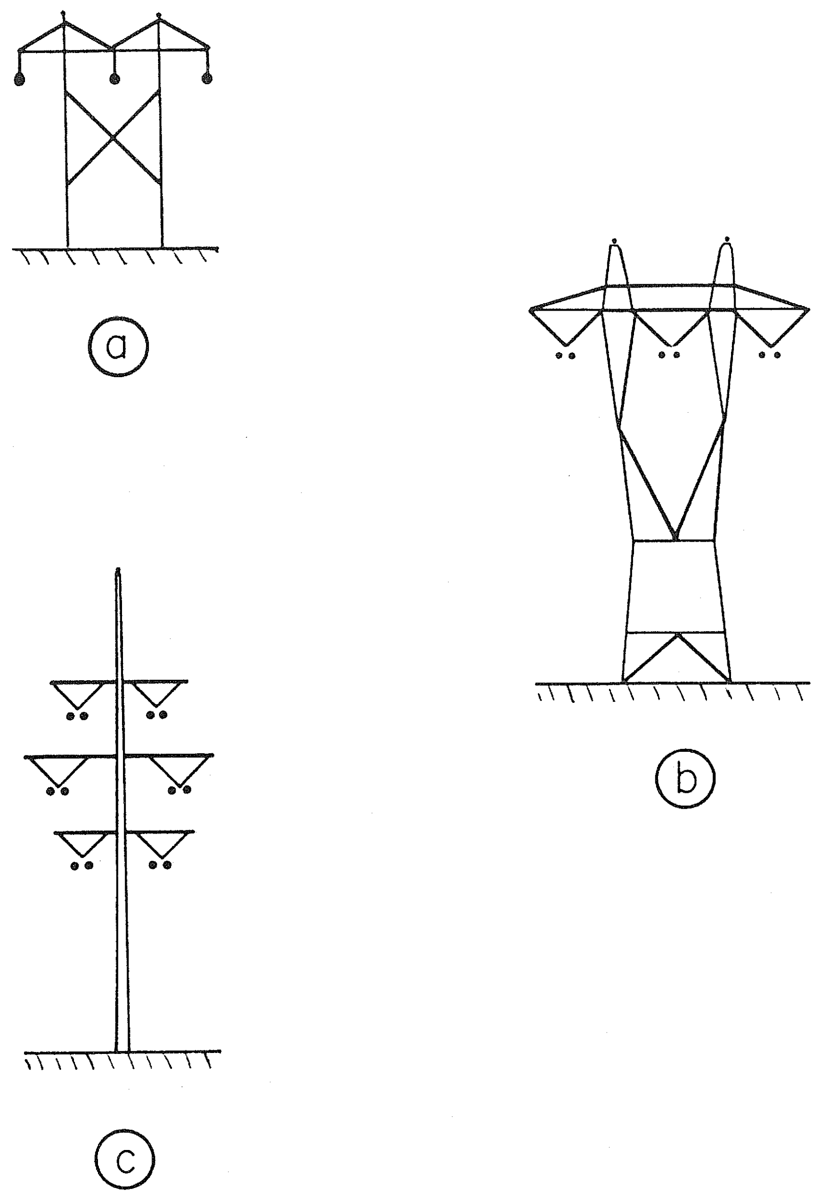


Fig. 2-4 Three typical AC transmission line configurations: (a) an H-frame-type structure, single circuit line with two shield wires; (b) a 500-kV lattice-type structure, single circuit line with two shield wires and with bundled conductors (2 per phase), each supported by a pair of (diagonally mounted) insulator strings; (c) a 345-kV pole-type structure, double circuit line with one shield wire and with bundled conductors (2 per phase), each supported by a pair of insulator strings. Source: adapted from Electric Power Research Institute, Transmission Line Reference Book: 345 kV and Above, 2d ed. (Palo Alto, California: EPRI, 1982)

in figure 2-4(a), or by two strings in a V-shaped arrangement, as in figure 2-4(b) and (c).

Shield Wires

Lightning is a frequent threat to reliable transmission line operation. Lightning may strike any of the high voltage conductors sending potentially damaging voltage and current surges through the transmission line. Most such lightning strokes can be avoided by suspending one or two conductors, grounded at each tower, above the three phase conductors. Called shield wires or ground wires, they absorb the lightning stroke in most cases, if the wires are properly located. The shield wire conducts the electrical discharge to the nearest tower and down the tower into the ground, leaving the phase conductors unaffected.

The design of DC lines is similar, except that only two conductors (or bundles of conductors) are required. One is needed for outward flow (often called positive pole) from the generator and a second for return flow (negative pole).

Substations

Transmission lines originate and terminate at substations. Transmission lines often begin at substations located at generating stations. They also end at substations--often about half the size of a football field--that are the familiar fenced-in areas at the outskirts of cities and towns. Both contain transformers, step-up transformers for increasing voltage at the generating stations and step-down transformers for decreasing voltage close to the loads. A substation can be the end of the transmission system and the beginning of the subtransmission or distribution system.

These power transformers can consist of three separate single-phase units, one for each phase of the three-phase power. Also, a single device called a three-phase transformer may be used. A great deal of heat is generated in the transformers, representing a not-insignificant loss of energy. As a result, the coils of wire making up the large transformer must be immersed in oil and cooled by means of banks of electric fans. Oil also serves as insulation, reducing transformer size. Power transformers often take the form of large box-like tanks covered with circular fans, topped by antenna-like insulators (so-called bushings) where the high voltage conductors from the line enter the tank.

On the customer side of each transformer, the substation has a voltage regulator intended to supply a constant voltage to the distribution system despite possible voltage variation along the transmission system. It consists of a series of discrete connections, called "taps," with slightly different voltage outputs, and an input voltage sensing device that automatically connects the input to the appropriate output tap so as to hold the output voltage constant. Frequently the transformer and voltage regulator are combined into a single device called a tap changing transformer.

Because substations interface transmission lines with other systems, they contain, besides transformers, a variety of equipment for protecting these other systems from faults along a transmission line. Also, the transmission system is protected from faults originating at the generating station or in the distribution system. Further, the transformers themselves need to be protected. As a result, protective equipment is installed on both sides of the power transformers at the substation. Such equipment is referred to as switchgear.

The substation equipment must protect the system against disturbances, such as those instances when lightning does hit a conductor of a transmission line, causing voltage and current surges to travel along the line. Lightning arresters divert the surge into the ground. Not all power surges are due to lightning, and the term surge arrester is also commonly used for these devices. For an exceptionally large surge, a fallen transmission line, or other large short circuit or fault in the system, it is necessary to disconnect the faulted portion of the system from the rest of the network. This is accomplished with a circuit breaker, a large switch that opens when too large a current flows through the equipment to be protected. Because it interrupts currents at high voltage, the circuit breaker must be able to quench the inevitable electrical arcing that occurs as the switch opens. It must operate quickly when directed to open by a device called a protective relay, which senses faults in the system. Advanced relays can determine whether a momentary disconnection is sufficient, in which case they can quickly order the circuit breakers to reconnect, or whether the system must be shut down until repair crews can repair the fault. Today, relays often contain microprocessors to monitor the system and decide whether to switch the circuit breakers on or off.

When a circuit breaker is open, one side is at a high voltage while the other side is not. It is often desirable to completely remove and protect the circuit breaker from the faulted system because, even though there is no current, the large voltage across the circuit breaker is still a hazard. Removal is accomplished by opening a simple mechanical "disconnect switch" on both sides of the circuit breaker. Disconnect switches are used to isolate circuit breakers, transformers, and other devices after current flow through the devices has been interrupted by the circuit breakers. Substation equipment is also protected by fuses and other current limiting devices.

Substations also contain bus works. A bus is a simple device (it can be thought of as a metal bar) that joins together several circuits into one common circuit. In figure 2-5, the bus bar at the generating station's substation integrates the output of the several generating units so that the integrated output can be stepped-up in voltage for transmission. For simplicity in the figure, the multiple conductors needed for three-phase supply are represented as a single line. At the primary substation, which supplies the primary distribution system (for simplicity, it is assumed that there is no subtransmission system), another bus takes the power that has been stepped-down in voltage and distributes it to several load centers. Figure 2-5 also shows typical positions of the transformers, circuit breakers, and disconnect switches.

Not shown in figure 2-5 are various other devices for running, monitoring, protecting, and controlling the substation and transmission line. These include devices for helping to maintain proper voltage on the line and instrument transformers for converting voltages and currents to the appropriate low levels for running the instruments in the substation, meters, signal lamps, and other indicating instruments. A major substation may be attended by one or more operators. If so, it has a control house with panel boards to inform the operators about system status and hand-operated switches under operator control for opening circuit breakers and disconnect switches.

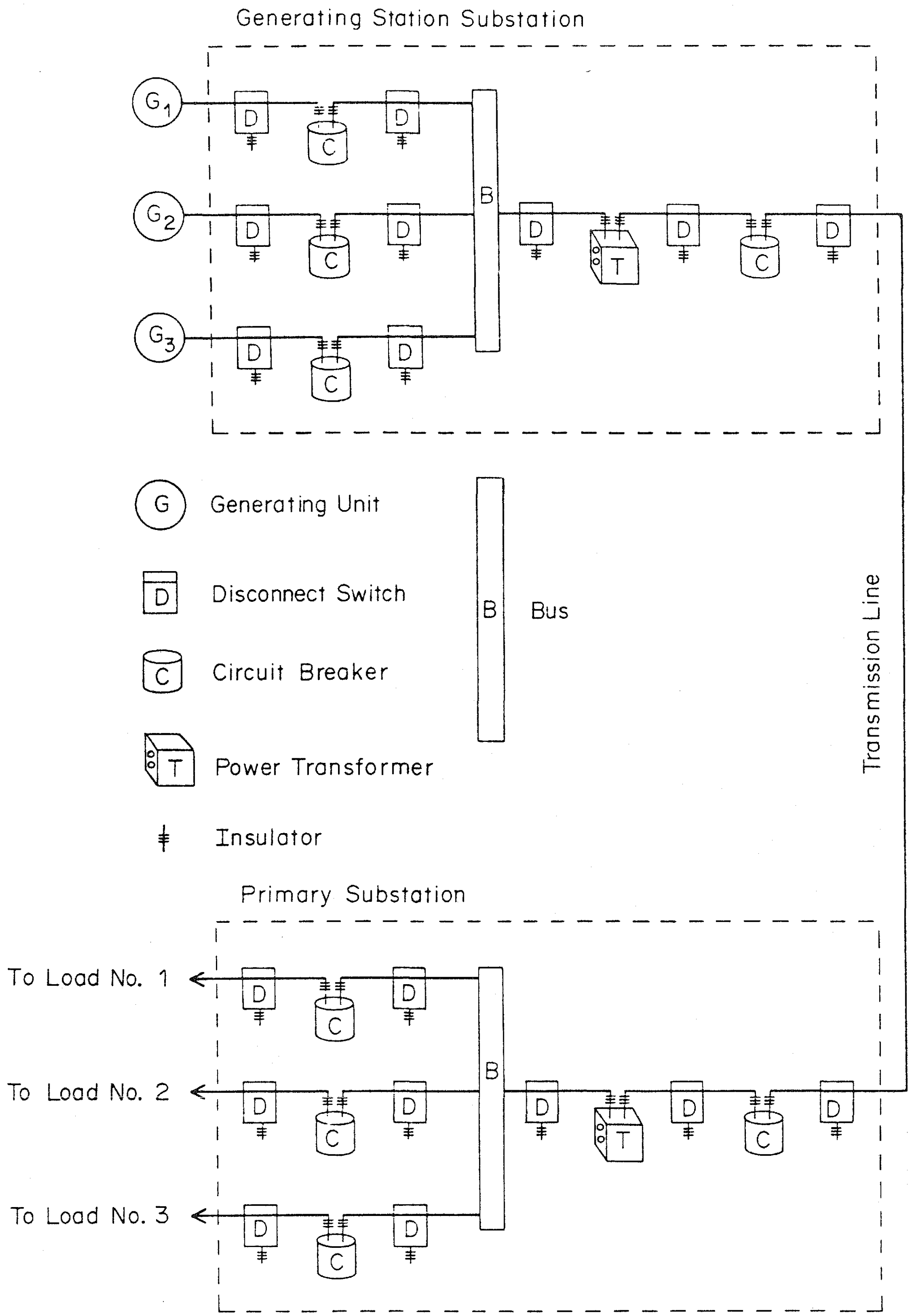


Fig. 2-5 Principal components of two substations

As we have seen, substations at the ends of a transmission line have transformers and switchgear. So too do substations along the line that feed power to local distribution systems. Other substations having only switchgear are usually installed along a long transmission line. These switching stations are used to shut down a portion of the line that contains a short circuit or other fault, without shutting down the whole line. By isolating the fault and cutting it out of the system temporarily, it is possible for power to reach most customers along alternate routes while a portion of the system is being repaired. In figure 2-2, the seven dotted-line boxes at the junctions of transmission lines represent switching stations.

A substation may be operated by remote control from a larger substation or from an operations control center. In modern systems, two-way microwave communication may link all generating stations, substations, and switching stations together under the control of a large digital computer, providing almost instantaneous diagnosis of system faults and appropriate actions.

Interconnections and Wheeling

The model in figure 2-2 shows a network of transmission lines connecting many generators and many loads. Such interconnections can link not only the components of one company's system, but can link together the generators and loads of several companies. The existence of these interconnections makes wheeling possible. Let us consider briefly some of the technical requirements for interconnections--both within a single company and among many companies. Then we can discuss the effects of interconnections on power transfer capability. This will provide some perspective on the ability of a company in an interconnected system to wheel power through its transmission network.

Interconnection Requirements

Consider the simple interconnected system in figure 2-6. For now, one may consider this figure as portraying a single utility with two generating units, G_1 and G_2, and two load centers, L_1 and L_2. A north-south AC transmission line links G_1 to L_1; another links G_2 to L_2, and an east-west

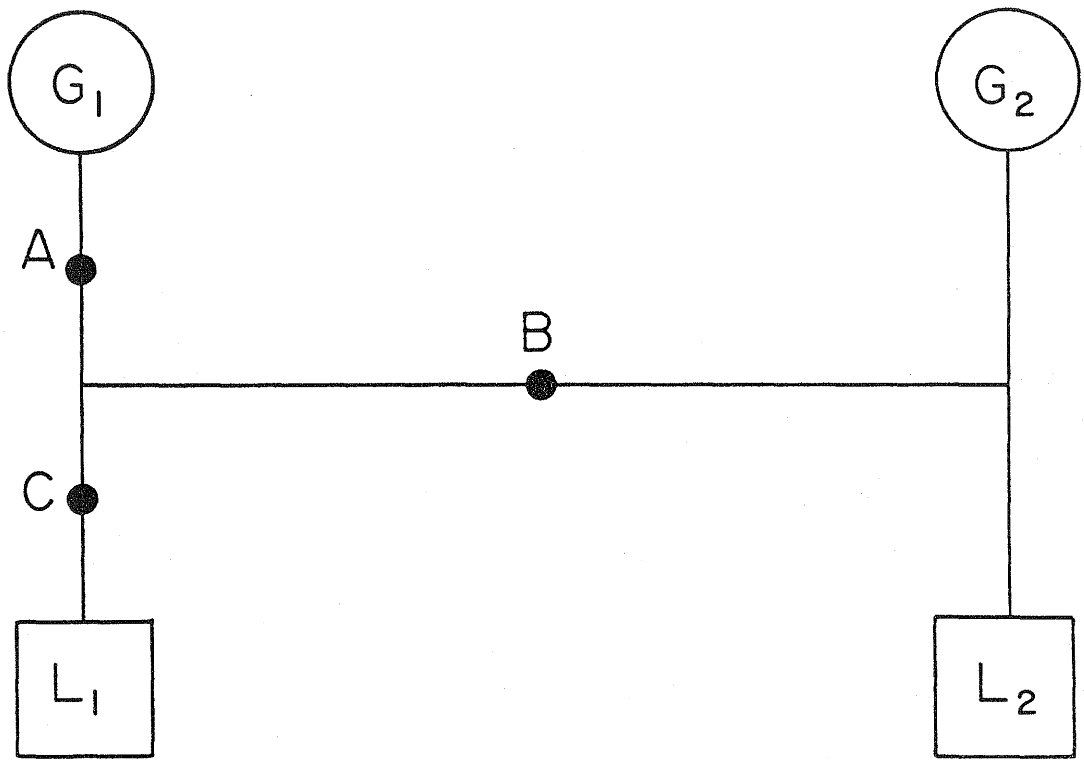


Fig. 2-6 A simple interconnected system with two generators G and two loads L

line links the first two as shown. For simplicity, each three-phase system with its several conductors and associated equipment is represented as a single straight line in the figure, and substations are assumed to be part of the generating station or load center. Interconnection among generating units and loads requires that system operators pay attention to unit synchronization, real power flows, and reactive power flows.

Synchronization

Both generators, G_1 and G_2, serve both loads, L_1 and L_2. Suppose for the moment that G_1 and G_2 each supply 100 megawatts (MW) of power, that L_1 consumes 200 MW, and that L_2 is shut down. If we ignore line losses (energy lost in transmission), power generation matches power consumption: 100 MW flows south past point A, 100 MW flows west past point B, and 200 MW flows south past point C. Recall (from appendix B) that AC power flow means that electrons at each point oscillate back and forth in time with the alternating voltage signals from the generators. In order for power to reach the load L_1, an electron at a point such as C must oscillate back and forth in time with both generators. This requires, of course, that both generators have the same output frequency of voltage and current oscillations so that each can contribute to electron oscillations of 60 cycles per second; if one generator tries to oscillate the electron at point C at 61 cycles per second and the other generator tries to oscillate it at, say, 59 cycles per second, clearly the electron could not do both. Further, the two generator signals must be synchronized so as to push in unison. If one generator pushes the electron at point C to the north while the other pushes it to the south, the two generators work against each other. If they are of equal strength and completely out of phase, no power gets transmitted to the load L_1. If they are partially out of phase, only a portion of the full power may be delivered.

Hence, synchronization of generators is an essential requirement for linking two or more generating units together with an AC transmission line. It requires coordination of both the frequency and the phase of the alternating voltage variations. A system that achieves this coordination and can maintain it despite sudden increases and decreases in load and despite possible loss of some generation or transmission facility is said to be stable. Maintaining stability is the principal engineering challenge facing interconnected utilities.

Synchronization is also necessary if two or more electric utilities are interconnected with AC transmission lines. Lines that connect two companies are often called tie lines. A group of companies interconnected with AC tie lines form a synchronous region. If the east-west transmission line in figure 2-6 were a DC line (which, of course, would not normally be economical for a single utility), it would not be necessary for the two generators to be synchronized. Instead, the inverter station, which converts the transmitted DC power back to AC, must produce an AC current synchronized with the oscillations of the network receiving the power.

U.S. utilities are interconnected in three synchronous regions with AC (and, in some cases, DC) links among regions. Some details of the U.S. systems and their links to Canadian systems are presented in appendix D. As networks grow larger, the difficulties of synchronization grow correspondingly large.[1]

Real Power Control

When generators are interconnected, whether within a single company or by AC tie lines between companies, system operators must pay attention to real power flows, that is, to the movements of power actually consumed by customers. Electric energy on an interconnected system of transmission lines flows from all generating sources to all consuming loads along all available lines, following the "path of least resistance." Without controls, the energy on the grid is like water on a lake: the lake is fed by various feed streams (generators) and drained by various outlet rivers (loads), and it is not normally possible to claim that certain streams supply only certain rivers.

In figure 2-6, suppose that G_1 and G_2 each supply 100 MW as before but now loads L_1 and L_2 each consume 100 MW. (Line losses are still ignored.) One could argue that both G_1 and G_2 supply power to L_1 and that both

[1] For a discussion of synchronization difficulties, see William C. Lindsey et al., "Network Synchronization," Proceedings of the IEEE 73 (October 1985):1445-1467.

generators also supply power to L_2. This is true in the sense that both generators contribute to voltage support on the transmission grid, and both are needed if the two loads are to be served. However, instruments at point B for measuring electrical current and power flow would show that, in this balanced situation, the east-west transmission line carries no power. Hence, it is possible to say that, in a real sense, G_1 supplies only L_1 and G_2 serves only L_2 in this case.

Consider, however, changes in load. When a single load is connected by a single transmission line to a single generator, the result of a load increase tends to act as a drag on the rotation of the generator; the generator's speed and hence its frequency tend to decrease. The generator has a governor that senses this slight frequency drop and supplies additional steam or other energy to maintain generator speed at the desired frequency. How is an increase in load met by interconnected generators?

In an interconnected utility, such as that in figure 2-6, the system's response to an increase in load L_2 depends on the equipment installed to handle load changes. An increase in load L_2 tends to reduce the frequency of both generators, G_1 and G_2. In the earliest interconnected systems of generators, the generator with the governor most sensitive to frequency changes (that is, with the smallest "deadband") would respond to the load increase. Then, equipment was installed that shared the load increase among all the on-line generating units of a utility. Later, governor sensitivities could be adjusted to take into account the need for economic dispatch so that the more economical the generating unit, the greater its share of the load increase. Today, a computer can be used to control from a central location the amount of increased energy production by each of the utility's generators. Environmental constraints on generating unit loading order can also be taken into account.

The energy control computer acts so as to restore the system to the standard frequency, but must have its own "deadband" within which the constant small perturbations in load can occur without continuous use of, and wear and tear on, each generating unit's control hardware. Under economic dispatch, a small load increase outside the deadband range of the control computer increases the output of the lowest cost unit not yet fully loaded. But, the (marginal) generation cost of each generating unit varies with its level of output. So, for a moderate size load increase that occurs over several minutes duration, the output level of several units may be alternately adjusted so as to keep the generating costs of all the units equal.

This plan of generation control may have to be overridden for a sudden large load increase. If a single generating unit is the most economical unit for absorbing the entire increase and if this unit cannot increase its output quickly enough to maintain system frequency within a permissible deviation from the standard, then more and more generating units can be brought into play to maintain a stable frequency. When output from all units matches load, generation can be gradually turned over to the most economical unit as its power output grows.

The more generating units in a utility, the larger a sudden load change it can absorb. Hence, the more utilities that are interconnected with one another, the more stable the interconnected system is likely to be. Utilities interconnect not only to enhance reliability and to lower capital costs, as mentioned earlier, but also to enhance stability.

Consider how generation is dispatched when utilities are interconnected. Suppose that G_1 and L_1 in figure 2-6 now represent the aggregated generators and loads of a single company, utility 1. Similarly, G_2 and L_2 represent utility 2, connected to utility 1 by the east-west tie line shown in the figure. As in the case of a single utility, no power will flow through the tie line if G_1 equals L_1 and G_2 equals L_2. A 20-MW increase in the load L_2 of utility 2 may be met by a 10-MW increase in the generation of each utility. Utility 1 experiences an increase in generation cost to satisfy the needs of utility 2. If not previously agreed upon, this is called an inadvertent power exchange. If generators are set to respond automatically to load changes throughout the interconnected system, how are inadvertent power exchanges held to a minimum?

Each utility in figure 2-6 monitors the frequency of its generators and the amount and direction of power flow at B, the border with its neighbor. Generator frequency and border power flow data are telemetered to each company's energy control center where an automatic generation control computer takes appropriate action. For example, suppose no power exchange is planned between utilities 1 and 2, but that 10 MW is flowing to the east at point B, and the generator frequency of each tends to decline. This frequency drop indicates that load has increased in the interconnected system, and the eastward flow indicates that the load increase is in the service area of utility 2. Its own generators are taking up a portion of the load change but should take up an additional 10 MW so as to reduce the power flow at B to zero (or to any other agreed upon value of a planned power exchange). Under the interconnection agreement between the companies, utility 2 then increases its generation by an additional 10 MW. Utility 1 need take no action, trusting that the action of utility 2 will quickly eliminate the need for any increase in the output of its generators G_1.

Westward power flow with falling generator frequency, on the other hand, calls for action by utility 1. In this case, L_1 is increasing so that G_1 must be increased.

If generator frequency tends to rise instead of fall, load is then decreasing and one of the utilities must reduce the level of its power generation. In this case, westward power flow in figure 2-6 indicates that there is an excess of generation over load in the east, which causes power to flow westward. This must mean that L_2 has decreased, and hence utility 2 must reduce G_2.

In this simple two-company example, utilities 1 and 2 are each a control area. A control area is a part of an interconnected synchronous system that matches its own internal generation with its own load. The three interconnected regions of the U.S. and Canada (excluding Quebec) contain some 143 control areas, each with an energy control center. A control area may consist of a single large utility, a large utility with a group of cooperating smaller companies, a power pool, or a holding company. Where there are several companies, one company or some group headquarters must run the energy control center for the entire group. If frequency decreases in an interconnected region, all generating units with frequency controls will respond almost immediately to meet the increased load. The control centers subsequently direct the generator tie-line controls to rebalance generation and load in each control area to achieve the planned tie-line loads. The control center is typically responsible for (1) maintaining a frequency of 60 cycles per second (60 hertz) throughout the control area and maintaining synchronism with other control areas, (2) dispatching units within the control area in the agreed upon order--usually in order of increasing generation cost, and (3) minimizing inadvertent power exchanges with other control areas.

Unlike the simple system of figure 2-6, control areas usually have several neighboring control areas, and there can be several tie lines connecting each pair of neighbors. Arrangements for firm wholesale power transactions and economy power exchanges among control areas determine the expected values and directions of power flows along each connecting tie line, and these can change from hour to hour. The control center must correct for deviations from the expected flows. Further, control areas containing more than one utility must have a procedure for determining discrepancies between generation and load for each utility within the area and a procedure for providing compensation for these differences. Control areas must, of course, take line losses into account, and they must monitor reactive power flows.

Reactive Power Management

As mentioned, when various generators and loads are interconnected it is important to synchronize both the frequency and the phase of alternating voltage variations. If all circuit elements and loads offered merely thermal resistance to AC power flow, the alternating voltage would always be completely in-phase with the alternating current throughout the interconnected circuitry. In practice, circuit elements and loads may retard the variations in voltage or current; hence voltage and current are often out-of-phase and, when this is so, the circuit is said to contain reactive power. (See appendix B for an explanation of the concepts of real and reactive power and for a discussion of how reactive power is generated, transmitted, and consumed.)

In addition to real power production, electric power generating units are usually operated so as to supply reactive power as well, that is, to produce an alternating current and voltage that are out of phase, with voltage variations delayed slightly with respect to current variations. This is done because most large loads delay the current, so that the effects of the generator and load together are to produce the desired in-phase variation of voltage and current. The load is said to consume the reactive power supplied by the generator.

The real and reactive power needs of a power system must be supplied by real and reactive power sources within the system. In case of inadequate source capacity, the interconnection will have to take care of the difference.

Consider figure 2-6 again. Assume now that initially G_1 supplies both real and reactive power to L_1 along a short transmission line, G_2 similarly supplies L_2, and the two systems are interconnected by a long east-west tie line. Assume that no reactive power compensation equipment is installed anywhere in the system. If we want to shut down G_1 for maintenance and supply both loads from G_2 alone, reactive power considerations may prevent this even though the generating capacity of G_2 is sufficient to supply both loads.

Also, it may be desirable to back off some generation by G_1 if G_2 is less expensive. As G_2 generates more, this could put an increasing strain on the ability of the system to compensate for reactive power, reducing the ability of the system to maintain stability in case of an accident. Then, choice of generating unit by location competes with choice by economic dispatch. Loading for economy and generating for stability are an operating compromise.

When generating units are interconnected by long transmission lines, the lines themselves can either supply or consume reactive power. As a rule of thumb, lines carrying light loads produce reactive power and lines with large loads consume it. Substation transformers also consume reactive power. The longer the line, the greater the reactive power effect. If a generating unit is too far from the load, it may not be able to supply enough reactive power to meet the combined needs of a heavily loaded line and the load. Then the generating unit cannot supply electrical energy to the load even though the energy generated equals or exceeds the energy demanded by the load plus the line losses along the way. This is because, by the time the alternating voltage and current arrive, they have become so much out of step that the voltage is not sufficient to effectively power electrical loads. Power generation in such circumstances not only fails to deliver the energy where it is wanted, it may result in energy emerging where it is not wanted, possibly damaging components of the bulk power supply system.

Interconnection of power systems requires the planning and management of reactive power flows. As explained in chapter 3, there are devices that can supply or consume reactive power and hence can compensate for undesirable voltage-current phase differences introduced by transmission systems and loads. Installing such reactive power compensation devices near loads and along transmission lines is one approach to reactive power management. Another is to forego use of more economical, distant power stations in favor of nearby stations when power is needed but adequate compensation equipment is not installed. Still another approach is to import distant power and run local generators purely as reactive power compensation devices.

Normally it is better, even necessary, to correct for reactive power locally. Utilities expect one another to manage their own reactive power and provide their own compensation so as not to impose on neighboring systems. Also, each control area, whether composed of one or several utility service areas, is expected to operate so as to avoid unplanned reactive power exchanges with other control areas.

Wheeling

Wheeling occurs when one utility performs an electric power transmission service for another utility and the one performing the service is neither a buyer nor seller of the power.

Figure 2-7 illustrates five utilities interconnected in a rather simple manner. Within each company's service area, all its generators and loads are lumped together as a simple G and L, connected by a single AC transmission line. Some pairs of companies are interconnected by AC tie lines as shown. If utility 1 generates power for consumption by the customers of utility 2, the flow of power along the tie line from 1 to 2 is not called wheeling, but rather it is a simple bulk power wholesale transaction between two companies. This transaction is accomplished as follows, ignoring line losses to keep the example simple. Suppose that 100 MW is to be transferred and that, before the transfer, G_1 produces 600 MW, which is consumed by L_1. Also, G_2 produces 400 MW, which is consumed by L_2. To transfer 100 MW from 1 to 2, utility 1 increases its generation G_1 by 100 MW, from 600 MW to 700 MW; and G_2 decreases its generation by the same amount, from 400 MW to 300 MW. Then 100 MW flows over the tie line between utility 1 and utility 2. If there were more than one tie line between these two companies, the power would divide up and flow over each tie line

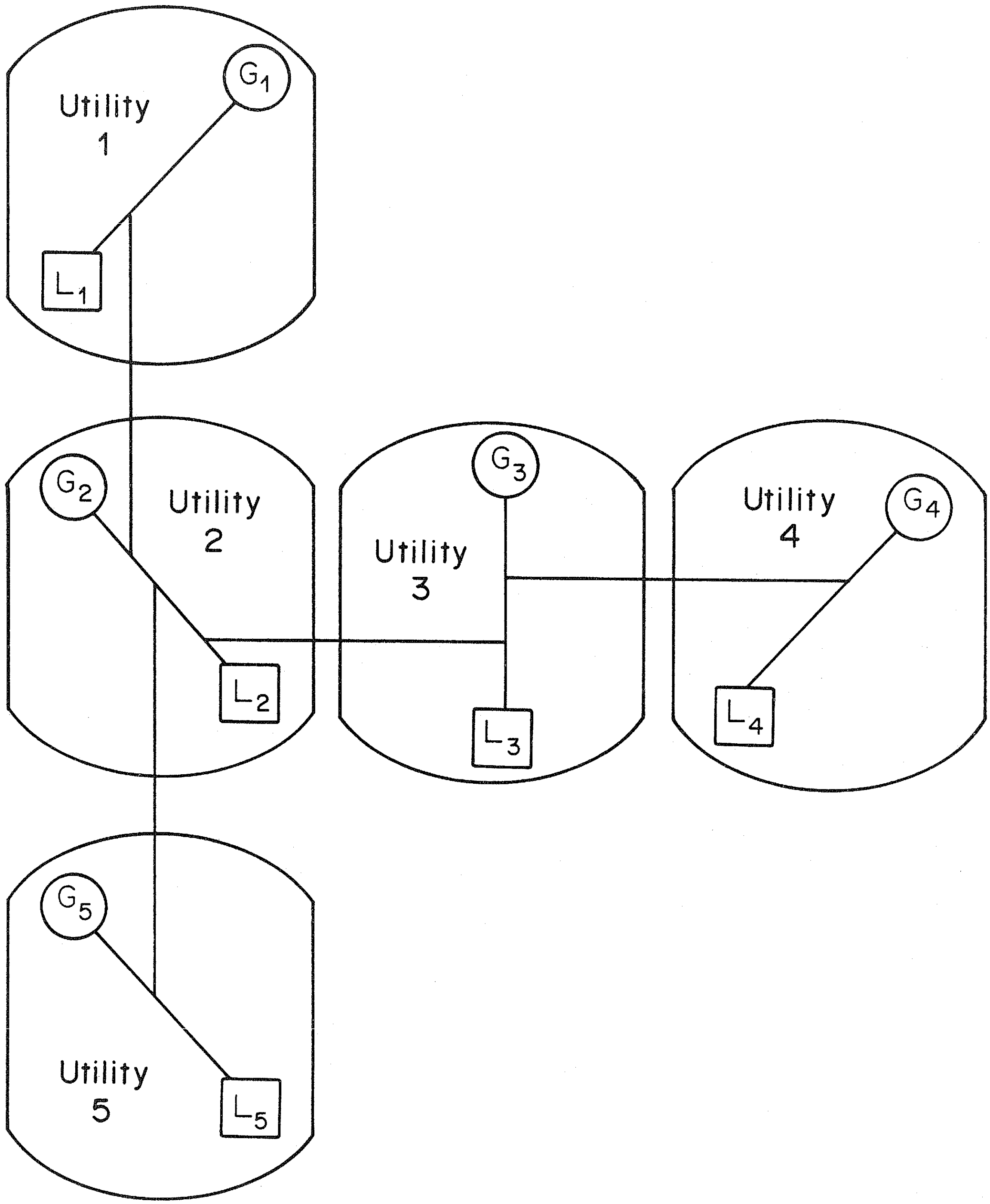


Fig. 2-7 Five interconnected utilities, each with generation G and load L, in a system with four tie lines

according to the amount of resistance and reactance (see appendix B) encountered along each line. Notice that the power is not directed, channelled, or pumped along a particular path, as in the case of oil or natural gas transfers via pipelines. The extra 100 MW of generation by utility 1 flows to utility 2 rather than, say, to utility 5 in figure 2-7 because 2 has a generation-load mismatch whereas 5 presumably does not. The transaction can also take place by planning for G_1 to increase its output in response to increases in load L_2.

This transaction is not called wheeling because only the transmission lines of utilities 1 and 2 carry power; and one of these is the seller, the other the buyer. However, exactly the same power flow would be called wheeling if utility 2 jointly owned with the first company a generating unit located in the service territory of utility 1. Now the 100 MW generated by G_1 is owned by utility 2, and utility 1 performs a transmission service to deliver it to the service area of utility 2. This is called two-party wheeling.

Three-party wheeling occurs, for example, when utility 1 in figure 2-7 sells power to utility 3 over the transmission lines of utility 2. The transaction takes place in exactly the same manner as before. Again ignoring losses, in order for utility 2 to wheel 100 MW it need take no special action; it simply must maintain the usual balance between its own G_2 and L_2. The actions are taken by utilities 1 and 3: 1 increases its generation by 100 MW at the same time that 3 backs off generation by 100 MW. (Alternatively, utility 3 may create a generation-load mismatch by increasing its load or decreasing its power purchases from another source.)

It should be emphasized that, from the engineering viewpoint, wheeling is no different from any other bulk power transfer. Wheeling refers to lack of ownership of the transmission facility by either the buyer or the seller. If utilities 1 and 2 were to merge into a single company, the same physical transfer of 100 MW from G_1 to L_3 would no longer be called wheeling.

Further, suppose utility 2 purchases 100 MW from utility 1 and, at the same time, sells 100 MW to utility 3. From an engineering viewpoint, again the same physical events occur; namely, 1 increases generation by 100 MW and 3 decreases it by 100 MW. But this is not called wheeling because utility 2 is both a buyer and seller of the power. Instead, we call this a simultaneous purchase-and-sale transaction, or simply a buy/sell transaction.

When utility 2 wheels power from 1 to 3, utilities 4 and 5 should be unaffected. This will be so, for the simple system of figure 2-7, if each utility manages its own real and reactive power as expected.

If utility 4 wants to purchase power from utility 1, then utilities 2 and 3 must wheel the power. This is called four-party wheeling or multiparty wheeling. Utility 5 should be unaffected in this case.

Wheeling usually increases the wheeling utility's line losses, but not always. When 2 wheels power from 1 to 3, the wheeled power adds to the native load on utility 2's transmission line that carries power from G_2 to L_2. More power means more line losses; in fact, the more power carried on the line, the greater the percentage of power lost.

But, given the simplified features of the utilities in figure 2-7, if utility 2 were to wheel power in the opposite direction, from utility 3 to utility 1, line losses are reduced, at least along the main (diagonal) transmission corridor of utility 2. This is because the wheeled power travels in a direction opposite to the native load power. Meters along utility 2's diagonal transmission line would detect no power flow toward utility 1, but would find a reduced level of flow from G_2 to L_2.

To see why this is so, consider what happens in a 100-MW wheeling transaction from 3 to 1. G_3 increases its output by 100 MW, and G_1 backs off its output by 100 MW. The generator G_2 can now supply L_1 with the missing 100 MW while the extra 100 MW of power from G_3 goes to L_2. This reduces the power flow from G_2 to L_2 by 100 MW and reduces line losses for utility 2.

The wheeler may also be affected by the need to provide reactive power compensation. When utility 2 wheels power from 1 to 3, the reactive power consumed by its transmission line may have to be compensated by running G_2 at a higher level so as to generate reactive power. But, when 3 supplies 1 through utility 2, the reduced power flow on the main transmission corridor may reduce utility 2's own reactive power compensation needs.

This is relatively easy to see in the case of the aggregated generators and loads for utility 2 in figure 2-7. In real companies, generators and loads are scattered around the service area, and the effect of wheeling on line losses is harder to portray. Wheeling usually increases losses, but may decrease them depending on such factors as the pattern of generating units on line, the distribution of loads, and the amount and direction of wheeled power--factors that can vary from hour to hour.

This feature of power flows--that flows in opposite directions tend to cancel one another--also applies to wheeling in opposite directions. Suppose utility 1 in figure 2-7 agrees to sell 100 MW to utility 4, and utility 3 agrees to sell 100 MW to utility 5 at the same time. One can imagine the flows taking place as agreed upon, with an additional 100 MW flowing in each direction through utility 2. But the main corridor of utility 2 is not experiencing an added load of 200 MW because the two 100-MW flows are in opposite directions. In reality, it experiences no added load: the 100 MW from G_1 flows to L_5 and the 100 MW from G_3 goes to L_4. Power moves along natural pathways, regardless of contractual agreements to the contrary.

Power finding its own pathway becomes especially important when there is more than one path from generator to load. Consider figure 2-8, which shows the same five utilities as figure 2-7 with two additional interconnections: utility 1 is directly connected to utility 3 and another tie line links utility 5 to utility 3.

Suppose 4 agrees to purchase 100 MW from 1, and utility 3 agrees to wheel the power. The parties contend that the 100 MW will flow along the utility-1-to-utility-3 tie line, through 3's service territory, and finally along the utility-3-to-utility-4 tie line. This path, called the contract path, is illustrated with arrows drawn on figure 2-8.

Despite this agreement, the actual path of power flow over this interconnected AC network is determined by the relative impedances of each of the three paths made possible by the new interconnections. Power seeks the path of "least resistance." A typical outcome is illustrated in figure 2-9. Here, only 55 MW follows the 1→3 tie line; the other 45 MW flows on the 1→2 tie line. Of this power reaching utility 2, most (30 MW) goes directly to utility 3, but some (15 MW) reaches utility 3 by going through utility 5. The power flows through utilities 2 and 5 are called loop flows. Eventually, all 100 MW reaches the purchaser, utility 4. In this example, the contract wheeler eventually delivers the full amount of power, but the transaction affects two other companies that were not parties to the wheeling agreement.

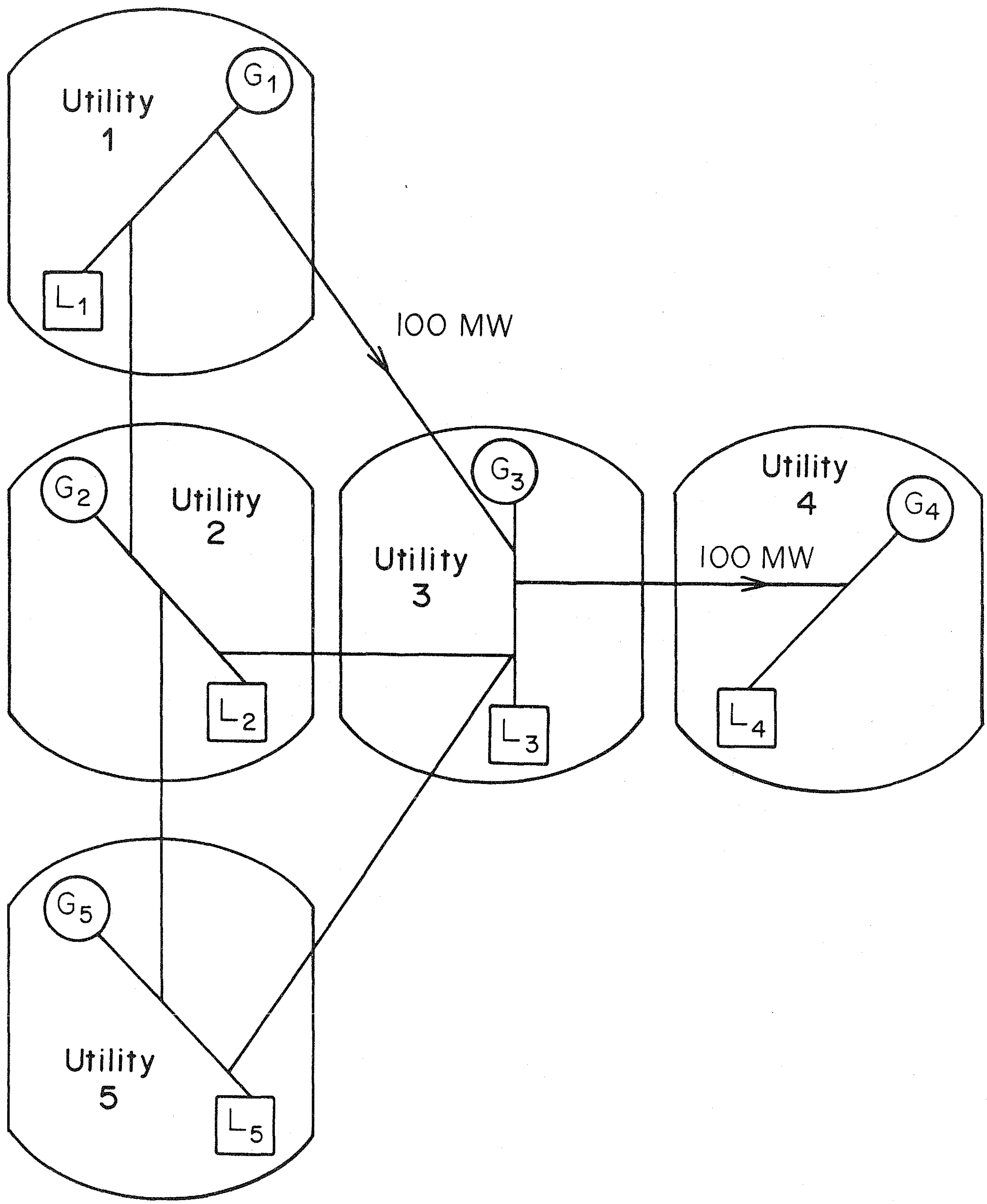


Fig. 2-8 Five interconnected utilities with six tie lines where utility 3 wheels 100 MW from utility 1 to utility 4 along the contract path indicated by arrows, with line losses ignored

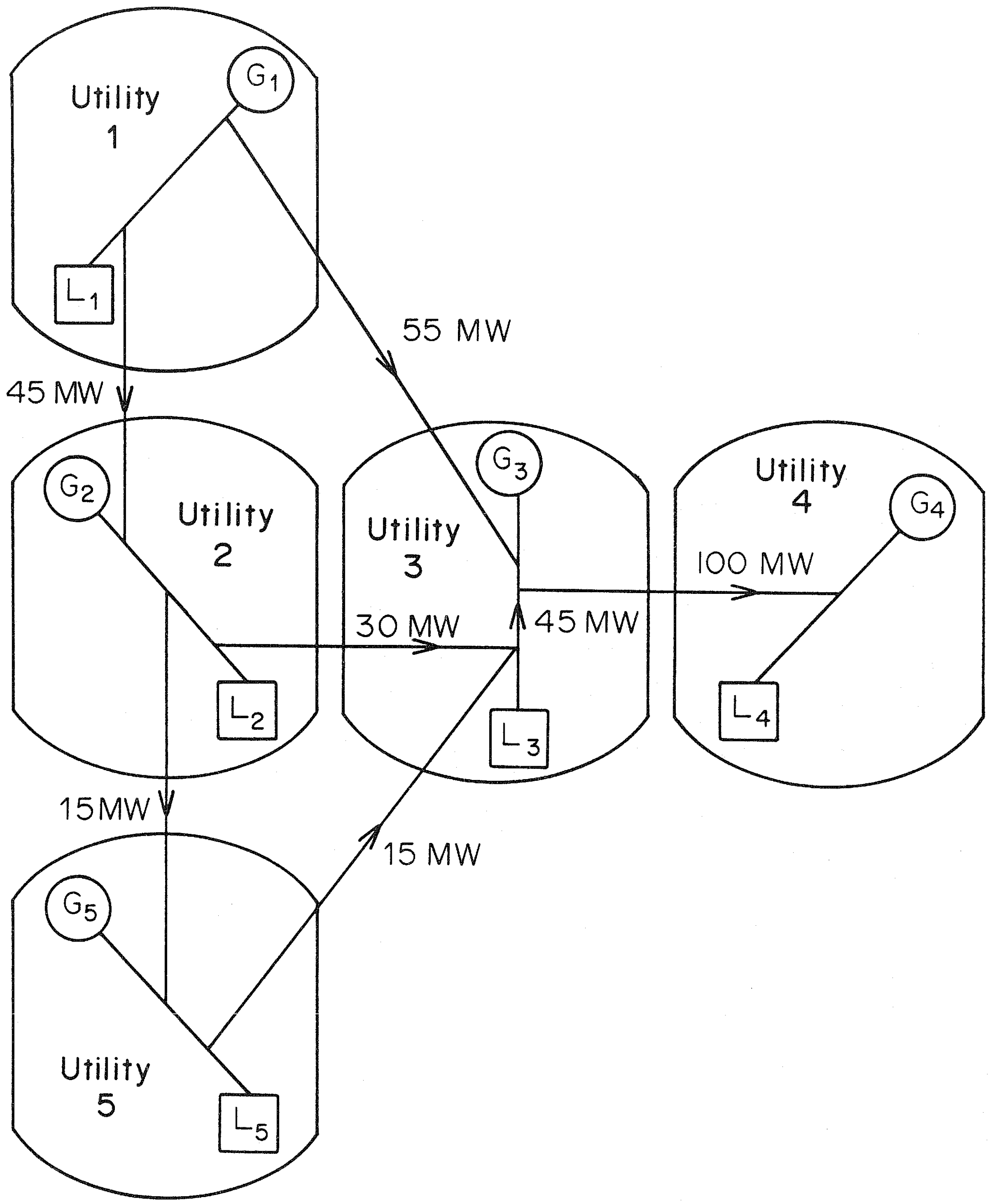


Fig. 2-9 Actual power flow pathways where utility 3 wheels 100 MW from utility 1 to utility 4, with line losses ignored

At times, loop flow causes the amount of power flowing along a particular path to be greater than the amount intended. Suppose that as the transaction intended in figure 2-8 occurs, utility 2 also sells 100 MW directly to utility 5. For simplicity, assume all this power flows on the 2→5 tie line. This tie line must have at least 115 MW of transmission capacity to accommodate both the agreed-upon 100 MW and the inadvertent 15 MW depicted in figure 2-9. This 15 MW is sometimes called counterclockwise circulating loop flow because it follows an almost complete circuit from utility 1 to 2 to 5 to 3. Loop flow limits other uses of the inadvertent wheeler's transmission facilities.

The contract wheeler does not always transmit the full amount of power. For example, if utility 3 contracts to wheel power from 1 to 5, half or more than half of the power may flow through 2. The unwilling wheeler can experience increased line losses and may have to take added steps for reactive power management. As suggested by figure 2-9, parallel paths that are shorter, and hence closer to the contract path, usually experience more loop flow than do the longer, more distant pathways, if all other factors are equal. Distant higher voltage routes of lower impedance may experience more inadvertent flow, however, than nearby lower voltage routes.

CHAPTER 3

WHEELING CAPABILITY

Wheeling must take place over the existing transmission networks of the utilities that separate the seller and buyer of power. Historically, these networks were designed primarily to link each utility's own generating stations and load centers, and only secondarily to link a utility to its neighbors. Today, in some areas with closely coordinated power pools, transmission networks may be compared to interstate highways in that they are designed to move large quantities of out-of-state traffic efficiently through the area without undue impact on local traffic. Other areas, however, still rely on their historical transmission systems to move power. A major wheeling activity through such an area can be compared to moving heavy interstate road traffic through a network of many smaller roads, which are designed for moving traffic among scattered local towns and which lack adequate traffic control equipment. The result, of course, is congestion and disruption of road service for local residents.

In the case of road traffic, several solutions to this problem are available. One, for local authorities to refuse road service to outsiders, is not a legally available solution. If an increase in outside traffic is heavy and permanent, other solutions must be pursued. Street signs, traffic lights (sometimes computer controlled), and other traffic control devices can be installed to increase the efficiency of use of existing roads and to direct traffic around, rather than through, population centers. Widening existing roads increases the volume of traffic they can carry. Additional smaller roads can be built to facilitate local resident traffic, while easing the passage of outside traffic as a side effect. And, if funds are available, a new large highway can be constructed primarily to serve outside traffic; then local travel is not congested and local residents may benefit from access to the new highway themselves.

In the case of electric power movements, a similar set of solutions to the congestion problem exists. Utilities may refuse to wheel and so keep out outside traffic. If wheeling traffic is allowed in, and is viewed as heavy and permanent, new equipment (sometimes computer controlled) may need to be installed along transmission paths to increase the efficient use of existing lines, and existing lines may need to be upgraded in their power-carrying capacity. Additional short, low voltage lines may be needed to ensure continuity of electric service to local residents, and, if funds are available, construction of a new, long, high voltage line may be required to transmit wheeled power without affecting local service.

The principal purpose of this chapter is to explore, with a minimum of technical prose and mathematical expression, the factors that affect the capacity of a single AC transmission line, the factors that affect the power transfer capability of a network of lines, and the ways of expanding the capability of the network for wheeling. This facilitates the discussion in part II of the costs of expanding transmission capacity for wheeling.

Capability of a Single Transmission Line

Discussion of a utility's capability and cost for wheeling often turns to the question of the power carrying capacity of an existing transmission line or set of lines. The amount of power that a given AC transmission line can carry is determined by several factors. These include the length of the line, the voltage for which the line is designed, the heating effects of electric current, the ability to sustain a high voltage along the length of the line, the stability of the electrical balance between generators and loads, and the reliability of the network of lines to which any one line belongs. In this section, the power carrying capability of an isolated line is discussed. The next section treats how this capability may be constrained by network considerations.

Voltage and Current Limits

The amount of power carried by a transmission line conductor increases with both the voltage and the electric current. More precisely, power is the product of the voltage and the current. Increasing either the design voltage of a line or its current-carrying capacity increases the amount of power it can carry.

Once the line is designed and built, its maximum voltage is relatively fixed by the design of the line, that is, its height, conductor configuration and spacing, amount of insulation, and so on, as well as the design of the substation that feeds power to the line. If the voltage is well above the design value, "flashover" or "sparkover" can occur; that is, an arc can develop between two conductors or between a conductor and the ground. The insulating ability of an insulator string may be overcome by a voltage that is too high, or by the contamination (pollution) of its surface, causing electric current to flow through the string and degrading its ability to support the conductor. Further, a voltage higher than design voltage exacerbates the corona problem (appendix C) and adversely affects the internal insulation of transformers and other equipment.

Some voltage variation is allowed, however, in a tolerable zone. A line is usually designed for a somewhat higher voltage (usually 5 percent) than it is nominally rated to carry. For example, a nominal 345-kV line is typically designed for a maximum voltage of 362 kV; a nominal 500-kV line is often operated at 525 kV and can carry up to 550 kV; and a nominal 765-kV line is usually designed for a maximum voltage of 800 kV. So lines can be operated, under certain conditions, above the nominal voltage but within the tolerable zone and hence, for a time, may be able to carry more power than the line rating nominally specifies.

With the transmission line operating at its design voltage, the amount of power traveling along the line is determined largely by the amount of current flowing through the conductors. One limit to the power-carrying capacity of the line, then, is a limit to the current it can carry. Current encounters electrical resistance--a kind of electric friction. Overcoming this resistance consumes some of the electric energy, converting it to heat. This lost energy, together with energy lost in transformers and other devices, is referred to as "line losses."

If too much electrical current were sent along any conductor, it would eventually melt. A current large enough to melt a conductor is clearly an absolute limit to the power transfer capability of a line. Of course, in practice no operating decision would be made to send such a large amount of power along a line, and if it happened inadvertently circuit breakers would open to protect the line. In fact, circuit breakers are set to open to protect the line from heating effects much less drastic than melting. As a conductor becomes too warm, its great weight causes the conductor to lose its mechanical strength and to develop an increasing sag between supporting towers. This reduces the clearance of the conductor above ground and disturbs the carefully designed spacing between conductors. Even without appreciable sag, periodic overheating of a conductor still reduces its mechanical strength, making it more likely to break under adverse conditions, such as high winds, and reducing its expected service life. Further, heating a conductor also heats the insulators that support it, affecting their strength and life.

These effects establish a thermal limit to transmission line loading. Ideally, one would specify a maximum conductor temperature according to the duration of the heating effect (a half-hour thermal limit, a one-hour limit, a four-hour limit, a continuous thermal limit). Since temperature is hard to measure, in practice engineers often specify a maximum current instead. Also, protective relays that activate circuit breakers are designed to detect currents, not conductor temperatures. If the maximum current is specified conservatively, the line may be able to carry more power than it is rated for--at least for a while--but perhaps at the cost of reducing the service life of the line.

The temperature of a conductor is determined by a balance between two competing processes. One is current flow in the conductor, which generates heat and tends to raise the conductor temperature. The other is the dissipation of heat into the air, which depends on the air temperature, the amount of sunshine, wind, ice build-up on the line, and other factors. Dissipation, of course, tends to lower the temperature. If a large current generates heat faster than it can be dissipated, the conductor temperature rises. How hot the conductor gets depends in part on how long a time this large current flows. The current limit can be exceeded for short times without violating the temperature limit.

The thermal limit on the line current, and hence on power capacity, can vary by as much as one-fourth between summer and winter. That is, a line that can carry at most 400 MW during a hot August noon hour may be able to carry 500 MW on a cold January night, if the thermal limit is the governing limit in each case.

Periodic slight overheating of conductors and insulators may be the economically best strategy. Even though it may shorten the life of the transmission line or increase the repair rate and maintenance costs, this action may delay the need for construction of a new line. The least cost approach depends on the present values of the costs of the two actions, overloading versus earlier new construction.

The thermal limit is the governing limit on transmission line capacity for short, lower-voltage lines. As a rule of thumb, for lines under 50 miles long and under 138 kV, it is the heating effect that limits the power-carrying capacity of the line. The higher voltage (EHV) lines have very large conductors to alleviate the corona problem, and these conductors can usually carry much more current than the line design calls for. The voltage (corona) limit comes into effect before the current (heating) limit does. For lines longer than 50 miles, other limits usually force the line to carry less power than either the corona or thermal limit would allow. These other limits are discussed next.

Voltage Drop Limit

Unless steps are taken to counteract it, the voltage along a long transmission line tends to decrease with increasing load. Since voltage is required at the load site to operate the load, the power that can be delivered to a distant receiving substation is limited by the amount of voltage drop along the line.

Three effects contribute to the voltage drop. One is simply the normal resistance of the line to the current. Some of the electrical energy is converted to heat in the conductors. So the energy delivered is less than the energy sent, and the voltage at the receiving end is less than the voltage at the sending end. However, with high enough transmission voltage level, these thermal losses and voltage drops can usually be held to a reasonable level and hence are not a major contributor to voltage drop. (Thermal losses in substation transformers are usually more of a problem.)

A second effect is that some electric current may leak out of the lines by discharging through the insulators or through the air, as mentioned previously under the corona effect. However, in properly designed lines that are not overloaded, this effect is usually small and can be ignored.

The third effect is quite important. A transmission line, like any other device that carries alternating current, can experience a voltage drop because of the reactance of the line itself. For a voltage and current that vary in unison under pure resistance conditions, reactance is the introduction of a slight time difference between the voltage and current variations. More reactance results in greater time difference between the voltage and current. Reactance can lead not only to a voltage drop but also a voltage increase. (See appendix B for an introduction to inductive and capacitive reactance.)

The amount of reactance associated with any small segment of the line is small, producing at most a small voltage change and getting the voltage and current only very slightly out of step. But as lines get long--over 50 miles--the cumulative effect can be appreciable. Lines that are about 50 to 200 miles long are limited in their power carrying capacity by the necessity to limit the voltage drop caused by the current flowing through reactances along the line.

While inductive reactance and capacitive reactance individually contribute to voltage drop, together they tend to counteract one another, so that less voltage drop occurs. The capacitive effect increases with voltage and the inductive effect with current, so that the net voltage change depends on the voltage-current combination. Consider a transmission line that is held at its specified maximum voltage at the sending end, and has a certain capacitive reactance along the line. If the line carries a small amount of power and hence a small current, the capacitive effect created by the alternating voltage outweighs the small inductive effect created by the small alternating current. In this case, the line is said to supply reactive power, as explained in appendix B. On the other hand, if the line carries a large current, the line consumes reactive power because the inductive effect outweighs the capacitive effect. In either case, a large reactance can result in a lower voltage at the receiving end of the transmission line.

Sending just the right intermediate amount of current along the line creates an inductive effect that exactly cancels the capacitive effect. Therefore, for a unique pair of voltage and current values there is no net reactive voltage drop along the line. In such a condition, the line neither generates nor consumes reactive power. Only a voltage drop related to ordinary resistance exists. With minimum voltage drop, the voltage at the end of the line receiving power is almost the same as the voltage at the sending end.

The power delivered at the receiving end under these conditions has a unique value; it is the product of the unique values of voltage and current that produce cancelling reactive voltage changes. This is called the natural power of the line, and the load served by the line under these conditions is called the natural load of the line. (Sometimes, it is called the surge impedance loading of the line, but the name--while commonly used--is something of a misnomer.)

A line can carry more than its natural load, up to a point. Assuming the sending-end voltage is already as high as it can be, increasing the power on a line means increasing the line current. However, increasing the current creates a larger inductive effect along the line, and this causes a voltage drop along the line. Then, a lower voltage is available at the receiving end to serve the load. As long as the current increase outweighs the receiving-end voltage decrease, more power is delivered to the load. However, as still more current flows in the transmission line, the inductive effect becomes progressively greater, causing ever larger voltage drops along the line. Eventually, a point is reached where any further increase in current would be outweighed by the voltage drop. At this point, the power that can be transmitted is at its maximum. Since the power is the product of the line's voltage and its current, any further increase in current results in a decrease in the product of current and voltage--that is, a decrease in the delivered power.

For long transmission lines, this theoretical limit to transmission line capacity is lower than the thermal limit and represents the theoretical maximum power that the line can carry. Because inductive reactance increases with line length, the power carrying capacity of a line grows smaller as the line gets longer--all other factors being equal.

However, in practice transmission lines cannot carry even this theoretical maximum amount of power. There are two principal reasons for this, one related to a practical limit to voltage drop along the line and the other related to a practical limit to the degree to which inductive reactance may cause the voltage and current to be out of step.

As just explained, a long transmission line, operated at its natural power, has a constant voltage along its length, still ignoring the voltage drop due to resistance effects. As the power increases above this natural value, the voltage then decreases along the line length, from a maximum value at the sending end to a lower value at the receiving end. It is usually necessary to limit the voltage drop along a line to about 5 percent (though this is a matter of utility policy and some would allow drops as large as 10 percent). This is so that the insulation along the line is uniformly stressed and also so that a tap changing transformer at the receiving end of the line receives an input voltage within the range at which it is designed to operate. Remember that it has to maintain a constant output voltage. If the power on a line were allowed to increase from the natural power level to the theoretical maximum, the voltage drop along the line could be as much as 30 percent. If the utility adopts a 5 percent voltage drop limitation, then a new, more practical limit to power transfer is established at a level below the theoretical maximum.

It should be mentioned here that there are several ways to "get around" this new limit, most of which require additional capital investment. The sending-end transformers and sending-end line insulation could be strengthened for a higher voltage, so that a larger one-way power transfer is planned for. Also, the receiving-end transformer can be designed to maintain a constant output over a wider range of input voltages.

More importantly, the inductive effects along the line at high power levels can be reduced or eliminated by either of two actions: running the generator so as to produce capacitive reactive power and installing equipment along the transmission line that produces capacitive effects. The generator can be operated so that the voltage generated lags the current; then the effect of the line inductive reactance is to bring voltage and current back into step. The generator is then said to supply reactive power and the line to absorb it. The generator provides "voltage support" as well as real power. The other action is to install one of several compensation devices that add capacitive reactance to the circuit. By neutralizing inductive effects, such devices are also said to provide voltage support, or to supply reactive power to compensate for the reactive power absorbed by the transmission line. Further consideration of compensated lines is deferred to a later section of this chapter; the remainder of this section treats only uncompensated lines.

For uncompensated transmission lines about 50 miles long, the voltage drop limitation constrains power transfer to about three times the natural load. (Under 50 miles, the thermal limit dominates.) One hundred mile long lines can carry up to double the natural load without violating a 5% voltage drop limitation, but 200-mile long lines can carry power no more than about 130 percent of the natural load because of this limitation. For uncompensated lines over one or two hundred miles long, a new limitation on line capacity arises, one related to system stability.

Stability Limit

With an uncompensated line, the generator must be run so that voltage leads or lags the current in order to balance the leading or lagging effects of the line, the substations, and the load. On a line carrying its natural load, there is no voltage drop related to line reactance, and if the load were purely resistive the generator voltage and current would be in step. Usually the load is inductive, so in the "compensated" line the generator voltage must lag the current to the same degree that the load (including substations) causes voltage to lead the current.

If the uncompensated line carries more power than the natural loading, the line inductive effect adds to that of the load, requiring the generator voltage to lag the current to a greater degree. There is a limit to how much voltage lag the generator can tolerate and still continue to maintain 60-cycle alternating voltage. It happens that this "lag limit" corresponds to the theoretical maximum power capacity, the point at which further increasing the current begins to decrease the power transfer capability. Because longer lines require less current to create the same reactive effect, they reach the "lag limit" at a lower maximum power. Hence, the longer the uncompensated line, the less power it can carry. At a length of 775 miles, an uncompensated line's reactance fully exhausts the ability of a 60-cycle generator to have voltage out of step with current; the theoretical maximum power transfer capability of such a line is zero.

In practice, the maximum length of an uncompensated line is much less than 775 miles, and the most power that is permitted along a line of given length is much less than the theoretical maximum for the following reason. As the customer turns on more electrical equipment, he draws more current and consumes more power from the transmission line, which in turn automatically draws more power from the generator. The generator must maintain a constant rotational speed in order to keep the current and voltage variations at 60 cycles per second. To maintain 60-cycle speed as the demand for power increases, the turbine supplying power to the generator must increase its own power output to match the transmission line's increased demand for power. If it does not, then either the voltage drops or the generator slows down. But, voltage regulators are installed to keep the generator output voltage constant, making the second alternative more likely.

Recall that, if a transmission line were carrying its theoretical maximum power, any further increase in current causes an even greater decrease in voltage, so that the power transmitted along the line falls. Then, just as the transmission line draws more current, it also demands less power. The turbine-generator receives conflicting signals: send more current and send less power while maintaining constant output voltage. In response, the generator is likely to slow down and not maintain 60-cycle output. This is because, at a slower generator speed, current can be higher for a given voltage while less power is generated. Hence, attempting to pass more power through a transmission line than its theoretical maximum results not only in less power transfer but also in one or more of the system's devices falling out of 60-cycle behavior. When this happens, the system is said to be unstable. Maintenance of 60-cycle stability is among the highest priorities of system operators.

System stability is threatened whenever a transmission line operates at or even near its theoretical maximum power transfer capability. At this transmission level any small unplanned additional current or voltage drop can throw the system out of balance. The start-up of a new load, the opening of switches at a substation, or the reduction in power output of a generating unit can affect stability if a line is operated too close to the theoretical capacity limit. To keep the system stable in light of these common minor disturbances, the line should be loaded to no more than, say, 85 to 95 percent of the theoretical limit. Further, to keep the system stable in case of a less common major disturbance, such as the loss of a major parallel power line, a generation failure, or a major lightning stroke, it is common practice to limit line load to 65 or 70 percent of the theoretical maximum. The exact figure would depend on the degree of conservatism of the utility regarding system stability.

For 345-kV transmission lines longer than 200 miles, this stability limit imposes a more severe constraint on line capacity than the voltage drop limit. For higher voltage lines, the stability limit is imposed at somewhat shorter distances--as little as 100 miles for lines approaching 1000 kV.

Typical Line Capacities

Consideration of these thermal, voltage drop, and stability limits results in trends in the variation of capacity limits for various voltages and lengths of uncompensated line. These trends, studied by Dunlop and others, have been converted to typical megawatt limits by the authors and are shown in table 3-1. For example, a 138-kV line that is 50 miles long can carry at most about 145 MW of power. A shorter 138-kV line could carry no more power because 145 MW represents the thermal/corona limit to its capacity. A longer 138-kV line must carry less because, without compensation, the additional line reactance effect causes more voltage drop; excessive voltage drop is prevented by limiting the reactance effect, and this is accomplished by limiting the power transfer. Still longer 138-kV lines must limit this effect even more severely to avoid stability problems. Table 3-1 indicates that the 138-kV line has no bundled conductors; that is, each phase of the three-phase power is carried by a single conductor. As another example, an uncompensated 400-mile long, 500-kV line with three bundled conductors per phase can typically carry at most 810 MW, equivalent to the output of a typical large modern coal or nuclear unit.

The primary factors determining line capacity are voltage and length.

TABLE 3-1

APPROXIMATE POWER CARRYING CAPABILITY OF UNCOMPENSATED AC TRANSMISSION LINES[a] (MEGAWATTS)

Nominal Voltage (kV):	138	161	230	345	500	765
No. of Conductors/Phase:	1	1	1	2	3	4
Line Length (miles)						
50	145	195	390	1260	3040	6820
100	100	130	265	860	2080	4660
200	60	85	170	545	1320	2950
300	50	65	130	420	1010	2270
400	—[b]	—	105	335	810	1820
500	—	—	—	280	680	1520
600	—	—	—	250	600	1340

Source: Charles A. Powel, Principles of Electric Utility Engineering (Cambridge: The Technology Press of MIT, 1955; New York: John Wiley & Sons, Inc., 1955), p. 187; Electric Power Research Institute, Transmission Line Reference Book: 345 kV and Above 2nd ed. (Palo Alto, California: EPRI, 1982), p. 15; R. D. Dunlop et al., "Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines," IEEE Transactions on Power Apparatus and Systems PAS-98 (March/April 1979): 607.

Notes: a. This table is useful for estimating the amount of power a line can carry, given its rated voltage and length, but it has limitations. Assumptions are that voltage drops must be limited to 5 percent, that stability requires the line load to be no more than 65 percent of the theoretical maximum, and that line losses can be neglected. Lines that compensate for reactance may be able to carry more, and lines that are part of an integrated network may be required to carry less than the amounts in the table. Line capacity is also affected by conductor configuration (see text).

b. Low voltage lines are not used for very long distance transmission, so unrealistic table entries are not included.

Capacity increases roughly as the square of the voltage. This is especially evident for the lower voltages where there is always one conductor per phase. At higher voltages, the capacity also depends importantly on the number of conductors per phase and the positions of the conductors relative to one another. For example, the table gives the capacity of a 300-mile,500-kV line as 1010 MW when there are three conductors per phase. If there were two or four conductors per phase, the capacities would be about 870 MW or 1070 MW, respectively.

Capacity depends on how far the power must travel. If an 800-MW nuclear unit is located about 100 miles from a city it serves, a 345-kV line would be adequate to connect the two. But if an 800-MW hydroelectric facility is 400 miles from its load center, an uncompensated 345-kV transmission line would be able to deliver less than half the power generated. A more costly 500-kV line would be required instead.

The capacities of the lines shown in the table would be affected if resistive line losses were taken into account. That is, the power delivered at the receiving end would be less than the power put into the line at the sending end. The amount of power a line may carry is also affected by the electrical characteristics of generators and loads, by substation characteristics, and by the number and type of other lines making up the network.

The amount of power loaded on a line may be affected by the system operator's judgement of such factors as the probability of a lightning stroke on the line and the degree of installed lightning protection. Areas with frequent lightning strokes would be well protected. (Tampa claims to be the "lightning capital of the world" with 3000 to 4000 hits to the Tampa Electric Company's system not uncommon in an afternoon.) Protective devices are costly, and little protection may be installed in an area, such as a desert, with a history of little lightning threat. When lightning does threaten a poorly protected line, then the transmission line load can be temporarily backed off to avoid a surge that, added to the planned load, could either threaten system stability or damage the line.

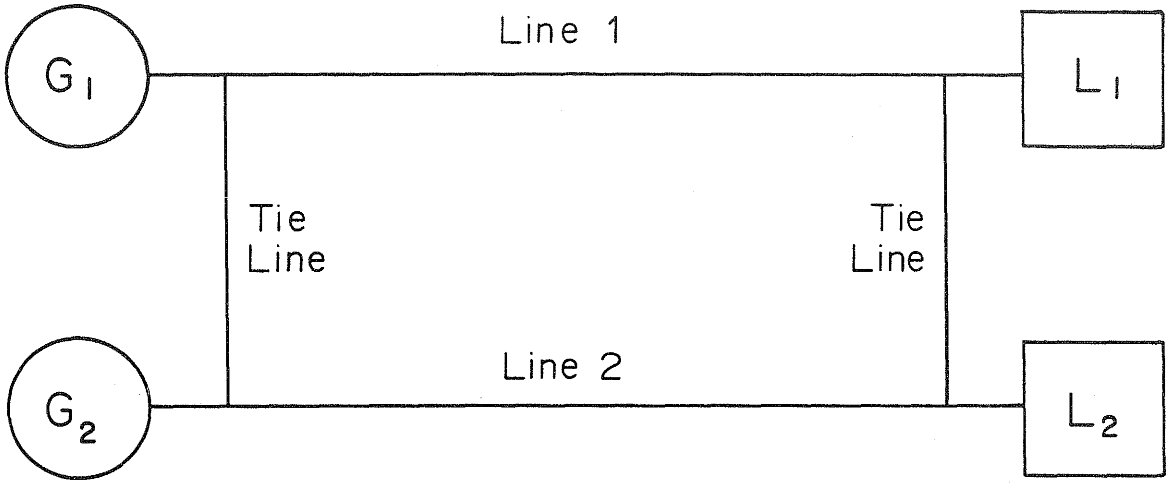
Capability of Interconnected Lines

Most of the previous discussion concerns the power transfer capability of an isolated uncompensated transmission line, such as a single line linking a lone generating station to a single load. A compensated line can carry more power than an uncompensated line, as discussed in the next section. In practice, a line is normally part of an interconnected system of lines linking many generating stations to many loads. A particular line within the system may be limited to carrying less power than that for which it is designed because of system-wide considerations. These limitations are discussed in this section.

These limitations are apparent in a single utility with several generating stations and several loads interconnected by means of a transmission network. If many such utilities are interconnected, the technical limitations on power flows are, in principle, no different from those of the single utility--though in practice the problems of coordination become more complex as the number of generators and loads increases and as the number of independent companies and operators increases. The limitations relate to problems associated with the actual pathways of real and reactive power flows and with reliability constraints.

Power Flow Paths

In chapter 2, the idea of inadvertent loop flow was introduced in connection with figures 2-8 and 2-9. An example of a loop flow problem that limits wheeling capability is in figure 3-1. Generators G_1 and G_2 supply loads L_1 and L_2 over two interconnected transmission lines. The power transfer capability of line 1 alone is 500 MW and that of line 2 is 200 MW. Initially, line 1 carries 150 MW and line 2 carries 100 MW. System operators want to increase the flow from G_1 to L_1 by 300 MW. Call this case 1. This is well within the capacity of line 1, which can handle an additional 350 MW of power. Also, the new total power flow, 550 MW, is less than the combined capabilities of the two lines, 700 MW. However, if operators were to attempt to transmit the additional 300 MW, it would not flow on line 1 only, but divide up and flow along both paths. In our example, an additional 180 MW goes on line 1 and 120 MW on line 2. The



	Line 1	Line 2	Total
Capability (MW)	500	200	700
Initial Load (MW)	150	100	250
Case 1			
Added Load (MW)	180	120	300
Total Load (MW)	330	220	550
Case 2			
Added Load (MW)	150	100	250
Total Load (MW)	300	200	500

Fig. 3-1 Two principal transmission lines, 1 and 2, each transmitting power from a generator G to a load L, with two tie lines interconnecting the principal lines

total flow on line 2 would be 220 MW, which exceeds this line's capability. This would cause circuit breakers to shut down line 2. Suddenly, the whole 550 MW load is borne by line 1; this exceeds its capability; and line 1 shuts down. Hence, loop flow considerations prevent the transfer of an additional 300 MW in this case.

Reactive power considerations may also impose limitations. Suppose that system operators now try to send less additional power from G_1 to L_1: 250 MW. Call this case 2. Then 150 MW flows on line 1 and 100 MW on line 2. This exceeds neither line's capability but loads line 2 to its maximum. Power flow along the route using line 2 now consumes a great deal of reactive power. This is because a fully loaded transmission line consumes a lot of reactive power and because this route is a long route, further increasing the reactive power consumption. This leads to a voltage drop at L_1, which prevents L_1 from consuming the power; in effect, this system is not capable of delivering an additional 250 MW of real power.

These two cases illustrate several points. One is that the amount of power a line can carry in practice depends not only on its own capacity, but also on the capacity of its parallel neighbors. If line 1 belongs to a potential wheeler who agrees to move power from G_1 in one company to L_1 in another company, the wheeler may be limited by the unused transmission capability of the neighboring utility that owns line 2. This is so even if the wheeler appears to have sufficient transmission capacity of its own to handle the entire transaction. Where a transmission network is a spider's web of interconnected lines, the limit to the ability to transmit power between any two locations is set by the weakest thread in the web, not the strongest. This weakest thread may be outside the service territory of the utility agreeing to wheel.

Further, the wheeler must recognize the need to supply or consume additional reactive power to complete the transaction. If line 1 belongs to the wheeler and line 2 belongs to another company that is not part of the wheeling transaction, the reactive power consumed in this latter utility's system may force it to provide local reactive power compensation to make voltage and current more nearly in phase. It may be required, for example, to run G_2 at a higher level of output so as to supply the reactive power consumed by line 2.

Another point is that system operators must determine ahead of time how much power will flow over each line. This determination is made using a load flow study. Load flow studies require the solution of electrical equilibrium equations, and these studies become more time consuming and expensive as the number of generating units, lines, loads, substations, and other devices grows. A proper load flow study considers both real and reactive power flows for each of the three phases of AC flow. Sometimes, an approximation based on one-phase flows is adequate, and a crude estimate that ignores reactive power--a so-called DC load flow study--may suffice for some purposes. Operators may dispense with load flow studies for day-to-day transactions of a repetitious kind with which they are experienced and for transactions involving small amounts of power flow on lines that are not heavily loaded. But, when large new loads or generating units are added to a system or a major wheeling transaction is planned, a full load flow study may be essential.

Reliability Constraints

A third point illustrated by the example associated with figure 3-1 is that an outage on one transmission line can cause an outage on its neighbor. This raises the threat of a chain of cascading outages that could shut down electricity supply to a large region. Just such an event caused the well-known Northeast blackout in November 1965. One measure for avoiding such a cascade is to operate transmission lines well below their maximum capacity, so that an outage on one line can be easily absorbed by the unused capacity of parallel lines.

In this case, a transmission line may be limited in the amount of power it can carry to a value well below its technical capability as shown in table 3-1 in order to satisfy a reliability criterion. By reliability, we mean here the degree of assuredness with which the utility provides uninterrupted service to customers. To increase reliability is to decrease the probability of a service interruption. To help increase reliability, line 1 in figure 3-1 may be limited to, say, 350 MW so that it has the ability to back up line 2 in case lightning, accident, or other event should disable line 2.

Unused transmission capacity can contribute to reliability not only by backing up other transmission lines, but also by backing up generating units. Recall the chapter 2 discussion in association with figure 2-2 concerning reliability and networking. In figure 2-2, one or both of the horizontal transmission lines may represent excess transmission capacity that is used only when a major generating unit or a major transmission line goes out of service. Also, the interconnections with neighboring utilities may be constructed primarily to allow these utilities to back one another up in case of generating unit failure.

In such cases, the unused transmission capacity is constructed because it is a less expensive way to meet a target reliability level than constructing extra reserve generating capacity. Or it is constructed to provide the additional network paths needed for sufficiently reliable service to a distribution system formerly reached by too few pathways. This is often less costly than building new back-up generation capacity close to each distribution system.

If the utility depicted in figure 2-2 constructs this "excess" transmission capacity as part of a least cost plan to avoid new generation capacity costs, then it will want to operate its system under normal conditions with these lines less than fully loaded. This is so even at the time of system peak demand--perhaps especially so at this time--in order to provide continuous service to customers if an abnormal condition arises, such as a generating unit outage or failure of another transmission line in the network.

Then the amount of loading allowed on a given line depends on the probability and duration of various possible outages and failures, the resulting extra loading the line would have to take up, and of course the level of service reliability that the utility tries to maintain. Load flow studies of large firm bulk power exchanges between companies are used to find the actual power flows over each line in the network, and they are also used to study the effects of such exchanges on network reliability. How will the network react during the exchange if a large generating unit goes down, a large load starts up, or a principal transmission line is switched out of service? These are not rare occurrences, so it is important for reliability purposes to study how the power flows would redistribute themselves in such cases.

Load flow studies, properly done, give not only the real power flows, but also reactive power flows, generating unit outputs, load levels, the current along each line, the voltage at every substation, the relative phase of the voltage and current, and more. But such studies give these values for a single moment in time. After a change in the system, some time--from a few hundredths of a second up to several minutes--is required for the power flows to rearrange themselves and for the system to reach a new state of equilibrium. Load flow studies are static in that they give only the new values, assuming a new equilibrium condition is reached.

However, depending on what happens during the brief period of adjustment, the system may not reach the new equilibrium state predicted by the load flow study or may pass through a transient state with unacceptable characteristics. Voltage may drop too low in some areas, for example. There may be a loss of synchronization among system generating units. System frequency may deviate slightly from the 60-cycle standard following a system disturbance. Also, localized voltage or frequency effects may propagate through the system for several minutes. An important consideration in each case is whether the system is self-correcting. If the anomalies decrease and the system tends toward the 60-cycle equilibrium predicted by the load flow study, the system is stable. If not, especially if the system cannot maintain the standard frequency, it is unstable.

Computer programs exist that can analyze the stability of the system under a given disturbance. Such stability studies are important for determining the effects of bringing a new generating unit on line or adding a major new load--and for gauging the consequences of a major outage. Ideally, stability studies would be performed for each major planned bulk power exchange to determine the effects of accidental loss of generation, load, or transmission under the new conditions. Nevertheless, time and expense prevent an individual simulation of the effects of unexpected changes in each generator, load, and line in the network. For the same reason, simultaneous independent disturbances, such as a lightning stroke shutting down a major transmission line during an unplanned nuclear unit shutdown, are usually not studied. Instead, engineering judgment is used to select changes in the larger facilities closer to the planned transmission corridor for reliability studies. The reliability study may be a stability study, a proper load flow study, a simple "DC load flow study," or reliance on experience and judgment for estimating the effects of bulk power flow on reliability. Use of such judgment, together with an operating practice of maintaining reserve transmission capacity, is often considered adequate for maintaining system reliability. For this reason, planning full use of transmission network capacity without full reliability study makes system operators anxious. Operators prefer some level of unused transmission capacity, but the level may vary from company to company, depending on the degree of conservatism with respect to reliability.

The unused transmission capacity that interconnects with a neighboring utility can be used for economy interchange, where the neighbor's power is less expensive than the utility's own generation, provided this economy service can be interrupted for the emergency reliability needs of either party. However, in planning construction of new interconnections, a utility may plan enough capacity for both reliability requirements and for firm power imports or exports. This creates uncertainty about how much transmission capacity is truly in excess of reliability needs and how much may be available for firm wheeling.

Increasing System Power Transfer Capability

Suppose a utility has a long AC transmission line running from a distant generating station to a major load center and it becomes necessary to increase the amount of power that can flow along this path. Several options for accomplishing this are available to the company, depending on the line design, its existing power carrying capability, and the size of the power increment. These options range from a temporary relaxation of reliability constraints to the construction of another line along the same right-of-way.

Power transfers can be increased by altering the limits imposed by reliability, stability, voltage support, and thermal/corona problems. These alterations may require complementary upgrading of substation capabilities because substation capacity can limit power transfers even if line limitations are overcome.

Improving Reliability

Where reliability of service to customers imposes a limit on line capacity, one can, at a risk, ignore the limit for a while and hope nothing goes wrong. This may be acceptable if the company starts with a very conservative reliability target and if the chances of an outage are small, the violation of the limit is for a short time, and the extent and duration of any probable outage are limited.

As a preferred alternative to ignoring the reliability limit, one may be able to increase a line's reliability, and so raise its power transfer capability, by such means as adding more or better lightning protection, surge arresters, and substation switchgear.

When a line's loadability is limited by the reliability constraints of a parallel line (recall case 1 in figure 3-1), it is sometimes possible to modify the distribution of power over parallel lines. This can be done by installing a phase-shifting transformer, or phase shifter, in one of the lines. The power carried by that line can decrease, while the power on parallel lines increases to make up the difference. Alternatively, the phase shifter can increase power flow on a given line and ease the loop flow burden on neighboring lines. Phase shifting transformers can come with permanent settings built in or with adjustable controls to optimize power flows under various operating conditions.

While use of phase shifters is not uncommon on lines up to 138 kV, they have often not performed well on higher voltage lines in the past. Recent developments in solid-state technology hold promise of significant potential for increasing the capabilities of existing transmission networks with phase shifters. However, they introduce additional line losses into the transmission system, and transmission capacity expansion may be limited by the power handling capability of any phase shifters in the system. Therefore, for several reasons, their use for expanding wheeling capability is limited at this time.

Beyond these measures, capacity additions to other parts of the transmission network may ease the reliability requirements on a particular line, allowing it to carry more power. Locating new generating units near load centers could have the same effect.

Compensating Reactance

Alleviating limitations on line power-carrying capability imposed by stability considerations and by the need for voltage support are considered here together. This is because both are related to transmission line reactance and both are treated by counteracting this reactance. As we have seen, line reactance effects can be counteracted, within limits, by controlling the current/voltage lagging of the generator output. Typically the generator supplies reactive power; that is, it causes the generator voltage to lag the alternating current. But another, though most costly, way of controlling reactance effects is sometimes necessary; this is to install reactive power compensation devices along the transmission line, particularly at substations.

A variety of reactive power compensation equipment is available, with the various devices more or less suited for several specific applications. All these devices help to maintain system stability with a steady load, though not all are useful for maintaining stability when the load undergoes sudden large changes. Some help to limit any voltage drop; some limit any voltage increase beyond the intended voltage value when load falls; and others can help in both ways.

The simplest reactive power compensation devices are the inductor, which compensates for capacitive reactance, and the capacitor, which compensates for inductive reactance. The inductor is often called simply a reactor (short for inductive reactor), and the capacitor is sometimes called a condenser. These two devices can be connected either in series with the transmission line or in parallel with it. A parallel connection to the ground is usually called a shunt connection. These connections are illustrated in figure 3-2. Compensation equipment is usually installed at substations, unless the line is long enough so that additional compensation along the way is required. This may be as much as every 50 miles or as little as every couple of hundred miles.

Possible compensation equipment includes shunt capacitors, shunt reactors, series capacitors, and series reactors. The first three are commonly used, the fourth less so. Shunt devices are useful for both voltage control and system stability and are needed on EHV lines of all lengths. Series devices are used more for maintaining stability, and series

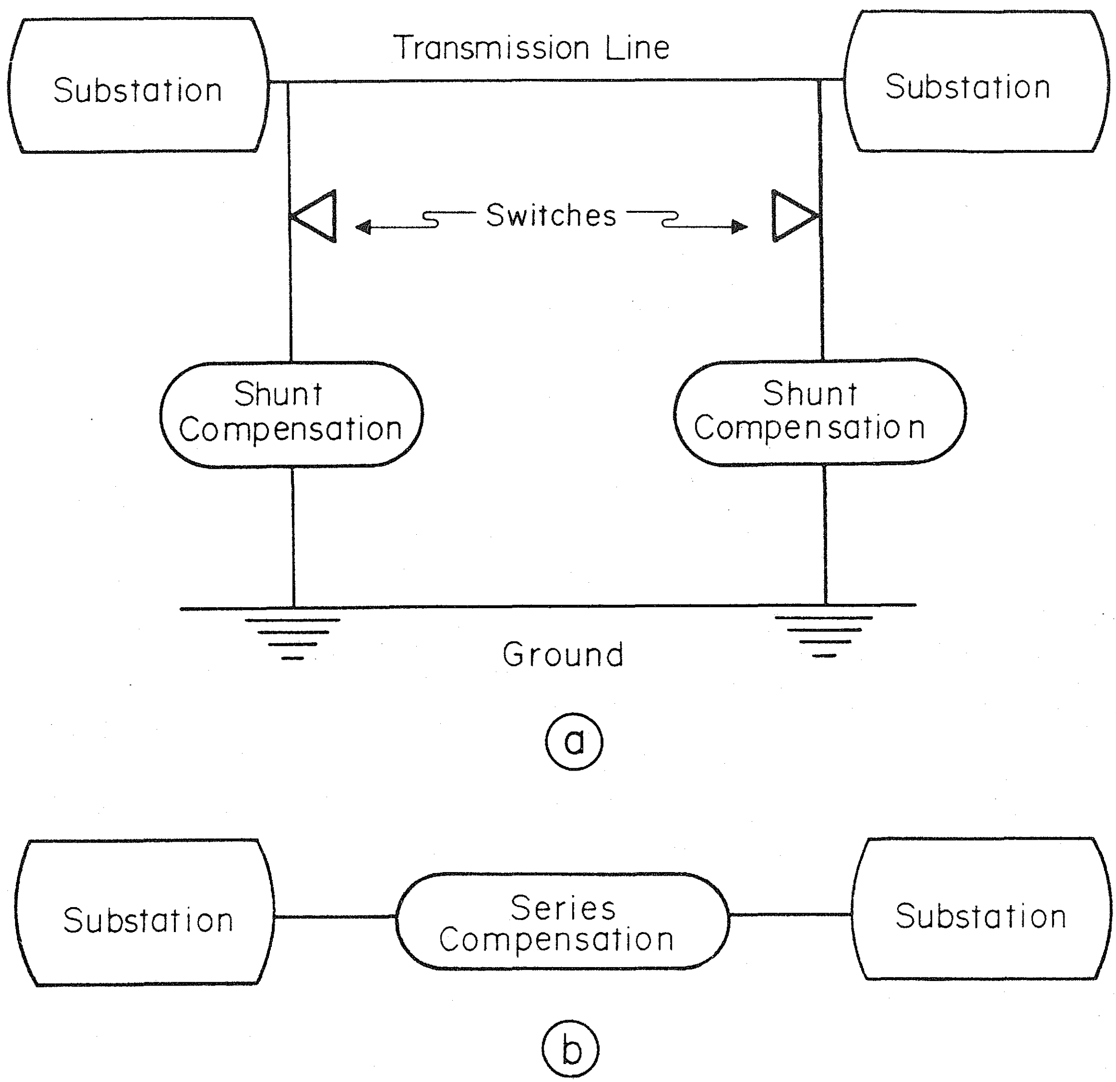


Fig. 3-2 Two methods of connecting compensation equipment (reactors or capacitors) to a transmission line running between two substations: (a) shunt connection, and (b) series connection. Shunt compensation is often located at substations, either at the receiving station only or at both the sending and receiving stations, as shown in (a). Additional shunt compensation may be added at intermediate points along long lines. Series compensation is relatively insensitive to its location along the line.

capacitors are particularly useful for very long distance transmission.

The shunt capacitor is used both for limiting voltage drops and for improving system stability where the generator-transformer-line-load system has excess inductive reactance. (It is also used to supply reactive power where a DC line meets an AC line because no generator is available there to produce reactive power.) It is not possible to construct a single shunt capacitor large enough to meet the reactive power supply needs of a major substation, and so shunt capacitors are added to the system in groups, called banks. An individual capacitor in a bank can withstand no more than 2 to 20 kV, depending on type, and can supply no more than 200 to 600 reactive kilovolt-amperes (kVAr, called "kilovars") of reactive power, whereas the needs of a major line are many times this figure and are measured in "megavars," MVAr. (Recall that appendix B contains a discussion of electrical units of measurement.) Banking allows a need of virtually any size to be met. Roughly 60 percent of the industry's installed supply of reactive power consists of small shunt capacitor banks mounted on distribution system wood poles; another 30 percent is located at small distribution system substations, fed by subtransmission systems; and only 10 percent is installed in larger transmission-to-subtransmission station equipment. Shunt capacitors are only occasionally applied on an EHV system, but an important current trend in the industry is to increase the use of these higher-voltage banks so as to increase the transmission capability of existing systems.

The shunt reactor provides help in maintaining system stability by counteracting line capacitance-related effects, and it is most useful for controlling line voltage shifts that occur as line capacitance effects change over time with a varying load. It is useful particularly for limiting voltage increases. Voltage tends to increase not only with gradual load changes, but also with sudden shutdown of a large load or with lightning strokes; the shunt reactor helps limit voltage rises due to all these causes. Shunt reactors are commonly installed on EHV lines of 345 kV, 500 kV, and 765 kV. There may be one reactor for each phase conductor or one three-phase reactor for all three conductors.

Alternatively, shunt reactors (called tertiary reactors) may be installed on the low voltage side of the substation transformer. At 500 kV, a typical single-phase shunt reactor is rated at absorbing about 50 MVAr; a three-phase 500-kV reactor typically is rated at 70 MVAr. Tertiary reactors are usually three-phase, typically 25 MVAr at 13.8 kV.

Series capacitors are used primarily to improve the stability of a system containing a long transmission line while permitting greater power transfer along the line. They do so by directly cancelling line inductive reactance effects. A bank of series capacitors is installed along the line, supported on a tall platform that electrically insulates the bank from the ground. The rating of the bank is determined by the number of capacitors it contains. Originally, series capacitors were used exclusively on distribution circuits, but this use is no longer common. Especially in the western United States, they are being installed on EHV transmission lines as an economical way to boost line capacity.

Series reactors do not materially help with voltage control or system stability because loads are generally inductive. These devices are installed mainly to retard current build-up in case of a short circuit, not to provide reactive power compensation.

The compensation devices just described have the advantages of simple construction, easy operation, low maintenance, and relatively low capital and operating costs. They also have some disadvantages. The primary one is that the amount of compensation is fixed at the installed value. At best, some control can be achieved with a shunt device by a switch that connects or disconnects the device and the line. A large shunt capacitor bank can usually be switched on or off as the need for reactive power changes. Too much capacitance under light load conditions causes the voltage to become too high. But the act of switching can introduce unwanted voltage pulses into the system. Very large capacitor banks can be switched on in stages; indeed, automatic switches that respond to time of day, voltage, even kilovars are available; but the cost of this more elaborate switching equipment is appreciable.

A shunt reactor is a single unit that is either on or off. So system designers must estimate the most useful rating for the device before it is installed. The rating is typically made in terms of the percentage of transmission line capacitance that is compensated, and ratings of actual units vary between 10 and 90 percent. The amount of compensation is governed by the desire to minimize costs, including reactor costs, given the anticipated line loading and the characteristics of the generators and loads.

A series capacitor is not only fixed in rating, but also it cannot easily be switched out of the circuit--though protective switchgear can bypass the capacitor in the event of a high voltage surge. Under light load conditions, the reactive power supplied by the series capacitor must itself be compensated for, so that some form of additional shunt reactor compensation, which can be switched on and off, may be necessary. The series capacitor cannot tolerate a voltage much above its design voltage and so the cost of overvoltage protection equipment must be incurred. Another problem with the series capacitor is that, in highly compensated transmission circuits, it can occasionally cause any of several undesirable electrical effects, all associated with unwanted electrical waves oscillating back and forth along the line. Because the frequency of these waves is below the normal system frequency of 60 cycles per second (the so-called synchronous frequency), this group of effects is given the common name of subsynchronous resonance. The energy caught up in these oscillations seeks an outlet, and that outlet can be as serious as induced mechanical vibration in system components. Subsynchronous resonance can flex, even break, the shaft of a large turbine-generator unit.

It is possible to have better than simple on/off control over the amount of compensation through the use of solid-state switching devices that sense changes in voltage level and reactive power requirements and automatically switch on or off many shunt capacitors or shunt reactors as needed. The key component of the system is a solid-state switch, called a thyristor, which has no moving parts but can turn on or off parallel circuit components. Such a system can provide an almost continuous range of compensation levels. These compensation systems have several names, depending on their purpose; they can be designed to supply reactive power (the thyristor-switched capacitor), to absorb reactive power (the thyristor-controlled reactor), or to do either as needed (the <u>static VAr generator</u>).

These systems are not inexpensive. A transformer is required to reduce the transmission line voltage to about 13 to 35 kV so as to operate the thyristor. Physically, the static VAr generator looks like a substation with its busworks, controls, cooling systems for the thyristors, reactors, capacitors, and circuit breakers. It requires considerable space, typically

100 square feet per MVAr for large installations rated at 50 MVAr and above. While costs are high, adding static VAr generators to existing lines is often an inexpensive alternative to new transmission line construction.

Over the last ten years, static VAr generators have come into increasing use to solve transmission problems and are now replacing, for many applications, an earlier device for continuous control of the amount of compensation, the synchronous condenser. The synchronous condenser is basically a large motor, which is designed to rotate in unison with (and hence be in synchronism with) system generators, but which drives no load. In maintaining synchronism, it responds to a falling voltage (usually caused by transmission line inductance) by forcing the voltage to lag the current; that is, it acts like a capacitor, hence the term "condenser." Thus it tends to support the voltage. Further, it responds to a rising voltage by acting like a reactor, inhibiting voltage rise.

For more than 40 years, synchronous condensers have been used to control voltage and the supply of reactive power. Units capable of supplying up to 250 MVAr have been installed to solve transmission capacity problems. These also are expensive devices. A unit cannot use high transmission voltage directly and so requires a transformer. It must be constantly cooled once started and needs a starting motor to get it moving again once stopped, requiring about a quarter of an hour to get up to full speed.

Both the static VAr generator and the synchronous condenser create some "harmonics," undesirable electrical oscillations along the transmission line, but these are less of a problem for the synchronous condenser. For both, the performance capability is much more sensitive to location along the transmission line than is the case for the more passive compensation devices discussed earlier. The static VAr generator requires more complex busworks, controls, and protection from overvoltage, but it responds very quickly to system changes. The synchronous condenser performs better when overloaded, but requires a strong concrete foundation, has high maintenance requirements, and responds more slowly to system changes.

Taken together and deployed appropriately, these various reactive power compensation devices can raise the limit on transmission line capacity imposed by voltage support and stability requirements. The capacity limit can be moved toward to the more fundamental limit imposed by thermal and corona effects.

The voltage and stability limits cannot be removed entirely, however, for long lines. This is because reactive power is created and absorbed throughout the line's length, whereas compensation equipment must be installed in "lumps" at fixed locations, so that practical compensation can be good but not perfect. Further, most of the installed compensation is in the form of fixed-value capacitors and reactors that can only crudely compensate for continuous changes in reactive power needs. While some devices can provide an almost continuous range of compensation levels, they are less commonly installed, and they can give rise to troublesome electrical problems if a very high level of compensation is attempted in order to achieve a very high capacity level.

An additional difficulty that particularly pertains to wheeling is that many transmission lines may have little compensation equipment or have equipment of low rating. This occurs where lines were installed for short-haul traffic, but are now called on for use as a leg in a long-haul wheeling transaction.

Upgrading the Line

When all avenues of reliability improvement and reactive power compensation have been exhausted, the only way remaining to increase further the power-carrying capability along a given right-of-way is to alter or add to the existing transmission line. The ways to send more power are to increase the voltage, increase the current, or both.

More power can be transmitted by raising the sending-end voltage. When this voltage is as high as it can go without experiencing insulator breakdown or corona problems, further increases in voltage require the addition of insulators to the string and possibly replacement of the conductors with larger diameter conductors. Since these changes could require an increase in the height of the conductors and in their spacing, the changes may be tantamount to replacement of the line with a higher voltage line.

In this case, a better option may be to construct a second line along the same right-of-way if enough space is available. If not, replacement of an existing single-circuit line with a double-circuit line can be considered. It is not uncommon for double-circuit towers to be constructed with only one circuit strung along the towers in order to provide for future expansion. In this case, of course, the way to increase transmission capacity is to string the second circuit. However, double-circuit lines have lower reliability than two single-circuit lines because damage to a single tower can remove two parallel circuits from service.

For transmission of power at distances over 400 miles, construction of a new high-voltage DC line is frequently preferred today. (Over the next ten years, AC transmission at 1000 to 1500 kV will be tested by several nations for such long distances.) DC lines are very reliable and require no reactive power compensation, though large amounts of compensation are required by the converter stations at both ends of a DC line where it interfaces with AC lines. The amount and direction of power flow can be controlled much more easily with DC than with AC lines. DC lines require only two conductors instead of the three needed for three-phase AC power flow, and they can carry more power than AC lines for a given conductor diameter and insulator string length. Hence, to expand the capacity of an existing right-of-way, a new DC line could be constructed next to an existing AC line along the right-of-way, or the AC line could be converted to a DC line. Such conversion requires the addition of rectifier and inverter equipment at the ends of the DC line and possibly new line conductors and insulators.

Simple DC replacement is not possible if the long transmission line must serve local loads along the way because the expense of installing inverter equipment at each locality would be too high. In this case, replacement of an AC line with a hybrid transmission line is an option. This is a double-circuit line with one AC and one DC circuit, with the AC circuit serving local loads. The hybrid line has several times the power-carrying capacity of a single AC line. In addition, the HVDC circuit can help to increase the stability of the parallel AC circuit and can reduce potential problems with subsynchronous resonance in the series-capacitor compensated AC line.

PART II

WHEELING COSTS

CHAPTER 4

COSTS INCURRED BY THE WHEELER

The costs incurred by a wheeler of electric power can vary greatly depending on the characteristics of the wheeler and the circumstances of wheeling. Depending on the situation, some cost components may be high, low, negative, or not incurred at all. Wheeling costs are incurred by all companies that experience a change in power flows over their transmission lines during wheeling, whether or not they are part of the wheeling contract path.

Costs are considered here in two general categories: short-run costs and capital costs. Short-run costs are all operation, maintenance, and opportunity costs incurred in completing a wheeling transaction. Capital costs are the costs of new major equipment purchases and facilities construction incurred to provide wheeling services over the long term.

Short-run Costs

The various short-run costs incurred by the wheeler can be categorized as either generation costs or other short run costs. Generation costs are almost always of concern to the wheeler; other short-run costs are often judged to be too small or too difficult to quantify.

Generation Costs

In the absence of wheeled power, the wheeling utility supplies its own native loads by having certain of its generating units on line at various levels of generation output. With wheeling, both the number and location of units on line, as well as their generation levels, can change. The result is a change, usually an increase, in generation costs.

A generation cost increase means primarily an increase in fuel costs. For a hydroelectric utility, any generation cost increase is determined largely by the replacement cost of water; so it can be low or high depending on whether water is abundant or in short supply. There may also be a small, probably unmeasurable, increase in generation operation and maintenance costs reflecting such changes as increased coal handling expense and more wear and tear on cooling water pumps.

Generation cost changes caused by wheeling are associated with changes in line losses, reactive power requirements, spinning reserve requirements, and economic dispatch. Generation cost changes are difficult to measure and require computer models to calculate accurately. Line losses cause large cost changes and, in practice, are always estimated, even if inaccurately. Generation cost changes due to other factors are usually small; in practice, they are often ignored or assumed to be accounted for within the limits of accuracy of the line loss cost estimate.

Generation for Line Losses

The cost of line losses is the cost of generation needed to make up for line losses. Since energy is converted to heat in conductors, transformers, and other circuit equipment, more than 100 MW of generation is needed to deliver 100 MW of power to a primary substation bus (recall figure 2-5). Hence, extra fuel must be consumed to make up for losses. The cost depends on the size of the line losses and on which generator or generators supply the additional power.

The amount of line losses in a wheeling transaction is affected by several factors. Suppose wheeling takes place along a single line. Then the amount of line losses depends on the length of the line, its voltage, the amount of power wheeled, the load already on the line without the wheeled power, the amount of reactive power carried by the line, and the direction of power flow.

Figure 4-1 helps sort out these factors. It shows a typical loss-load curve for a 345-kV line of 100 circuit-miles (where the number of

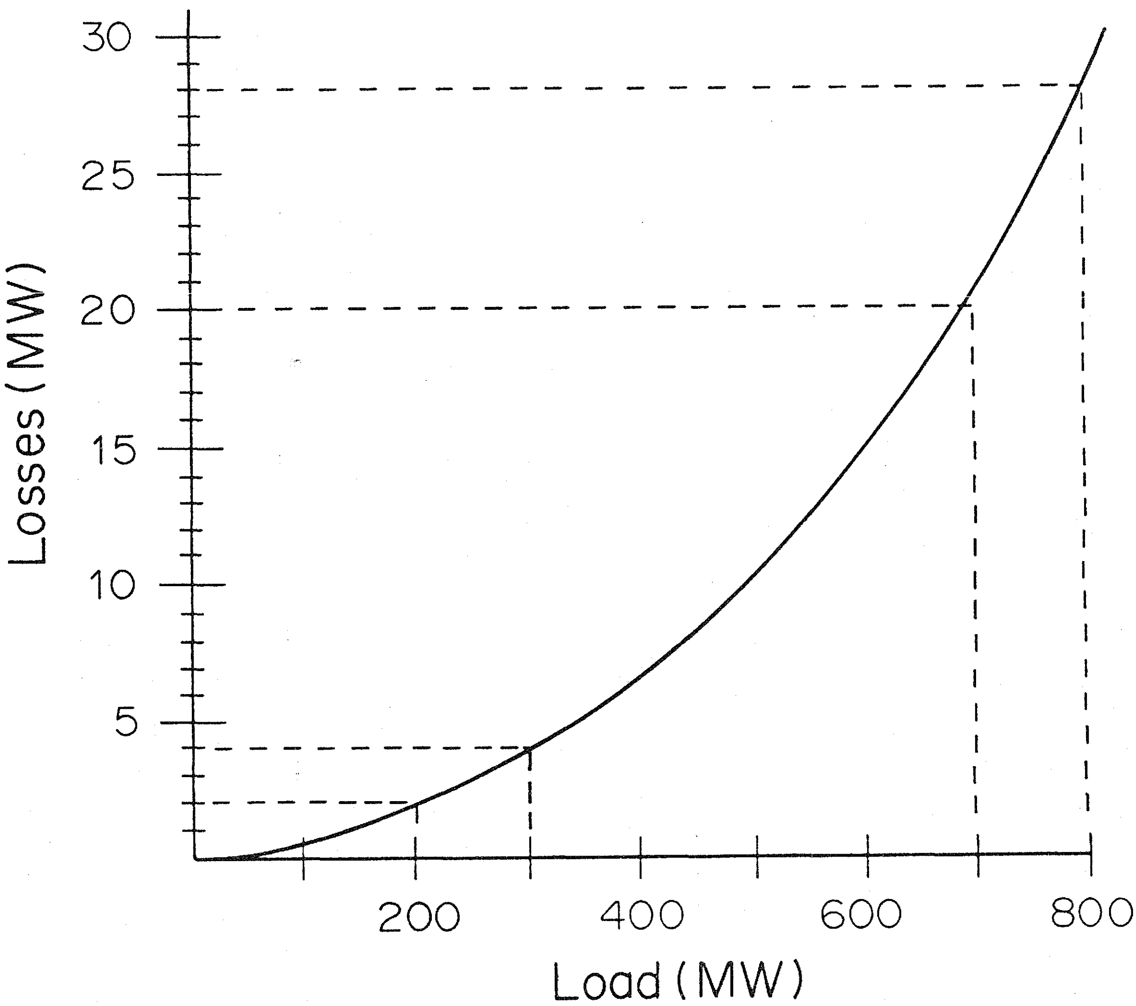


Fig. 4-1 Example of the relation of losses to load on a single transmission line. This example is typical of the loss per 100 circuit-miles on a 345-kV transmission line. Losses increase with line length and decrease with line voltage. Source: Gregory S. Vassell and Raymond M. Maliszewski, "AEP 765-kV System: System Planning Considerations," IEEE Transactions on Power Apparatus and Systems PAS-88 (September 1969): 1320-1328.

circuit-miles is the length of the line multiplied by the number of circuits on the line). For example, if power transmitted to the load at the receiving end of the line is 500 MW, the curve indicates that line losses are 10 MW. Then, 510 MW must be put into the sending end of the line in order to deliver 500 MW. About 2 percent of the power (10 MW ÷ 500 MW) is lost in transmission. Other lines would have different losses: a 200 circuit-mile 345-kV line would lose 20 MW in delivering 500 MW, or 4 percent; a 100 circuit-mile 765-kV line, however, would lose only about 1 MW to transmit 500 MW, a loss of 0.2 percent. For any given line, losses depend on the load factor of the line, the ratio of actual load to line capacity. Actual losses, expressed as a fraction of peak losses, vary with load factor F roughly according to $0.8\ F^2 + 0.2\ F$, that is, approximately linearly for small loads and quadratically for loads that approach line capacity.[1] Hence, losses associated with wheeling depend on the size and direction of the native load on the line.

Consider the losses associated with wheeling 100 MW on the line in figure 4-1. If the native load on the line is 200 MW, wheeling 100 MW raises the losses from 2 MW to 4 MW. Wheeling causes a 2-MW increase in losses, which is 2 percent of the amount wheeled. For each hour that these losses occur, the energy lost is 2 megawatt-hours (MWh), given by 2 MW x 1 hour, which equals 2000 kWh. If the appropriate generation cost is (say) 4 cents/kWh, the cost of line losses is (2000 kWh per hour) x (4 cents/kWh) = $80 per hour.

At this level of transmission, the average loss, expressed as a percentage of total line load, is (4 MW ÷ 300 MW) x 100% = 1.3 percent. (If one argues that each of the three 100-MW increments is equally responsible for the total 4-MW loss, then the loss associated with wheeling 100 MW is only 1.33 MW.)

Suppose now that the native load on the line is 700 MW when 100 MW is wheeled. As indicated in figure 4-1, wheeling increases line losses from 20 MW to 28 MW. The incremental line loss is 8 MW. Whereas in the previous

[1] B. M. Weedy, Electric Power Systems, 3rd ed. (New York: John Wiley & Sons, 1979), p. 38; other studies indicate $0.7\ F^2 + 0.3\ F$, see F. J. Calzonetti et al., An Evaluation of Electricity Export as a West Virginia Coal Utilization Strategy (Morgantown, WV: West Virginia University, Energy Research Center, September 1985).

example, losses equaled 2 percent of the 100-MW delivery, here they equal 8 percent. Now the cost of line losses is $320 per hour. Average losses increase to 3.5 percent = (28 MW ÷ 800 MW) x 100%.

In these examples, it is assumed that the power wheeled flows in the same direction along the line as the native power. Wheeling in the opposite direction reduces line losses. Recall from chapter 2, especially the discussion of figure 2-7, that counterflow reduces rather than adds to the load on a line. If the line in figure 4-1 carries a native load of 800 MW, then wheeling 100 MW in the opposite direction produces no new losses, but reduces the wheeler's losses from 28 MW to 20 MW. This allows the wheeler to reduce its generation by 8 MW and save on fuel costs. As a result, there is no line loss cost imposed on the wheeler; instead the wheeler experiences a line loss savings. (Some would refer to this as a "negative cost.")

A transmission line often carries reactive power from a generator to a load. As the amount of reactive power the wheeler must carry increases, line losses increase and hence the loss expressed as a percentage of delivered power increases also. Further, as the load on the transmission line increases with wheeling, the need for reactive power compensation changes. It may be necessary to switch on the line's installed compensation equipment, if any. The compensation devices themselves add to line losses, but their use may decrease overall system losses as the reactive power carried by the line decreases.

In practice, wheeling usually does not take place over a single line, but over a network of interconnected lines of various lengths and voltages. Line loss costs can be high on some lines and low on others; they can be positive along some lines and negative along others. However, as power flow divides itself over more lines the losses on any one line usually decrease. The true line loss cost is the sum of the costs over all affected lines. Since some of these costs are positive and others negative, it is the net cost that matters. Where several utilities are involved in the transmission, there may be a net positive cost along the lines of one and net negative along another's.

Accurate determination of the costs of line losses requires computer software. The various line flows can be determined with a load flow study; losses can be found, and costs can be calculated with a generation dispatch model for each company supplying the power to cover the line losses.

However, industry practice often has been to use some measure of the wheeler's average percentage line losses, instead of computer models, to estimate the power lost in wheeling. This practice was necessary in the past because of limited computational ability. It may continue to be convenient for short-term or small quantity power exchanges. However, if wheeling continues to increase in importance, more accurate calculation of line losses may become the norm as the speed and quality of engineering software improves.

The cost of the power lost in wheeling depends on whether the seller, the wheeler, or the buyer supplies the make-up power. It is possible to wheel 100 MW by letting the buyer receive 100 MW less losses, but this is never done in practice. The amount said to be wheeled is always the amount the buyer needs to receive. The buyer has a contract to receive 100 MW from the wheeler, and the seller and wheeler must agree on a procedure to account for losses. The usual practice is as follows. Suppose they agree that the wheeler's losses for a 100-MW wheeling transaction are 5 MW. Then the seller supplies an extra 105 MW to the grid while the buyer imposes an excess demand of 100 MW on the grid. If 5 MW is an accurate estimate of losses, then there is no line loss cost imposed on the wheeler. If it is inaccurate, the wheeler (and the wheeler's customers) may enjoy a gain or suffer a loss. Neighboring utilities may also experience changes in transmission line loads and hence changes in generation costs related to line losses. But, they are often not compensated for any cost increases under current industry practice.

Generation to Supply Reactive Power

It is sometimes necessary for a utility to run a generating unit so as to supply reactive power locally to the transmission system, as discussed in chapter 2. (See "Reactive Power Management" in the section of chapter 2 entitled, "Interconnections and Wheeling.") Some additional fuel expense and associated generation expenses are incurred when this happens, though they are often small. For generating units already on the line, the additional fuel expense associated with adjusting their reactive power outputs is quite small. However, in those cases when a high-cost cold unit must be started up and run to provide voltage support for the import of power from a cheaper, more distant unit, fuel expenses can be significant.

Wheeling may create a need for generation to supply reactive power. The buyer may or may not fully compensate the reactive power consumptions of its loads. Even if these are compensated, the wheeler's transmission lines and substations consume reactive power as the lines become fully loaded, creating a need for local compensation. The wheeler may not have reactive power generating compensation equipment installed along the lines or may not have enough compensation capacity to meet the needs of a heavily loaded line. Then running local generators at no load to supply reactive power could become necessary.

The reactive power effect of wheeling depends on the loading of the line in the absence of wheeling. Recall that a line loaded to its natural power level neither generates nor consumes reactive power. If addition of wheeled power moves the net power flow toward the natural level, the need for reactive power compensation is reduced. This would occur if more power is added to a lightly loaded line or if wheeled power flows counter to the native power flow of a heavily load line. Conversely, if the native power on a line is at or above the natural power level, wheeling more power in the same direction creates a need for a source of reactive power--possibly a local generating unit.

Spinning Reserve Generation[2]

Wheeling may cause a change in the wheeler's spinning reserve requirements. Spinning reserve refers to the unused capacity of generating units operated at synchronous frequency but at a no-load or partial-load level. This reserve capacity is on standby for immediate use in case another generating unit in the system goes down. The U.S. regional reliability councils set rules for the amount of spinning reserve required, taking into account the number, size, and location of generating units; the number, size, and location of loads; and the available transmission capacity

[2] Richard C. Tepel et al., Analysis of Power Wheeling Services, prepared for the U.S. Department of Energy, (November 1984); Allen J. Wood and Bruce F. Wollenberg, Power Generation, Operation, and Control (New York: John Wiley & Sons, 1984).

linking these generators and loads. The spinning reserve must be adequate to make up for the loss of a major generating unit within a specified time period without an extreme or prolonged deviation from standard synchronous frequency. The location of spinning reserve units is determined in part by the capacity of transmission lines to carry their power.

To the wheeling utility, the seller represents a new source of power and the buyer represents another load. If the source is comparable in size to the output of the wheeler's largest generating unit, then the wheeler must plan his spinning reserve requirements taking into account the possible loss of the seller's power. Even though the wheeler would be permitted to cut off power supply to the buyer in this case, system stability must be protected during the time required for this to occur. This may require more spinning reserve, and hence more fuel expense and other generation O&M expenses.

Generation for Economic Dispatch

Wheeling may change the wheeler's fuel cost of meeting native load. Native load is normally met using economic dispatch. In simple terms, this means bring generating units on line in order of increasing generation cost. In practice, implementing economic dispatch is somewhat more complex for several reasons. The generating cost of a unit changes as the output of the unit increases. Several units, instead of one large economical unit, should share the burden of increasing load so that the system is not vulnerable to the loss of the one large unit. The ability of various units to follow sudden load increases or decreases and the spinning reserve requirements of the system must be taken into account. Further, since the objective is to deliver, not generate, power at the lowest cost, line losses and the location of generating units with respect to current loads is a factor. Importantly, transmission line loading capability may constrain the choice of generating units for economic dispatch.

For all these reasons, the set of generating units and their output levels for meeting native load may be different with and without wheeled power on the transmission lines. This may be so even after accounting for generation for line losses, reactive power, and spinning reserve. For example, even though line losses may be exactly compensated for by the seller's supplying just the right amount of added power to the wheeler, the new load levels on the wheeler's various transmission lines may alter the wheeler's economic dispatch choices and hence change his fuel costs. Also, wheeled power could use up transmission capacity along a corridor connecting the next most economical generating unit to a load center, requiring that this unit to be skipped over in the loading order.

Other Short-Run Costs

A wheeling utility may experience no other short-run costs, aside from fuel costs and associated generation O&M expenses. However, under some circumstances, other short-run costs may be borne by the wheeling company. These are opportunity costs, transaction costs, and the costs of physical depreciation. We conclude by examining whether changes in reliability impose short-run costs on the wheeling utility.

Opportunity Costs

When wheeling uses up the wheeler's capacity to trade power with its neighbors, the wheeler may miss some opportunities for economical trades. It may have to pass up the opportunity of purchasing low cost power to displace its own higher cost generation, or it may forego the chance of making a profitable sale. In addition, it may not be able to participate in a diversity exchange with another company with a peak load occurring at another time.

Further, a particular wheeling transaction may use up wheeling capacity, precluding other wheeling arrangements, by other pairs of utilities, that have a higher value. Since these other utilities would be willing to pay more for the wheeling service (absent a cap on price), the loss of these potential revenues creates a missed opportunity for the wheeling utility equal in value to the opportunity costs of others.

Opportunity costs may be incurred by a utility that offers firm wheeling but might not be incurred with interruptible wheeling, depending on the conditions of interruption in the wheeling contract.

Opportunity costs cannot be known precisely in advance because they depend on what opportunities happen to arise for mutually beneficial wholesale transactions. However, in some cases a wheeler can estimate the value of foregoing certain regularly occurring opportunities.

Transaction Costs

Transaction costs are the increases in operating expenses associated with scheduling, coordinating, conducting, monitoring, and completing the wheeling transaction. Much of these costs are employee wages, which may increase if staff is added to handle a permanently higher level of wheeling.

The cost of any load flow and stability studies to assess the feasibility of wheeling is a transaction cost. The utility may pay others to do these studies or develop its own models and staff expertise. There are also the costs of informing neighbors of possible loop flows, coordinating generation control with them, and settling accounts for any inadvertent loop flows or additional generation by neighbors. After the wheeling transaction, there are the costs of billing the parties for whom the wheeling is performed. Normally the transaction costs of wheeling are quite small compared to generation costs, and in practice are often ignored in setting wheeling rates.

Physical Depreciation Costs

Increasing the level of power flow along transmission lines shortens the service life of the transmission system. The heating effect of line losses degrades the physical properties of such components as conductors, insulators, and transformers. The result is that these components must be replaced sooner than would otherwise be the case. This moving forward in time of a future cost increases the present value of that cost. Any such increase in present value caused by wheeling represents a cost imposed on the wheeler by the extra physical depreciation of the transmission system. In addition, there may be extra maintenance expense if the frequency of line inspections increases with some measure of load over time.

Wheeling power counter to the flow of native power produces a depreciation savings. As in the case of line losses, the net cost of physical depreciation is found by summing the costs and savings over all lines involved in the transaction.

Because much of the physical depreciation is caused by heat due to line losses, the amount of depreciation caused by additional power flows depends on the flows already on the line. Recalling the discussion of figure 4-1, the deterioration caused by adding 100 MW to a lightly loaded line may be immeasurably small, while adding 100 MW to a line already operating near its thermal limit can be significant. If a line is never allowed to approach its thermal limit for reliability or stability reasons (here recalling the discussion in chapter 3), depreciation costs may always be negligible. In practice, these costs are ignored in current wheeling contracts.

Reliability Costs

Wheeling may decrease service reliability. As transmission lines take on increasing load, the probability that some customers lose service generally increases. The service interruption may be related to either loss of transmission capacity, loss of system stability, or loss of generation, as explained in chapters 2 and 3. The more heavily loaded a transmission line, the more vulnerable it is, for example, to a lightning stroke overloading the line and taking it out of service. The more heavily loaded a line, the less capable it is of providing backup transmission service when a parallel line goes down. In the case of transmission that is constructed to link loads to generation reserve capacity (as a lower cost alternative to constructing more generation near loads), the more heavily loaded the line is with wheeled power, the less generation reserve margin is available to serve loads.

When retail customers of the wheeler lose electric service, they bear the costs of any reduced reliability, not the wheeling utility. The manufacturer loses production; the supermarket, refrigeration; the teenager, top-twenty music. The costs depend on the timing, the duration, and the extent of the service outage, the availability to the customer of backup power, and the customer's individual circumstances and psychological needs. Because of the varying types of costs and typically large number of customers, the costs of a service interruption are notoriously difficult to estimate, even after the fact, for an actual service outage. Estimating the costs borne by customers in a possible future outage of uncertain timing, duration, and location is of course still more difficult.

If the total cost borne by customers were known or estimated, the cost of reduced reliability could be estimated as follows. Suppose the cost of a 10-minute service interruption at noon on a weekday in a certain distribution area is $10 million, and the probability of such an interruption on any weekday is known (from load flow and stability studies) to be one in a million. Then the cost is either zero, if no interruption occurs, or $10 million if one does. However, in probability terms the expected value of the cost is $10 (= $10 million x 1/1,000,000). Further suppose that a wheeling transaction takes place that increases the probability of the interruption to one in ten thousand. It is still very likely that no interruption will occur and that none of the $10 million cost will be incurred. However, the expected cost is now $1,000 (= $10 million x 1/10,000). The cost increase associated with wheeling is $990 (= $1000 - $10).

This cost is borne by customers. If the utility can reduce the probability of an outage back down to one in a million by investing less than $990, it should do so. This is because customers would prefer a sure (say) $600 cost increase to an expected $990 cost increase. Where utility investment does occur to improve reliability, it generally represents a capital cost of the type discussed in the next section; then it is not a short-run cost but a long-run cost. When the required investment costs more than $990, it is not justified on a cost basis. Then retail customers may experience reduced reliability. For customers without backup equipment, either they bear a short-run cost or the wheeler bears a long-run cost.

While this is a correct costing procedure, the difficulties of measuring actual costs and of calculating probabilities have resulted in the substitution of a simplified rule of thumb for this procedure, as illustrated in figure 4-2. This figure illustrates a hypothetical relationship between the probability of some service interruption occurring on any given day and the load factor on a particular transmission line. (The numbers are not based on actual engineering data.) It shows that any increase in line loading results in an increased probability of interruption and hence in an increased expected cost. But a company may adopt a rule of thumb that the line should be loaded to no more than 70 percent, for example, of capacity in order to "maintain reliability." Any loading up to 70 percent is permitted. In this illustration, a 70 percent load factor

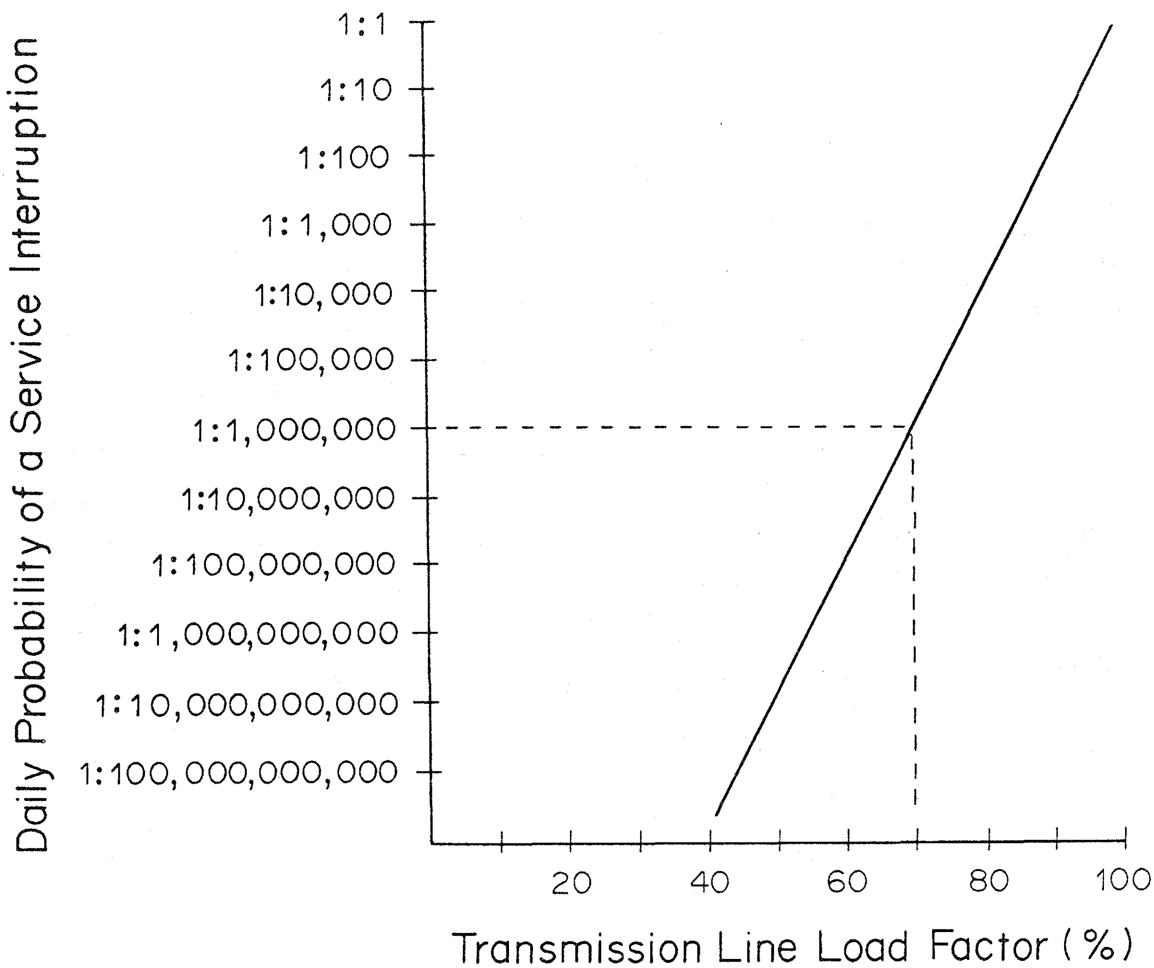


Fig. 4-2 Daily probability of a service interruption in terms of the load factor of a transmission line (This graph is intended to illustrate the concept and is not based on actual data.)

results in a one in a million chance of a service interruption on any given weekday. This may seem small, but with about 250 weekdays (other than holidays) in a year it amounts to one chance in 4000 each year. When this chance is combined with the chance of outage in other lines and the chance of generation and distribution system outages, the resulting likelihood of any given customer experiencing a service interruption can become significant.

Because various transmission lines play different roles in the transmission network, the graph in figure 4-2 would show a different slope for another line. The one-in-a-million target may occur at a 75-percent load factor for another line, for example. Hence, utilities will select different maximum load factors for different lines. These ceiling loads can reflect not only the different functions of the lines but also the degree of conservatism of the utility with respect to service reliability.

Use of a maximum load factor rule has implications about reliability costs. Implicitly, it assumes that the probability of an interruption for lower load factors is so close to zero as to be identically zero. Then changes in load factor below the 70-percent ceiling are assumed to impose no costs. Load factor is never permitted above 70 percent, except in emergencies, and even then should be reduced below 70 percent as soon as possible. It is as if the cost of exceeding 70 percent were infinite so that no finite price could compensate for the increase in reliability costs.

Use of the rule is an efficient simplification insofar as it allows system operators to make judgements quickly about line loading levels. Treating reliability costs as either zero or infinite is an acceptable approximation to the true reliability costs under two conditions. One is that the utility should have the optimal level of investment in transmission capacity; that is, the cost of new capacity should just equal expected customer cost savings with new capacity--considering the needs of both retail and wheeling customers. Second, each line's maximum load factor should be set at the "break-even" point, where the reliability cost of exceeding the ceiling by (say) one percent just equals the benefits of increasing transmission capacity by one percent.

Reliability costs may not be incurred with interruptible wheeling when wheeled power can be unloaded from transmission lines to meet the wheeler's emergency needs. However, reliability can be affected to some degree because of the time required to detect the emergency and rearrange power flows.

To summarize briefly, while customers may experience expected short-run reliability cost changes with changes in wheeling loads, the wheeling utility does not. It either experiences no short-run reliability cost (apart from the possible generation cost changes previously discussed) or incurs a long-run cost if meeting wheeling demand reliably requires new capital investment.

Capital Costs

An expected long-term demand for wheeling service may motivate a utility to expand the capability of its transmission system to move power through the system with minimal negative effects on native loads. Here we consider, first, some factors that affect the decision to expand transmission capability and hence that affect cost responsibility and, second, the capital costs of alternate ways to expand this capability.

Cost Responsibility

A utility may choose to expand its transmission system's capability for any one of several reasons, and it may not always be clear that the capital costs can be attributed solely to the wheeling service.

Transmission is sometimes constructed to realize fuel cost savings by connecting load centers to a source of cheap fuel such as a coal mine-mouth generating unit. The cost of transmission plus coal generation must be less than the cost of local generation with a cheaper fuel. Also, the cost of transmitting electricity from the mine-mouth plant must be less than the coal transportation cost. Decisions about constructing a hydroelectric facility at a site far from a load center, constructing a nuclear power plant away from a population center, and constructing a coal-fired generating station away from an area with air-quality concerns are all based in part on an analysis of economic trade-offs that depend on the cost of transmission. In each case, the costs of distant generation plus transmission should be less than the cost of local generation.

Besides fuel cost savings, construction of new transmission capacity can be a low cost substitute for construction of new generation capacity. As we have seen, this is because loads in a region can then share reserve generating capacity (the likelihood of simultaneous need for reserves being small) and because diversity in the peak times of the various loads allows fewer generating units to meet their simultaneous peak demands. Again, use of this strategy depends on an economic choice: the capital cost of new transmission must be less than the capital cost of new generation, with adjustments for changes in O&M expenses, particularly the fuel savings realized by always running the least cost generating units in a large interconnected system.

Also, new transmission that strengthens the internal network of a utility or strengthens the interties among companies brings the secondary benefit of improved reliability. Lines with more capacity and corridors with more lines are more stable than a single, heavily loaded line. Systems with more pathways from generators to loads are less likely to have a service interruption if one transmission line goes down, and, as discussed in chapter 2, large systems with strong interconnections are more stable and reliable if a big generating unit goes down. While the calculation is not ordinarily made by companies, the cost of a new transmission line might be justified by the reduction in reliability costs alone. However, the costs are incurred by one company and the reliability benefits are often shared by many.

Finally, of course, new transmission capacity may be constructed for providing wheeling services to neighboring companies. Here too the decision should be based on an economic choice: whether the expected revenues from wheeling over the life of the new line cover wheeling costs, including capital costs. If a line were built exclusively for the use of a particular pair of buying/selling utilities, these companies could enter into a long-term contract guaranteeing their right to use the line and the wheeler's recovery of costs. (Recall that if the trading partners own the line the term "wheeling" does not apply.) But if the line were to be built solely for the general wheeling needs of several neighbors, the wheeler would need to be confident that enough wheeling would take place to recover his capital costs. This would depend on his estimates of such factors as the size and expected duration of fuel cost differences among neighbors, and the amount and duration of these neighbors' extra generating capacity and capacity shortfalls.

The point of this discussion is that a particular transmission construction project may be undertaken to meet several of the objectives just discussed. The size and location of a line may be dictated by the desire to optimize the sum of several benefits: fuel cost savings, generation capacity savings, increased reliability, and serving the wheeling needs of neighbors. A line may be constructed that is not cost-justified on the basis of any one objective, but is justified on the basis of meeting several objectives. Hence, new construction may be undertaken in part to satisfy the need for wheeling, and the costs of the new capability are then common to wheeling and other functions. The determination of wheeling costs then depends on the method selected for allocating common costs.

The Costs of Expanding Capability

An electric utility may need to purchase and install additional equipment in order to wheel. The needed equipment may be as little as a new meter or as much as a new transmission line. The discussion that follows groups these needs in order of increasing costs, under the headings of miscellaneous equipment needed for wheeling, reactive power compensation equipment, and new transmission circuits. These categories correspond to the three sets of actions discussed in chapter 3 in the section entitled "Increasing System Power Transfer Capability." Miscellaneous equipment needed for wheeling is the lowest cost category, and there may well be no such additional cost for most large companies.

The principal capital costs of wheeling are the costs of increasing the power transfer capability of a transmission system in order to accommodate the extra load imposed by wheeled power without violating thermal, stability, and reliability limits. As discussed in chapter 3, if transfer capability is limited by considerations of voltage support and stability, installing reactive power compensation equipment may be the least cost way to expand capability. But if thermal or corona effects limit capability or if the line already has as much compensation as system stability allows, a new circuit or new line may be required for the system to carry additional transmission loads.

Equipment for Wheeling

A utility that has not historically engaged in much power trading may need to incur the cost of adding miscellaneous equipment in order to wheel reliably and efficiently.

In order to carry larger loads reliably on its transmission system, the utility might have to improve its substations, add switchgear such as relays and circuit breakers, upgrade its voltage control equipment, improve the lightning protection, and add additional electrical insulation at some locations. In order to monitor flows and coordinate generation with its neighbors, a company that has not already done so would have to install meters along tie lines, add telemetry and possibly computer facilities, and perhaps upgrade its automatic generation control (AGC) equipment.

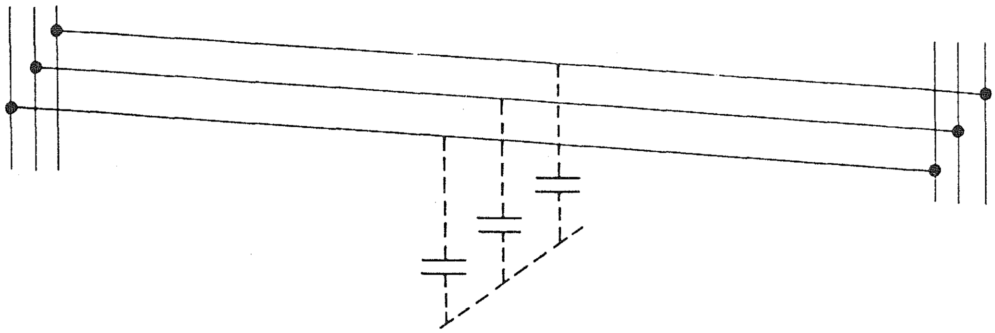
It may be useful or necessary to add a phase-shifting transformer to some lower voltage transmission lines to help control the flow of power. Phase shifters cost about $7,000 per MVA.

Compensation Equipment

As discussed in chapter 3, reactive power compensation equipment may have to be added to an existing transmission line in order to wheel power on the line or system of lines without degrading the voltage or threatening stability. The cost depends on several factors but, where this option is available, the cost is generally less than the cost of obtaining the same transmission capacity increment by building a new line.

The type, size, and cost of compensation equipment depend very much on the voltage, length, and design of the line and on the expected variations in loading on the line. They are also affected, especially for a higher voltage line, by system operating philosophy and the characteristics of the rest of the interconnected network. As a result, an engineering study is needed for each individual case to determine the appropriate type and size of equipment and hence its cost.

Figure 4-3 gives an example of how some compensation equipment costs are determined. Figure 4-3(a) shows a 150 mile long, 765-kV transmission line with no compensation. The line's capacitance (represented by the dotted lines) may adversely affect voltage control so that some shunt



(a)

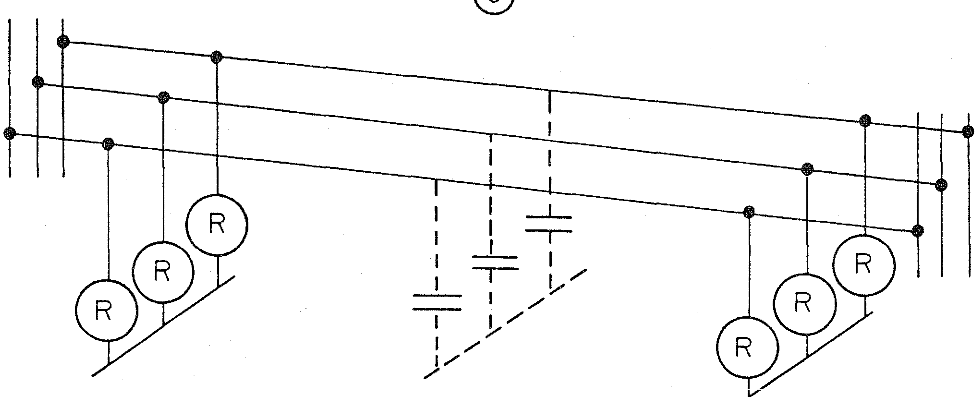
Voltage (kV)	Typical 3-Phase Reactive Power Requirements (MVAr per Mile)
138	0.10
345	0.85
500	1.6
765	4.5

Source: Prof. S. Sebo, Electrical Eng. Dept., Ohio State University

(b)

4.5 MVAr per mile x 150 miles = 675 MVAr

(c)



(d)

600 MVAr x \$5,000 per MVAr = \$3,000,000

(e)

Fig. 4-3 Cost of shunt reactors for an 89%-compensated, 150-mile long, 765-kV transmission line: (a) uncompensated line with capacitance (dashed lines); (b) typical inductive reactive power needs per mile of 3-phase line; (c) inductive reactive power needed for 100% compensation; (d) 89%-compensated line with six 100-MVAr shunt reactors (R); (e) cost of compensation.

reactor compensation is required, as discussed in chapter 3. The amount of reactive power needed to fully compensate the line is determined by an engineering calculation. The table in figure 4-3(b) gives typical needs in terms of MVAr per mile of three phase line; these data vary with line capacitance, which depends on such factors as conductor material, construction, bundling, spacing, and suspension height. As shown by the calculation in part c of figure 4-3, full compensation of a 150-mile, 765-kV line requires 675 MVAr.

The shunt reactors in service on EHV lines supply anywhere from zero to ninety percent of the line's compensation needs. Nearly full compensation can be achieved by installing six 100-MVAr shunt reactors as shown in figure 4-3(d): there is 300 MVAr at each end of the line, with a 100-MVAr reactor connected in a shunt arrangement to each end of the three phase conductors. Thus the line's capacitive reactive power is 89 percent (600 of 675) compensated. Shunt reactors cost about $5,000 per MVAr. The cost of nearly full compensation, as set out in figure 4-3(e), is about three million dollars. Shunt reactor compensation is especially useful for lines operated at light load.

Heavily loaded lines, on the other hand, usually need capacitive reactive power to compensate the generally large inductive reactive power caused by high line current. The effect of compensation is to make the lines appear electrically shorter. Adding capacitive compensation to the long lines in table 3-1 moves their power-carrying capabilities from the values listed toward the values listed for 50-mile long lines of the same type. As discussed in chapter 3, perfect compensation is not possible so that even well compensated long lines cannot achieve 50-mile capacity levels.

The amount of capacitive reactance needed for compensation in the transmission system depends on how much reactive power is consumed by the load on the receiving end of the line and how much of this is corrected locally near the load. Local correction can be done by the customer (the so-called power factor correction), by the buying utility in its distribution system, or by the buying utility running local generators to supply reactive power. The transmission system's need for capacitive compensation also depends on how much reactive power can be supplied by the sending-end generating units. Further, it depends on the inductive reactances of the transmission line and transformers, and these in turn depend on such things as line length, conductor material, the number of conductors per phase, and the spacing of bundled conductors.

Capacitive reactance can be supplied by installing shunt capacitors at the receiving end of the line. More effective cancellation of line inductive reactance, especially for voltages of 345 kV and above and for very long lines, is achieved by installing series-capacitor compensation near the midpoint of the line. In either case it may still be necessary to add shunt reactors also in order to limit voltage increases with sudden loss of load.

Manufacturers quote shunt capacitor costs of about $4,000 per MVAr and series capacitor costs of about $8,000-$10,000 per MVAr. Shunt reactors cost $5,000-$6,000 per MVAr. Installed costs with control equipment can be twice the manufacturers' costs or more. For example, a typical 1987 installed cost of shunt capacitors is about $8,000 per MVAr at 345kV, which increases to $12,000 with controls. At higher voltages, the latter cost may be as high as $15,000. As mentioned, the capacitive MVAr requirements of a line depend on several factors, but a typical uncompensated 150-mile long, 345-kV line can require about 150 MVAr capacitive, while about 200 MVAr capacitive is a typical requirement for a 150-mile, 500-kV line. In these examples, then, the total cost of capacitors would be about one to two million dollars for full shunt compensation and two to four million dollars for series compensation.

While series capacitor compensation is preferred over shunt compensation for increasing long distance, high voltage transfer capability, its use is hampered by the subsynchronous resonance effects that accompany it. As a result, compensation is limited to some 30% to 70% of line reactance to avoid these effects. There are 500-kV lines in the Southwest, for example, that carry about 900 MW each into Los Angeles. These are series compensated at only the 35% level to avoid harmful resonances; if compensation could be increased to 70% without damage to the system, the lines could each carry about 400 to 600 MW more.[3]

Capacitor banks and shunt reactors, which can be mechanically switched into or out of transmission circuits, are adequate under normal operating

[3] "Device Depresses Harmful Waves," Electrical World, October 1985, p. 36.

conditions with total load and reactive power requirements changing slowly. They can be less than adequate when things change quickly during a major disturbance, such as a sudden loss of load, loss of generation, or loss of a major parallel line. The best way of controlling reactive power quickly in such cases is with a static VAr generator (chapter 3), which can supply or absorb reactive power as conditions change. This thyristor-controlled device is superior to the synchronous condenser for most applications. It can increase the power-transfer capability of existing lines while improving voltage control and system stability under a wide range of abnormal conditions and reducing transmission system losses. A company that wants to add reactive power control equipment to increase its wheeling capability may select a static VAr generator because it does a better job of control under a wider range of conditions.

The cost of a static VAr generator also varies with several factors, including the maximum positive and negative VArs the facility must handle, its design level of performance, cooling requirements, and the space available for the facility. For facilities larger than 50 MVAr, the cost is about $15,000 to $20,000 per MVAr. (Unit costs are higher for smaller facilities because many of the components cost the same regardless of size.) Hence, a facility of the 150 to 200 MVAr size range would cost about two to four million dollars.

Where several lines move power to a common load center, it may be more economical to construct one static VAr compensation facility at the load center than to provide separate compensation for each of the several lines. Recently, a utility in a Western state had difficulty supplying receiving-end reactive power to five 345-kV lines, each over 100-miles long, running from generators to a major load center. Adding a single, large 300-MVAr static VAr generating facility at the load center solved the problem. The $5.5 million facility cost less than adding series capacitor compensation to each line and was one-fourth the cost of building a new line. The facility increased system power transfer capability by about 300 MW, 14 percent of prior capability.[4]

---

[4] J.D. Tucker and S.A. Miske Jr., "Power Delivery: Mechanical Switching Cuts SVC Costs, Losses," Electrical World, November 1985, pp. 61-62.

New Transmission Circuits

When all other avenues have been exhausted, if more transmission capacity is needed in order to wheel power, a new line may need to be constructed or a new circuit may need to be added to an existing line.

The authors initially experienced considerable difficulty in obtaining estimates of the costs of new transmission lines from published sources. Formulas in the literature for estimating line costs were too old to be of use. Telephone inquiries to some industry organizations produced no useful result. The few examples of recent line costs in the trade press gave numbers that were too diverse to be helpful. We were reminded of Powel's comment in his 1955 text:[5]

> The cost of transmission lines does not follow any recognizable formula. Two identical lines built in the same general locality by different organizations may vary widely in cost.

Therefore, we surveyed NARUC member agencies to obtain useful information on recent transmission line construction costs. The survey and its results are described in the next chapter.

After our survey was initiated, Oak Ridge National Laboratory published an excellent study on transmission line costs and the Energy Information Administration (EIA) of the U.S. Department of Energy began a multi-year project to develop a national data base on transmission line costs, though it will be a few years before EIA data are available to others for analysis.[6]

---

[5] Charles A. Powel, Principles of Electric Utility Engineering (published jointly by The Technology Press of MIT, Cambridge, and John Wiley & Sons, New York, 1955), p. 192.

[6] The Oak Ridge study is Comparison of Costs and Benefits for DC and AC Transmission, ORNL-6204 (Oak Ridge, TN: Oak Ridge National Laboratory, February 1987). For information on transmission data collected by the Energy Information Administration, contact the EIA Electric Power Division at (202)586-9850.

CHAPTER 5

SURVEY OF CURRENT TRANSMISSION LINE COSTS

This chapter contains the results of an NRRI survey and analysis of the construction costs of transmission lines in the mid-1980s.[1] We consider how costs vary with changes in line design and other variables. The variables examined are line length, voltage level, number of circuits, terrain conditions, population density, supporting structure, and the part of the country in which the line is located. The NRRI surveyed regulatory agencies in the United States and Canada requesting information needed to determine the effects of these variables on cost. Commission responses were compiled in two data sets.

The first section of this chapter discusses the survey, the commission responses to the survey, and the primary and reduced data sets. In the second section, the primary data set is used for an "average cost" analysis of line costs and a reduced data set is used for an "estimated cost" analysis.

The average cost analysis simply determines the average costs reported to us for various groups of lines. The simple average cost is computed for each group, and the results are compared to see how average cost changes from group to group. Estimated cost analysis uses regression to estimate a cost equation relating design variables to cost, and uses the estimated equation to generate cost estimates for building any new line, whether or not such a line is included in our data set.

---

[1] For additional sources of information on transmission line data and costs, see footnote 6 in chapter 4.

Survey and Data Sets

In March 1986, the NRRI surveyed regulatory agencies in the continental United States and Canada requesting information on electric transmission lines put in service by electric utilities since 1980. A survey letter was sent to forty-seven state commissions, the District of Columbia, and to four Canadian agencies.[2] It asked for:

> examples from your state of the costs of recent transmission construction. Lines that went into service in 1980 or later would be suitable.
> The data needed are:
> * the cost per mile (or the total cost) of recent or proposed AC or DC transmission line construction by an electric utility you regulate
> * the length of the line
> * the voltage of the line and its stated capacity
> * the year the line begins operation
>
> Any additional information related to cost that you can provide would be helpful, such as:
> * line type (e.g., poles versus towers; single circuit versus double circuit)
> * the type of terrain and the population density through which the line passes
>
> NRRI would like this information for all electric utilities in your state, if available, or for a good representative sample.

Thirty-five state commissions and three Canadian agencies responded.

Primary Data Set

The majority of line information sent to us was used to determine average line costs, but not all. Hence, our primary data set contains all useful information we received, but excludes some data, such as data on lines that did not include line cost. Insufficient information was provided for some variables of interest for us to examine their effects on cost: notably, line capacity. In the primary data set, only overhead AC lines with a voltage level of 115 kV or greater are included; underground lines,

---

[2] Nebraska was excluded because it does not regulate electric utilities. Nova Scotia, Ontario, Prince Edward Island, and the National Energy Board were surveyed.

DC lines, and lines under 115 kV are excluded. Line observations from the Canadian agencies were eventually excluded also because of fluctuations in currency exchange rates. The resulting primary data set has information on 274 transmission lines with a total length exceeding 9,000 pole-miles and total expenditures over $3 billion.

The survey asked for construction costs, which should not include other line costs, such as the cost of the right-of-way. Most respondents did not indicate which components of transmission costs (the line itself, the right-of-way, substations, and relays) were included. Those few who did so indicate said some non-construction costs were in fact included, but most presumably have excluded these costs. The Handy-Whitman Construction Cost index is used to adjust costs to 1985 dollars.[3] Line length is recorded in pole-miles and, for the lines in the primary data set, ranges from 0.1 pole-mile to 444 pole-miles.[4] The line's voltage is its design voltage in kilovolts. Where the reported voltage was not specified as either the design voltage or the operating voltage, we assumed it was the line's design voltage. The voltage levels in the data set are 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 500 kV, and 765 kV.

The number of circuits is either one or two. When a line is reported having both one and two circuits, use of two circuits is assumed.[5] About 90 percent of the 274 lines specifying circuits are single-circuit lines.

Reports on changes in terrain and population density along the line were reduced to simple generalizations for recording the line's characteristics in the data set. Terrain descriptions are reduced to either "good" or "bad." Population density and supporting structure are categorized simply also: either "high" or "low" for population density, and "poles" or "towers" for structure. Many responses supplied just these simple categories; however, in other cases we reduced descriptive accounts

---

[3] The Handy-Whitman cost index for transmission plant measures regional price inflation for line inputs commonly used. Costs for lines with an in-service date past 1985 are assumed to be in 1985 dollars.

[4] Length in pole-miles measure a line's geographic mileage. Length in circuit-miles measures conductor mileage. For single-circuit lines the two are equivalent; however, for double-circuit lines a line's length in circuit-miles is double its length in pole-miles.

[5] An exception occurs when the response states explicitly that the line is single circuit but with the capability of adding another circuit. In this case, one circuit is recorded in the data set.

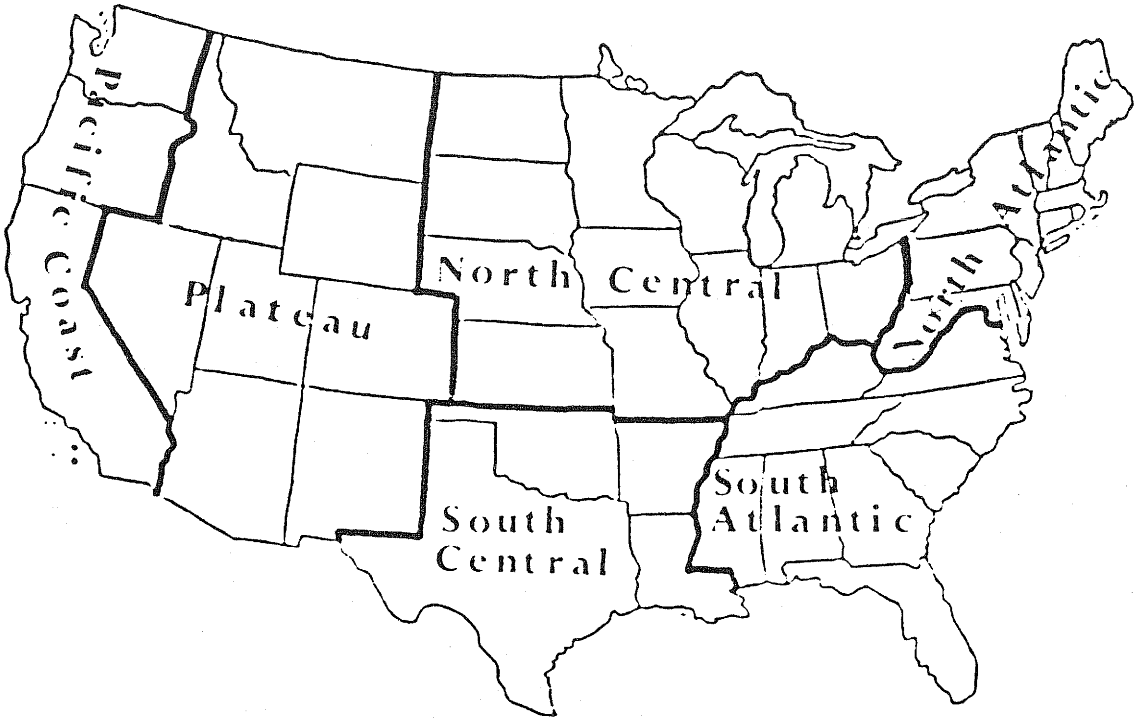
and detailed definitions to these general categories. Good terrain includes flat areas, rolling countryside, farmland, desert, and wooded areas. Mountainous landscape and canyon lands are considered bad terrain. Urban and suburban areas are considered high population density areas, whereas low density areas include rural and moderately populated areas. Lattice structures are grouped with towers, and H-frames are considered poles. For lines in the primary data set, 84 percent are on good terrain, 90 percent are built in low-population areas, and 71 percent use poles for support.[6]

The effect of U.S. location on cost is handled by grouping the reported lines according to the six Handy-Whitman regions covering the lower 48 states. A map of the United States delineating these regions is in figure 5-1. The regions, with abbreviations in parentheses, are the North Atlantic (NA), South Atlantic (SA), North Central (NC), South Central (SC), Plateau (PL), and Pacific Coast (PC) regions.

Broken down by region and voltage, the number and length of lines comprising the primary data set are reported in tables 5-1 and 5-2. Each line in the primary data set and the associated set of data for that line constitute one "observation" in our statistics. The number of observations ranges from a low of 14 in the Pacific region, where observations are for three voltage levels only, to a high of 69 observations in the South Atlantic region, which provided observations for all voltage levels. The number of observations by voltage level ranges from a low of 3 for 765-kV lines to 75 for 230-kV lines. Two-thirds of the 9,674 pole-miles reported are for two voltage levels: 500 kV and 230 kV. Over one-third of the reported pole-miles are in the Plateau region.

Expenditures for these lines are in table 5-3. The North Atlantic region reported the least expenditures for new lines, $335 million; the Plateau region reported the most over, $1 billion. Well over half the expenditures are for 500-kV lines. Caution is advised in using these totals because the apparent regional differences in new transmission investment could, in part, reflect unequal sampling.

[6] The percentages are based on 186, 176, and 233 observations respectively. These numbers differ because not all lines specified information for each variable.



(PC) Pacific Coast: California, Oregon, Washington
(PL) Plateau: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming
(NC) North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin
(SC) South Central: Arkansas, Louisiana, Oklahoma, Texas
(NA) North Atlantic: Connecticut, Delaware, Maryland, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, West Virginia
(SA) South Atlantic: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia

Fig. 5-1 Handy-Whitman Regions

TABLE 5-1

NUMBER OF REPORTED LINES
BY REGION AND VOLTAGE

Voltage	Handy-Whitman Regions						Total
	PC	PL	SC	NC	NA	SA	
115 kV	2	3	2	1	8	17	33
138 kV	0	3	9	14	29	5	60
161 kV	0	4	2	12	0	2	20
230 kV	4	10	8	5	14	34	75
345 kV	0	5	12	21	7	1	46
500 kV	8	7	8	1	5	8	37
765 kV	0	0	0	0	1	2	3
Total	14	32	41	54	64	69	274

Source: Primary data set

TABLE 5-2

LENGTH OF REPORTED LINES
BY REGION AND VOLTAGE
(in Pole-Miles)

Voltage	Handy-Whitman Regions						Total
	NA	NC	PC	SC	SA	PL	
115 kV	67	2	13	24	97	102	305
138 kV	264	104	0	40	26	83	517
161 kV	0	127	0	39	36	327	529
230 kV	161	143	30	364	828	914	2440
345 kV	150	274	0	549	64	474	1511
500 kV	115	340	1039	470	642	1467	4073
765 kV	58	0	0	0	241	0	299
Total	815	990	1082	1486	1934	3367	9674

Source: Primary data set

TABLE 5-3

EXPENDITURES ON REPORTED LINES
BY REGION AND VOLTAGE
(in Millions of 1985 Dollars)

	Handy-Whitman Regions						
Voltage	NA	NC	SC	PC	SA	PL	Total
115 kV	22.1	.2	3.3	2.0	10.9	6.1	44.6
138 kV	60.3	25.8	9.9	0	5.2	3.8	105.0
161 kV	0	13.1	8.3	0	5.0	27.8	54.2
230 kV	65.1	27.1	33.1	10.6	141.9	175.0	452.8
345 kV	65.9	167.0	117.2	0	19.8	126.7	496.6
500 kV	84.0	127.5	259.2	509.7	261.8	708.6	1,950.8
765 kV	37.5	0	0	0	178.9	0	216.4
Total	334.9	360.7	431.1	522.3	623.5	1,048.0	3,320.4

Source: Primary data set

Reduced Data Set

The reduced data set is formed by placing two more conditions on line observations in the primary data set. These conditions reduce the number of usable observations. Whereas the primary data set has 274 observations, the reduced data set has 148 complete observations. The variables in both data sets and their units (if any) are presented in table 5-4.

The first condition is that each line observation in the reduced data set must be complete; that is, all variables must be reported for the line to be included. Secondly, we excluded lines either with a length under one pole-mile or costing less than $10,000 per mile.[7] The first condition is imposed in order to use a regression technique that works best with complete data sets. The second condition is imposed because our focus is on lines of moderate to long length. We felt that the inclusion of extremely short lines could bias the results and that lines costing under $10,000 per mile could not reflect the total cost of building a line from the ground up, but must reflect special situations.

[7] Many low-cost lines were reported in Iowa, costing from $10,000 per mile to $120,000 per mile; these were included in the reduced data set.

Average and Estimated Costs

Two analyses of transmission line costs are discussed in this section: an average cost analysis and an estimated cost analysis. Costs are in 1985 dollars per pole-mile; however, this unit is often called "dollars per mile" for convenience. The average cost analysis uses simple averages of line costs in the primary data set; it shows how average cost changes as one variable, such as voltage, changes. The estimated cost analysis, discussed second, uses regression techniques on the reduced data set to estimate a cost equation. This can be used to produce cost estimates for lines not represented in the data set. For example, as table 5-3 indicates, we have no information about the average cost of 345-kV lines in the Pacific region. However, we can estimate the cost of such a line using the cost equation.

Average Cost Analysis

Line costs change with changes in voltage level and, as expected, the trend is for higher voltage lines to be more expensive. Average cost per mile, along with the high and low reported costs, by each voltage level for each line in the primary data set is presented in table 5-5.[8] The fact that, at the lower voltages, average costs appear not to be correlated with voltage suggests that other factors greatly affect cost. These factors may include the linearity of the voltage-cost relationship, line length, region of construction, and other line variables. (See table 5-11, which corrects for some of these effects.) The large differences between high and low reported costs also suggest that variables other than voltage affect cost strongly.

The data suggest that increases in voltage may be associated with less than proportional increases in cost, that is, that scale economies with respect to voltage may exist.[9] The effect of line length on cost per mile was examined. The correlation between these two variables is 0.02, which

---

[8] Based on lines specifying both total cost and line length. Average costs are computed at each voltage level by summing the lines' total costs and dividing this sum by the sum of their lengths.
[9] "Scale economies" is being used somewhat loosely. By strict definition, scale economies require all inputs to be increased proportionately.

TABLE 5-4

DATA AND UNITS IN THE
PRIMARY AND REDUCED DATA SETS

Variable	Reference Symbol	Units or Coding
Cost	C	in 1000s of 1985 dollars
Voltage	V	in kilovolts
Length	L	in pole-miles
Circuits	N	0 = single 1 = double
Terrain	T	0 = good 1 = bad
Density	D	0 = low 1 = high
Structure	S	0 = pole 1 = tower
Region	NA, NC, SA, SC, PL, PC	0 = not located in region 1 = located in region

TABLE 5-5

AVERAGE COST PER MILE OF REPORTED LINES BY VOLTAGE
(in Thousands of 1985 Dollars)

Voltage	Number of Reported Lines[a]	Average Cost Per Mile[b]	High Cost	Low Cost
115 kV	29	147	2014	5
138 kV	60	203	1365	6
161 kV	20	103	340	71
230 kV	74	188	1324	7
345 kV	43	329	1568	92
500 kV	36	479	1561	105
765 kV	3	726	802	639

Source: Primary data set

a. Only observations specifying both line cost and length are used.
b. Costs appear not to increase uniformly with voltage because of effects discussed in the text; see table 5-11 for correction of these effects.

suggests that there is little or no relation and that no scale economiesexist with respect to length.[10]

A line's number of circuits, terrain conditions, supporting structure, and population density each affects cost in the expected way.[11] The average cost for single-circuit lines, computed from the primary data set, is $304 thousand per mile, whereas double-circuit lines average $463 thousand per mile. Lines built on good terrain, for about $299 thousand per mile, cost less on average than lines built on bad terrain, which average $411 thousand per mile. The average cost for lines built on poles is $266 thousand per mile, which is considerably less than the $462 thousand per mile when towers are used for support. Lines built in low-population areas average $305 thousand per mile, whereas in high-population areas the average cost increases to $425 thousand per mile.[12] The percentage increase in average line costs attributable to two circuits, bad terrain, high population density, and towers are 52 percent, 38 percent, 39 percent, and 74 percent, respectively.

Another variable important in accounting for cost differences is the region where the line is built. The average costs for lines located in each region, along with high and low reported costs per mile, are presented in table 5-6. The table shows that average costs per mile vary a good deal from one region to another, but that costs per mile vary even more within each region. Some of the cost variation within a region must be due to variations in voltage and other factors. Perhaps the variation among regions is due to such factors as a greater trend toward higher voltage lines in the Western United States or higher population density in the

---

[10] Correlations are used because length and costs are continuous variables. Attempts to classify each variable into ranges for making comparisons can be misleading. The correlation between line length and total cost is, of course, significant (0.68), which supports the expected relation that longer lines cost more.

[11] In the discussion that follows, average cost is computed by first finding the cost per mile for each line and then taking the simple average of these costs per mile for lines with the particular characteristics examined. Futher, it is assumed that line length is not a factor. For example, any difference in the costs per mile of one and two circuit lines is independent of the lengths of the lines.

[12] The number of observations used to compute average costs is: (single, double) = (219, 45); (good, bad) = (155, 28); (poles, towers) = (159, 66); and (low, high) = (158, 17), as defined in table 5-4.

TABLE 5-6

AVERAGE COST PER MILE BY REGION
(In Thousands of 1985 Dollars)

Region	Number of Reported Lines[a]	Average Cost per Mile[b]	High Cost per Mile	Low Cost per Mile
South Central	41	290	996	83
Plateau	33	313	1521	7
South Atlantic	64	322	802	5
North Central	51	364	1568	43
North Atlantic	64	410	2014	39
Pacific	12	483	1163	159

Source: Primary data set

a. Only observations specifying both line cost and length are used.
b. As discussed in the text, regional average cost differences may be explained, at least in part, by regional differences in line voltage, population density, and so on.

Northeast. Either factor would raise costs. However, regional cost differences might be due to variables not otherwise included in table 5-4, such as higher labor costs. The estimated cost analysis that follows helps to sort out whether a regional cost effect, not captured by our other variables, exists.

Estimated Cost Analysis

As the results based on average costs suggest, the variables in our data set affect transmission line cost and often do so in the expected way. The natural extension of this approach is to compute and compare average costs when changing variables in combination, for example, changing both structure and terrain simultaneously. This combination yields four cost averages: poles on good terrain, poles on bad terrain, towers on good terrain, and towers on bad terrain. However, analyzing all possible combinations yields hundreds of different designs, many of which are not represented in our data set or only weakly represented by one or two observations. There are 672 combinations of voltage, circuits, terrain, density, structure, and region. Having just two observations per combination would require 1344 line observations to calculate the average cost for each combination. This is five times greater than the number of observations we have, and the reliability of each average based on only two observations would be low.

To overcome this, regression analysis is used. The regression approach is less data demanding; however, this does not imply it is a superior approach, just a more practical one given our data limitation. A discussion comparing the results of these two approaches follows later.

The Estimated Equation

The cost equation we use is one of many that could be used to model transmission line cost in terms of our set of variables. It is selected over others because it accounts for over 90 percent of cost variation. With this equation, all the variables account for an appreciable amount of cost variation. The cost equation, expressed in the symbols and units of table 5-4, is

$$C = V^{\beta_1} L^{\beta_2} \exp(\beta_0+\beta_3 N+\beta_4 T+\beta_5 D+\beta_6 S+\beta_7 NA+\beta_8 PC+\beta_9 SC+\beta_{10} SA+\beta_{11} NC).$$

In this equation, cost is a function of voltage, length, and the (natural) exponential of the other variables. The β's are regression coefficients, to be estimated.

In order to estimate the coefficients in the cost equation using linear regression techniques, the equation is transformed from its present multiplicative form to an expression setting cost equal to the sum of products of variables, or their natural logarithms, and their respective coefficients. This is accomplished by taking the natural logarithm of both sides of the cost equation. The transformed equation is[13]

[13] A random error term was included in the equation for regression analysis, but is omitted here for clarity.

$$\ell nC = \beta_0+\beta_1\ell nV+\beta_2\ell nL+\beta_3N+\beta_4T+\beta_5D+\beta_6S+\beta_7NA+\beta_8PC+\beta_9SC+\beta_{10}SA+\beta_{11}NC.$$

Neither equation contains a variable for the Plateau region. It is not ignored; instead, its effect on cost is included in the equation's intercept term β_0. The included regional variables, then, give the effect on line cost of building the line outside the Plateau region. The effect on the log of cost of building the line in the North Atlantic region, for example, is given by $\beta_0+\beta_7$, because NA = 1 in this region and PC, SC, SA, and NC equal zero in this region.

The transformed cost equation is regressed using the reduced data set and regression software written by Statistical Analysis System (SAS), installed on an Ohio State University computer system.[14] The results of the estimation process are presented in table 5-7. In addition to listing the variables, the table gives the estimated coefficients, the standard error of the estimates, the t-values, and the R^2-value of the transformed equation.[15] An R^2-value of 0.93 indicates that the transformed equation and the variables used account for 93 percent of the cost variations in the reduced data set. The estimated relation between construction and design variables is

$$C = V^{0.55}L^{0.94}\ \exp(2.05+0.46N+0.26T+0.38D+0.47S+ \\ 0.64NA+0.46PC+0.41SC+0.33SA+0.25NC).$$

To use the equation to estimate the cost of a new transmission line in 1985 dollars, assign values to the variables. For example, the cost of a 50-mile double-circuit 230-kV line, built with towers on good terrain in a

---

[14] The SAS procedure is "Proc Reg" and is found in the 1982 SAS "Statistics" edition. The procedure uses a standard linear regression procedure to estimate each variable's effect on cost.

[15] The purpose of the t-test is to determine if a coefficient is statistically different from zero, and hence if its variable has a statistically significant effect on cost. The t-value is computed by dividing the coefficient estimate by its standard error, which is a measure of dispersion around the estimate. A t-value around 2 or above for our data set suggests the coefficient is statistically different from zero. The value of R^2 is a measure of how well the equation fits the data; its value can vary from zero (the equation does not fit the data at all) to one (perfect fit).

TABLE 5-7

ESTIMATED COEFFICIENTS AND OTHER STATISTICS
FOR THE TRANSFORMED COST EQUATION

	Dependent Variable:	log of total cost (ℓnC)		
	Sample Size :	148 observations		
	R^2 :	0.93		
Independent Variable	Coefficient Symbol	Estimated Coefficient	Standard Error	t-value[a]
Intercept	β_0	2.05	.50	4.06
ℓnV	β_1	.55	.10	5.33
ℓnL	β_2	.94	.04	24.83
N	β_3	.46	.10	4.55
T	β_4	.26	.10	2.53
D	β_5	.38	.12	3.08
S	β_6	.47	.10	4.58
NA	β_7	.64	.15	4.39
PC	β_8	.46	.17	2.75
SC	β_9	.41	.17	2.41
SA	β_{10}	.33	.15	2.17
NC	β_{11}	.25	.14	1.72[b]

a. For our sample size, a t-value of 1.98 or greater indicates that the coefficient is statistically different from zero at the 5 percent significance level (two-tailed test).
b. The coefficient is significant at the 9 percent significance level (two-tailed test).

low-population area located in the North Atlantic region, is estimated, using the units in table 5-4, as follows:

$$C = (230^{0.55})(50^{0.94})\exp[2.05+.46(1)+.26(0)+.38(0)+.47(1)+ .64(1)+.46(0)+.41(0)+.33(0)+.25(0)],$$

$$= 29{,}400 \text{ thousand 1985 dollars}$$

$$= \$29.4 \text{ million}$$

This is about $588,000 per mile. This estimated cost is the most probable cost given the cost variation of the reduced data set. However, there is a very small chance, of course, that the cost of any given new line with these characteristics would cost exactly $588 thousand per mile. Statistical analysis of the cost variation in the data indicates that there is a 50-50 chance that this type of line would cost between $437 and $796 thousand per mile. Ninety percent of such lines would cost between $300 and $1,150 thousand per mile; this range is called the 90-percent confidence interval. Additional information on confidence intervals is in appendix E.

Significance of Factors Affecting Costs

The presence of scale economies with increasing line voltage and line length were examined using the t-test.[16] The results indicate there are scale economies with increasing voltage level; that is, increasing line voltage does result in a less-than-proportional increase in line cost. For example, the estimated cost increase for doubling a line's voltage from 115 kV to 230 kV is 46 percent. This assumes that other factors remain thesame, in particular, that increasing voltage does not change the structure from poles to towers. The actual cost increase may differ from 46 percent, of course, because of the limitations of the data set. Given the possibility of error, there is a 95 percent chance that the correct estimate of the effect of doubling voltage falls in the range, 27 percent to 68 percent.[17]

---

[16] This is similar to the test to determine if the coefficients are statistically different from zero. If there are no scale economies, the voltage and length coefficients, β_1 and β_2, would not be significantly different from 1. Then, for example, the numerator of the t-value for voltage is $1-\beta_1$. The denominator is the standard error of β_1, as before.

[17] The 46 percent value is found using 0.55, the estimated voltage coefficent. The formula for calculating the percentage increase is $[(V_2/V_1)^{0.55} - 1] \times 100\%$ where V_1 and V_2 are the two voltage levels considered. The validity of this finding depends on the confidence interval about 0.55. With a 95 percent confidence interval, the percentage cost increase in going from 115 kV to 230 kV can be as little as 27 percent or as much as 68 percent. This interval is a 95 percent confidence interval calculated by using $0.55 \pm 1.98(0.10)$. That is, 27 percent is calculated using $0.35 = 0.55 - 0.198$ as the voltage

(Footnote continues on next page)

The presence of scale economies with increasing line length is less well supported statistically. If β_2 equals one, the cost per mile is independent of the length of the line. This length coefficient is 0.94, close to one. The bounds for a 95 percent confidence interval around 0.94 are 0.86 and 1.01. Since this interval includes 1 and numbers slightly higher, the presence of scale economies is not assured. (In fact, it is possible, in principle, that there are diseconomies.[18]) With 0.86, 0.94, and 1.01 as possible values of the length coefficient, table 5-8 lists the percentage change in costs per mile when increasing line length from one pole-mile to the length specified. As the data in the table suggest, cost per mile may well decrease with increasing line length; however, this effect, if it exists, tends to level off after 100 miles or so.[19]

We also computed the percentage cost increases with two circuits, bad terrain, high population density, and towers; these are 58 percent, 30 percent, 46 percent, and 60 percent, respectively. From this we estimate that the cost of stringing a second circuit on an existing line is about 58 percent of the cost of putting up a single circuit line of the same type. For these variables, the cost increases estimated with regression analysis are less than those computed on the basis of average costs. A 95 percent confidence interval around the estimated coefficients of these three variables yields the corresponding intervals of percentage cost increase. These are for two circuits, 30% to 93%; for bad terrain, 6% to 58%; for high

---

(Footnote continued from previous page)

coefficient, and 1.68 is calculated using 0.75 = 0.55 + 0.198. The number 1.98 is the t-value used to generate a 95 percent confidence interval, and 0.10 is the voltage coefficient's estimated standard error, from table 5-7.

[18] Even an 85 percent confidence interval, which is a moderate level of confidence, ranges from 0.88 to 0.99.

[19] The leveling off at 100 miles could be the result of having few observations for lines of this length or longer. For the reduced data set, only 13 of 148 lines are 100 pole-miles or longer. The maximum length is 310 pole-miles. Also, the relation may be too complex to be captured by linear analysis. For example, cost per mile may decrease, at first, with increasing length as fixed engineering costs are spread over more miles, and later increase as longer lines acquire more switchgear and compensation equipment.

TABLE 5-8

PERCENTAGE CHANGE IN COST PER MILE
FOR LINE LENGTH GREATER THAN ONE MILE
WITH THREE LENGTH COEFFICIENTS

Line Length	% change in cost/mile for β_2 = 0.86	% change in cost/mile for β_2 = 0.94	% change in cost/mile for β_2 = 1.01
25 miles	-36%	-18%	+3%
50 miles	-42%	-21%	+4%
100 miles	-47%	-24%	+5%
150 miles	-50%	-26%	+5%
200 miles	-52%	-27%	+6%
250 miles	-54%	-28%	+6%
300 miles	-55%	-29%	+6%

Source: Entries are calculated with the formula, $(L^{\beta_2 - 1} - 1) \times 100\%$

population density, 15% to 86%; and for towers, 31% to 95%. All three average cost increases fall within these cost intervals.

Estimated differences in cost between regions are shown in table 5-9, where the cost in each region is compared to the Plateau region cost, which is lowest. The results are somewhat different from the simpler average cost results. All regional costs are significantly different from the Plateau region cost (with the possible exception of the North Central region). Also presented for each region is a range of cost increases within which we have 95 percent confidence that the true regional effect falls. It is possible that costs in the North Central region are no higher than in the Plateau region, for example, and that South Central costs are the same as Pacific costs.

In summary, the average and estimated effects on cost of the variables considered are consistent with one another in that almost all average effects fall within the 95 percent confidence intervals of the estimated effects. All coefficient estimates produced by the regression procedure are statistically different from zero at the 95 percent confidence level, except

TABLE 5-9

PERCENTAGE COST INCREASE FOR
LOCATING A LINE OUTSIDE
THE PLATEAU REGION

Other Region	Percentage Cost Increase	Percentage Cost Change Interval
North Central	+28%	-3% to +70%
South Atlantic	+39%	+3% to +99%
South Central	+51%	+8% to +109%
Pacific	+58%	+14% to +120%
North Atlantic	+90%	+43% to +153%

Source: Estimated cost equation

for the North Central coefficient estimate.

Typical Line Cost Estimates

To put the results of the cost estimation into perspective, we here present cost estimates for lines varying by voltage and region but with fixed typical values for the remaining variables. The other variables are assigned values weighted according to their frequency of occurrence in the primary data set. It is assumed that 16 percent of all lines traverse bad terrain and 10 percent pass through high population density areas. Table 5-10 presents the percentage of lines supported by towers for each voltage level examined. The intent is to develop cost estimates that account not only for voltage but also for associated cost effects, such as more likely use of towers at higher voltages. In this way, the estimated cost is a more reasonable benchmark of probable line costs.

Estimated costs of typical transmission lines, as determined by these weighted input variables, are given in table 5-11 by voltage and region. Appendix E gives the 90-percent confidence intervals about these estimated costs.

TABLE 5-10

PERCENTAGE OF REPORTED LINES SUPPORTED ON TOWERS, BY VOLTAGE

Voltage	Percentage with Towers
115 kV	7
138 kV	4
161 kV	3
230 kV	24
345 kV	56
500 kV	70
765 kV	100

Source: Primary data set

TABLE 5-11

ESTIMATED COSTS PER MILE OF TYPICAL SINGLE-CIRCUIT LINES 50 POLE-MILES IN LENGTH, BY REGION AND VOLTAGE (in Thousands of 1985 Dollars per Pole-Mile)

	Handy-Whitman Regions					
Voltage	PL	NC	SA	SC	PC	NA
115 kV	90	120	130	140	150	180
138 kV	100	130	140	150	160	190
161 kV	110	140	150	170	180	210
230 kV	150	190	210	230	240	290
345 kV	220	280	310	330	350	420
500 kV	290	370	400	430	460	550
765 kV	410	530	570	620	650	780

Source: Estimated cost equation using weighted input variables from data primary set.

Capacity Costs

Although the survey requested information about transmission line capacity, capacity was reported for only 109 of the 274 lines in the primary data set. For the sake of good statistics, the foregoing analysis was performed without a capacity variable.

However, the cost of a line also varies with capacity, which is determined principally but not exclusively by line voltage. Attempts to estimate cost directly from capacity or from both capacity and voltage produced poor results with our small (109 observations) data set. As an alternative, we estimated, using another regression analysis, the capacity expected at each voltage level, then used the cost-to-voltage relation previously estimated in order to link cost to capacity in an approximate manner.

Cost per megavolt-ampere (MVA) can be estimated by dividing a line's total cost by its capacity rating in MVA. (At a power factor of one, capacity in megawatts equals the MVA capacity rating; otherwise, the MW capacity is less than the MVA rating.) Cost per MVA per mile is computed by dividing a line's cost per mile by its capacity. In table 5-11, for example, a typical 50-mile single-circuit 500-kV line in the South Atlantic region costs about $410 thousand per mile, or $20.5 million in total. If this line can carry 2000 MVA of power, then its capacity cost is around $10,250 per MVA, or $205 per MVA per mile.

Table 5-12 presents estimates of costs per MVA per mile at each voltage level. The entries are computed by dividing the average of the regional estimated costs per mile at each voltage by the expected capacity rating at that voltage. The expected capacity ratings are estimated, in another regression analysis, using the 109 observations in the primary data set that specify both capacity and voltage. The expected cost per MVA per mile is (roughly) inversely proportional to voltage.

The data in table 5-12 are not greatly affected by variations in line capacity or line length. At any one voltage, line length does not affect cost per MVA per mile very much because the slight decreases in cost per mile with increasing line length are accompanied by similar decreases in the line's expected capacity rating, thereby keeping the cost-to-capacity ratio fairly constant. Also, despite significant variations in cost and capacity

TABLE 5-12

EXPECTED CAPACITY COST, BY VOLTAGE
(in 1985 dollars per MVA per mile)

Voltage (kV)	115	138	161	230	345	500	765
Capacity Cost	$1000	$780	$630	$460	$310	$220	$150

Source: Table 5-11 and capacity data in the primary data set.

at each voltage level, in our data set lower capacity lines cost less than higher capacity lines. At each voltage level, line cost and capacity rating are positively correlated; that is, lower cost lines have lower capacity ratings. Hence, the cost per MVA is about the same at any one voltage for lines of different capacity.

The total capital cost of a new line includes both construction costs and other costs such as the cost of right-of-way. These other costs are highly dependent on the role the line is expected to play as part of an integrated system and on the property values along the way. Total capital costs are typically 20 to 30 percent higher than construction costs.

PART III

WHEELING PRICES

CHAPTER 6

PRICING FOR GOOD DECISION-MAKING

Appropriate pricing of wheeling services depends both on the objective one seeks to attain with pricing and on the legal, regulatory, institutional, and industry organizational environment within which this objective is pursued. This chapter sets out the principal objective that guides our pricing analysis.

In the next two chapters, 7 and 8, this objective is applied to various pricing environments. While the objective remains the same throughout, different pricing rules can emerge in various environments. Chapter 7 contains a discussion of ratemaking in an environment where cost-based rates are appropriate. Chapter 8 treats the pursuit of our objective in several other environments; it considers pricing mechanisms that do not result in cost-based rates.

The latter two chapters treat good pricing rules, with minimum discussion of the practical difficulties of implementation. Chapter 9 covers implementation difficulties and discusses possible approximations to these good pricing rules, which may be necessary--at least at first--for practical implementation.

Pricing Goals

Our objective in this report is to determine wheeling prices that lead to good wheeling decisions. Many electric utility industry analysts believe that the level of power transfers among utilities is less than optimum. They contend that inadequate use is made of the existing interconnected networks and that many opportunities to expand the capacity of existing networks are not exploited.

It is not our purpose here to examine the validity of this belief. Several lengthy and costly studies of this issue over the last 25 years have not been unquestionably definite regarding the cost effectiveness of strengthened interties among utilities.[1] It is a difficult area of study that takes into account engineering adequacy, economic feasibility, regulatory authority, and legal questions of ownership rights and antitrust obligations, as well as environmental and health concerns. The engineering-economics calculations are complex enough that at least some of the assumptions and data are always open to question or challenge.

Instead, our purpose is to find wheeling pricing rules that further, rather than impede, the goal of overcoming inadequate transmission system use and expansion, if such inadequacies exist. We are looking for pricing rules that motivate all parties to make good decisions about the use of the transmission system and about its expansion.

Good wheeling ratemaking alone is not sufficient to overcome other barriers to optimal system use that may exist. Other impediments that can impede optimal use include such factors as engineering reliability requirements, pricing policy for wholesale power, and policy questions of who should be allowed access to transmission networks for the purpose of buying and selling power.

The question of how to price the wheeling service is related, in the policy debate, to these other impediments. However, for the purpose of analyzing this question one must begin by separating the wheeling price issue from other related issues. Hence, in chapter 7 we seek a wheeling price based on the cost of moving power from one point in the grid to another, without regard to who owns the power or who buys it. In this view,

---

[1] See U.S. Federal Power Comission, National Power Survey (Washington, D.C.: U.S. Government Printing Office, October 1964); U.S. Department of the Interior, Transmission Study 190 (New York, NY: U.S. Government Printing Office, 1968); Edison Electric Institute, Ten-Year Report on Load Diversity, Based on 1962-71 Load Data (New York, NY: EEI, 1972); Congressional Research Service, National Power Grid System Study--An Overview of Economics, Regulatory and Engineering Aspects (Washington, D.C.: Library of Congress, 1976); and U.S. Department of Energy, The National Power Grid Study, DOE/ERA-0056-1 (Washington, D.C.: U.S. Government Printing Office, January 1980).

once society decides, through its lawmakers, who is entitled to wheeling service, then all those entitled would pay the same cost-based price.

Some would recommend the alternate view that wheeling prices should be distorted to compensate for any current or future "bad" societal decisions regarding such issues as access to preference power, cogenerator access, or requirements customer access. Alternate views are treated in chapter 8.

Also, at the time of this writing, several agencies are considering various impediments to better transmission system use. The Electric Power Research Institute is studying the technical impediments to increased wheeling; the Federal Energy Regulatory Commission (FERC) is studying reforms in wholesale power pricing; the National Governors' Association is studying electric transmission policy with an emphasis on state policies affecting transmission; and the Office of Technology Assessment is conducting a similar study with an emphasis on the federal role.

Also, The National Regulatory Research Institute is conducting a follow-on study to the present volume. It will examine nontechnical impediments to wheeling: economic, regulatory, legal, and institutional impediments. Instituting proper pricing for wheeling would remove one important economic impediment, but clearly other factors could still inhibit optimum transmission system development and use.

The goal of good wheeling decision-making is appropriate for several reasons. Regional disparities in electric fuel costs and in extra available generating capacity suggest to some that more interregional power transfers and thus more wheeling are needed, but that the decisions required to meet this need are not being made. It is in this context that the wheeling pricing policy question arose, and thus studying pricing so as to promote good decision-making is appropriate. In particular, pricing to promote transmission system optimum-use and expansion reflects, we believe, the orientation of the Strategic Issues Subcommittee of the NARUC Committee on Electricity, which requested the NRRI to do this study.

Additionally, pricing for good decision-making corresponds closely to the pricing goal of economic efficiency recommended by economists. As such, this criterion makes various candidate pricing schemes susceptible to analysis and measurement regarding how well they achieve the goal. By contrast, some other legitimate goals, such as fairness and the understandability of rates, are more matters of opinion than analysis, and so less suitable for a research effort. This orientation toward efficient economic decision-making is reflected in the title of this report.

The economic efficiency criterion is helpful, because it serves to draw attention to the question, "What difference does it make whether price is high or low?". That is, the criterion helps to identify the good or bad consequences of pricing policy. The economic efficiency criterion, in particular, focuses on the decisions made by customers and suppliers. Inappropriate pricing can distort short-term usage decisions of customers, for example. In addition, the customer's decision regarding longer-term, electricity-using investment projects can be distorted by incorrect pricing. What is needed is a pricing policy that limits both kinds of pricing distortions. Although having no distortion is the ideal, some distortions must be tolerated in practice.

Pricing wheeling so as to encourage good decision-making is appropriate also because of the apparent trend toward an increasingly market-oriented character of the electric utility industry. With this trend, a pricing scheme based on principles other than efficiency in decision-making might quickly become obsolete.

Pricing for the goal of good decision-making also corresponds closely to what Bonbright calls "the optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received."[2]

Other legitimate wheeling pricing objectives exist, but are of secondary importance in our analysis. Those who give higher weights to other objectives would, we recognize, arrive at pricing conclusions different from ours. Our pricing conclusions will, we believe, be recognized as good pricing rules by those who share our objective.

Where several pricing objectives exist, there is the inevitable need for compromise among objectives. Besides good decision-making, other legitimate goals include such objectives as feasibility of application, avoidance of price discrimination, ability to meet a regulatory revenue

[2] James C. Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961), p. 292.

requirement, fairness, and simplicity of rates. Compromises between efficiency and feasibility of application are a major concern of the authors; this is the subject matter of chapter 9. Rate simplicity, on the other hand, is of some concern, but less so than in the case of retail ratemaking; the wheeler's "customers" are other utilities, presumably capable of dealing with an elaborate rate design if necessary. Compromises between good decision-making and avoidance of price discrimination and between good decision-making and the revenue requirement are discussed in chapter 8. The analysis in chapter 7 seeks to define the most efficient cost-based rates, with minimal attention to the other objectives.

Everyone agrees that fairness in ratemaking is important, but unfortunately, parties disagree about what is fair. Is it fair, for example, to charge a utility's retail customers the same rate for use of the transmission system as the rate charged to other utilities that want power wheeled? Is it fair to set different rates for wheeling depending on whether the source of power is an investor-owned utility, a cogenerator, or a supplier of hydroelectric preference power? Is it fair to set a higher rate to wheel requirements power than coordination power? Reasonable arguments can be made on each side of these questions. The effects of some fairness considerations on good decision-making are also treated in chapter 8.

Normally, compliance with current laws and judicial decisions is an important constraint in ratemaking studies, but not so here. This is because policy makers want to take a fresh look at such issues as whether utilities should be required to wheel, whether utilities should be allowed to earn real profits in their more competitive markets, and whether large industrial customers should be exempted from certain franchise restrictions. Since a fresh look may lead to new laws and regulations, a study that takes existing laws and regulations as immutable constraints could mislead policy makers about which pricing policies are best in the absence of constraints.

Even if all parties agreed on the pricing objective, there is no single best way to price wheeling services. The pricing policy that best encourages good decision-making depends on the environment, an important aspect of which is regulatory law. One normally associates cost-based rates with an environment in which the utility has a legal obligation to serve and the regulatory agency has a legal obligation to set rates that meet a revenue requirement. At the present time, the FERC believes that it does not have the authority to order a utility to wheel, but it must set zero-economic-profit rates, that is, rates that merely recover costs, including the cost of capital. It seems likely that traditional cost-based rates established in this environment, while they may meet traditional notions of fairness, will not encourage good utility decisions about the level of wheeling service to offer. Some change in the law or regulatory price may be needed if traditional cost-based rates are required where optimum transmission use is the goal. Either the regulatory agency can be given the authority to order wheeling or non-traditional cost-based rates can be allowed--rates that offer utilities the opportunity to earn and keep real profits from their wheeling service.

Chapter 7 treats cost-based rates without a regulatory revenue requirement. Chapter 8 begins with a discussion of the appropriateness of having a revenue requirement with cost-based rates for wheeling service. It then treats optimal pricing in an environment where utilities have no obligation to provide wheeling service (as at present) and the FERC no longer has the obligation to base rates on costs. Several mechanisms for determining wheeling prices in this environment are analyzed with a view toward selecting mechanisms that encourage good wheeling decision-making.

The remainder of this chapter explores the concept of good wheeling decisions in more detail, and discusses the pricing of loop flow power.

Good Decisions

A good decision about power trading or wheeling is a decision to undertake a transaction for which the benefits exceed the costs. A bad decision is either a decision in favor of a transaction where benefits are less than costs or a decision to forego a transaction for which benefits exceed costs. If all parties make all the good decisions that can be made, the electric system is operated and expanded in the optimal, least cost way. To see why this is so, let us begin by assuming that all decisions concern short-term economy energy opportunities.

Two-party Trading

Before considering good wheeling decisions, let us consider two neighboring companies that can trade directly without wheeling, one with a system lambda of 3¢/kWh and the other with a lambda of 7¢/kWh. An extra kilowatt-hour of electric energy generated by the first company and sold to the second company costs 3¢ to produce and displaces a kilowatt-hour that would have cost 7¢ to produce; thus there is a benefit of 4¢. The costs, which include some transmission tie line losses, administration, and perhaps other small costs, are 2 mills per kilowatt-hour, for a net benefit of 3.8¢. It is a good decision to engage in such a trade, of course.

The correctness of this decision does not depend on which of the two companies enjoys the 3.8¢ gain from trade. The selling price could be 3.2¢, 6.8¢, or anything in between. Conventional ideas of fairness suggest a split-the-difference price of 5¢ (where costs are equally shared).

As additional energy is sold, the seller's production cost rises and, as the buyer backs off his most expensive generation, his production cost falls. Eventually, one of two situations occurs: either the seller supplies all the buyer's power or the seller's production cost increases until it almost equals the buyer's decreased production cost. In either case, the cost of the last kilowatt-hour consumed by the buyer is

$$\lambda_S + \text{transportation cost},$$

where λ_S is the production cost of the seller and the transportation cost is the cost per kilowatt-hour of completing the transaction. This includes any line losses, bookkeeping, or other costs. If the tie lines or metering devices between the two neighbors are inadequate, the necessary costs of improving these also contribute to the transportation cost.

Figure 6-1 illustrates the relationship between production costs and prices for the power exchanged. As more power is traded, λ_S increases and λ_B (the production cost of the buyer) decreases. When finally λ_S and λ_B differ only by the transportation cost, the optimum amount of power Q_0 is exchanged. For additional energy exchanges, costs exceed benefits. If the price that the buyer pays for the power is set by a split-the-difference formula, the price starts at 5¢/kWh and either increases or decreases,

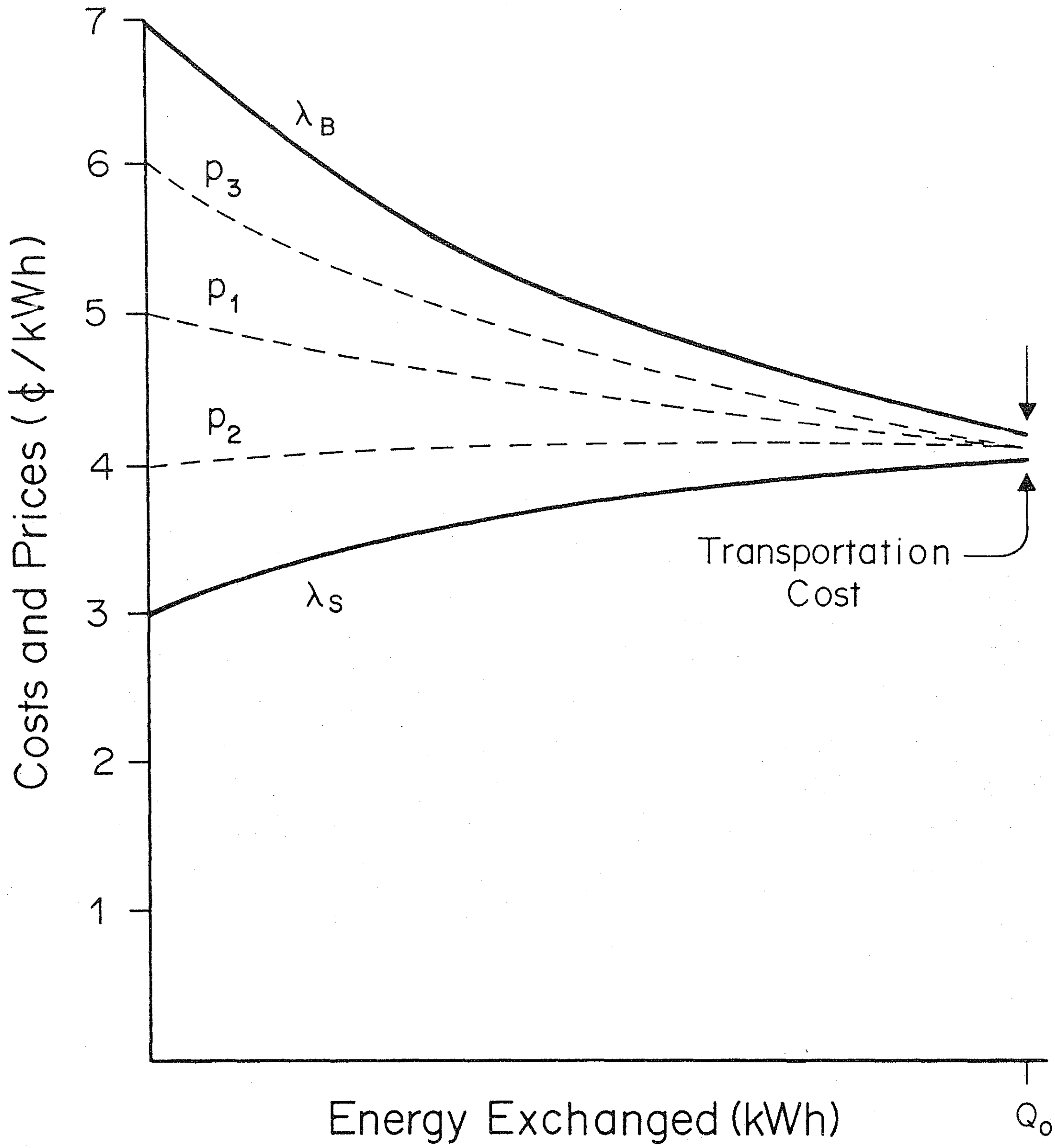


Fig. 6-1 Energy exchanged between two neighboring electric utility companies, S and B, with varying production costs, λ_S and λ_B, under good pricing rules

depending on whether λ_B or λ_S changes more rapidly. In the figure, price decreases, as illustrated by the dotted line p_1. The area between the price line p_1 and the line λ_B, less the buyer's share of the transportation cost, represents the buyer's benefit from the transaction; the area between p_1 and λ_S (less seller's transportation cost) is the seller's benefit. Pricing rules that provide for something other than a 50-50 split of the gains can be used. Lines p_2 and p_3 represent prices for which the buyer and seller, respectively, garner three-fourths of the gains from trade.

Under any of these pricing rules, it is more advantageous for each of the two companies to trade than not to trade. Hence, regardless of which of these pricing rules is used, the result is the same: energy is exchanged until the production costs of the two companies differ by the transportation cost of the exchange. The good decision by each company to exchange power up to this point is encouraged by any of these three pricing rules.[3]

At this point, the power flows are the same as one would find in a centrally dispatched power pool made up of these two companies. That is, the incremental cost of power to either company is that of the last generating station on line, using economic dispatch for all stations in the pool, plus a transportation/administration fee. All three pricing rules illustrated in figure 6-1 result in the same amount of power traded, Q_0.

Some other pricing rules discourage good decision-making. For example, suppose the buyer must pay a price equal to the seller's production cost plus 2 cents per kilowatt-hour. This price is illustrated by the line p_4 in figure 6-2. In this case, the buyer purchases an amount of energy Q_1, which is less than the optimum amount Q_0. This is because, for amounts greater than Q_1, the price p_4 is greater than the buyer's own production cost λ_B. This pricing rule could be based on a fairness argument, one which suggests that the buyer should pay a 2¢/kWh share of the fixed costs of the seller's generating units. But the rule leads to bad decision-making. It causes the buyer to decide against buying any more than Q_1. As the buyer looks at his

[3] Current literature on economic experiments suggests, however, that parties may be reluctant to trade, even when rationally a trade is in their own self-interest, if they perceive that the division of the gains is unfair. See, for example, Charles R. Plott, "Laboratory Experiments in Economics: The Implications of Posted-Price Institutions," Science, May 9, 1986, pp. 732-738. See also the game theory discussion in chapter 8, footnote 6.

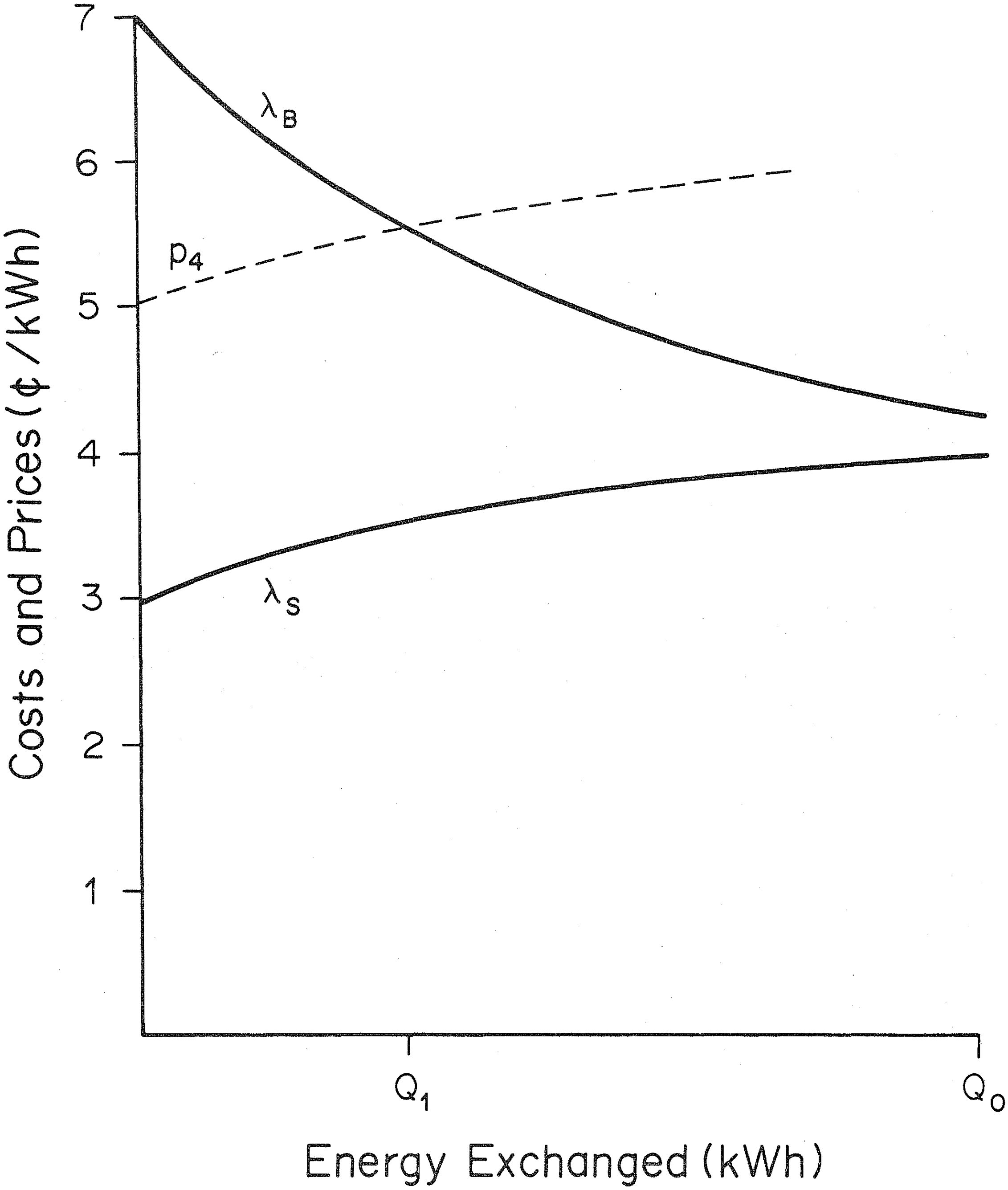


Fig. 6-2 Energy exchanged between S and B where price equals λ_S plus 2 cents per kilowatt-hour

own benefits (decreased production costs) and costs (the price of purchased power) for purchasing more than Q_1, bad pricing causes this transaction to fail his personal cost-benefit test. Yet, for the two parties together, the incremental benefits of additional trading outweigh the additional costs.

Another bad pricing rule is one that sets the price equal to the seller's production cost without providing compensation for his share of the transportation costs. In this case, the seller decides to sell no power at all because he loses money on each kilowatt-hour sold. Here, bad pricing blocks a good power trading decision.

Before moving on to the situation where wheeling can be used to complete an exchange, let us summarize certain insights about two-party power exchanges; we shall find that similar results apply to the wheeling case:

1. Good decisions are those that result in incremental benefits to all parties greater than incremental costs for all parties.
2. There is no single best pricing rule for power exchanges that results in good decision-making. A variety of pricing rules can do so; these rules differ according to how the gains from trade are shared among the parties.
3. All pricing rules that promote good decision-making result in neighboring companies having incremental production costs that differ, at most, by the incremental cost of moving power between them.
4. One may decide on the basis of fairness among pricing rules that promote good decisions, but starting with a fairness criterion may result in a rule that causes bad decisions to be made.

The third insight is true only if no other, nonprice impediments exist to block trades. For example, if the buyer fears an excess capacity penalty for purchasing much of his power needs from another utility, he may be discouraged from trading even though the trading price gives the proper incentive. (The follow-on NRRI study of nontechnical impediments to wheeling treats many such impediments.)

Three-party Trading

Consider now the case where three or more utilities are interconnected, though not all directly. A simple example is shown in figure 6-3(a), where tie lines connect utilities S and W, and also W and B, but S and B are not directly linked. Two-party trades can take place between S and W and between W and B, but S and B can complete a power transaction only if W agrees to wheel.

From the discussion above, if power exchanges are priced for good decision-making (and if no nonprice impediments to exchanges exist), we would expect S and W to trade until their incremental production costs are nearly equal; that is, these costs would differ at most by the incremental cost of moving power between them. Also, W and B would trade power until their costs are nearly equal. The obvious result is that power trading occurs until the incremental production costs of S and B are nearly equal; they differ at most by the cost of moving power from S to B.

Suppose S and B are like the seller and buyer in figures 6-1 and 6-2, with initial system lambdas of 3¢/kWh and 7¢/kWh, respectively. For purposes of example, suppose W's initial production cost is 5¢/kWh.

In this case W buys power from S to reduce its own supply costs, as in the two-party case just considered. Also, W can either sell some of its own generation to B or can buy additional power from S to sell to B. If a good pricing rule is used, such as the 50-50 split-the-difference rule, W will choose the lower cost source because this increases the size of his 50-percent share of the gain. W continues buying power for his own consumption and buying or generating power for sale to B until all cost differences between the two pairs of companies are reduced to the transportation costs of moving power between them.

It is convenient to think of W's purchases from S as divided into two transactions: one is a purchase for W's own consumption, and the other is a purchase for sale to B. Assume, for simplicity, that only the second transaction occurs; this allows us to illustrate the second transaction in figure 6-3(b) simply without taking into account either W's production curve or the effect of the first transaction on S's and B's production curves. In the S-W transaction, S enjoys a gain in the amount denoted by area S in figure 6-3(b); W's gain is the area labelled W_1. Similarly, for the sale

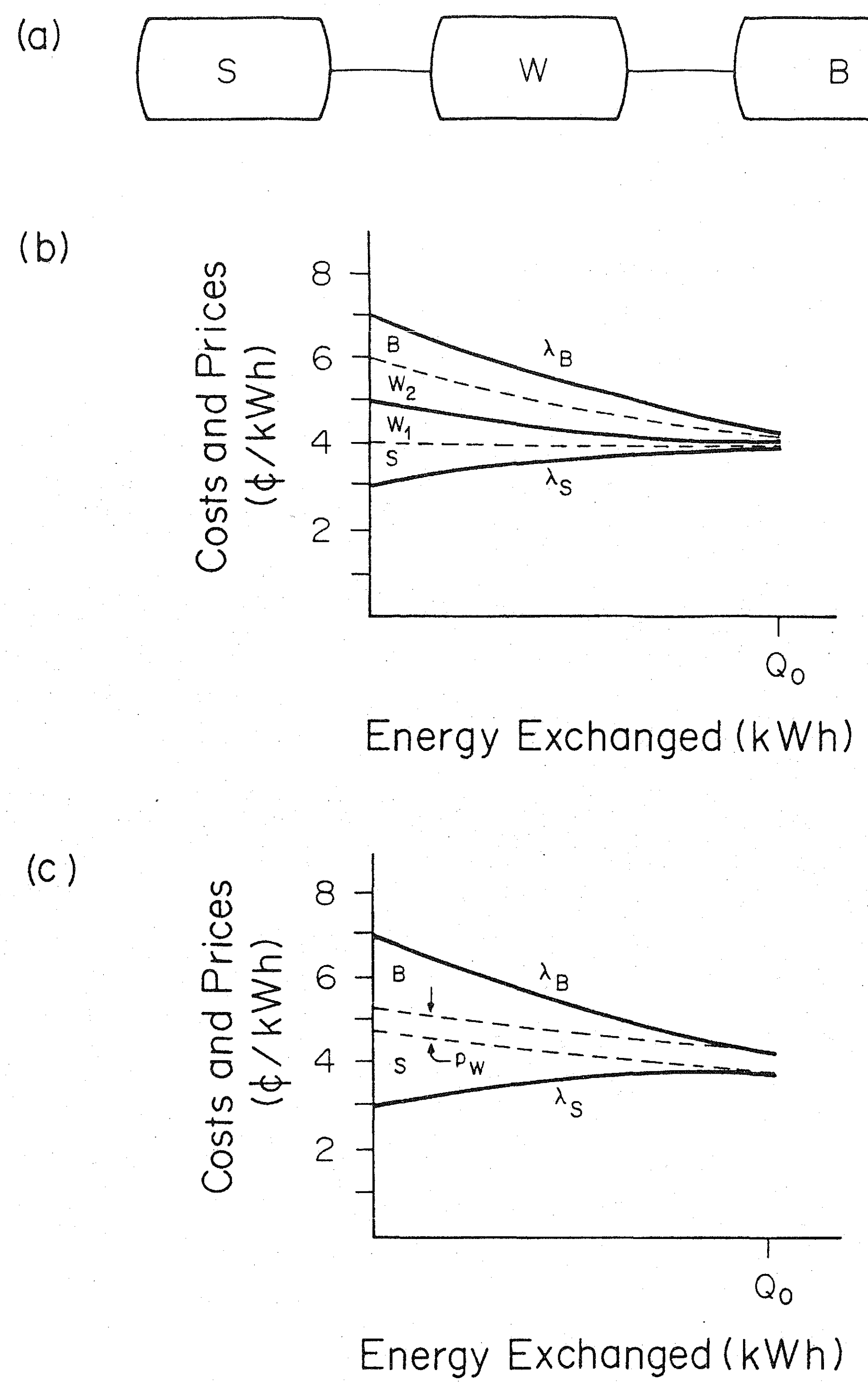


Fig. 6-3 Energy exchanged among three companies, S, B, and W: (a) company interconnections; (b) W engages in simultaneous purchase and sale; (c) W wheels at cost

from W to B, their gains are represented by the areas labelled W_2 and B respectively in figure 6-3(b). In each case, the gain to any party is reduced by that party's share of the transportation costs.

Notice that, apart from transportation costs, W's total benefit, W_1 plus W_2, is half of the available gains from trade, while S and B each get about one quarter. These transactions represent good decisions because all available gains from trade are pursued. The optimum amount of energy Q_0 is exchanged. W buys from S whenever S can supply power at a cost less than that of W's most costly generating units. The full amount Q_0 is exchanged regardless of W's initial lambda value, if lambda is interpreted broadly as the marginal supply cost and if S has no supply limitation. Then the sum of S's lambda plus the delivery cost represents W's marginal supply cost; in effect, it is W's "lambda". If S has a lot of low cost power for sale, S's power would displace all of W's and B's generation that costs more than S's generation plus delivery costs. If S has limited amounts of low cost power, an equilibrium is reached in which all three companies produce power and the production costs (λ's) of the last unit on line in each system are given by:

$$\lambda_S + \begin{bmatrix}\text{cost of moving} \\ \text{power } S \rightarrow W\end{bmatrix} = \lambda_W$$

$$\lambda_W + \begin{bmatrix}\text{cost of moving} \\ \text{power } W \rightarrow B\end{bmatrix} = \lambda_B$$

$$\lambda_S + \begin{bmatrix}\text{cost of moving} \\ \text{power } S \rightarrow W\end{bmatrix} + \begin{bmatrix}\text{cost of moving} \\ \text{power } W \rightarrow B\end{bmatrix} = \lambda_S + \begin{bmatrix}\text{cost of moving} \\ \text{power } S \rightarrow B\end{bmatrix}$$

$$= \lambda_B$$

In all events, good decision-making leads to a distribution of power flows identical to what would occur under economic dispatch of the generating units of the three companies.

Suppose now that S and B agree to a two-party wholesale transaction at a split-the-difference price, but they need W to wheel the power. If W either agrees to wheel or is ordered to wheel, the amount of energy exchanged and the sharing of the gains depend on the wheeling price.

The wheeling price might be set equal to the incremental wheeling cost, which may be 0.4¢/kWh, for example. If so, then S sells B power until B's production cost is 0.4¢ above S's. This situation is illustrated in figure

6-3(c), where it is assumed that the wheeling price p_W equals the wheeling cost, which here does not increase as more power is wheeled. Now, W captures none of the gains but merely gets reimbursed for costs. S and B each get half the gains, as indicated by the areas labelled S and B in figure 6-3(c). Clearly, this outcome is preferred by S and B to the earlier arrangement, in figure 6-3(b), under which W gets half the gains.

While each way of dividing the gains can be supported by a fairness argument (and chapter 8 treats gain-sharing further), the point to be emphasized here is that either way leads to good decision-making. In each case, the optimum amount of energy Q_0 is exchanged, and the end result is that the incremental production costs of S and B differ at most by the incremental cost of moving power from S to B.

Other rules for pricing the wheeling service may or may not result in good decisions, as shown in figure 6-4. Figure 6-4(a) illustrates another pricing rule that does result in good decisions. The wheeling price is set higher than wheeling cost in order to give W the incentive to wheel in an environment where wheeling cannot be ordered by a regulatory authority. The price is set equal to the cost of wheeling plus one-third of the gains; that is,

$$p_W = C_W + (\lambda_B - \lambda_S - C_W)/3,$$

where C_W is the incremental cost of wheeling from S to B. If C_W is 0.4¢/kWh, then the total gains from trade are initially 3.6 ¢/kWh (7¢ - 3¢ - 0.4¢), and each of the three parties receives an equal share (1.2¢). The seller S sells his power to the buyer B at the price p_S, which is λ_S plus one-third of the gains. The value of p_S in this example is initially 4.2¢/kWh. The buyer pays the wheeler the price p_W, which starts at 1.6¢/kWh and decreases with increased trading. The price p_B paid by the buyer is $p_S + p_W$; it starts at 5.8¢/kWh. When p_W is reduced to the incremental cost of wheeling, C_W, the wheeler will decide to stop wheeling. This occurs at the same time that S's gain and B's gain shrink to zero and they too decide that they have no more incentive to trade. The amount of energy going from S to B is again the optimum amount Q_0 that appears in the two cases in figure 6-3. Once again, the parties decide to trade until incremental production costs differ at most by the incremental power transportation

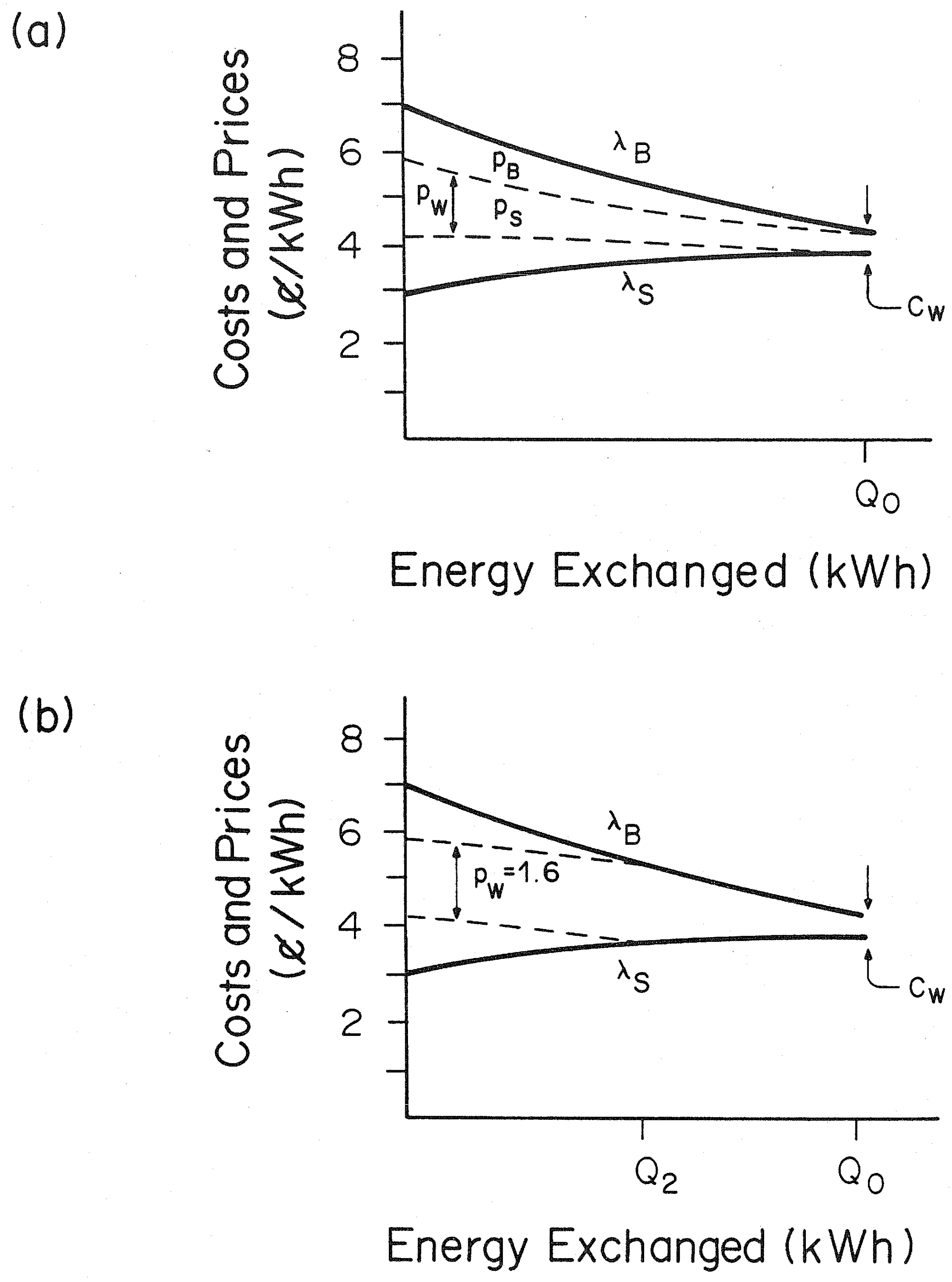


Fig. 6-4 Energy exchanged between S and B where W wheels the energy under two other pricing rules: (a) W receives one-third of the gains, and (b) the wheeling price is fixed at 1.6 cents per kilowatt-hour

cost.

A bad pricing rule, from the viewpoint of good decision-making, is illustrated in figure 6-4(b). Here the wheeling price is again set above wheeling cost so as to give W an incentive to wheel: $p_W = 1.6$¢/kWh. But, in this case the initial wheeling price applies to all power wheeled. S and B exchange power using a split-the-savings (after allowance for wheeling payments) pricing rule. They decide to trade until their savings after wheeling payments go to zero. This occurs at the level of trading Q_2, which is less than the optimum amount.

In this latter case, despite a good rule for pricing power, a bad rule for pricing wheeling leads to a bad result. The bad result is characterized by nearby utilities having incremental production costs that differ by an amount greater than incremental transmission costs.

However, even with a bad rule for pricing wheeling, a good result can still occur (through the mechanism of figure 6-3(b)) if W engages in buy/sell transactions. Indeed, W would prefer this method of achieving a good result because W captures a greater share of the gains: compare W's gains in figure 6-3(b), 6-3(c), and 6-4(a).

It may be appropriate here to refer to the discussion in chapter 2, especially that associated with figure 2-7, regarding the fact that power flows in identical ways in some situations, whether or not wheeling is involved. The point is made there that the difference between wheeling and other wholesale transactions is not a difference in power flows but a difference in power ownership. Here, a similar point becomes clear; the difference between wheeling and simultaneous buy/sell transactions is not a difference in power flows but a difference in ways of sharing the gains from trade.

From the viewpoint of good decision-making, either approach or a combination of approaches can yield good results provided wholesale power prices and wheeling prices are well designed.

A Test for Good Decision-making

In large interconnected electric power systems, such as those depicted in the control area map in appendix D (figure D-1), extending the arguments presented above leads to a similar result for a system of many companies.

With efficient pricing for power trades and wheeling services, and in the absence of nonprice impediments to power transfers, the marginal generation supply costs of any two companies will differ by no more than the marginal cost of transferring power between them. We shall refer to this result as <u>the equalization of marginal costs across the grid</u>.

Equalization of marginal costs across the grid is a test of whether all parties are making good decisions. In fact, it is the observation of large regional disparities in system lambdas that supports the widespread belief that the level of U.S. power transfers is inadequate and that more wheeling is needed.

The goal of marginal cost equalization can be achieved without any wheeling, however, if every pair of neighboring utilities trades optimally. Wheeling expands the number of trading partners and furthers this goal. But without at least some two-party trades, it is doubtful that wheeling transactions alone could achieve the goal. In figure 6-5, for example, wheeling along any of three contract paths would tend to eliminate marginal production cost differences between S and B. Differences between U, V, and W would not be much affected by such trading, however. It is possible to suppose that U purchases electricity from V by wheeling through S; by such transactions, marginal costs could be equalized eventually. Such a convoluted arrangement makes less sense, however, than supposing that both U and V trade directly with S, particularly since the marginal generation cost of S is lower than that of either U or V. Direct trading would seem to involve smaller transaction costs in such a circumstance. In any case, both wheeling and direct two-party coordination sales are useful in promoting the goal of marginal cost equalization.

It is important to realize that marginal cost equalization across the grid correctly and completely characterizes efficient supply conditions regardless of the sequence of transactions followed in achieving it. The critical aspect of the situation depicted in figure 6-5 is that there are profits to be earned in power trading. Paying a wheeling utility only the marginal cost of wheeling divides these profits quite differently from a series of buy-sell arrangements, however. Regardless of where the profits come to rest, a situation in which marginal costs are equalized across the grid is one with no further incentives for trading. Conversely, as long as some marginal costs are not equal along any tie line, additional trading

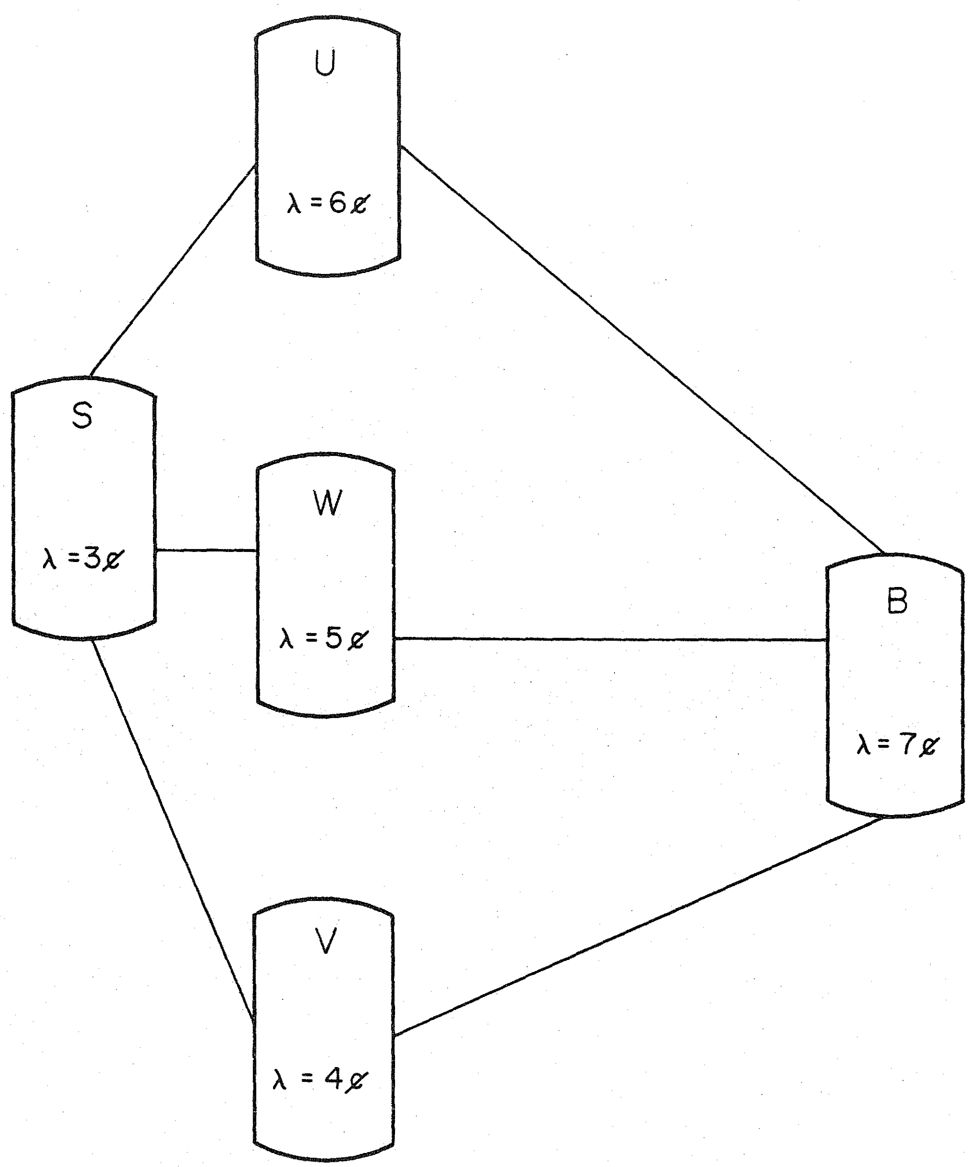


Fig. 6-5 Five interconnected electric utility companies with marginal production costs, before trading, as shown in cents (per additional kilowatt-hour produced)

would be a good decision. Any regulatory rule that furthers the goal of network equalization of marginal costs has the virtue of promoting good decision-making and hence economic efficiency. (Whether the benefits outweigh the costs associated with administering the rule is another matter.) The point to be emphasized here is that the conditions of supply efficiency are the same regardless of the distribution of the economic rents. A regulatory policy, be it mandatory wheeling at marginal cost prices or not, that distributes the profits in a particular manner can be consistent with supply efficiency if additional trading continues until all gains from trade are eliminated. The most contentious part of regulatory policy may well be the rent-distributing aspects of it. Dealing with such issues requires the regulator's best social judgment. A wide variety of such judgments can be consistent with the goal of supply efficiency.

It might seem to be a simple matter to apply this test of good decision-making to the current U.S. situation by comparing the system lambdas of various control centers in an interconnected region. Indeed, this is simple in a static world where nothing changes. Suppose that the system lambda for each utility in figure 6-5 is known and never varies (because each company serves a constant, never-changing load), and suppose that the marginal transmission costs are known and constant. Then the companies would trade power until marginal costs are equalized across the grid, as shown in figure 6-6. This figure shows the final equilibrium result of trading. For example, the system lambda of utility S has risen from 3.0¢/kWh in figure 6-5 to 3.8¢ in figure 6-6. S supplies power to U at a transmission cost of 0.2¢/kWh. Hence U's lambda has declined from 6¢ to 4.0¢. Similarly, W's lambda (3.9¢) equals S's lambda (3.8¢) plus the transmission cost (0.1¢). Utility V, however, decides not to buy from S because V's lambda (4¢) is already less than the sum (4.1¢) of the lambda of S and the 0.3¢ delivery cost. Recall that the equalization test requires only that the lambdas of S and V differ <u>at most</u> by 0.3¢.

Up to this point, we have assumed that costs are being equalized in the short run, with transmission capacity fixed at its current value. Now assume that capacity can be added in a reasonable time-frame, less than the time needed for construction of new generating facilities, so that system lambdas are still the only relevant marginal generating costs.

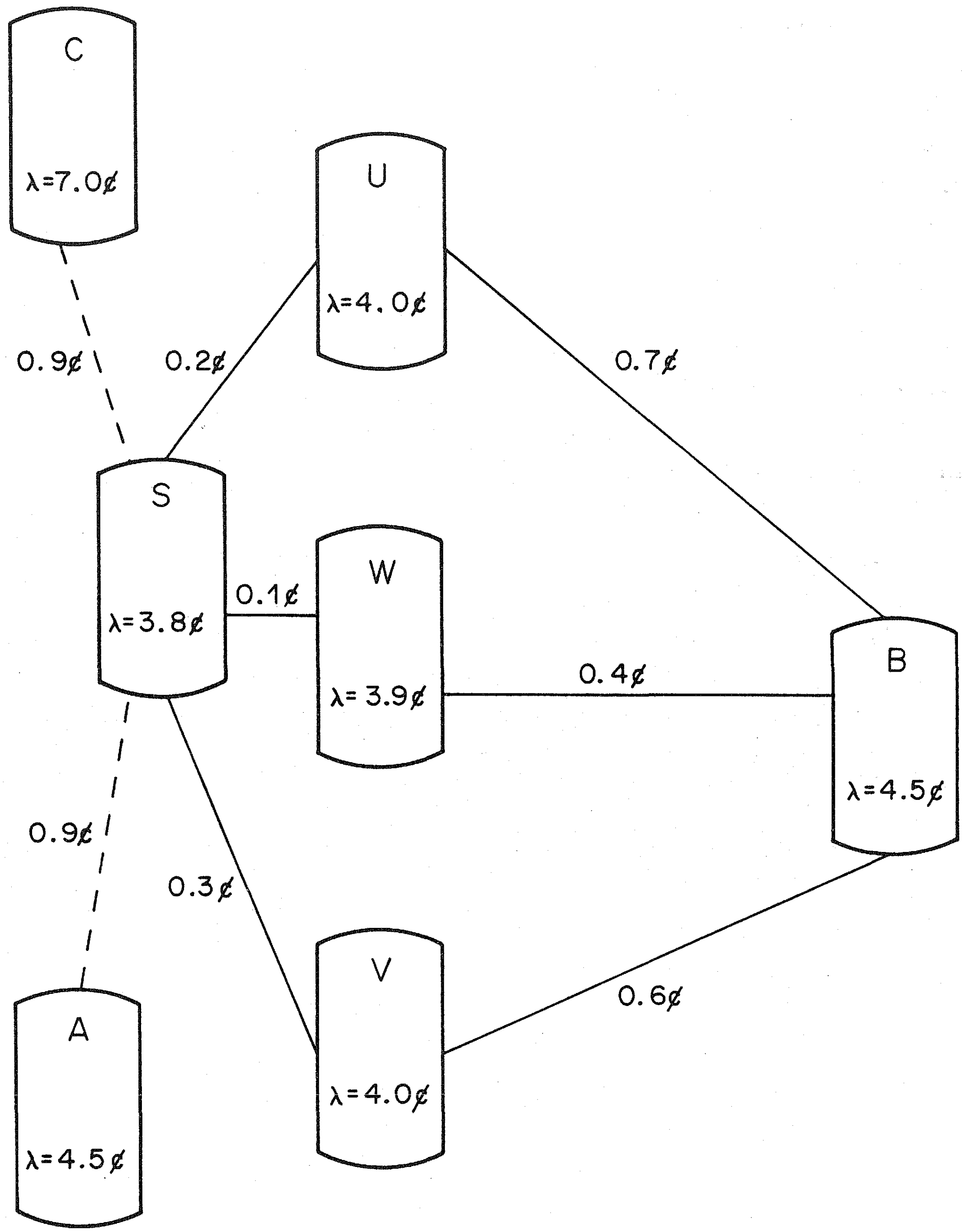


Fig. 6-6 Five interconnected companies, after trading, with marginal production costs and marginal transmission costs as shown in cents (per additional kilowatt-hour produced or transmitted); also shown are companies A and C, not now interconnected with S

Another utility, A, is not interconnected with S, but could be interconnected if a new transmission line (dashed line) were constructed at a levelized cost of 0.9¢/kWh. (One may also assume that A and S are interconnected with a line that cannot carry as much power as A and S would like to trade, and 0.9¢/kWh is the incremental cost of expanding its capacity.) However, the decision not to construct a line between S and A is a good decision because A can generate electricity for 4.5¢ whereas the delivered cost of energy from S would be 4.7¢.

Utility C is also not connected with S, but in a static world a new line should be built between S and C because trading with S would lower C's system lambda from 7.0¢ to 4.7¢.

In a nonstatic world, however, applying the marginal cost equalization test is more difficult for several reasons:

(1) The system lambdas of the companies vary from hour to hour (though they follow a predictable daily pattern).

(2) The system lambdas can vary significantly over time. The future system lambda of S in figure 6-6 depends heavily on the number of utility customers S will attempt to supply. Also, lambda reflects primary fuel prices, which vary from year-to-year. Thus, C's decision to build a new transmission line depends on his 7.0¢ lambda, which may reflect (say) high oil prices, as well as the lambda of S, which depends on the demand for S's power. If oil prices decline over time, the project may no longer be a good decision. On the other hand, A's decision not to build may later appear to be wrong if subsequently the price of his primary fuel increases with respect to S's. Recent history suggests that primary fuel prices tend to rise and fall together, though by different percentages, and that there is usually a lag between the price change of one fuel and that of another. During the lag period, additional transmission capacity may seem justified if it is assumed that the price disparity is permanent. While it need not be permanent to justify new transmission capacity, it must last for a long enough period to pay back construction costs with transmission prices set appropriately, given the period of the disparity. Uncertainty about fuel price creates uncertainty about

what is a good decision. As a result, an apparently good decision, like construction of a C-S transmission line, may not be made.

(3) The transmission costs are difficult to determine. The short-run costs, discussed in chapter 4, may require computer modeling to determine and may vary significantly from line to line.

(4) Where there is a transmission capacity constraint, incremental transmission line costs must be determined. These costs, discussed in chapter 5, vary significantly with several factors. Moreover, to apply the test it is necessary to convert the line cost from dollars per mile to dollars per kilowatt, then to cents per kilowatt-hour. The last step especially requires certain estimates (or arbitrary assumptions) about such variables as annual number of peak hours or line capacity factor over the line's useful life. These estimates create uncertainty about the best value to use for actual incremental transmission cost per kWh.

Despite these difficulties that policy makers would encounter in applying the test to the U.S. power system today, the marginal cost equalization test is a good guideline for policy makers interested in pricing. Prices can be designed so as to promote marginal cost equalization; then utility planners--for buying, selling, and wheeling utilities--all have incentives for good decision-making as they make their future plans based on their own best estimates of future costs and loads.

If a long-range planning horizon is used, however, then the test is applied, not using system lambda as the marginal electricity production cost, but using the long-run marginal cost of electricity generation. This includes the cost of expanding generating capacity as well as those production costs that vary in the short run. The result is a similar, but somewhat different test, based on the equalization of long-run incremental bulk power supply costs across the grid. These costs are the costs to the various utilities of optimally expanding their capacities to generate and transmit electric power. This new test is a test of whether all parties are making good long-run investment decisions about generating and transmission capacity and about electricity-consuming facilities.

Different pricing rules may be effective for equalizing short-run and long-run marginal costs. This concept is developed further in the pricing policy discussion of chapter 7. Before turning to this subject, let us complete the example of short-run marginal cost equalization in order to obtain an insight about compensation for loop flows.

Loop Flows

Returning to figure 6-6, consider what the cost is of moving power from S to B and how this service should be priced for good decision-making.

Loop Flow Costs

Moving power from S through U to B costs 0.2¢/kWh + 0.7¢/kWh, as shown in the figure, for a total transportation cost of 0.9¢/kWh. Similarly, the transportation cost is 0.5¢/kWh via W and 0.9¢/kWh via V.

With ordinary transportation decisions, one chooses the lowest cost route.[4] But because of loop flows, power moves over all three routes regardless of which appears to be the least cost. Although the route through W would probably be selected as the contract path, costs are incurred along all three paths.

To find correctly the marginal transportation cost from S to B, remember that S and B complete a wheeling transportation as follows: B backs off its generation by the number of kilowatt-hours to be wheeled as S increases its generation by this amount. Suppose that each kilowatt-hour divides over the three routes in such a way that 0.3 kWh flows via U, 0.5 kWh flows via W, and 0.2 kWh flows via V. Then the one kilowatt-hour flow imposes a cost of:

[4] An analogous problem would be one where a produce buyer (B) in the midwest must choose between locally grown, but expensive, greenhouse tomatoes and less expensive Southern California tomatoes (S). U, W, and V represent alternative transportation modes, such as rail, truck, and ship, for moving produce across the country. One selects the least cost transportation mode, then chooses between the two types of tomatoes according to which has the lower delivered cost. However, the analogy breaks down when loop flows are considered.

$$
\begin{aligned}
0.3\ \text{kWh} \times 0.9¢/\text{kWh} &= 0.27¢ && \text{on the U route,} \\
0.5\ \text{kWh} \times 0.5¢/\text{kWh} &= 0.25¢ && \text{on the W route, and} \\
0.2\ \text{kWh} \times 0.9¢/\text{kWh} &= \underline{0.18¢} && \text{on the V route.} \\
\text{total} &= 0.70¢ &&
\end{aligned}
$$

Hence the total transmission cost imposed on the network in figure 6-6 by moving one kilowatt-hour from S to B is 0.7¢.

The weighted average transmission cost is 0.7 cents per kilowatt-hour. This is the appropriate value to use for the incremental transmission cost from S to B in our test for good decision-making. Utility B's incremental supply cost (4.5¢) is equal to the production cost of utility S (3.8¢) plus delivery cost (0.7¢).

It may seem that B could lower its supply cost further in figure 6-6 by buying power directly from W. W's cost is 3.9¢, and the costs imposed by the power that flows over the W→B tie line is only 0.4 ¢/kWh. It would seem that W can deliver power to B at a delivered cost of 4.3¢. In fact, this is not so. This is because only some of the extra power generated by W would flow over the W→B tie line; in this example, half follows this direct route. The other half, in effect, flows through S and U or V. As a result, only half the power W supplies to B costs 0.4¢ to deliver. The total delivery cost is higher.

This result means that the cost of moving power from W to B is not the same as the cost of moving power along the W→B tie line. Let us see how to find the cost of moving power from W to B in this case.

Remember that W was able to lower its own supply cost (from 5¢ in figure 6-5 to 3.9¢ in figure 6-6) by purchasing power from S. If W agrees to sell power to B, W increases its generation by the same amount that B backs off its generation. To keep the example simple, assume the amount is just one kilowatt-hour. As mentioned, W's increased generation does not cause an additional kilowatt-hour to flow over the W→B tie line. Instead, the power flows reach a new equilibrium, which can best be explained by assuming that the equilibrium is reached in a two-step process. First, as W produces one more kilowatt-hour, this energy flows directly to W's own loads, displacing a kilowatt-hour supplied to W by S. Now, S has an extra kilowatt-hour of generation while B has a one-kilowatt-hour deficiency. In the second step, then, power flows from S to B over all three routes.

Therefore, the incremental cost imposed by the "direct" sale from W to B is W's supply cost (3.9¢) less the step 1 savings in transmission cost for energy delivered from S to B (0.1¢) plus the step 2 transmission cost for energy flow from S to B over all three tie lines (0.7¢). Hence the incremental delivered cost of a direct two-party sale from W to B is 4.5 cents. Of course, this is the same as the cost of energy wheeled from S, the result one would expect at a cost minimizing equilibrium.

The cost of moving a kilowatt-hour from W to B in this example is 0.6¢; this is the delivered cost (4.5¢) less the cost of W (3.9¢). It can also be calculated as the sum of the costs along each route: 0.5 kWh flows on the W→B tie line at 0.4¢/kWh (costing 0.20¢); 0.5 kWh flows (counter to the main load) from W to S saving 0.1¢/kWh (saving 0.05¢); of this latter 0.5 kWh, 0.3 kWh takes the path via U to B (costing 0.27¢) and 0.2 kWh takes the path via V (costing 0.18¢). The total cost is 0.20¢ - 0.05¢ + 0.27¢ + 0.18¢ = 0.60¢.

Another approach to finding the same result for any amount of power flow is to calculate the weighted average of the costs of all possible paths, where the weights are the fractions of the total power flow along each path:

Path	Path Cost	Weight	Weighted Cost
W→B	0.4¢/kWh	0.5	0.20¢/kWh
W→S→U→B	0.8¢/kWh	0.3	0.24¢/kWh
W→S→V→B	0.8¢/kWh	0.2	0.16¢/kWh
		Total Cost:	0.60¢/kWh

The costs of loop flows, then, can be expressed in two equivalent ways: (1) the total transmission cost in dollars is the sum of the costs, expressed in dollars, along each route, or (2) the transmission cost, in cents per kilowatt-hour, is the weighted average of the costs, expressed in ¢/kWh, along each route, where the weights are the fractions of the total amount wheeled that move on each route.

The concept of weighted average costs for loop flows works on several levels. For example, although the route from S to U in figure 6-6 is depicted as a straight line, it actually may represent a complex network of transmission and subtransmission lines connecting the generating stations and load centers of utility S to those of utility U. The incremental transmission cost assumed for this route is 0.2¢/kWh, but in practice this cost would have to be found by examining the incremental costs along all the routes from S's service area to U's, giving more weight to the costs incurred on those tie lines along which more power flows.

Suppose that utilities U, W, and V are suddenly merged into a single company with a unified service area, and that this new company is asked to state the incremental cost in cents per kilowatt-hour of wheeling power from S to B. The appropriate cost is 0.7¢/kWh--the weighted average cost of moving power along the three principal routes through the unified service area.

On a larger scale, S, U, W, V, and B in figure 6-6 could represent, not single companies, but control areas (as in figure D-1). Then each entity, such as W, could consist of a group of companies. Weighted averaging of costs would be used to determine the transmission cost through the W control area. This would define the cost of a major transmission corridor, S→W→B. Also, the same procedure would be used to find the cost of transmission from control area S to control area B through the three intermediate control areas, that is, through three major corridors. This transmission cost is the weighted average of the three corridor costs, with the weights being the relative flow through each corridor.

This weighted-average approach to determining transmission costs where loop flows are involved allows the cost analyst to build up cost information in a step-by-step manner. Hence, one can determine the cost of moving power from one region to another by appropriately averaging the costs incurred through each major loop, without having to examine the flows along every minor line in the network, provided the cost for each loop is reasonably represented by a previously determined weighted average cost for that loop. This latter cost is ultimately built up step-by-step from weighted averages of incremental costs for individual lines. Using this step-by-step approach, the result is the same as if the costs of many individual lines were appropriately averaged to find the cost of major interregional loop flows. Conversely, our study of methods for determining wheeling costs in a network is now reduced to a study of methods for finding wheeling costs along a single line. Once a method is selected, it can be applied to each line segment along any path from buyer to seller. The cost along the entire path is the sum of the segment costs. The total cost of moving power from buyer to seller is the weighted average of the costs along all paths in the network that carry more than insignificant fractions of the wheeled power.

Loop Flow Pricing

While loop flow costs are incurred along all loops that carry more than insignificant amounts of power between seller and buyer, the arrangement for pricing the wheeling service may or may not provide compensation to the owners of each loop. Indeed, current practice is often to provide compensation only to the owners of lines along the contract path, trusting that those bearing loop flow costs will--by a sort of "gentlemen's agreement"--ignore these costs, if they are not too severe. However, loop flows that would strain transmission capacity or seriously threaten reliability along a loop can prevent a wheeling transaction from occurring.

If those companies off the contract path who bear loop flow costs were unaffected in their decision-making by this lack of compensation for inadvertent wheeling, efficient pricing requires only that the wheeling customers (that is, the buying and selling utilities) pay a price to the contract wheeler that covers loop flow costs. It does not necessarily require that the utility or utilities forming the contract path should share wheeling receipts with the bearers of loop flow costs, though fairness might suggest it.

Loop flow costs are an externality with respect to wheeling service, analogous to an air pollution externality that accompanies fossil-fuel generation of electricity. In the latter case, efficiency requires that the retail price of electricity include a surcharge to cover the costs imposed on persons exposed to pollutants. But it does not require that the receipts from the surcharge be dispersed to all such persons--though a fairness argument may suggest that this is an appropriate action. An alternative action is to use the surcharge receipts to install pollution control equipment, to the extent that the benefits of this action exceed its costs.

Similarly, there is no efficiency reason to pay utilities for the loop flow costs they bear, when they, like persons exposed to air pollution, are essentially powerless to prevent exposure to these costs. Wheeling receipts in excess of contract path costs could be used, for example, to expand contract path capacity, thus alleviating the loop flow problem, provided the benefits of such expansion justify the costs.

In most cases, however, utilities that carry inadvertent loop flows are not powerless, and most likely base some decisions on their compensation or lack of it. While small loop flow costs may be borne voluntarily, large costs are likely to lead to pressure of one sort or another on the contract path wheeler to forego such arrangements. This influence can range from a simple request, to reliability council advice, to perhaps legal action. If the loop flow costs involve more than short-run costs (as defined in chapter 4), so that the utility experiencing loop flow would have to expand its transmission capacity to support it, such a utility would be in a strong position to block good decisions to expand the power transfer capacity of an interconnected network.

Even if a regulatory authority, such as the FERC, could order wheeling, there would probably be compelling legal requirements that all utilities bearing significant power flows be compensated, not just those along some governmentally designated "contract" path, or "regulatory" path as it might be called. Especially if some of the pathways require capacity expansion to comply with a regulatory order, appropriate compensation for the costs incurred along each pathway would seem necessary if the regulatory order were to survive judicial review.

These arguments suggest that loop flow utilities are not mere helpless observers of the principal decision makers--the buyer, seller, and contract path wheeler. If they influence the decisions, even just the long-run decisions regarding capacity expansion, then pricing for good decision-making suggests that compensation be provided for loop flow wheeling service. At the minimum, loop flow carriers should be compensated for the incremental transmission costs they bear.

Referring again to figure 6-6 and the associated example, for each kilowatt-hour that S sells to B along contract path W, good decision-making requires that U and V receive at least 0.27¢ and 0.18¢ per kilowatt-hour, respectively. How these funds flow is less important; for example, W could collect (at least) 0.70¢/kWh (including administrative costs) and distribute the receipts to the loop flow carriers, U and V.

Throughout chapters 7 and 8, it is assumed that any pricing policy discussed is applied in the context of reimbursement for loop flow costs. In particular, in the cost-based pricing discussion in chapter 7, consideration of methods for costing and pricing along only one transmission path is necessary. The total wheeling cost and charge for a power exchange are then found by taking a properly weighted average of the wheeling costs and prices along all paths that carry more than insignificant amounts of wheeled power.

Summary

To conclude this chapter, we extend our previous summary of insights about pricing two-party power exchanges to the case of multi-party exchanges.

1. Good decisions are those that result in incremental benefits to all parties greater than incremental costs for all parties.
2. There is no single best pricing rule for power exchanges or for wheeling that results in good decision-making. A variety of pricing rules can do so; these rules differ according to how the gains from trade are shared among the parties.
3. All pricing rules that promote good decision-making produce the result that the marginal generation supply costs of any pair of companies differ at most by the marginal cost of transferring power between them. We call this result, the equalization of marginal costs across the grid.
4. Marginal transmission cost between any buyer-seller pair in a network with parallel flow paths is determined on the basis of the weighted average cost per unit of energy over all paths linking the pair, where these costs are weighted by the fraction of the energy flow along each path.
5. Either a series of direct two-party sales, a series of multi-party wheeling transactions, or a combination of approaches is capable of achieving the efficient result, the equalization of marginal costs

across the grid. Further, from the viewpoint of good decision-making, there is no single best organization of the industry (individual companies, holding companies, power pools, brokerage systems, national grid, and so on): if power is priced efficiently and wheeling is priced efficiently, then (absent non-price impediments to power transfers and absent significantly different transaction costs with different ways of organizing the industry) the power flows that result are the same as those achieved by economic dispatch of the entire network. However, two-party sales and wheeling result in different ways of sharing the gains. Different ways of organizing the industry may also produce different distributions of gains.

6. One may decide on the basis of fairness among pricing rules that promote good decisions, but starting with a fairness criterion may result in a rule that causes bad decisions to be made.
7. Pricing for good decision-making requires that those who experience loop flow costs and who can affect decisions about the use and expansion of the transmission network be compensated at least for the incremental costs experienced between any buyer-seller pair.

These insights are the basis for the analyses presented in chapters 7 and 8. Chapter 7 treats cost-based ratemaking for wheeling that is compatible with good decision-making. In chapter 8, other pricing considerations, which may cause prices to deviate from costs, are taken up. Discussion of possible implementation difficulties is deferred, for the most part, to chapter 9.

CHAPTER 7

COST-BASED WHEELING PRICES

There is a variety of cost concepts that could form the basis of cost-based wheeling prices. The discussion in this chapter covers several concepts of what constitutes a cost-based rate. In evaluating each concept, the focus is upon whether it serves to encourage good decision-making, with regard to use of the existing bulk power supply system and also with respect to its expansion. An important test of whether prices are successful in encouraging good decisions is whether they promote the equalization of marginal generation and transmission costs across the grid. Each concept of wheeling cost is evaluated under this standard. The promotion of good decisions and economic efficiency with cost-based wheeling rates, then, is the focus of this chapter. Non-cost influences on wheeling prices are covered in the next chapter.

Other perspectives about the appropriate cost basis for wheeling prices could be reasonably held. They simply are not ours. In this regard, it is worth noting that the major alternative view is social fairness in the distribution of fixed costs; cost is ordinarily important in such value judgments. If fairness considerations prevail, it is sometimes useful to have a measure of how much economic efficiency must be given up in order to adopt an equitable pricing structure. The discussion of efficiency in this chapter can be useful in assessing the degree of inefficiency associated with particular policies.

From the consideration in previous chapters of the engineering rudiments needed to understand electricity transmission, there emerge two difficulties that must be confronted by a sensible pricing policy:

(1) Electricity flow in an AC network is likely to spill over to neighboring electric companies that are not formally a part of the wheeling arrangement. If prices are based on costs, carriers of

these loop flows can be reimbursed for their costs on the same basis as utilities along the contract path. Regardless of which cost concept is employed, the total costs and charges are determined as the weighted average of the costs and prices along individual paths, as discussed in chapter 6. Hence, here in chapter 7 the discussion of each cost concept treats only how the cost is determined for each path. Since a path is a series of transmission lines, only a discussion of how the cost concept applies to individual lines is necessary here.

(2) A large part of the cost of transmission is the cost of capital investment. Operating costs may be large or small in comparison, as hour-by-hour fluctuations in electricity demand can cause rapid variation in the loadings on some transmission lines. For cost-based pricing, this creates a tension between the need to vary prices rapidly to follow costs and the need for long-term rate stability for sensible planning of transmission use and expansion. Much of the discussion in this chapter treats this issue.

The four cost concepts covered in this chapter are embedded costs, operating costs, short-run marginal costs, and long-run marginal costs.

Prices Based on Embedded Costs and Operating Costs

Today, rates for firm wheeling service are typically derived from an allocation of the embedded capital costs of transmission with provision for reimbursement of average operating costs. Firm rates are usually expressed in capacity units of dollars per kilowatt. Rates for nonfirm service are commonly expressed in energy units of cents per kilowatt-hour. They appear to include, most often, reimbursement for average line losses, power factor correction, and miscellaneous administrative charges.

Here we consider the advantages and disadvantages of, first, embedded capital and average operating cost pricing for wheeling, and second, pricing at marginal operating expenses with no provision for capital cost recovery.

Embedded Cost

Wheeling prices based on embedded cost concepts charge customers average line losses plus some type of average, historical cost of the capital investment embedded in transmission facilities. The capital component might be collected on the basis of megawatt-hours, megawatts, or megawatt-miles. Such prices seem fair to many and, in addition, are relatively easy to calculate. They do not convey correctly, however, the cost consequences of a wheeling transaction.

The relation between line losses and load is nonlinear. In such circumstances, charging a customer average system line losses does not convey the correct cost consequences to him. Marginal line losses are higher than the average, assuming that the direction of the wheeling load coincides with that of the base load on the transmission system. Average cost pricing of losses, then, discourages a utility from wheeling because the revenues recovered are less than the costs incurred.

Similarly, the embedded capital cost per unit of power wheeled has no necessary relation to the additional capacity cost imposed on a utility by a wheeling transaction. More accurate price signals are conveyed to potential wheeling clients by current rather than embedded capital costs. Current cost, unfortunately, is sometimes more difficult to determine than embedded cost and could be a source of contention in practice. The current, incremental capacity cost of transmission is the cost (in current dollars) of the next project needed to enhance the capacity of the transmission network divided by the capacity increment. The project might be constructing a new line, stringing a second circuit on an existing line, or adding reactive power compensation equipment to a particular network segment. Efficient prices would be based on the current resource cost of transmission and not on embedded, historical cost.

When a utility has excess transmission capacity, adding embedded capital costs to the short-run operating costs of wheeling results in a wheeling price that is too high (as illustrated in figure 6-4). Such a price discourages potential customers from using otherwise idle facilities and therefore results in too little wheeling.

When a utility's load is approaching a transmission capacity constraint, pricing according to an embedded capacity cost formula that averages the historical costs of all a utility's transmission lines yields a price that is too low. It does not accurately inform wheeling customers of the long-term costs of wheeling service. These customers are encouraged to wheel too much power or to wheel over too great a distance.

Further, the returns available to utilities under this pricing approach discourage them from constructing new transmission capacity for wheeling service. This is because the utility must replace the capacity used for wheeling with new capacity at high current costs. In an environment where wheeling cannot be ordered, it is wiser for a company to retain its capacity for its own use in trading, and hence enjoy the full current economic value of this capacity, than to rent it to others at a price below replacement cost.

A rolled-in average formula is the basis for the current FERC policy for pricing wheeling. Because neither the line losses nor the capital cost portion of embedded cost pricing is based on the current costs of wheeling, such prices do not contain incentives for potential wheelers to engage in transactions that equalize marginal generation costs across the grid. The economies that might be achieved with a stronger, more heavily utilized transmission network are possible only through policies that encourage such equalization. Embedded cost pricing simply does not provide the encouragement.

Marginal Operating Costs

The embedded cost discussion may suggest to some readers that the appropriate way to price wheeling is to reimburse the wheeler for the "out-of-pocket" operating expenses of the wheeling operation, without recovery of historical fixed costs. For reasons set out in the embedded cost discussion, these operating costs should not be based on system averages, but on the cost increments (or decrements) caused by the incremental wheeling load on the transmission system.

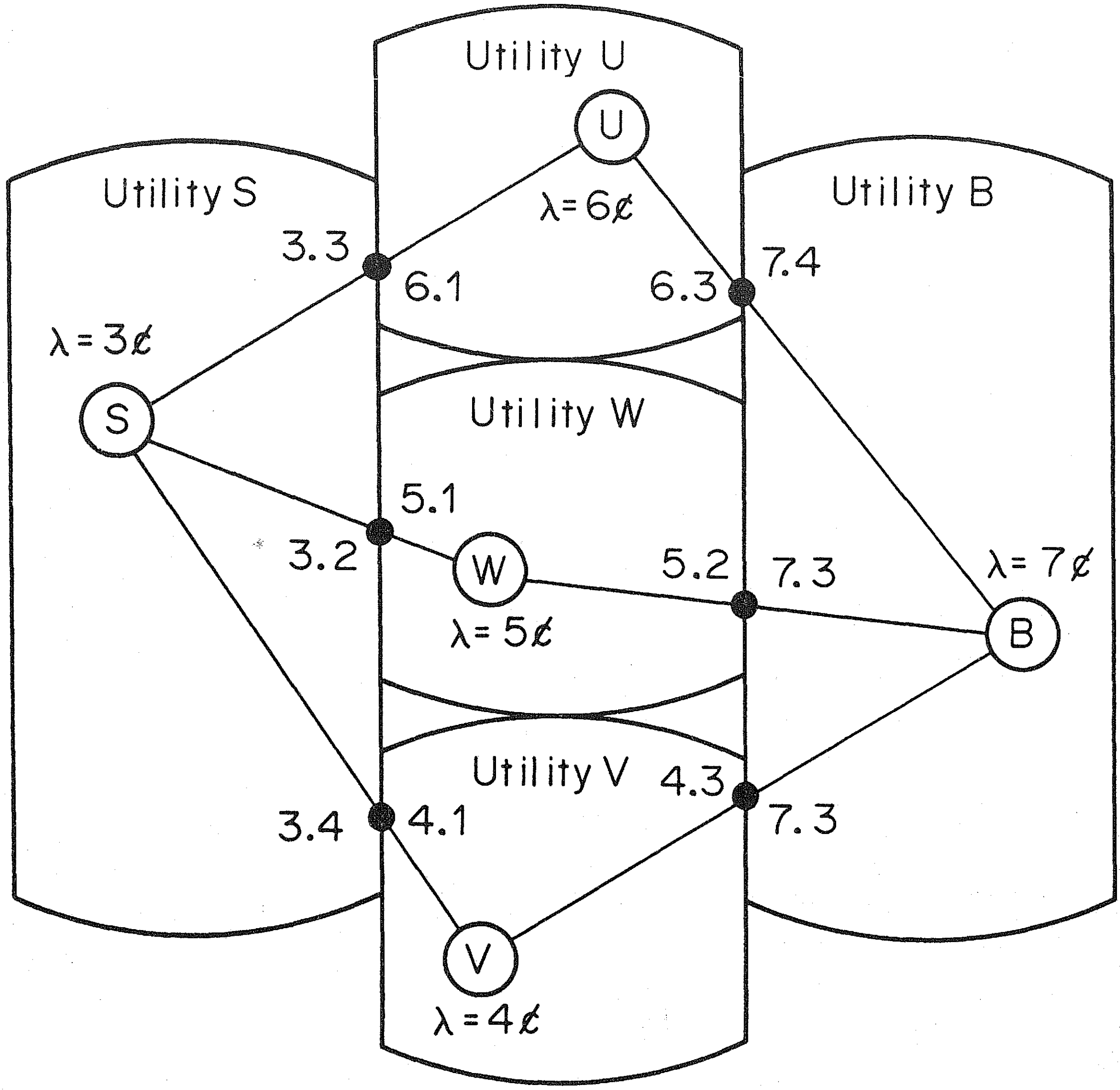
This, in fact, is an efficient approach to pricing wheeling in the case where excess transmission capacity exists and is expected to exist for a considerable length of time. In this particular case, operating cost equals short-run marginal cost--a more general measure of cost, as subsequently explained. In this discussion of operating costs, we develop the idea of costs and prices changing from place to place and examine the effects of a marginal operating cost pricing policy on good decision-making. This serves as an introduction to the concept of short-run marginal cost pricing for wheeling.

Here the objective is to describe only the marginal operating costs of wheeling. In the absence of immediate transmission capacity constraints, wheeling cost is intimately related to the costs of delivering electricity to different places in the transmission network.

In the previous chapter we developed the idea that at equilibrium the production cost of electricity for any utility equals (at most) the production cost for any other utility plus the transportation cost between them. This suggests that costs vary spatially, that is, from one point on the grid to another, according to variations in transmission costs. Figure 6-5 in that chapter is drawn as if cost were constant throughout any one utility, varying only between utilities. A more accurate representation of the situation depicted in figure 6-5 is shown in figure 7-1. Each utility has an extended service area, and service areas are contiguous, with no space between them. Even where two companies are not contiguous, the ownership of a tie line between them ends at a particular point for one company and begins at that point for the other. Hence, interconnection of companies is best represented, not by lines as in chapter 6, but by points of interconnection. In figure 7-1, the six large dots at utility borders represent six points of interconnection, called tie line buses.

Marginal operating costs vary throughout the service area. The marginal operating cost at any location is the system lambda, which is the production cost of the last generating unit brought on line, plus the transportation cost of moving power from this generating unit to that location.

In figure 7-1, the location of the last generating unit brought on line is depicted by a circle enclosing a letter designating the company; for example, the last, or marginal, generating unit of utility S is located at the circle containing the letter S. The complex of transmission lines connecting unit S to another company, utility W, is represented by a simple straight line from unit S to the point of interconnection with utility W. For simplicity, it is assumed at first that no more than one tie line connects each pair of companies.



	p_1(¢/kWh)	p_2(¢/kWh)	G(¢/kWh)
U path	0.2	4.1	3.9
W path	0.1	4.1	4.0
V path	0.2	3.9	3.7

Fig. 7-1 Five interconnected utilities with spatially varying production costs, before trading

If the marginal operating cost of transmitting power from S to the S-W interconnection point is 2 mills, then the cost to utility S of supplying power to a hypothetical customer at that point is 3.2¢/kWh. This is shown by the number 3.2 in the figure, on utility S's side of the border. The other numbers in the figure have a corresponding meaning. For example, the cost to utility W of serving the same hypothetical customer at the S-W interconnection point is 5.1¢/kWh. As the marginal generating unit of any utility changes, the cost of serving the interconnection point changes, not only because of possible differences in unit lambdas, but also because of changes in the transmission path to this point.

The situation shown in figure 7-1 is one where no power exchanges are occurring. The automatic generation control system of each company is operating so that each utility's generation meets its own load, and the power flows at each interconnection point on the diagram are zero. Because of this, there is a discontinuity in marginal operating cost at each bus.

This discontinuity can be removed by power exchanges between pairs of companies. As utility W purchases power from S, their two system lambdas approach (but do not reach) a common value. At equilibrium, when marginal costs are equalized between the two companies, the cost of supplying power to the S-W interconnection point is the same on the S-side and the W-side of that point. If all neighbors trade, all cost discontinuities can be eliminated. Discontinuities can also be eliminated by trades between non-neighboring companies if wheeling service is available at the right price.

Consider now the case where utilities S and B agree to a power sale and require wheeling. This is similar to the example discussed in chapter 6, as illustrated in figures 6-5 and 6-6, with two important differences. Here, only incremental running costs are considered because we have assumed there is no transmission capacity constraint, and hence no incremental capital outlays are caused by wheeling. The presentation of the example is somewhat different here also because we wish to focus on wheeling across a utility's territory. In chapter 6, a utility was represented essentially as a point, in effect the location of the marginal generating unit. In this discussion a utility has breadth. Wheeling refers only to the transmission across the portion of the network belonging to intervening utilities.

Assuming that utility S agrees to sell to B and that the intervening utilities have more than enough transmission capacity and are willing to provide it, we want to determine a wheeling price equal to the marginal operating cost of the wheeling transaction. The marginal operating cost to W of delivering electricity to its tie-line buses is shown in figure 7-1. It costs 5.1 cents per kWh for W to deliver energy to the tie line bus connecting it with utility S, and 5.2 cents to the bus with B. These marginal operating costs are made up of the various generating and other costs, principally line losses, as described in chapter 4. They vary with the loading on the lines from W's marginal generating unit to the buses. As discussed in chapter 4 (figure 4-1), if no power is flowing on the lines from unit W to the S-W bus, there would be (almost) no line losses along this path, and (absent other operating costs) the cost at this bus would equal the cost at unit W. Since the cost is 5.1¢ at the bus, some power flows along at least a portion of the network from unit W to the S-W bus.

Assume utility W serves a load center very close to the S-W bus, as S wheels power through W to B. Then the power from S flows to this load center, displacing power previously supplied by unit W. For each kilowatt-hour wheeled, utility W experiences a savings of 0.1¢, the cost of transporting power from W's marginal generating unit to the S-W bus. The kilowatt-hour displaced flows from unit W to the W-B bus, at a cost of 0.2¢, which is the difference in costs between these two points. The total operating cost of wheeling by W, then, is 0.1¢; this is the cost of moving power from unit W to the W-B bus (0.2¢) less the savings attributable to reduced flow from unit W to the S-W bus (0.1¢).

This same result can be found more simply, without any knowledge of the internal flows of utility W, by subtracting W's cost at the point the power enters W (5.1¢ at the S-W bus) from W's cost of the point the power leaves W (5.2¢ at the W-B bus). The result is 0.1¢/kWh. This method of finding marginal operating costs turns out to be a general result.[1] The marginal operating cost of wheeling across the territory of a particular utility can be found, as a spatial difference in marginal production costs, by subtracting the upstream cost from the downstream cost. Call this difference p_1. Calculated for utility W, the marginal wheeling cost, p_1, is

[1] Roger E. Bohn, Michael C. Caramanis, and Fred C. Schweppe, "Optimal Pricing in Electrical Networks over Space and Time," The Rand Journal of Economics 15 (Autumn 1984): 360-376.

0.1 cents per kWh. In figure 7-1, the marginal wheeling cost for utility U can be found similarly as 0.2 cents, and for utility V, also 0.2 cents.

The figure also shows the marginal operating cost difference between buses from the buyer's and seller's sides of the buses along each of the three transmission routes. Call these p_2. Through the territory of utility U, the difference in marginal operating costs between S and B is 4.1 cents per kWh, or 7.4¢ minus 3.3¢. Along this route, the possible gains from trading between S and B are only 3.9 cents per kWh, because of the marginal transportation costs through the territory of U. These gains are labeled G, and are found as $p_2 - p_1$ along any path. The gains from trade with utility W as the intermediary are 4.0 cents per kWh, and only 3.7 cents using the link through utility V.

If the electricity could be shipped along any route chosen by the buyer, the one through utility W's territory would be best, since this path's marginal transportation cost is least, only 0.1 cents per kWh, and the gains are greatest. This route might become the contract route, if all parties agreed.

The actual marginal operating cost of wheeling is more complicated, of course, involving utilities U and V, in addition to the wheeling utility, W. The wheeling transaction takes place by the simultaneous action of utility B decreasing its generation and utility S increasing its generation by the same amount plus line losses. More flow occurs over paths with less impedance. How the flow divides itself along the three routes can be determined with conventional load flow models. Suppose, as in figure 6-6, that 50 percent of the flow is along the contract path, 30 percent is through the territory of utility U, and the remaining 20 percent takes the southern route through V's service area. The marginal operating cost of wheeling is a weighted average of the three wheeling costs, which in this case would be 0.15 cents per kWh [0.5(.1)+0.3(.2)+0.2(.2)].

Charging 0.15 cents per kWh for wheeling would provide the correct incentives to engage in the transaction, still with the assumption of more than adequate transmission capacity. From the economist's perspective, this is the correct price regardless of how the wheeling proceeds are disbursed, if the wheeling could be mandated. That is, with obligatory wheeling, the function of price is to signal the buyer correctly about the economic consequences of his action. The 0.15 cent price does this, whether it is given entirely to utility W or whether it is split among the three utilities that provide actual transportation.

The loop flow in this example is an example of a real externality. The weighted average price of 0.15 cents per kWh correctly accounts for these externalities in that the aggregated price faced by the wheeling customers encompasses all parallel flow paths. Utilities U and V, however, are not indifferent about the transaction. The increased flow along their transmission links means that their own line losses are increased by the transaction, and these companies must increase their own generation to compensate. Economic efficiency would indicate that utilities U and V be paid for the de facto transmission services they provide. This could be accomplished by dividing the 0.15 cents transportation fee among utilities U, V, and W. The price based on marginal wheeling cost is large enough to provide the correct compensation because all the externalities were correctly included in the calculation to begin with. If the wheeling price were incorrectly set at 0.1 cents per kWh, based on the marginal wheeling cost solely along the contract path, there would be insufficient funds to compensate for the parallel flows.

In practice, an economically efficient wheeling price is a weighted average of the marginal operating costs along all affected wheeling paths. The proceeds would be divided among the transporting utilities according to their individual marginal costs. The resulting complexity of such a pricing arrangement would depend upon the frequency at which the prices were updated. To continually capture cost variations over time would require frequent updates, perhaps as often as every 5 minutes or so. Quoting a price, keeping track of the estimated line flows,[2] and accounting for the flow of funds would require an advanced, computer-operated accounting and pricing system. Less frequent updates, every 24 hours or perhaps monthly, would require less computer sophistication but would capture a smaller portion of the potential gains from trade. The transaction costs must be weighed against the improvement to economic efficiency.

[2] Utilities routinely calculate tie-line flow coefficients, using load-flow models, according to Bohn et al., op. cit. The resulting estimates can be used as the basis of marginal wheeling costs.

The principal drawback of setting prices equal to marginal operating costs is that transmission lines do not always have adequate capacity. This pricing approach does not provide signals for good decision-making regarding the costs of over-using the existing system. Relatively low wheeling prices may stimulate more demand for wheeling than the transmission system can handle.

This approach can equalize marginal costs across the grid if there is excess capacity throughout the network. This is an unlikely situation and one that would last only for a short time. It does not describe the networks in the United States today. To promote good decisions when transmission capacity is limited, pricing at full marginal cost must be considered.

Marginal Cost Pricing for Wheeling

Good decision-making is promoted by customers paying prices close to full marginal cost. The theoretical superiority of marginal cost pricing is usually not a matter of dispute any more, even by its current detractors.[3] Instead, the debate has focused on practical implementation issues such as various so-called second-best problems, including in particular whether to use short-run or long-run marginal cost, which calculation method to employ in either case, and the need to adjust prices to recover the revenue requirement. These issues have been widely discussed and so our comments here are brief; additional related comments are deferred to later chapters.

It is important at the outset to clarify the meaning of the terms "short-run" and "long-run" marginal cost. Short-run marginal cost can be thought of as running cost or variable operation and maintenance cost only if the transmission facility is not fully loaded. As congestion on a line increases, short-run marginal cost increases. That is, the concept of short-run marginal cost includes the notion of congestion costs. If price

[3] See, for instance, M. B. Rosenzweig and J. Bar-Lev, "Transmission Access and Pricing: Some Other Approaches," Public Utilities Fortnightly, August 21, 1986, pp. 20-26; and L. R. Jahn, "Pricing and Risk Allocation in Wholesale Rate Making," Public Utilities Fortnightly, July 24, 1986, pp. 29-33.

were equal to short-run marginal cost, price would serve to allocate limited transmission capacity to those users who place the highest value on the service on those occasions when excess demand exists. Long-run marginal cost, on the other hand, contains no congestion charge, but does include explicitly the cost of expanding capacity by an increment large enough to avoid congestion. Importantly, a time profile of short-run marginal cost would exhibit a great deal of variation. Sometimes, it would be as low as running cost and at other times it would exceed long-run marginal cost.

One pricing policy is to set the wheeling price equal to short-run marginal cost for all wheeling transactions; another is to set price at long-run marginal cost for all transactions. This section examines the use of both short-run marginal cost and long-run marginal cost as the basis for equalizing marginal costs across the grid.

Short-run Marginal Cost Wheeling Prices

The economics of short-run marginal transmission cost or spot market pricing of electricity has been studied and extensively developed by Schweppe, Bohn, Caramanis, and other researchers at the MIT Electromagnetic Laboratory.[4] This work has been done competently by a team of electrical engineers and economists and is, by far, the most thorough examination of the subject available today. This section begins by highlighting the results of this research. Readers interested in more detail are directed to the MIT report on wheeling, the final citation in footnote 4, and to appendix C of the NRRI report on Non-technical Impediments to Power Transfers (forthcoming, NRRI-87-8).

---

[4] See M. C. Caramanis, R. E. Bohn, and F. C. Schweppe, "The Costs of Wheeling and Optimal Wheeling Rates," IEEE Paper 85 SM 464-3, presented at 1985 Summer Meeting, IEEE Power Engineering Society, Vancouver, Canada; R. E. Bohn, M. C. Caramanis, and F. C. Schweppe, "Optimal Pricing in Electrical Networks over Space and Time," Rand Journal of Economics 15 (Autumn 1984): 360-376; M. C. Caramanis, R. E. Bohn, and F. C. Schweppe, "Optimal Spot Pricing: Practice and Theory," IEEE Transactions on Power Apparatus and Systems, PAS-101 (1982): 3234-3245; F. C. Schweppe, R. E. Bohn, and M. C. Caramanis, Wheeling Rates: An Economic-Engineering Foundation, Report TR 85-005, Massachusetts Institute of Technology, School of Engineering, Laboratory for Electromagnetic and Electronic Systems, September 1985.

A transmission network connects a geographically dispersed set of generating station buses with a set of load center buses (see figure 2-5). The short-run marginal cost of electricity supply at any bus i is given algebraically as

$$p_i^* = \theta(1 + \partial L/\partial D_i) + \sum_{\kappa} (\partial Z_{\kappa}/\partial D_i)\eta_{\kappa}$$

$$\begin{bmatrix}\text{short-run} \\ \text{marginal} \\ \text{cost}\end{bmatrix} = \text{[social cost of additional demand} \times (1 + \text{incremental losses caused by flow to i)]} + \text{[transmission constraint terms, summed over lines]}.$$

L is line losses, D_i is the demand at location i, and Z_{κ} is the power flowing in line κ. The η_{κ} are "shadow prices" indicating the value of a transmission line κ when it is used up to its capacity. These are zero in ordinary circumstances. The formula indicates that the marginal cost of additional load at any single point in the network includes the cost of additional stress placed on any and all transmission links. The incremental line loss term turns out to be the key factor in the marginal cost of wheeling and is discussed later.

The social cost of additional demand, θ, is the same for all customers and has two components:

$$\theta = \lambda + \mu$$

$$\begin{bmatrix}\text{social cost} \\ \text{of additional} \\ \text{demand}\end{bmatrix} = \begin{bmatrix}\text{marginal} \\ \text{generating} \\ \text{cost}\end{bmatrix} + \begin{bmatrix}\text{generation} \\ \text{curtailment} \\ \text{premium}\end{bmatrix}$$

The system lambda, λ, is the short-run marginal generating cost, which includes the cost of generating an additional kilowatt-hour of electricity at the marginal generating station plus any losses associated with transporting it to an arbitrarily selected bus in the network, called the swing bus. The curtailment premium, μ, is the price increment (shadow price) needed to limit demand to the present generation capacity. Ordinarily, it is zero; it is nonzero during peak times.

This pricing plan is equivalent to marginal operating cost pricing, as described above, when there are no generation or transmission capacity limitations. Then, μ and η_{κ} are zero. When no transmission or generating constraint is binding, the short-run marginal cost of electricity at any bus i is, in effect, system lambda plus the cost of transportation from the swing bus to i. The marginal transportation cost of electricity is the marginal line loss. Note that the term L in the first equation refers to the aggregate line losses over the entire network. The marginal effect of incremental demand at load center i on aggregate network losses can be determined with load flow models that are used routinely by large utilities and the regional reliability councils.

Wheeling is the transportation of electricity from one set of lines to another. The short-run marginal cost of power at any location i in the first equation includes the marginal transportation cost to that point. As in the simple case of marginal operating costs, the full short-run marginal cost of wheeling is the difference in p_i^* between the buses that receive the energy and those that send the energy on to its destination. If all the electricity to be wheeled enters the wheeling utility's network at one bus and leaves at another, the marginal wheeling cost is simply the difference in p_i^* at those two buses. Wheeling from a cogenerator to a distant industrial customer (possibly a plant owned by the cogenerator) would be an example of such a two-bus transaction. If the electricity is being wheeled from one investor-owned utility to another through the service area of an intermediate utility, the energy can enter and leave over several tie lines. In this case, the marginal cost of wheeling is found by adding up the incremental power flows at each tie line bus multiplied by the respective p_i^*. The information needed to make such calculations may be available as part of the automatic generation control (AGC) systems used by major utilities or else can be found from load flow studies. As discussed in chapter 2, the AGC system has algorithms that schedule and control power flows among utilities.

The idea that the short-run marginal cost of wheeling is the difference in marginal energy supply costs at two locations is good common sense and is intuitively appealing. The act of wheeling involves an increased inward flow of electricity at one bus and an increased outward flow at another. The formula for p_i^* correctly captures the short-run marginal cost of supply at each point, so the difference in p_i^*'s is a measure of the cost of transporting energy between them. The wheeling transaction may affect just line losses, or it may require that the wheeling utility redispatch some of its generating units for reasons discussed in chapter 4, such as to control the flow in transmission lines that might become overloaded. The net effect of these phenomena on the utility is not necessarily to impose costs. It is possible that line losses could decrease as a result of the wheeling, for example. This would happen if the wheeling flow is counter to the predominant direction of flow along the wheeling utility's lines. It is also possible that wheeling could alleviate transmission line constraints, thereby enabling the wheeler to dispatch generating units more economically. In all these cases, the difference in p_i^*'s correctly accounts for the short-run marginal cost of the wheeling service.

Short-run marginal cost pricing promotes good decision-making and equalizes short-run marginal costs across the grid. To see this, consider figure 7-1 again. If the system lambda of utility S would remain at about 3 cents per kWh regardless of how large its generation becomes as a result of the transaction with B, and if the lambda of B would remain at 7 cents despite its generation reduction, then the socially optimal arrangement would be for utility S to supply all the needs of B, assuming adequate generation and transmission capacities. In reality, the system lambda of utility S rises as it brings more expensive generating units on line to meet part of B's load. Likewise, B's marginal generating cost declines as it backs off of its own generation. Economically efficient trading would continue as long as the net gains from trade, G in figure 7-1, are positive. These are driven to zero when $p_2 - p_1 = 0$, that is, when the marginal cost of wheeling, p_1, is as large as the gross (before transportation costs) gains from trade, p_2.

The gains from trade could be eliminated for either of two reasons regarding real resource usage. Either p_2 falls or p_1 rises.

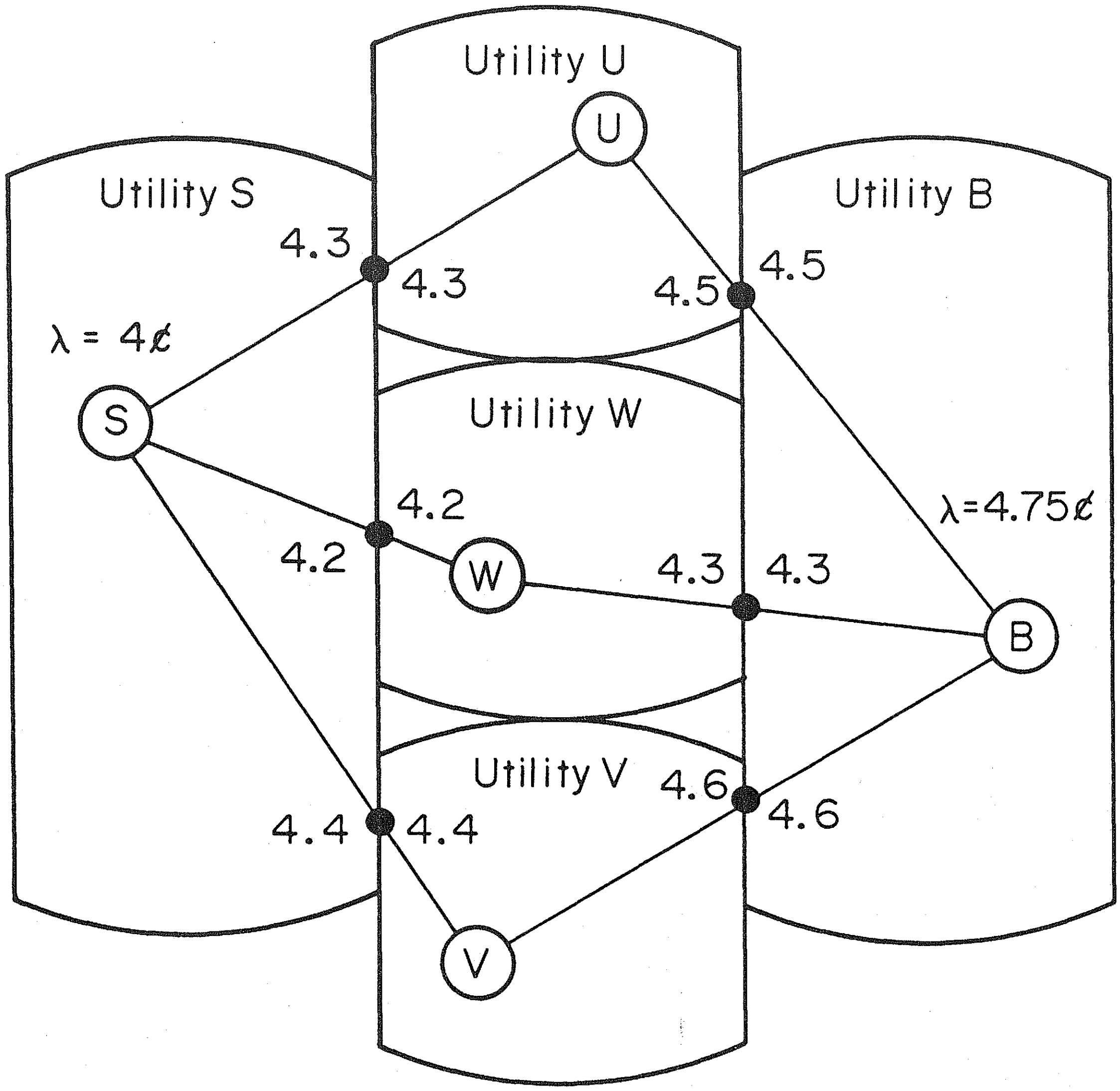
If transmission capacity is never constrained, the difference between p_2 and p_1 can be driven towards zero by reducing p_2, that is, by reducing the difference in the seller's and buyer's system lambdas. This will happen naturally if marginal generating cost increases with output in the short run. It may happen that the seller's marginal generation cost increases to 4 cents per kWh while that of the buyer is reduced to 4.75 cents. The difference between these costs is the total marginal transmission cost, of which the marginal wheeling cost is only a portion. The remainder is the cost of moving power inside S's and B's service areas. If the marginal wheeling cost remains at 0.15 cent per kWh, the utilities S and B would be indifferent to any additional wheeling. The wheeling price based on short-run marginal cost would eliminate the gains from trade, so that the marginal generating cost differential could be narrowed no further. If this condition characterized the network, the marginal energy cost on either side of the buses connecting the tie lines (the dots in figure 7-1) would be equal. Such a circumstance is illustrated in figure 7-2. In figure 7-2, there are no cost discontinuities at tie line buses. Because power flows eastward through B's tie line buses, the cost of power inside the service area of utility B is higher than at the border.

The equilibrium in this figure can be described in several equivalent ways. In each way, the weighted average cost of moving a kilowatt-hour from generating unit S to generating unit B is 0.75¢/kWh. This can be found either by adding the transportation costs along all the routes or by taking the product of the amount of power transported and the weighted average of the unit costs along all routes, as explained in chapter 6. Still another way of finding this cost is to find the weighted average of S's tie line costs, 4.27¢/kWh [from 0.3(4.3)+0.5(4.2)+0.2(4.4)] and also the weighted average of B's tie line costs, 4.42¢/kWh. Notice that the difference between these costs is 0.15¢/kWh, which is the weighted average wheeling cost. Hence, using weighted averages for each term we find, at equilibrium, that

$$\begin{bmatrix}\text{Cost of Power}\\ \text{at S's Border}\end{bmatrix} + \begin{bmatrix}\text{Cost of}\\ \text{Wheeling}\end{bmatrix} = \begin{bmatrix}\text{Cost of Power}\\ \text{at B's Border}\end{bmatrix}.$$

In the equilibrium of figure 7-2, the p_1's and the p_2's are equal across each company. The additional gains from trade associated with transporting electricity along any of the three possible paths are zero. No additional wheeling should be undertaken.

Gains from trade can be eliminated in another way, however, when there are transmission constraints. Recall that figure 7-2 is intended to illustrate marginal cost equalization across the network when there are no transmission constraints, and the price differentials across the territories



	p_1(¢/kWh)	p_2(¢/kWh)	G(¢/kWh)
U path	0.2	0.2	0
W path	0.1	0.1	0
V path	0.2	0.2	0

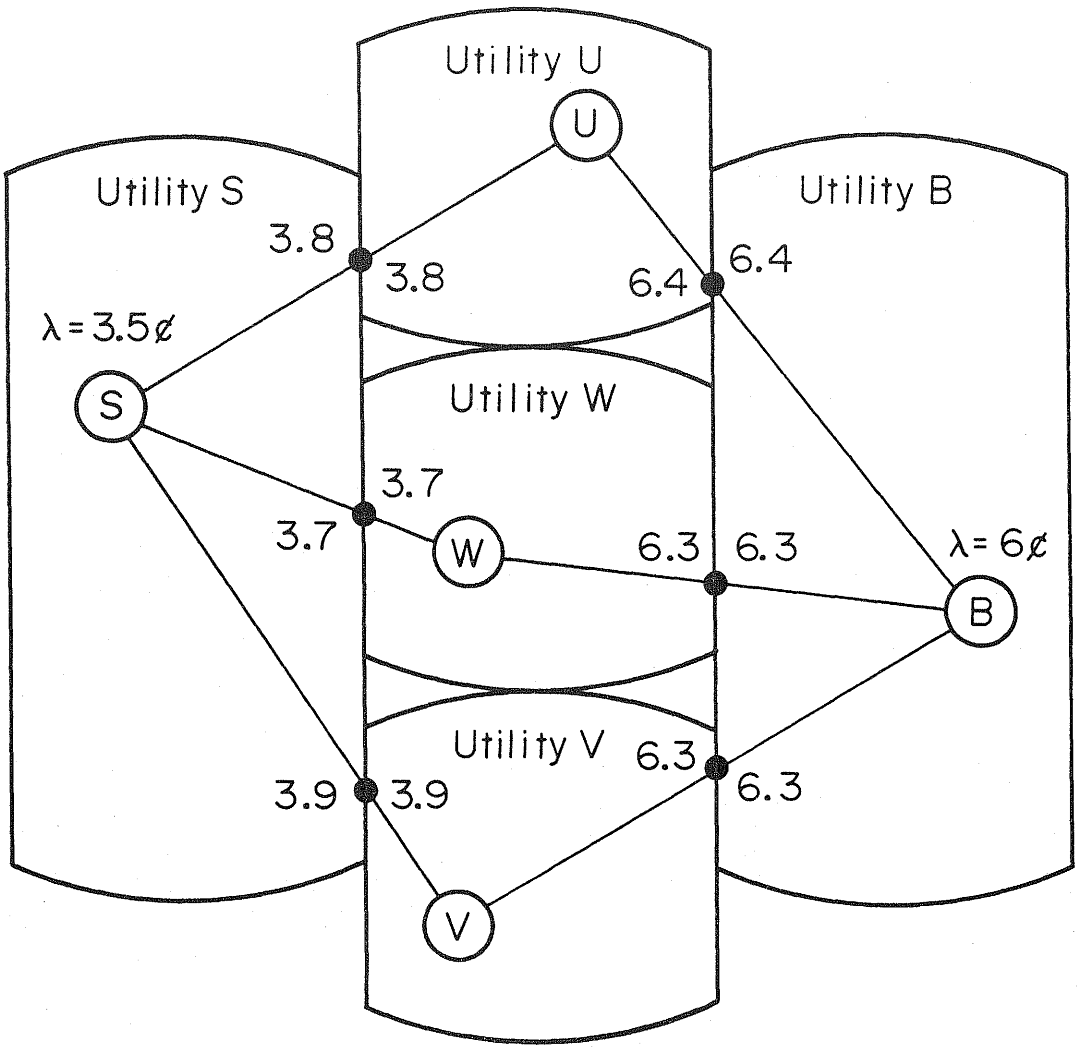
Fig. 7-2 Five interconnected utilities with spatially varying production costs, after trading with no transmission constraint

of utilities U, W, and V represent differences in marginal operating costs. Figure 7-3 shows what might happen if the transmission capacity limits along the tie lines were reached before marginal generation cost differentials are eliminated. In this case, the internal transmission cost from one side of the wheeling utilities to the other increases dramatically to account for the congestion on the lines. This cost rises to about 2.5 cents per kWh, several times as large as before. This condition reflects high usage of the tie lines, the internal transmission network, or both, and results in a correspondingly high marginal cost of wheeling.

It is not necessary for all three paths to approach full capacity for short-run marginal costs to rise. Recall the discussion in chapter 3, in association with figure 3-1, describing how a capacity limitation on one line can limit the power-carrying capability of parallel lines. If utility W in figure 7-3 is at full wheeling capacity, for example, while U and V operate at 50 percent of capacity, still U and V must refrain from wheeling extra power in order to avoid damage to W's system. In effect, the value of the transmission capacity of U and V rises because of the constraint encountered on W's system. The opportunity cost of using W's lines is a component of the short-run marginal cost of the entire system use. Hence, all the p's in figure 7-3 can rise if one rises.

This marginal-cost-based wheeling price is large enough to discourage any additional trading, which is the purpose of efficient pricing when confronted with resource limitations. The second way that resource usage, then, eliminates gains from trade is to push p_1 up to the level of p_2, that is, to increase the marginal cost of wheeling.

In both figures 7-2 and 7-3 the marginal cost of delivering energy to a tie line bus connecting two utilities is the same on both sides of the bus. It makes no difference whether such a bus is supplied by one utility or the other. When such a condition exists, the overall cost of supplying electricity throughout the network, involving in this case five utilities, is minimized. The supply side of the electricity market would be economically efficient in such circumstances. Such short-run marginal cost equalization is a good and economically efficient goal because, in the short-run, transmission capacity cannot be increased and hence no additional gains from trade are obtainable. As such, short-run marginal cost pricing promotes good decision-making that results in an equalization of marginal



	p_1(¢/kWh)	p_2(¢/kWh)	G(¢/kWh)
U path	2.6	2.6	0
W path	2.6	2.6	0
V path	2.4	2.4	0

Fig. 7-3 Five interconnected utilities with spatially varying production costs, after trading with a transmission constraint

costs across the grid.

The hour-by-hour changes in the loadings of transmission lines suggest that prices could be determined in a spot market on an hourly basis. If this is not feasible, time-of-use pricing could have an important role in promoting efficient use of transmission facilities. Such prices might be set beforehand according to time periods in which demand differences can be anticipated. In either case, the existence of time-varying transmission line loadings raises the same kinds of pricing issues that have been discussed many times in regard to generating facilities. There is no need to elaborate here upon the reasons for concluding that time-of-use pricing is appropriate. Such grounds have been covered before in many forums.

Much of the motivation in the MIT report is to explain very short-term price phenomena. Conventional time-of-day pricing is specified in pricing periods that are set months or even a year in advance. Such an approach improves economic efficiency, but in the view of the MIT analysts, larger efficiency gains can be achieved if prices would be responsive to current demand conditions. Price updates every 5 minutes, every hour, or even every 24 hours could provide accurate, up-to-date signals to users about the resource cost of electricity, according to this analysis. Whether or not such responsive pricing is practical, the method is useful for understanding the nature of short-term wheeling costs.

While short-run marginal cost pricing for wheeling is efficient for encouraging good decisions about short-term energy interchanges, its use for promoting good decisions about long-term wheeling contracts to carry firm power may have disadvantages. Long-run marginal cost pricing is considered next as an alternative.

Long-run Marginal Cost Wheeling Prices

Long-run marginal cost includes the costs of expanding the capacity of the transmission network as well as incremental running cost, appropriately determined. For the purposes of this report, there is no important difference between long-run marginal cost and long-run incremental cost. In practice, any method for calculating long-run marginal cost would be based on a specified increment of capacity. While it is true that the size of such lumpy increments affects the numerical calculations, the issue is not likely to have great policy importance. Any of several practical ways of computing long-run incremental costs would give approximately correct price signals, based on current capital costs. However, it is important that the method of calculation approximate as closely as possible the long-run incremental cost of providing the wheeling service; the calculation should not include inappropriate items that do not vary in the long run with the amount of power wheeled.

Capacity should be expanded in the order of the increasing costs of projects. For instance, the least expensive way of augmenting the capacity to transfer power might be to install capacitor banks for the control of reactive power and, if so, such a project should be completed first. Alternatively, the current configuration of the network might be expanded best by adding a second circuit to an existing single-circuit line if tower or pole design permits. Adding a completely new line with the required environmental and siting approval procedures is likely to be the most expensive way of expanding capacity. Regardless of the project, long-run marginal cost has a capacity cost component that is equal to the incremental cost of the project divided by the increment to capacity.

Congestion costs are not a part of long-run marginal cost because capacity can be adjusted in the long run so as to provide the optimal quality of service as measured by a congestion or reliability standard. Accordingly, a time profile of long-run marginal cost would be more or less constant or at least would not fluctuate nearly as much as would short-run marginal cost.

The concept of long-run marginal wheeling cost is related to a long-run equilibrium in an interconnected electrical network. Such an equilibrium would be characterized by an equalization of long-run marginal costs of bulk power supply across the grid. The generation and transmission capacity in all parts of the network would be adjusted optimally to provide for peak loads. Capacity would be sized to provide optimal reliability in such a long-run equilibrium, but no other surplus capability would exist. An important feature of this equilibrium is that choices about siting and expanding generating capacity, which are inherently long-run decisions, are linked to the long-run cost of transmission service, and not its current running cost or current state of congestion. In such an equilibrium, all opportunities for constructing new generation facilities and transmission lines so as to provide power at a lower long-run cost to any location in the network would be exhausted.

This type of equilibrium is unlikely ever to be achieved in practice because uneven load growth between regions and utilities results in transmission lines having varying degrees of utilization. Nonetheless, the concept is useful because it is suggestive about how good long-run decisions should be made and also about how to calculate the long-run marginal cost of wheeling services. In such equilibrium, an incremental wheeling transaction would require capacity expansion along every link taken by the power at the time of the expected peak demand, including parallel flow paths. Marginal capacity costs, then, are a weighted average of the expansion costs along each route, with the weights found by a load flow analysis at the expected peak flow configuration.

The running cost component of long-run marginal cost is a more subtle concept than the capital component. In particular, long-run marginal cost is not simply current running costs plus marginal capacity cost because expanded capacity can lower running costs, particularly line losses. As discussed in chapter 4 (see figure 4-1 and associated discussion), if a transmission line is replaced with a line of higher voltage, line losses decrease enormously for a given load. Further, new lines normally do not replace old lines, but supplement them, and the addition of parallel paths lowers line losses even if the new line's voltage is the same as that of the old line. Each of two similar lines can carry half the power of one line, but the losses go down by about a factor of four.

The cost of line losses varies with both the load on a line and the cost of extra fuel required to make up for losses. If the marginal loss factor (chapter 4) ranges from as little as 0.2 percent to as much as 20 percent, and if (marginal) fuel costs can vary from 1¢/kWh to 5¢/kWh, the cost of line losses can be as little as 0.002¢/kWh or as much as 1¢/kWh.

The cost of new transmission capacity is in the upper end of this range. Suppose that a new 100-mile long, 500-kV line is constructed. According to table 5-12, its cost is about $22,000 per megawatt (at 100 percent power factor). If annual carrying costs are 10 percent for 30 years, the capacity cost is $2334 per megawatt-year. Assuming the number of peak hours in the year is either 1000 hours or 500 hours, the capacity cost expressed in terms of peak energy transfers is about 0.23¢/kWh or 0.45¢/kWh respectively.

Suppose an existing 345-kV line has line losses costing 0.3¢/kWh and, if a parallel 500-kV line were added, losses for the two lines would drop to 0.05¢/kWh. If the 500-kV line has a long-run marginal capital cost of 0.35¢/kWh, then the total long-run marginal cost is 0.4¢/kWh (0.35¢+0.05¢). It would not be correct to add current running costs (0.3¢) to current capacity expansion costs (0.35¢), without taking into account the fuel cost savings (0.25¢) experienced in the long run.

Notice that it is sometimes possible for short-run marginal cost to be greater than long-run marginal cost, without a congestion charge contribution to short-run cost. This would occur when fuel is expensive and the unit cost of transmission capacity is low. In this case, good decision-making would require a utility to construct "excess" transmission capacity. The extra investment is not (at least immediately) to provide capacity, but to lower operating costs.

If a single-part price (¢/kWh) is used to collect long-run marginal cost, the signals to wheeling customers about their use of the system may not be as efficient as possible. That is, if both line losses and capital costs are recovered by a price that has the dimensions of cents per kWh, the wheeling of an additional kWh appears to be expensive to the wheeling customer.

The economic efficiency of long-run marginal cost pricing can be improved by a rate structure that has separate components for usage and fixed costs. The usage component would be a price per kWh, while the fixed component could take one of two forms: contract demand or maximum capacity used. In current wheeling arrangements, the most commonly used method is contract demand, in which case the customer faces essentially a fixed charge for the right to transmit the amount of power (in kilowatts) specified in the contract.[5] Pricing arrangements based on contract demand sometimes specify penalties for using capacity (kW) in excess of the contract demand,

[5] For a discussion of current wheeling rates, see Richard C. Tepel et al., Analysis of Power Wheeling Services (Oak Ridge, TN: Oak Ridge National Laboratory, November 1984); and Terms and Conditions of Existing Transmission Service Agreements and Tariffs (Washington, D.C.: Edison Electric Institute, 1984). These are summarized in appendix F.

in which case the customer's payment is not entirely fixed, but depends on his usage. Such penalties are only rarely imposed in practice, however, so that the contract demand form results in a basically fixed payment.

Less commonly, long-term firm wheeling arrangements sometimes charge for the actual maximum amount of power (kW) wheeled, possibly with a ratchet. As such, the customer effectively pays a demand charge. Because the demand charge is linked to the customer's peak demand rather than the wheeling system's peak, this raises the additional issue of how the system peak is affected. Because of load diversity among wheeling customers, an individual customer's and the system's peak may not coincide. It is likely that an additional unit of a customer's own peak load will result in less than one unit of additional system peak load. An efficiently designed demand charge would account for this phenomenon, which might be termed the marginal diversity effect. An extended discussion of optimal demand charges is not warranted here, however, since this pricing form is not a common feature of wheeling contracts. Also, the issue has been described in detail elsewhere.[6] This discussion concentrates on fixed payment contracts, such as the contract demand method.

Contrast, for a moment, two methods of long-run marginal cost pricing for wheeling service. One is a single-part price per kWh and the other is a two-part price consisting of a fixed annual payment (possibly based on contract demand) plus a smaller price per kWh. The two-part rate design is the more economically efficient of the two because the usage price is closer to the cost attributable to usage. The fixed payment can be thought of as a price paid to reserve a portion of transmission network capacity. The usage price in the two-part design should be running cost, adjusted for long-run fuel savings. In particular, it should not be short-run marginal cost, which contains a congestion charge during periods of shortage. That is, if a long-term contract has a fixed capacity payment, the usage price should not rise and fall as capacity is more or less utilized. To do so in an

---

[6] In the context of natural gas pipeline rate design, see J. Stephen Henderson and Jean-Michel Guldmann, Natural Gas Rate Design and Transportation Policy under Deregulation and Market Uncertainty (Columbus, OH: The National Regulatory Research Institute, 1986), pp. 35-39. In the context of retail electricity rates, see J. Stephen Henderson, "The Economics of Electricity Demand Charges," The Energy Journal, Special Electricity Issue, December 1983, pp. 127-139.

optimally configured network would recover capacity cost once in the average of short-run marginal cost and again in the fixed capacity payment. Such double recovery would be unfair, on its face, and in addition, would be inefficient since it would convey incorrect long-term price signals to users who are considering alternative investment decisions. Keeping the usage portion of price low during periods of capacity shortage is consistent with the notion that wheeling customers paying the long-run marginal cost price have contracted, in a sense, for some fraction of network capacity. That part of capacity is not subjected to short-term price rationing when capacity is short.

The principal issue with regard to long-run marginal cost pricing is whether such pricing would encourage good decision-making and, if so, under what circumstances. To charge long-run marginal cost for wheeling at all times, regardless of the state of congestion of the system, would equalize long-run bulk power supply costs across the grid, but the capital cost component of the price would discourage many good short-run transactions, preventing equalization of short-run marginal costs across the grid. In essence, the issue is whether to include capital costs explicitly in the calculation of wheeling prices or whether instead to depend upon the congestion-charge component of a short-run marginal cost price as an implicit mechanism for investment cost recovery. The next section contrasts the efficiency of these two approaches as the basis for wheeling rates.

Efficient Pricing with Cost-based Rates

The traditional issues regarding the choice of long-run or short-run marginal cost as the basis of efficient prices are well known and need not be repeated here. The interested reader can find an excellent discussion of these in Kahn.[7] Briefly, Kahn points out that marginal cost includes any additional cost imposed on the economy by additional use. Efficient prices always are equal to short-run marginal cost, at least in theory. In practice, the rapid fluctuations of short-run marginal cost make it an

[7] Alfred E. Kahn, The Economics of Regulation: Principles and Institutions, volume 1: Economic Principles (New York: John Wiley & Sons, 1970), pp. 70-86.

impractical benchmark for pricing power, according to Kahn and others. Despite the theoretical superiority of short-run marginal cost pricing, some type of long-run marginal, or incremental, cost is required as the basis for pricing, in this practical view.

Besides being practical, a sound theoretical reason for including capital costs explicitly in prices has recently been developed by an economist, John Jordan.[8] The theory has been disputed by another analyst, William Vickery, who defends the short-run costing as always being the proper approach.[9] The issue is important enough to warrant a brief review here, as an introduction to our discussion of the best way to recover transmission capital costs in wheeling prices.

Efficient Recovery of Capital Costs

Jordan takes the view that capacity for most kinds of facilities has multiple dimensions and that customers use these dimensions with varying degrees of intensity. The example chosen by Jordan is an airport, although the analogy to commonly used facilities such as an electric power transmission network is direct. Jordan points out that the capacity of airport runways can be sized in various ways depending on the mix of customers. Suppose the peak landing period is during the daylight hours and that the principal users during that time are smaller aircraft. The airport is also the hub of an air cargo operation that flies at night. The cargo planes are jumbo jets requiring a long runway. In Jordan's view, optimal landing fees during the daytime hours would include a congestion fee (to limit the frequency of landings to the capacity of the control tower) plus any maintenance costs associated with wear and tear of the runway (possibly zero). Off-peak or night-time landing fees would contain no congestion charge since the air cargo planes land only infrequently, but would include a capacity charge reflecting the fact that the runway length and concrete

[8] W. John Jordan, "Heterogeneous Users and Peak-Load Pricing Model," The Quarterly Journal of Economics (February 1983):127-138; and W. John Jordan, "Capacity Costs, Heterogeneous Users and Peak-Load Pricing," The Quarterly Journal of Economics (November 1985):1335-1337.

[9] William Vickery, "The Fallacy of Using Long-Run Cost for Peak-Load Pricing," The Quarterly Journal of Economics (November 1985): 1331-1334.

thickness must be sized to accommodate the jumbo jets. Use of a capacity charge is a departure from strict short-run marginal cost pricing. If the peak and off-peak prices based on these marginal costs do not cover total costs, prices would be raised according to the inverse elasticity rule.

In Vickery's view, appropriate prices are always based on short-run marginal costs, and since runways deteriorate only slightly in response to use, the off-peak landing fees in this example would be essentially zero, before any adjustment to cover total cost. The peak price for the numerous smaller planes would be the same in Vickery's off-peak plan as that proposed by Jordan. The Vickery off-peak prices are smaller (or at least no larger than) those advocated by Jordan. The revenue consequences are plain. In order to cover total costs, the markups to Vickery's short-run marginal cost prices must be larger than the markups for Jordan's prices. In consequence, owners of the smaller, daytime-landing planes would pay more of the capital costs of the runway under Vickery's scheme than they would under Jordan's proposal.

An additional example serves to make the distinction even clearer and relates it to the wheeling case. Suppose the off-peak users need certain night navigation equipment installed at the end of the runway. The peak users have no need for such equipment, which for the sake of exposition has no maintenance or depreciation expense so that running costs are zero. Jordan would identify the navigation equipment as a particular dimension of capital investment attributable to the night-time cargo operation and as such would include the associated capital costs in the night-time landing fees. Vickery would base prices on short-run marginal cost and hence recover the capital cost of the navigation equipment by markups, presumably based on the inverse elasticity rule.

In both views, there is no question of eventual capital cost recovery. Price markups are made to ensure the financial solvency of the complete airport. The issue has to do with the fundamental pattern of prices--whether user charges should include any capital cost component for equipment and facilities that, once installed, are fixed with respect to usage. Jordan has provided an initial theoretical reason why efficient prices might include a capital charge component. In effect, his argument is that the cargo company has entered into an implicit contract that provides for the installation of night-time navigation equipment in exchange for the cargo company paying for it. Jordan suggests that landing fees be used to recover the capital costs of the implicit contract. The remainder of this section elaborates upon this idea in the context of electric bulk power supply systems.

Firm wheeling customers may be willing to pay a price equal to long-run marginal cost as part of an implicit contract that reserves for them a portion of transmission network capacity. This raises the important question of whether it is efficient to shelter a portion of the network dedicated to a firm customer from (what can be thought of as) the short-term bidding process that might allocate it instead to another customer who happens to place a very high current value on network access. That is, suppose a utility's transmission capacity is divided as follows: 50 percent is set aside for the use of its own retail customers, 20 percent is under long-term contract to firm wheeling customers, up to 10 percent can be sold under interruptible arrangements, and 20 percent is held back as reserves. Under this scheme, short-run marginal cost would include a congestion charge large enough to limit interruptible use to 10 percent. The economic efficiency of such an arrangement can be examined in two ways.

First, efficiency would be promoted by having all transmission customers correctly ordered at all times so that those with the greatest willingness-to-pay at the moment would have access. This view argues that the entire network should be available for short-term price rationing and that no part should be sheltered. A second, alternative view is that it is efficient to avoid the inherent risk and high transaction costs of spot market participation. Joint ownership of a transmission line is a kind of long-term contract that is chosen when parties wish to assure access and thereby minimize the risk of being displaced in the future. Such contracts can be efficient in the view of Oliver Williamson and others who have written in the economics literature dealing with the transaction costs of contracts.[10] Where long-term firm wheeling is needed, there are transaction costs associated with frequent bidding for capacity, and there are risks of being interrupted that some customers would strongly prefer to

[10] See Oliver E. Williamson, Markets and Hierarchies: Analysis and Antitrust Implications (New York: The Free Press, 1975); Oliver E. Williamson, "Transaction-Cost Economics: The Governance of Contractual Relations," Journal of Law and Economics, October 1979.

avoid. It seems clearly possible that the efficiency gains associated with risk reduction and transaction-cost economies can be more important than the short-term efficiency losses associated with occasional incorrect ordering of users by willingness-to-pay. Accordingly, a long-term firm wheeling contract would be an efficient choice for some users. Economic theory, then, does suggest that reserving at least some of the transmission capacity for long-term firm wheeling can be appropriate and efficient. In effect, long-term wheeling customers enter into an implicit contract in which a utility agrees to provide adequate capacity in exchange for the customer agreeing to pay a price that includes a capital component. It is similar to Jordan's example of a cargo company implicitly contracting for the installation of night-time navigation equipment.

Whether prices are efficient ultimately has to do with whether they distort the decisions of economic agents. In the case of electric utilities, the investment decisions of the wheeling utility are not necessarily distorted differently by a long-run or short-run marginal cost pricing policy, especially if a revenue requirement assures the utility's investors that costs are recoverable regardless of the pricing basis. The decisions that are most likely to be distorted by pricing choices are those made by customers. Utilities, as economic agents, respond principally to profits, while customers respond to prices. In the case of wheeling service, however, the customers are most often other utilities, requirements customers, or cogenerators whose own generation and transmission investment decisions are affected by wheeling prices.

For the purposes of this discussion it is useful to distinguish between the customer's long-run and short-run decisions. Electric energy usage is primarily a short-run decision, while the customer's investment decisions about electricity-generating and electricity-using equipment are long-run in nature. It is possible that the price of wheeling might distort either or both of these types of decisions. Efficient prices are those that distort both decisions minimally. It is tempting to conclude that customers wheeling interruptible energy be charged short-run marginal cost while those wanting firm wheeling service that requires reservation of capacity be charged long-run marginal cost. This arrangement allows customers the option of choosing between firm wheeling service at long-run marginal cost and interruptible service at short-run marginal cost. Customers would then decide between the two pricing forms largely on the basis of whether their wheeling decisions involve short-term or long-term choices. Indeed, this is the essence of our conclusions regarding efficient wheeling pricing. The reasoning leading to this conclusion must deal with one important question, however: What, if anything, is wrong with charging short-run marginal cost to all customers?

In principle, short-run pricing ought not to distort the long-run investment decision of wheeling customers. Recall that short-run marginal cost rises and falls above and below long-run marginal cost in the course of the utility's investment cycle. If the transmission projects are timed optimally and the network capacity utilization rate is optimal, then the present value of the time pattern of short-run marginal costs (which fluctuate widely) should equal, more or less, the present value of the long-run marginal costs. There is little difference between the average over time of short-run and long-run marginal costs of wheeling in an optimally configured transmission network. The congestion component of the short-run cost substitutes for the capital component of long-run cost. If transmission capacity could be added more frequently in smaller increments, without losing economies of scale, any difference between the two cost standards would tend to disappear.

If wheeling customers can anticipate that the network will be sized more or less correctly over several investment cycles, they can expect to pay the same average price (over each investment cycle) whether the instantaneous price is based on short-run or long-run marginal cost. In such circumstances, the customer's investment decisions regarding electricity-producing and electricity-using equipment would not be distorted by a short-run marginal cost pricing policy. Since the customer's day-to-day usage decisions would be distorted by long-run marginal cost pricing, however, the efficient price would be based on short-run costs. In an optimally configured network, one would argue, the criterion of good decision-making suggests that short-run considerations underlie prices because correct customer expectations about future prices can be relied upon to guide the customer toward rational investment decisions.

The limitations to the above line of reasoning are clear, perhaps even obvious. First, the transmission network most likely is not configured and sized optimally. Peak use of the network may be at or close to system capability in some regions of the country and not in others. The identity of which regions and lines have surplus capacity changes from time to time. The existence of surplus capacity in some areas should not be surprising. In the United States, public utilities are commonly thought to have large reserve margins because they are called upon to serve all demands and also because as a society we have decided implicitly that we desire highly reliable electric service, which can be provided by large reliability reserve margins. Second, even if the network size were optimal, it is by no means clear that customers could make rational forecasts of short-run cost-based prices and arrive at expectations that correctly mimic long-run costs. Customer myopia tends to mean that current prices are given disproportionately greater weight when forecasting future prices, with the result that customer expectations are likely to depend on the portion of the cycle in which the customer finds himself. In these circumstances, a short-run marginal cost pricing policy does not provide efficient price signals to users regarding their long-run investment decision to install electricity-generating and electricity-using equipment.

Our conclusion, then, is that in practice both short-term and long-term marginal cost pricing are imperfect. Prices based on long-term marginal cost distort some wheeling customers' short-term usage decisions even if a two-part, fixed-variable rate design is used. Prices based on short-term marginal cost can distort the investment planning decisions of other wheeling customers. Good decision-making and economic efficiency are enhanced by a pricing policy with the smallest aggregate distortion, possibly some combination of short-run and long-run marginal cost pricing. That is, both kinds of customer decisions must be considered when fashioning efficient prices.

The best way to promote efficiency, then, is to segment wheeling markets. Wheeling for such purposes as transmitting short-term economy energy is best priced at short-run marginal cost. In contrast, wheeling for a customer who wants to buy long-term, firm power in lieu of constructing his own generating capacity should be priced with consideration given to the effect of price on that customer's investment decisions. In the latter case, the decision about whether to have electricity wheeled or to build a generating station is an important decision that many investor-owned utilities, requirements customers, and possibly large industrial customers or cogenerators may face increasingly in the future. It is a decision greatly affected by the wheeling price, and a long-run marginal cost wheeling price would more correctly inform such customers about the long-term resource value of the wheeling service than would the current value of short-run cost. Such a customer needs to compare the present value of long-run cost of purchased power plus the long-run cost of wheeling with that of the new generating station.

Between the extremes of economy interchanges and very long-term firm capacity requirements are many intermediate types of power sales agreements (set out in appendix D) that may require wheeling. We divide these into two types, those that require firm wheeling service and those that do not, pricing the former at long-run marginal cost and the latter at short-run marginal cost and allowing the customer to select the type of service that better meets his needs. At this point, it is good to remember that short-run marginal cost is not necessarily just running cost. In times of capacity shortages the customer charged short-run costs would pay a high price consisting, in part, of a congestion charge. This has the effect of rationing that portion of capacity set aside for short-term or interruptible customers to those customers who value the service most highly. During such a time of shortage, firm customers paying for long-term access to the network would not pay any congestion charge. Their price would not fluctuate according to current capacity conditions.

Over the long term of a wheeling utility's transmission investment cycle, the average wheeling price paid by interruptible and firm customers would be more or less the same, if the network capacity is optimal. Thus, market segmentation, in itself, does not constitute price discrimination. If, in actuality, network capacity almost always exceeds peak demand, interruptible customers would pay a lower price, on average over the cycle, than would firm customers. Several regulatory responses to such *de facto* discrimination are possible.

One possibility is to do nothing, that is, to give implicit regulatory approval to the long-term difference in prices. This is, after all, a long-term problem and knowing how to correct it, without a crystal ball that foretells future short-term and long-term pricing patterns, is very difficult. Even if a long-term difference in the prices can be discerned, regulators may justify it on equity grounds. It may be fair, this argument would go, to charge firm users for capital cost and to charge short-term customers only running costs. Alternatively, regulatory approval of the discrimination might be based on grounds that the result is more or less the same as value-of-service pricing. Price markups guided by the inverse-elasticity rule to cover the revenue requirement (discussed further in chapter 8) might be quite close to those based on the interruptible-firm distinction. Finally, the price difference should be justifiable, in our opinion, from the perspective of economic efficiency. Recognizing the possible distortions to the customer's usage and investment decisions, the decision to charge long- or short-term costs should balance these competing concerns.

Another type of regulatory response would be to adjust prices so as to remove any time-average price difference. In doing so, one would accept the implicit social decision to build surplus transmission capacity and to incorporate this into both interruptible and firm wheeling prices. (The following suggestion applies to other public utility services by analogy.) Suppose that a 20-percent capacity reserve is deemed necessary on each line to maintain acceptable reliability in the transmission network. In effect, each line's capability is defined as 80 percent of its actual capability. Firm wheeling prices could be based on long-run incremental cost where the capacity increment is computed as 80 percent of the installed, additional capacity. This has the effect of making the price about 25 percent larger than it would be otherwise. The similar adjustment to short-run marginal cost would be to add a congestion charge component to short-term rates so as to limit total peak demand to 80 percent of installed capacity. The idea is that prices may have a limited ability to allocate capacity in some rapidly changing circumstances. Because the loading on some transmission links may change quite rapidly, faster even than spot prices would be able to adapt to, an unallocated reserve is needed that will never be sold separately. Congestion charges would be levied in a way that has the effect of limiting ordinary, peak demand to 80 percent of capacity. This suggestion treats the need for reliability reserves symmetrically between short-run and long-run marginal cost pricing. The relatively stable long-run marginal cost computed under this suggestion would have a capacity component equal to about 125 percent of capacity cost computed with no reserve. Similarly, the time-varying short-run marginal cost should have an average equal to long-run marginal cost computed in this way. No time-average price discrimination would be anticipated with this treatment of reliability reserves as long as capacity is added optimally while maintaining the fiction that usable capacity is only 80 percent of actual capability.

A difficulty with this suggestion is that short-run prices must be allowed to rise to about 125 percent of capacity costs when capacity is only 80 percent utilized. When the time arrives to do this, short-term customers would undoubtedly object to paying such high prices when there is unused capacity (the 20-percent planned margin) available, unless the reserve is clearly justifiable on a reliability basis. Regulators may be tempted to agree because future load growth is uncertain and an argument can be presented that the future need to expand the network would not be hastened if it were 90 percent utilized today, instead of only 80 percent. The regulatory policy makers listening to such an argument may be different individuals from those who approved the previous policy that the "20 percent shall not be allocated nor sold," thereby increasing the temptation. Such a temptation should be avoided, of course, if the policy of having a reliability reserve is to be consistently maintained over time. As experience with short-term or spot pricing grows, utilities may become more confident of the capacity-allocating abilities of such pricing and may be able to plan on a smaller, unallocated, reserve margin. (The suggestion presented here is equally applicable to a 20, 10, or 5 percent margin.) The important aspect is to treat long-run and short-run marginal cost symmetrically in any adjustment for reserve margins.

To summarize briefly, this section has discussed a theoretical reason for including capital costs in regulated wheeling prices in some circumstances. The thrust of the argument is that pricing policy should encourage good customer decisions of both the short-run and long-run kind. It should minimize the distortions to either kind of decision that might result from incorrect pricing signals. This can be accomplished by giving customers the choice of firm service at long-run marginal cost or interruptible service at short-run marginal cost. Firm wheeling needs lasting several years are likely to be in competition with power supply alternatives, such as customer-owned generation or perhaps the substitution of other fuels for electricity. With such needs, the customer is likely to choose firm wheeling service. Correct investment decisions by such customers require that they be given correct long-term price signals that include the capital cost of transmission. The price signal is improved if it is divided into fixed and variable parts so as to distort minimally the short-term usage decisions of those customers needing to reserve firm capacity. The customer without firm needs or with a greater willingness to risk power supply interruption is likely to choose interruptible service. Persistent surplus transmission capacity or incorrect customer expectations impair the ability of a short-run marginal cost pricing policy to convey correctly the capital cost component of wheeling. The problem of persistent surplus capacity, if it exists and if such a reserve margin is socially desirable, can be dealt with in a symmetrical way that has the effect of raising prices based on either long- or short-run marginal cost.

Firm and Interruptible Wheeling Service

From the discussion so far, we conclude that in order to encourage good decisions about the efficient use and expansion of the transmission system, wheeling prices ought to be based on the marginal costs associated with two types of wheeling services--firm and interruptible. Wheeling customers can choose the quality of service that they need. We would prefer having wheeling customers interrupt their own service as short-run marginal cost rises to having a contract or administrator decide who should be interrupted and when.

The distinction between firm and interruptible wheeling services is not a precise one in current industry practice. Our use of these terms does not necessarily correspond exactly to the way they are used in the industry today. For our purposes, the important distinction is that firm wheeling service typically involves a commitment to provide transmission capacity more or less with the same priority as provided to native load customers. In contrast, transmission load pressing on system capacity is a reason for interrupting nonfirm wheeling customers, which suggests such users have a lower priority. Our use of these terms does not correspond to power sold for resale and that sold under interchange agreements, for example. Some sales for resale might need firm wheeling, while others might use a nonfirm wheeling arrangement if back-up power is available.

In most cases, an interruptible customer either has a short-term need and is willing to be interrupted because back-up supply sources are available or else he is willing to assume the risk of being cut off. Such a customer may have a contract lasting several years, which specifies a continuing wheeling service that is subject to interruption. Firm customers usually have a continuing, long-term need for wheeling that is not easily interrupted. Typically, these arrangements last for several years, or even decades. (See appendix F for data on terms of wheeling contracts.)

Generally speaking, under current practice firm wheeling service is not interrupted, except in unusual circumstances such as lightning strokes, floods, dangers to system reliability, or installations of equipment.[11] In particular, inadequate capacity is not generally a condition for interrupting firm wheeling service, unless the reason can be traced to unusual circumstances such as those just listed. There is an implicit commitment in such contracts to provide additional facilities if needed for the firm wheeling agreement.

Interruptible service, sometimes called nonfirm, can be interrupted for other reasons. If the reasons are listed, the service is sometimes called conditionally interruptible. A typical condition leading to interruption is a need for the transmission capacity to carry native load. Other contracts may allow interruption for any reason, at the discretion of the wheeler and are called unconditionally interruptible.

Gradations of service length and contract firmness between these two extremes are clearly possible. Conditional firm service for one utility may be quite similar to another's nonfirm, or interruptible, service. Either type of service could be requested in practice by a customer wanting moderately firm service.[12]

---

[11] A. Stewart Holmes, "A Review and Evaluation of Selected Wheeling Arrangements and A Proposed General Wheeling Tariff," Federal Energy Regulatory Commission Staff Working Paper, September 1983, p. 11.
[12] The current FERC policy regarding the allocation of demand-related costs for nonfirm wheeling rates is not yet clear. In a case involving Kentucky Utilities Company the FERC excluded such costs, but included them in a non-firm wheeling service provided by Florida Power and Light Company. See William W. Lindsay, "Wheeling Rates: FERC Policies and Some Alternatives," presented to the Electricity Consumers Resource Council Seminar on Wheeling, Washington, D.C. (September 27, 1985).

To implement this concept of firm and interruptible wheeling service, a utility could divide its transmission capability into several parts. A large portion would be set aside for core (retail) customers and not used for wheeling services, at least not during system peak periods. Some portion, say 20 percent, could be held in reserve for reliability purposes and would not be available for wheeling. The remaining transmission capability could be used to provide wheeling services. Long-term firm wheeling arrangements priced at long-run marginal cost would be given first priority because they presumably have the higher value. The remaining capability could be used for interruptible wheeling service at short-run marginal cost. Customers desiring long-term service would have the option of arranging for firm wheeling service at a fixed price or participating in the interruptible portion of the market for an extended period. The choice would depend on the user's perception of the relative price riskiness of the interruptible market in comparison to any difference in expected prices between the firm and interruptible markets over the period during which wheeling service is required.

If the demand for firm service is less than the system capability available for wheeling, then both a firm and an interruptible market could exist. When the system is not congested, prices in the interruptible market would be less than prices in the firm market. Firm customers would be those who choose to pay a premium, during periods of surplus capacity, to guarantee their use of the system throughout cycles of temporarily excess and deficient capacity. When the system is congested, most interruptible customers would choose to decline service at the high price set by short-run marginal cost, but some might seek to obtain a firm contract for use of the system at the (now lower) long-run marginal cost price. Each customer's decision would be based on his own self-interest, given his assessment of the duration of the congestion, the likely short-run marginal cost price variations, and the value of the wheeling service for his own needs.

As short-run price rises, some demand may shift towards firm service. While honoring all pre-existing firm contracts, a utility may need an efficient way to decide which new customers should be served when there is a rapid increase in the demand for firm service. If the demand for firm service should exceed available capability, the most efficient way to ration capacity would be to have customers bid for use of the system. Customers who have contracted for firm service would undoubtedly object to such a bidding scheme, however. Alternative administrative rationing rules include (1) service to each customer in proportion to contract demand levels, (2) first come, first served and (3) length of firm service contract, based on the theory that those who agree to pay the long-run marginal cost price for the longest time place the highest long-term value on the wheeling capacity.

It is important to recall that nonfirm or interruptible wheeling service can be interrupted because of a lack of capacity to carry peak load. We have suggested that wheeling prices based on short-run marginal costs would lead to good decisions on the part of nonfirm users. The suggestion is to use price to ration capacity in times when it is short, rather than to have an administrative rationing rule. Such a pricing policy would result in high prices part of the time and low prices part of the time. The entire policy presupposes that short-run marginal costs are sometimes higher and sometimes lower than long-run marginal costs. This means, in effect, that some interruptible customers are actually interrupted part of the time. That is, the congestion charge component rises to ration capacity, which induces some interruptible customers to leave the system temporarily. The act of rationing with price is the economically efficient equivalent of an administrative rule to cut off service without raising price, as is current practice. If there were no need to interrupt nonfirm users, the short-run marginal cost would be below the long-run cost most of the time. In such a circumstance, the time-average of short-run marginal cost would be less than that of long-run marginal cost with the result that nonfirm customers receive essentially the same quality of service, that is, no interruptions, for a lower price. This would constitute price discrimination, in our view, and is not what we envision when suggesting that segmenting the market into firm and nonfirm services can improve its efficiency.

Notice that there are two ways, in effect, of obtaining uninterrupted service. An interruptible customer who actually paid short-run marginal cost all the time would not be interrupted at all, assuming at least some capacity is always available for interruptible service. Other interruptible customers successfully manage to lower their wheeling bills by choosing to be interrupted when the short-run marginal cost rises above their willingness to pay. That is, an interruptible customer is charged a low average price as a result of his own actions to forego service at high prices. The average price is not known until after the fact, of course. In this regard, a customer desiring firm service for a short time (for example, when a nuclear plant down for two months of maintenance) could contract for interruptible service. If he continues to pay when the short-run marginal cost is high, he avoids the interruption. It would be inappropriate to offer him short-term firm service at a discount from long-run marginal cost. If he believes the long-run marginal cost price is too high because he foresees no capacity constraint during the two-month period, he has the option of expressing this belief by choosing interruptible service for the two months. Furthermore, if he receives a series of such discounted contracts, he would pay less than the time-average of short-run marginal cost, which is the price paid for continually contracting for interruptible service, thereby receiving, in effect, long-term firm service at a lower price in a roundabout way.

Thus far, our argument has been that the time-average of short-run marginal costs equals that of the long-run. There is no persuasive quality-of-service reason for trying to make the time-average of interruptible prices smaller than the firm service price, in our view. The effective price for uninterrupted service ought to be the same whether the customer receives such service by signing a firm contract or by continually paying short-run marginal costs in the interruptible market. Customers who are actually interrupted pay a lower average price over time.

Although quality of service is not a reason for a time-average price difference between firm service and continued service under an interruptible contract, there may be a difference in the financial riskiness of the two future price patterns. The fluctuations in future interruptible prices are likely to be larger than those for firm service. It is possible that risk-averse buyers of essentially the same wheeling service would be willing to pay more on average if they could avoid price swings in future years. Alternatively, the price of interruptible contracts would be discounted because of this risk. The riskiness is purely financial and is not due to any difference in frequency of interruption. If such an effect exists, it has not been empirically verified to our knowledge, and it might justify only a small discount for continued service in the interruptible market in any case. Until there is such verification, we suggest that no distinction be made, with the result that the expected value of the time-average of short-run marginal cost should equal that of long-run marginal cost.

We note that the option of customers to participate in firm and interruptible markets can be exercised in a variety of ways. In particular, a customer may contract for some mix of firm and interruptible wheeling service. In this way, he can fashion a portfolio of contracts that serves his financial and reliability needs better than either type of contract alone.

Because interruptible customers pay short-run marginal costs, the order of interruption is determined by price, in the market we envision. In contrast, current wheeling transactions are interrupted under conditions specified in the contract, or at the discretion of the wheeling utility. Such contracts call for the price to remain constant and for the interruption to be governed by administrative and contractual rules. This type of nonprice rationing cannot correctly order customers by willingness to pay in all circumstances, and so is inefficient in comparison to a price rationing mechanism. Administrative rules, however, can be less costly to implement in some circumstances and can establish interruption priorities for broad classes of customers. The tradeoff between price and nonprice rationing mechanisms is between efficient ordering of customers and administrative ease. The discussion of short-run marginal cost pricing in this report reflects our emphasis on good, efficient decision-making.

The pricing principles as outlined thus far would promote good transmission usage decisions on the part of interruptible users since short-run marginal cost pricing would encourage transactions that tend to equalize short-run marginal electricity costs across the network. During times when capacity is limited, such a price would rise as the congestion, or lost opportunities, component becomes larger. In this way, the rising price would provide some indication to the utility and to regulators that additional transmission capacity is warranted. The long-term marginal cost price paid for long-term firm wheeling service provides good information that customers can use in making their own investment decisions. The demand for service at such a price would help the utility assess the need for expanding the transmission system. The price signals are improved if the long-run price is composed of two parts, an energy and a demand component.

From the viewpoint of economic efficiency, the imperfection that remains in a two-part (fixed-variable) pricing structure is its potential for incorrectly ordering customers in accordance with the value they attach to wheeling capacity. In theory at least, one way to reduce this imperfection would be to arrange the wheeling contract so that some or all of the wheeling rights can be resold. Suppose a wheeling arrangement consists of two parts. One is a contract for covering customer-specific facilities and equipment that connect the customer to a utility's high-voltage transmission grid. The second is a long-term contract for use of the grid itself. The second contract could have a value to another user; the first would not. Technical problems aside, if a market existed in which the second, general type of access contract could be bought and sold among customers, the remaining imperfection would be reduced. Customers that place a higher current value on use of the high-voltage grid could bid contracts away from current holders, who would not have to sell them except voluntarily. A firm wheeling customer may wish to terminate the arrangement ahead of schedule, and a resale market would facilitate this. Without the resale market, the customer would rely on the contract's notification and termination conditions. The flexibility added by the possibility of reselling would make the fixed payment, long-term wheeling contract more attractive to begin with.

In addition to gains in economic efficiency, such a resale market would have certain regulatory advantages as well. By monitoring the market price of capacity, a commission could assess the need for expansion of the network.

Despite these advantages of writing long-term wheeling contracts so they could be resold, the prospects for such a market institution seem dim for several reasons. To resell transmission contracts would require either voluntary cooperation by the utility to accept the new wheeling customer or else regulatory authority to mandate wheeling. For most purposes, the FERC cannot now mandate wheeling, and utilities are unlikely to agree to accept any and all new wheeling customers voluntarily since at least some potential users of wheeling services are likely to be current retail customers. Agreeing to wheel in such a case would facilitate retail competition with neighboring generating facilities, an activity that is understandably disagreeable to most utilities and in conflict with franchise rights, even if it may be economically efficient. In addition, a geographical difference in location between the current holder of a wheeling contract and a potential buyer could create technical difficulties. The loadings on particular generating units could be different, the extent of any parallel flows could change, and so on. (These last difficulties might be addressed in the variable portion of the pricing structure contained in the contract.) Further, any resale market is likely to be thin, that is, have few buyers and sellers, and consequently the improvement to efficiency may be small. At any rate, the improvement to economic efficiency from even an efficiently organized resale activity seems small in comparison with that of (a) including capacity costs in long-term firm wheeling contracts and (b) pricing of such services with a two-part, fixed-variable rate structure. For all these reasons, secondary markets in wheeling contracts seem unlikely.

The principal conclusions of this chapter are that economically efficient cost-based wheeling prices are based on marginal costs and are different for different types of services. Wheeling customers can choose between firm and interruptible service. Firm wheeling contracts are efficiently priced so as to explicitly include incremental capacity costs. Interruptible contracts would have no explicit capital component but should include an understanding that a congestion charge is to be added whenever capacity limits are approached. In addition, a pricing structure for long-term firm wheeling arrangements that contains both a fixed and variable component would improve the signals given to wheeling customers and would encourage good decisions regarding both the use and potential expansion of the network.

CHAPTER 8

NON-COST INFLUENCES ON WHEELING PRICES

The ideal method of pricing wheeling services is one that results in marginal costs being equalized across the grid. The previous chapter describes how long-run and short-run marginal cost pricing fosters good decision-making on the part of firm and interruptible wheeling customers and how the network equalization of marginal costs is promoted thereby.

In practice, regulators must consider a variety of non-cost issues that are relevant to wheeling pricing policy. These are grouped into three categories for discussion in this chapter. The requirement that wheeling revenue cover total embedded cost is familiar, although it has a somewhat novel aspect in the context of wheeling. A second group of issues has to do with the effects on wheeling pricing policy of certain features of the electric utility industry, with some customers having better competitive alternatives than others, for example. The third category addresses pricing institutions, such as auctions for transmission capacity, that do not rely solely on cost reimbursement for providing an incentive to wheel, but allow wheeling utilities to realize some portion of the gains from power trades.

Revenue Requirements

While pricing wheeling services at marginal cost (short-run marginal cost for interruptible users and, optionally, long-run marginal cost for firm users) encourages wheeling customers to make good decisions, such pricing does not necessarily yield revenue precisely equal to the transmission embedded cost revenue requirement. Ordinarily, because of the reserve margins associated with public utility capacity, short-run marginal cost prices produce too little revenue. However, prices based on long-run marginal costs for all users are likely to be large, relative to those calculated from embedded costs. In the case of wheeling, the prices for all users of transmission service must be lowered from marginal cost in such a circumstance, or else excessive revenue would be collected.

Whether the problem is too much or too little revenue, prices must deviate from marginal cost if a revenue requirement must be met exactly. The only two policy choices then are either to have a policy of marginal cost pricing for wheeling with no revenue requirement or to have a revenue requirement with wheeling prices that come as close as possible to achieving the goal of good decision-making.

Having No Revenue Requirement

If the direction that prices must deviate from marginal cost is downward, this raises a question about the wisdom of meeting a transmission revenue requirement at all. Suppose marginal cost pricing for transmission service were adopted for all users, including residential and commercial retail customers. Then, the utility would collect revenue greater than the embedded costs of its transmission system.

For the purposes of regulation, such economic profits or rents should be distinguished from the rents due to abuse of monopoly power. One view of regulation is that it is intended to mimic the outcome of a competitive market. In such a market, entrepreneurial profits are earned when prices based on the marginal cost of the least efficient firm in an industry result in profits for firms that have a lower cost structure. A monopolist earns excessive profits, more than entrepreneurial profits, by exerting monopoly power, which could take the form of a constriction of output or a resistance to entry by other firms. Regulation that truly mimics competition would prevent monopoly profits but would allow entrepreneurial profits. In this view, marginal cost pricing of transmission for all customers with no revenue requirement would be the best way to promote good decision-making and yield more than adequate revenue for the utility to remain financially solvent. The most fundamental conflict between prices based on embedded costs and those based on marginal cost, then, has to do with regulation's failure to distinguish between entrepreneurial rents and monopoly rents. Positive profits due to marginal cost pricing of wheeling are not the result of any exercise of monopoly power but rather reflect the effects of inflation and to a lesser extent the fact that environmental and other routing considerations make current transmission projects more expensive per mile than previous ones. Current regulatory practice does not allow such profits to accrue to the utility. The social decision to give such profits to ratepayers is not neutral with respect to economic efficiency. The outcome is a rolled-in pricing policy that keeps the wheeling price below the market-clearing level. Accordingly, the social value of the marginal use made of the transmission network is less than its marginal cost. There is a quantifiable misallocation of resources as a result.[1] This social waste could be avoided only by revising the social intent of regulation to permit a public utility to earn any entrepreneurial profits while continuing to deny it rents that are due to its monopoly position. If public utility regulation were redefined in this manner, marginal cost estimation and pricing would be an essential feature of the new oversight procedures.

Of the various parts of the electricity industry, the generation and transmission functions are better candidates for such revised regulatory treatment than would be the local distribution portion. Generation no longer appears to have significant economies of scale. In such circumstances, competition among regions and energy sources is likely to play an increasingly important role in the future. The emergence of markets, perhaps only imperfectly competitive, for bulk power will erode the regulator's ability to roll-in prices across a variety of investment vintages. Marginal cost pricing becomes more appropriate in such circumstances. In contrast, the distribution function remains a natural monopoly so that marginal cost pricing with no revenue requirement is impossible.

In addition, the application of a revenue requirement within the territory of a single investor-owned utility makes more sense for the distribution function than for transmission services. With today's technology it is possible to transfer power economically over distances that span several utilities. The traditional revenue requirement imposes a

[1] The detailed argument concerning rolled-in pricing distortions is presented in K. A. Kelly, J. S. Henderson, et al., State Regulatory Options for Dealing with Natural Gas Wellhead Price Deregulation (Columbus, OH: National Regulatory Research Institute, 83-7, 1983), pp. 40-51.

financial break-even condition upon areas that are small in comparison to the economical size of the transmission network. The result is a patchwork of embedded cost prices that bears little resemblance to the marginal resource costs needed to provide service.

A rational pricing policy for transmission service also would account for several realities. It is not possible with current technology for large users to bypass the transmission grid. It is not possible to direct the energy flow along a contract path or any other particular route. There is always one or perhaps a few lines that reach capacity first as the load in any network increases. All of these observations together suggest that a pricing policy for evolving a stronger, more efficient transmission grid would be based on the marginal cost (per MW-mile) of improving the capacity of the weakest link needed to complete a wheeling arrangement, without lowering the price to meet an embedded cost revenue requirement. Indeed, the oldest transmission systems that are most in need of improvement are likely to be the weakest link and also to have the lowest embedded cost. Then, perversely, application of the revenue requirement may provide the weakest incentive to improve those systems most in need of improvement.

Implementing the policies suggested by the preceding argument undoubtedly would stretch the limit of current FERC authority over wheeling transactions. It is nonetheless useful to have an overall sense of the design of an efficient national transmission pricing policy as compromises are considered.

Having a Revenue Requirement

If a revenue requirement is judged to be socially desirable or even necessary, the traditional method of allocating the revenue requirement to functions, classes, and customer groups is one that does not encourage good decision-making. For the reasons discussed in chapter 7, the resulting "costs" of service are typically unrelated to the actual cost increases or decreases imposed on the transmission system by additional use of that system.

Good decision-making requires that, if price must deviate from marginal cost, it do so in such a way that minimizes the relative economic damage among the various customer groups. Overall economic well-being, in this view, is best served by a price deviation for each customer or service that is inversely proportional to the respective price elasticity of demand. This is the so-called Ramsey, or inverse-elasticity, rule. The rationale for Ramsey pricing is good decision-making; if prices must deviate from marginal costs, let the deviation be least for those whose decisions are most sensitive to price. Fully implemented, Ramsey pricing would apply to both retail and wholesale transmission service.

To follow the Ramsey rule, however, requires a knowledge of the price elasticities of the various demands for wheeling services. Such elasticities always are difficult to estimate, even for retail markets. With wheeling, the relevant elasticities are those associated with an intermediate product, transmission, the demand for which is only indirectly observed. Even if electricity services were unbundled, as is happening in the natural gas market, with separate prices for generation, transmission, and distribution, many customers would continue to choose an integrated electricity service. Most residential and commercial customers of investor-owned utilities are likely examples. Elasticity measurements would be required, then, for the transmission service portion of captive retail customers' demand and for the separate wheeling service provided to wholesale customers or any large industrial customer allowed to purchase power elsewhere. The degree of uncertainty about the elasticity estimates is likely to be large in such circumstances.

If the revenue requirement is to be partially maintained but the measurement and use of elasticities is judged to be impractical, there are several practical policies that can be used to keep the current arrangement of territory-specific revenue requirements. One is to charge wheeling customers prices equal to marginal costs, while retail customers continue to pay a typically lower, embedded cost price. With such a policy, the retail portion of the revenue requirement would be met and the wholesale portion met or exceeded. The principal drawback to such a policy, even with the option of interruptible service, is that it may be judged unduly discriminatory.

An alternative way to fulfill the revenue requirement would be to proportionally reduce prices from marginal costs for one or both customer groups, wheeling customers and captive retail customers. The policy does not encourage good decision making, however. It creates the appearance that transmission service is cheap relative to its actual resource cost. In the long run, this will encourage non-economical and excessive use of the transmission system.

The last and most attractive alternative for dealing with the revenue requirement for wheeling service would be to phase it out over a period of years. This could be implemented as some variation of the block pricing proposal for generation, made by the National Economic Research Associates.[2] NERA suggests that a customer's existing or "old" generation load in some base period be priced using embedded costs in the traditional way. New loads or use would be priced at the incremental cost. The proposal seems particularly interesting for dealing with the problems posed by requirements customers, discussed in the next section. At this point, it should be noted that the intent of the proposal is to price new usage, beyond some point in time, at incremental costs. The details of implementing such an idea could take any number of forms. For the idea to work, however, requires that after the policy is initiated a larger and larger fraction of sales be priced at marginal cost. If marginal cost prices are greater than those associated with embedded costs (which must be true for the policy to work at all), this means that over time a traditional revenue requirement type of calculation will play an ever smaller role. As sales grow, a larger fraction would be priced at marginal cost because the portion receiving embedded cost prices is fixed. If the embedded cost portion were not fixed, the market would quickly see through the calculations and recognize that prices are based on some mix of embedded and marginal cost principles, which would serve to dilute the marginal cost price signal for new load.

An example may help to clarify how the concept can be applied to wheeling services. Suppose the FERC adopted NERA's proposal and announced that in five years all jurisdictional transactions will be divided into old and new categories. Suppose the wholesale customers of a utility contract for an aggregate of 100 units of transmission service at that time. After a year, demand grows to 110. The FERC prices 100 units at embedded costs and 10 units at incremental costs. After five years, demand grows to 150 units.

[2] See the comments submitted by NERA in Phase II of the Federal Energy Regulatory Commission's Notice of Inquiry, 85-17. The proposal is similar to the block-billing portion of FERC NOPR 85-1 for natural gas.

For the policy to work, the 50 incremental units need to be priced at incremental costs and the 100 "old" units need to be priced more or less the same as when the policy was initiated.

To see why, suppose this pricing plan is not followed. Instead, suppose the Commission decides that some of the previous five years of investment should be placed in the rate base and recovered using embedded cost allocation principles. The reason for such a decision might be that the Commission thinks that pricing one-third of the utility's investment (50 out of 150 units) at marginal cost is too great a deviation from the traditional revenue requirement treatment. If this happens, and the Commission decides, in effect, that only 20 percent (say) of the transmission investment can be priced at marginal cost, this will be quickly understood in the wholesale market. At such a time, the pricing policy will be perceived as a 20/80 mix of marginal and embedded cost calculations.

In order for the policy to continue to give incremental price signals over time, the 100 units must be priced at their embedded costs as determined when the incremental cost pricing policy is adopted. This means that the policy will eventually phase out the traditional revenue requirement. After the final vintage of transmission equipment priced at embedded cost is retired, all transmission service would be priced according to some version of incremental cost principles. It is important, then, to recognize that the NERA suggestion works best if the revenue requirement is ultimately dropped. In effect, NERA has proposed that the revenue requirement slowly be phased out and replaced with marginal cost pricing.

We have already discussed the idea that marginal cost pricing for all transmission service would lead to good usage and investment decisions on the part of customers. If marginal cost pricing covers cost, there is no need for prices to deviate from marginal cost in order to recover fixed costs. In such circumstances, marginal cost pricing does yield positive economic profits for the utility. NERA's suggestion, in effect, phases in a new regulatory philosophy that would allow such entrepreneurial profits, but would continue to prevent monopoly profits by holding prices to marginal costs. Such a philosophy has much to recommend it, and deserves serious consideration by regulators. The discussion here is intended to point out that the NERA proposal has the long-run implication of reducing the importance of, if not eliminating, the traditional, embedded-cost, revenue requirement and replacing it with one based on incremental costs.

Revenue Requirements and Price Discrimination

A policy issue raised by the revenue requirement is that marginal cost pricing for some, but not all, customers may be judged unduly discriminatory. That is, a transmission service price based on low, embedded cost for retail customers, but based on higher marginal cost for wheeling customers may create a price difference severe enough that commissioners or others would find it unacceptable. On the other hand, the price difference may be small and justifiable in a commissioner's perception. An argument supporting the latter position is that full-service customers are entitled to the benefit associated with the fact that embedded costs are low in their own service area. Such customers, in effect, have financed the utility's investments through their willingness to enter into a long-term, implicit contract to pay for the entire electric utility system. Customers that desire wheeling services want only a portion of the utility's services and as such are not interested in the same type of long-term, implicit contract. The regulatory judgment in such a case may be that the wheeling customer is not entitled to a share of the economic rents associated with low embedded costs, but the retail customer is. The utility's obligation to serve also may be different for wheeling customers. This type of policy assessment is based on social equity grounds, and can be persuasive. The need for a revenue requirement is related to the legal, regulatory, institutional, and technical environment. The law may require it and regulators may desire it.

Despite this, policymakers should be aware that price differences, between the implicit price of transmission embedded in retail rates and the explicit price of transmission used for wheeling service, may lead to bad decisions on the part of some users, regardless of whether the differences seem appropriate on social equity grounds. It is not always possible to anticipate the creative ways customers will find to take advantage of price differences, but regulators should recognize that such incentives accompany any set of prices, due to regulation or not, that contain excessively large differences. It is important for regulators to consider whether or not such price differences can be viably maintained or whether there are economic forces that would tend to erode such differences. Price differences that are too large may create incentives for some customers to seek an alternative, low-priced supply, irrespective of whether the incremental cost of such a supply is smaller. Such differences can arise in a variety of ways--a topic of the next section.

Industry Organization Issues

There are at the present time several key policy issues relating to the organization of the electric power industry in the United States. While it is not the purpose of this report to resolve these issues, they do affect the policy-maker's ability to implement a policy of cost-based wheeling rates.

The electric industry includes about 3500 firms having a variety of sizes and ownership forms.[3] Included are investor-owned utilities (IOUs), municipal utilities, cooperatives, federal agencies, and state and county power authorities.

There are about 250 IOUs that supply about 75 percent of the retail power market (to final customers) in the U.S. Wholesale transactions are sales between utilities and consist of sales for resale and interchange transactions. Sales for resale includes sales to requirements customers, unit commitment contracts, and other arrangements for which the power flows from a seller to a buyer more or less in the same direction day after day. Interchange transactions include economy power exchanges for which the role of buyer and seller may be switched from day to day depending on the condition of the network and the utilities' dispatching. (For more detail on the types and terminology of power exchanges, see appendix D.)

There are somewhat more than 2000 municipal utilities. Some of these generate and distribute power, while others are limited to a distribution role only. These companies are exempt from federal taxes and usually from state and local income taxes and property taxes as well. Also, interest on

---

[3] See Paul L. Joskow, "Mixing Regulatory and Antitrust Policies in the Electric Power Industry: The Price Squeeze and Retail Market Competition," in Antitrust and Regulation, ed. Franklin M. Fisher (Cambridge, MA: The MIT Press, 1983).

their bonds is exempt from federal and sometimes state and local taxes on the incomes of bondholders. The price such utilities pay for capital, then, is lower than that paid by an IOU, which is subject to such taxes.

About 1000 cooperative utilities supply power mostly to rural areas of the U.S. Coops generate some power, but most rely on power supplied by federal agencies or IOUs. Coops are eligible for federally subsidized funds under the Rural Electrification Act of 1936 and in addition are non-profit organizations exempt from most taxes.

There are six federal power systems, supplying about 10 percent of U.S. generation. Most of this power is sold for resale to munis and coops. Large industrial customers buy about 30 percent. Much of this power is produced by federal dams, financed by federal appropriations. The Federal Power Act provides that publicly-owned utilities are given first preference for power produced by federal dams. Such power tends to be cheap because it is priced to recover operating costs, which are very small, plus low embedded costs.

Differences in the price of capital due to low, tax-exempt financing of some power plants, and differences in the embedded costs of power plants, as exemplified by the federal system of dams, create differentials in the price of power throughout the U.S. There are other sources of price differences as well. Differences in fuel cost, particularly between coal and oil using regions of the U.S., can be very important, especially when oil prices change in unexpected ways. The recent emergence of cogeneration is a factor that has caused some inexpensively produced power to be available to at least a few large retail customers. In the Northeast and the Northwest there appear to be potentially large sources of power from Canadian generation, mostly from hydroelectric sites. All these factors serve to make electricity prices across the U.S. very uneven.

This inequality of prices, due partly to the institutional framework and partly to differences in economic circumstances, is a violation of what economists like to call the law of one price.[4] This constellation of

---

[4] The law of one price says that a single, homogeneous commodity cannot sell for more than one price if reselling is possible and costless. If reselling is not costless, a corollary is that price differences must be no more than the reselling costs. That is, the price difference will be smaller than the

(Footnote continues on next page)

price differences can be maintained as long as inertia, transaction costs, or other impediments prevent customers from seeking the lowest-priced power sources. In recent years, the emergence of economical, high voltage transmission has enlarged the geographical area in which customers can compete for low-priced power. The result is that pockets of favorably-priced power become attractive to a wider set of customers, some of whom need wheeling services in order to purchase it.

When the cause of the electricity price differentials is the market price of fuel, such enlarged competition is precisely what is needed to return the system to its equilibrium. That is, increased competition for coal made possible by coal-by-wire wheeling arrangements is one example of many world-wide market adjustments that serve to bring the price of coal and the price of oil back into balance. Either the system lambdas of distant regions converge, or the low cost region eventually supplies all the power needs of the high cost region. Long-distance transmission of electricity can help to eliminate the differentials in power prices that give rise to the demand for such transmission. The market dynamics put into motion by the long-distance transmission (most likely wheeling) are self-correcting in this instance. As such, wheeling serves an economically efficient purpose.

In contrast, long-distance trading made possible by wheeling (or any other kind of reselling) does not necessarily eliminate price differences created by the institutional framework. Power made cheap by low tax-exempt interest rates or by the low embedded costs of federal dams remains cheap regardless of the identity of the buyer fortunate enough to be allocated the privilege of purchasing it. Because this power is in short supply (the government does not keep building dams to meet the demand for preference power), the price differential cannot be eliminated by increased trading, and the incentive that others have to seek low-priced power remains. If the incentive is strong enough so that multiple buyers can economically transport the power to their respective load centers, contention among the parties is likely to persist. Since trading cannot eliminate the contention, the parties seek administrative rules that allocate the scarce

---

(Footnote continued from previous page)
transaction costs of the reselling, because otherwise an incentive is created to trade which will drive the price difference down to the transaction costs.

power. Such rules can take the form of law--the Federal Power Act's preference provisions--or the form of administrative hearings in which customers contend for wheeling arrangements in order to have access to low-priced power. In either case, the price system is not used to allocate scarce resources. Instead, rationing is guided by government policy.

Wheeling induced by institutional arrangements, then, is not economically efficient, in itself. That is, it is not motivated by differences in incremental costs that reflect society's valuation of resources. It is not the sort of trading that tends to be self-correcting, so it provides no signals as to where resources should move. It is, rather, a form of rent-seeking in which buyers engage and thereby split up the economic rents established by embedded cost pricing, especially where embedded costs themselves contain a subsidy. Because it is inefficient in this sense, some commentators refer to this as "bad" wheeling or as the "wheeling of money, not power."

Despite the fact that wheeling can be motivated by bad reasons and, by itself, can reduce the efficiency of the electric power market, it is possible, nonetheless, that preferential treatment of some power sources is desirable on social equity grounds. That is, lawmakers may recognize that pricing federal power at low, embedded cost levels represents a permanent distortion to the economic efficiency of the system, but may conclude that the efficiency loss is justifiable because of the improvement to social equity. The perception of the Congress might be that rural customers ought to receive most of the implicit federal subsidy, for example.

In addition to the permanent, static distortion just described, policymakers need to be aware, also, of the dynamic distortion. Technical progress that reduces the cost of transmission will continue to enlarge the geographical area in which parties can economically pursue the rents inherent in the low-priced federal and tax-exempt power. The contention in administrative forums such as the FERC can be expected to grow as a result.

Apart from the administrative expense of allocating power to the contenders, the principal difficulty associated with the dynamic distortion is that it disrupts the pattern of revenue flows and perhaps load flows in a utility's service area. When a retail customer requests wheeling services so as to take advantage of lower, embedded-cost, priced power, the utility faces the prospect of losing a customer for whom it has planned and constructed facilities. In addition, the PUC-approved retail rates or FERC-approved wholesale rates paid by that customer are part of a larger arrangement of how fixed costs are shared among all customer classes. As customers switch suppliers, these fixed cost burdens shift in unexpected ways. This adds to the ongoing disruption associated with the ebb and flow of population, industrial relocation, plant closings, economic recessions, and so on.

An important policy question that regulators must contend with is, Who are the residual claimants in such circumstances? Do captive residential and commercial customers pay or do the utility's shareholders pay for the fixed cost burden that shifts as a result of some customers switching suppliers? The answer is by no means clear. Competitive markets would make the shareholder the residual claimant. There would be no way to charge remaining customers any price other than marginal cost, regardless of whether some customers choose to buy from the firm. On the other hand, the answer may depend on whether electricity prices are above or below marginal cost. If the residential price is less than marginal cost (because of low, embedded costs), the addition of some fixed cost burden, previously shouldered by a large customer now gone, up to the level of marginal cost is not as onerous as if the residential price were at marginal cost to begin with.

Another important policy issue is how to consider the utility's service obligation to wheeling customers within its control area, who were previously retail customers. Service obligations ought to correspond to the nature of the service provided. Because back-up generation service incurs costs, such service ought not to be available free to wheeling customers. Utilities fear that they are implicitly obligated to provide such service even if the wheeling customer claims otherwise. If the wheeling customer's power source is temporarily out of service, the customer is not likely to have his service cut off. Standby charges may be an answer in some situations, but would be difficult to force upon a reluctant customer who claims no need for such service. After all, some customers come and go from the system routinely. Residential electricity users who move do not continue to pay their previous electric company on the theory that their move and consequent switch in power suppliers somehow disrupts that company's planning process. Analogously, perhaps a business could reincorporate under a new name when it switches power suppliers and thereby escape any standby charge imposed by the PUC or FERC.

Interestingly, the NERA proposal, discussed earlier in this chapter, has some important implications with regard to both the issue of service obligations and the issue of who bears the burden of supplier switching. As mentioned, the proposal is that old loads be priced at the embedded cost of the traditional supplier and that new loads be priced at incremental costs. Also, a requirements customer that found a new supplier would be credited for the cost avoided by its traditional supplier. It is possible to do this under the NERA proposal because the customer has a continuing obligation to pay embedded cost prices for its old load. That fixed obligation would be reduced by any costs actually avoided because of the switch in suppliers. The customer would have an incentive to switch its old load under this scheme only if the price obtained from the new supplier is less than the cost avoided by the traditional supplier. Effectively, the customer who wants to switch continues to pay its traditional, fixed obligations under this scheme. The customer can gradually avoid such a burden by finding a lower cost supplier and paying marginal costs for his 'expanding' new load. The continuing payment for old load to the traditional supplier acts as a standby charge of sorts. The proposal, then, in effect addresses both the issues of service obligations and who is the residual claimant.

The purpose of this report is to discuss the pricing of wheeling, not to sort out the major institutional issues of the electricity industry, or to fashion a major policy proposal regarding them. However, the NERA proposal is worth the consideration of the FERC and state regulators. A major difficulty with the proposal, in our view, is that with the passage of time the definition of old load and its embedded cost will become obscure. After 10 years, the identity of even major wholesale customers can change. Also, the associated embedded costs are gradually becoming smaller because the rate base is disappearing. For these reasons, some explicit consideration is needed about how to move from the old, embedded cost policy to what is implicitly a new, marginal cost policy.

This section has pointed out that non-cost influences on the pricing policy for wheeling must be viewed in the current environment of the U.S. electricity transmission networks. These networks are now allowing effective competition to materialize over larger distances than in the past.

This is clearly a desirable social outcome because it allows more vigorous trading and creates more opportunities for customers to find low cost supplies. It also has a tendency, however, to erode traditional buyer-seller relations and to make difficult the maintenance of preferential pricing structures. As a result, policy makers need to consider wheeling pricing issues and industrial structure issues together. Many of the structural issues are well beyond the scope of this report, though they may be treated in the companion NRRI study of power transfer impediments. Without elaboration, some of the relevant policy issues have to do with possible industry restructuring (for example, creating a competitive generation sector, having a unified and nationally regulated transmission network, and retaining local distribution franchises), open access to the transmission network, and the structure of federal preferences. Many of these are U.S. Congressional issues. Without Congressional action, the ability of the FERC to mandate wheeling is severely limited and almost nonexistent. In such circumstances, utilities are more likely to enter into voluntary wheeling arrangements if the price and other terms of the contract create the proper incentives. The remainder of this chapter addresses pricing policies and industry arrangements that may have such incentives.

Policies to Encourage Wheeling

In an environment where wheeling cannot be ordered, there is a variety of ways to create incentives and thereby encourage a utility voluntarily to offer wheeling services. The pricing of the service is an important, but not the only, policy instrument.

As discussed in chapter 6, any of several efficient pricing mechanisms ought to encourage good decision-making on the part of customers and the utility. Some pricing mechanisms give all gains from trade to the buyer and seller, but others result in the wheeler keeping a portion of the gains. Equalization of marginal generation and transmission costs across the grid remains a good test for assessing the efficiency of wheeling arrangements. Those arrangements that promote such an equalization tend to improve network efficiency, while those that create larger differences in marginal costs are not productive, in the sense that they must be countered by other arrangements that reduce the marginal cost inequalities.

At the same time, regulators are concerned with monopoly power and want to control monopoly profits. Any policy to encourage wheeling must be one that prevents a utility from intentionally restricting wheeling capacity so as to drive up the wheeling price.

The policies considered here are the simultaneous purchase and sale of power, auctions for transmission capacity, flexible pricing for wheeling, and the use of brokerage arrangements. Each of these, in one way or another, permits the wheeler to enjoy some share of the gains from trade. Another policy, not discussed at length, for encouraging wheeling where wheeling cannot be ordered is simply to set price above cost--say, at cost plus 10 percent.

Simultaneous Purchase and Sale

For any potential wheeler an alternative to wheeling that results in a greater share of the gains is to purchase power from the seller and resell it to the buyer. The question for policy makers is whether to encourage such transactions in order to reduce marginal cost disparities across the grid, rather than to encourage wheeling, if both can yield the same efficient result.

A commonly used pricing arrangement for two-party power interchanges is to split the difference between the seller's incremental cost and the buyer's decremental costs. This gives about half of the gains from trade to each party, as explained in chapter 6. The arrangement is a common form of economy interchange agreement. In such transactions, whether a utility is a buyer or seller can change from day to day. The arrangement promotes the economically efficient use of generation resources since it tends to reduce differentials in marginal generation and transmission costs across the grid. Equalization of marginal costs across tie lines remains the appropriate benchmark for the production side of economic efficiency.

Where three or more utilities are involved, either a series of two-party trades or wheeling can be used to equalize costs. A pair of two-party trades, which we call a simultaneous purchase-and-sale transaction, gives the middle utility a share of the gains, and thus power transfer by this utility is encouraged. However, the efficiency of a series of two-party trades is questionable in these circumstances. To illustrate the source of the inefficiency, consider an example in which the buyer, seller, and wheeler are all investor-owned utilities. The wheeler is geographically between the buyer and seller. The utility that is in the position of potential wheeler can agree to wheel or, instead, can refuse to wheel and engage in a pair of two-party trades, a simultaneous buy-sell arrangement that has the same effect of moving power from the seller to the buyer. As set out in chapter 6, the simultaneous buy-sell arrangement creates the opportunity for the middle utility to split the difference with both the buyer and the seller. In this way, the middle utility can receive about half the total gains from trade that exist because of a difference between the buyer's and the seller's marginal costs. The fairness of such an arrangement is generally criticized by opponents who would prefer the middle utility to receive a smaller share.

More importantly, the simultaneous buy-sell agreement may be inefficient. Depending on the way the seller computes its incremental costs and the way the buyer computes its decremental costs, this arrangement tends to prevent marginal costs from being equalized. That is, the middle utility's share of half the gains is greater than his own marginal transmission costs and therefore creates an inefficient wedge or difference between the buyer's and seller's marginal costs in any particular transaction. Some eastern utilities have agreements to wheel at a smaller share (usually 15 percent) of the net savings, which has a similar, although smaller effect.[5]

An example may help to illustrate the matter further. Suppose the difference between the buyer's and seller's marginal costs (after accounting for marginal transmission costs, including line losses) is initially 4 cents per kWh. All three utilities have rising, short-run marginal costs so the difference is reduced by trading. If the middle utility recovers half of the initial gains (that is, 2 cents) on each kilowatt-hour traded, the buyer and seller have no incentive to engage in trade beyond the point where the difference is 2 cents. The middle utility receiving a portion of the trading value, in excess of his own marginal transmission costs, has a chilling effect on the incentives for the buyer and seller to trade.

---

[5] W. W. Lindsay, "Wheeling Rates: FERC Policies and Some Alternatives," Presentation to Electricity Consumers Resource Council Seminar on Wheeling, Washington D.C., September 27, 1985, p. 21.

This chilling effect is not necessarily fatal to the incentives for the three utilities to equalize marginal costs. If additional trades can be made, between the buyer and seller or between the wheeler and the other utilities, the differences among the marginal costs can be reduced further. The chilling effect simply reduces the amount of the trading gains that can be eliminated with any single transaction. Multiple transactions would eventually succeed in eliminating the marginal cost differentials, even with the middle utility receiving half of the initial gains for each transaction between buyer and seller.

The conclusion is different if the wheeling utility receives half the total gains, instead of the initial ones. If buyer and seller can correctly compute areas under nonlinear system lambda curves and agree to share some fraction of the total gains with the wheeler, they can reach the marginal cost equalization point in a single transaction. The wheeler's fraction could be 1/2, 1/3, or 1/10, and the desired equalization would be achieved in any case. An additional discussion of continuously changing wheeling prices appears in chapter 6 in association with figures 6-3 and 6-4. In practice, computing areas under such nonlinear curves is difficult. The buyer may calculate his decremental costs, which is an average cost reduction over some increment of power. The seller likewise finds an average incremental cost. Such approximations to marginal cost prevent the traders from reaching a marginal cost equalization point in a single transaction, even if the wheeler receives no portion of the gains. With multiple transactions, the buyer and seller would eventually discover or approximate the marginal cost equalization point. If the wheeler receives a share in excess of his resource costs, the process of finding the equilibrium requires more iterations or transactions. The, perhaps obvious, difficulty is that time and transaction costs may limit the number of transactions that realistically can be consummated. On an hourly basis, it may be possible to arrange only one transaction between any pair of trading partners. Such a limit, along with a wheeler receiving a share, can inefficiently restrict the trading.

On the other hand, if the middle utility wheels and receives only his marginal transmission costs as a fee for his services, this chilling effect would disappear. It is economically efficient for the difference in marginal generating costs between buyer and seller to be equal to the wheeler's marginal transmission costs. With marginal cost pricing of transmission services, fewer transactions are needed to equalize marginal generation costs across the network.

The conclusion is that simultaneous buy-sell arrangements that yield the middle utility a fee greater than marginal transmission costs may tend, in practice, to prevent marginal costs from being equalized across the grid. The same conclusion can be reached whether the reason for the transaction is economy interchange or a longer-term arrangement, such as the backing out of oil-fired generation.

Between investor-owned utilities that routinely engage in economy interchanges, wheeling is likely to be less important than bilateral trades, which can accomplish the equalization of marginal costs in the absence of wheeling. Longer-term arrangements, such as coal-by-wire or power supply contracts for requirements customers, depend more heavily on wheeling. In such cases, marginal cost pricing, perhaps with a premium of 10 percent or so to encourage wheeling, should compensate the wheeling utility for the resources actually used. Whether to wheel for requirements customers at all raises a set of institutional and other broad policy issues described in the previous section of this chapter.

In this context, the use of simultaneous buy-sell transactions instead of wheeling at marginal cost prices appears to represent a form of monopoly power, albeit, an imperfect one.[6] It tends to prevent, or at least retard, the approach to an economically efficient use of the network. It can result in effective wheeling prices that are much larger than marginal costs.

---

[6] Interestingly, the middle utility (or wheeler), as a third party, receiving half of the gains from trade between a buyer and seller corresponds, in some cases, to the Shapley value solution in cooperative game theory. This happens if the wheeler, as well as the seller, has the capacity to serve the buyer, and the wheeler's costs are intermediate to the other two. If, instead, the wheeler lacks the capacity to sell to the buyer, and the seller's and wheeler's marginal generation costs have already been equalized through bilateral trades, then the Shapley value assigns equal shares of the gains from trade to all three parties. Such examples are illustrative because they suggest that simultaneous buy-sell arrangements can be thought of as a voluntary, cooperative contract, and also because they point out that value-of-service concepts, and not marginal cost concepts, are at the foundation of such arrangements.

Bidding for Transmission Capacity

Value-of-service pricing for wheeling services is an alternative to cost-of-service pricing, which can help to equalize marginal costs across the grid in some circumstances. The best way to determine the value of service where there are many competing wheeling customers is to ask them to bid against each other for the use of the transmission network.

In its comments in Phase I of the FERC NOI on wheeling, the Pacific Gas and Electric Company proposed that an auction be held for transmission capacity.[7] A certain, prescribed portion of transmission capacity would be reserved for core customers, residential and commercial retail service, as well as wholesale service to requirements customers. The remainder of the transmission capacity would be available to other utilities on a nondiscriminatory basis. The price would be established by an auction. The company suggested that such a scheme would be used only in workably competitive markets for bulk power. Baltimore Gas and Electric Company proposed a similar bidding scheme for its surplus capacity.[8]

An auction would be an economically efficient way of rationing scarce transmission capacity to those most willing to pay for it. Such a pricing arrangement is considerably different from the traditional cost-of-service basis for regulated prices, however. The user's value of service, or willingness to pay, is clearly the major component of his bid for access to fixed facilities. The wheeler is able to capture almost all of the gains from trade.

Bidding for transmission capacity would need to be combined with strong regulatory oversight of the utility's investment program for transmission facilities. The danger is that a utility in a monopoly position could keep transmission capacity scarce in order to drive up the price. A regulator could compare a reliable estimate of the long-run incremental cost of transmission service with the current bids to develop a sense of whether additional capacity is needed. If current bidding is higher and is likely to remain so, more capacity is needed. Such a market-based pricing scheme could help both the company and its regulators in assessing the need for

[7] See the Comments of Pacific Gas and Electric Company, FERC Docket RM 85-17, (Phase I), August 9, 1985.
[8] See Baltimore Gas and Electric Company, FERC Docket ER 86-353.

investment. In effect, the auction would help to determine the congestion component of short-run marginal costs. When this rises frequently above long-run incremental costs, more capacity is warranted.

Auctions could be held separately for interruptible and for firm service. An amount could be set aside for each market, which could be adjusted depending on the prevailing prices in each. If interruptible prices began to exceed those bid for firm service, the amount allocated to the interruptible market could be increased. Such adjustments would have to be made in full recognition of existing firm contracts. If no capacity can be made available to interruptible users from the firm service market, more transmission investment would be appropriate.

Alternatively, the market separation could be established by selling long-term firm access at long-run incremental cost, perhaps with a small surcharge to create an incentive for the utility to do this. The amount sold under such firm contracts would be subtracted from the surplus capacity to be auctioned in the interruptible market. As auction prices approach the firm contract price, there may be some incentive for interruptible users to buy firm service, perhaps for a short time. If so, there may be a need to limit the amount of capacity to be sold in the firm market. Then, if interruptible prices are bid above long-run incremental cost, a need for new investment is apparent.

Auction proposals, such as these, provide an opportunity to allow market forces to determine the price of transmission capacity.[9] There may be some markets and circumstances for which an auction is particularly suited. The interruptible market is a good example.

Nonetheless, reliance on an auction will not relieve a regulatory commission of the need to estimate marginal transmission costs, in our view. Reliable estimates of marginal costs could be used by a commission in a variety of ways. One would be to establish a benchmark against which auction prices could be compared to see if additional capacity is needed.

---

[9] In auctions with few participants, strategic behavior of trying to guess the other fellow's bid can be a problem. The Vickery auction is designed to overcome this defect. Briefly, the winning bid is the highest one; however, the winner pays the second-highest bid. This eliminates the need for any participant to guess the limit of an opponent and then slightly out-bid him. There are a variety of auctions that could be tailored to the regulatory environment. See William Vickery, "Counterspeculation Auctions and Competitive Sealed Tenders," Journal of Finance 16 (March 1961):8-37.

Another, more direct, use would be as the basis of regulated prices. Administered prices, however, tend to be unresponsive to market forces. Regulators may wish to allow some flexibility if marginal cost is to be used as the standard for price.

Flexible Pricing

A flexible pricing policy would allow a commission to exert some control over prices and yet allow prices to be somewhat responsive to the market. Price ceilings and floors would be set by a commission, allowing a utility the discretion of where to place the price of transmission services within the established range. For firm service, the ceiling might be 125 percent of long-run marginal cost and the floor might be 75 percent of the long-run marginal cost. The utility would submit estimates of long-run marginal cost, using its own method, as well as its proposed prices for firm service. The commission could check the estimates independently. If the proposed price appears to be in the upper portion of the range, exceeding long-run marginal cost, additional capacity would seem to be appropriate on economic grounds. The commission then could assess the utility's investment plans and inquire about the number of requests for service received by the utility at the prevailing price. In this way, the utility would have some flexibility in pricing its services, the prices should be sufficiently attractive that the utility has some incentive to provide access to its transmission facilities, and the commission would be provided with the kind of information it needs to assess any monopoly abuse by the utility and the need for additional investment.

A similar mechanism could be established for interruptible service also. In this case, the floor and ceiling prices could be based on short-run marginal cost. As such, the range is likely to be much larger since short-run marginal cost can be as low as marginal line losses and as high as needed to prevent congestion. The floor might be marginal line losses, and the ceiling price could be the same as that for firm service. The utility would submit its estimates of marginal line losses for representative interruptible transactions that could be used to fashion the floor price. As the interruptible price approaches long-run marginal cost, the commission would receive a signal that transmission capacity is becoming short and expansion may be appropriate.

In the zone of flexibility for interruptible customers, the commission might relax its regulation in some circumstances. If the commission found the interruptible market to be workably competitive, it would authorize an auction. Otherwise, it could approve the usual type of flexible pricing. The zone of flexibility might be restricted if the commission found the interruptible market to be susceptible to monopoly abuse, although the circumstances that would yield such a finding are not readily apparent.

Flexible pricing can be tailored to market conditions and can be compared to marginal cost benchmarks so as to allow a commission to oversee the utility's pricing and investment program. Core customers could be treated in the traditional way with prices determined from embedded costs.

Brokerage Arrangements

Brokerage arrangements, such as the "Florida broker," are a way for utilities to trade power routinely in an organizational forum that is less restrictive than a formal power pool. Member utilities are willing to wheel power at cost because, at other times, they can enjoy the gains from buying or selling when other members wheel at cost.

In the Florida broker system, a utility can submit prices at which it is willing to buy and sell power in the next hour, its decremental and incremental costs respectively.[10] The broker uses a computerized, high-low matching rule. The buyer with the highest decremental cost is matched with the seller having the lowest incremental cost. Next, the second highest decremental cost is matched with the second lowest incremental cost, and so forth. In each match, the price is set by the split-the-difference method. The computer algorithm determines the costs of transmission losses, whether a transmission path is available, and whether the two utilities have a contract. Importantly, the trades take place at different prices. While it would be feasible to revise the broker system so that all trades would be conducted at the same price, that of the marginal deal, the participants in

[10] See the discussion in appendix D. The system is also described in J. P. Acton and S. M. Besen, The Economics of Bulk Power Exchanges, Rand Report N-2277-DOE (Santa Monica, CA: May, 1985).

the broker prefer the current arrangement. As such, the Florida broker operates more like the stock market than an auction that sets a single price. (Not all auctions do. The weekly Treasury Bill auction results in trades at different effective prices, for example.)

If wheeling is required for a particular transaction, the wheeling is provided at an effective price of about 1 to 3 mills per kilowatt-hour, depending on the instance involved. Such a price is much smaller than the wheeler's share of a simultaneous buy-sell transaction.

The Florida broker is a voluntary agreement among buyers and sellers of economy energy, principally the major IOUs. Because each expects to be sometimes a buyer and sometimes a seller, each has an incentive to cooperate in the broker system. Because of the geographical locations of the participants, some are more likely to be wheelers than others. The wheeling price is intended to overcome this asymmetry. Otherwise, the agreement could rely on reciprocity, and forego any explicit wheeling pricing.

A broker arrangement, like power pools, is particularly efficient with regard to short-term economy interchanges. Long-term firm wheeling is different in several ways. The energy flow is more predictably one-way. The wheeling service is generally desired on a more firm, less interruptible basis. The buyer of the power may have little, if any, generation capacity. Hence, an efficient price for firm wheeling would be greater, no doubt, than that provided by the Florida broker, which is for non-firm wheeling. Also, brokerage arrangements, like power pools and holding companies, do not attempt to equalize costs across the whole interconnected grid, but only across some portion of it. Some beneficial trades are undoubtedly excluded. Nonetheless, the Florida broker is an example of voluntary wheeling taking place at prices producing gains for the wheeler much less than those associated with simultaneous buy-sell transactions.

Conclusion

The policies considered here are those that result in the wheeling utility capturing a larger share of the gains from trade than cost-based wheeling prices allow. One policy is to encourage the use of simultaneous purchase and sale transactions, instead of wheeling, by a utility between the buyer and seller. In some ways, this is like a wheeling arrangement with value-of-service pricing; in other ways, however, it may be an inefficient mechanism for clearing the market. A more efficient mechanism would be to determine the value of the wheeling service directly with some sort of bidding mechanism. This approach, while efficient, gives the wheeler virtually all the gains from trade, and would require the most regulatory oversight to prevent abuse.

Flexible pricing is a compromise policy that has many of the attractive features of market-based pricing, while allowing more regulatory involvement and permitting wheeling rates to be tied to wheeling costs. If rates must be equal to costs, a brokerage arrangement may bring some advantages to its members in terms of lower power costs, which gives them an incentive to participate in the arrangement even though they too must wheel at cost.

Whether any of these policies or a policy of cost-based rates will emerge over the next decade depends on the direction of change in a dynamic industry environment. This chapter has outlined some of the broad regulatory and industrial structure issues that impinge upon a transmission pricing policy that seeks to encourage good decision-making by electricity users. Marginal versus embedded costs is at the heart of several issues, as it is in many other regulatory pricing issues. The pricing problem is complicated in this instance by the existence of federal preference rules and other low administered prices. Matters of national policy concerning the organization of the network, open access to the transmission grid, and competition in bulk power supply are important in this regard, but are probably beyond the current authority of the FERC or state regulators.

Probably within the current legal authority of the FERC, an optional, phased-in marginal cost pricing policy is attractive. It initiates a policy of incremental cost pricing in an important segment of the electricity industry. Its phased-in nature preserves the rents received from current, embedded cost pricing for old load for at least some number of years. It creates good marginal cost pricing signals for economy interchange transactions as well as for wholesale transactions of requirements customers.

A major hurdle that an incremental pricing policy must overcome, whether phased-in or not, is whether it can be put into practice. This topic is considered at length in the following chapter.

CHAPTER 9

PRACTICAL ASPECTS OF WHEELING RATEMAKING

The principles for pricing electricity wheeling presented in previous chapters would encourage good decision-making, if implemented. Chapter 8 suggests that the institutional setting and the structure of the market are important considerations in implementing a wheeling pricing policy. In addition, there are practical aspects of measuring service costs and designing pre-set rates that must be considered. These are addressed here.

Measuring Service Costs

There are five areas of difficulty for measuring the costs of wheeling service: determination of load flow, calculation of line losses, valuation of opportunity cost, capacity measurement, and estimation of long-run marginal cost. There are several ways in which each type of difficulty can be overcome. The design of efficient wheeling rates can be influenced by the manner in which these difficulties are resolved.

Load Flow Determination

A wheeling transaction results in an energy flow that cannot be separately metered apart from all the other energy flowing at the same time. Without direct metering, the effect of a wheeling transaction on the transmission network is best determined by load flow analysis (using computerized models of the network) before and after the transaction. Detailed network models are used routinely by large utilities and the regional reliability councils. The specific analysis of a proposed wheeling transaction could be subject to criticism, debate, and some contention. The analytical tools to sort out the problem are available, although the large number of details provides ample opportunity for reasonable people to conduct such studies differently.

The analysis begins with the simultaneous increase in generation in one geographical area and equal decrease (adjusted for losses) in another. The configuration of generation and loads should reflect the peak period. The load flow program can find the difference in the loading of each line as a result of the wheeling transaction. The analysis could be conducted for representative variations in load that occur during the peak period. The difference in megawatt loading of each line can be multiplied by the line's length as a measure of the MW-miles for each part of the network.

Load flow analyses range in complexity from relatively simple DC static-flow models to dynamic models designed to study the short-term stability of the electrical network when it is subjected to transient power impulses such as lightning strokes. Static models of an AC network accounting for real and reactive power flows fall somewhere midway within this range. Utilities have differing degrees of ability to do load flow calculations quickly. Some are quite sophisticated and have real-time capability in this area. Some depend on the modeling efforts of others, such as the area reliability councils.

It would be helpful if a standard load flow model were developed, on which all parties would agree. If the parties to a wheeling transaction cannot agree on the power flows, regulators might consider resolving the dispute using a simpler idea. Measure in miles the most direct route between the buyer and seller along the transmission network and multiply this by the contract demand or actual peak demand (MW), and add some 10 to 20 percent to allow for indirect, parallel flows. Use the load flow studies submitted by the parties to determine the relative flows among the affected utilities. The idea here is to limit the use of load flow studies to establishing relative and not absolute levels of energy flow if the parties cannot agree. This could be done in several ways. One would be to find for each utility the average of the MW-mile flows affecting it in the various studies submitted in evidence. To avoid creating an incentive for the parties to submit numerous and possibly biased studies, a representative study could be chosen from the buyer, seller, and each affected utility and then averaged. Particularly outlandish results could be given only a small weight in the average.

This alternative way of using load flow studies reduces the regulator's reliance on them since the studies establish relative flows only. The overall absolute level of service is measured by the most direct distance involved and the amount of the energy involved. If the wheeling is opposite to the predominant direction of network flow, this alternative method may require modification. The implications of a counterflow are treated later in this chapter.

Line Loss Measurement

In the absence of any capacity constraints, the marginal cost of wheeling is mostly marginal line losses in the short run. Perhaps the best way of incorporating these into prices would be to adopt the responsive pricing proposed by the MIT research group.[1] Marginal line losses are correctly incorporated using their method of calculating wheeling rates as the difference in the spot electricity prices between two locations. Marginal line losses could also be found as a byproduct of the load flow studies just discussed.

If the expense of conducting these types of studies is too great, the AC load flows could be approximated by those in a DC network model. The model could be used to find the losses at several representative times, perhaps at 40, 60, 80, and 100 percent of expected peak load. In each case, before-and-after flows and associated losses would be compared. Such approximations may not be good for actual operational control in a large system but would be useful for strategic planning purposes, according to the MIT group.

In addition, the DC flow approximation provides a useful aid to our understanding. The approximation expresses line losses as a quadratic function of the real power (MW) flow in each line. This is a nonlinear relation with line losses increasing proportionally more than any increase

[1] M. C. Caramanis, R. E. Bohn, and F. C. Schweppe, "The Costs of Wheeling and Optimal Wheeling Rates," Paper 85 SM 464-3 presented at 1985 Summer Meeting, IEEE Power Engineering Society, Vancouver, Canada.

in load. Because of this nonlinear relationship, incremental line losses are greater than the average at any loading of the line. Incremental losses are about twice the average losses. This provides a convenient rule of thumb that the marginal cost of wheeling as a percentage of system lambda is approximately twice the average percentage loss along any line.

So if a wheeling utility transports energy on behalf of others along one of the uncongested lines that has a 4 percent average loss (at its current loading), the marginal wheeling cost is about 8 percent of system lambda. This wheeling cost is positive if the wheeled energy flows in the same direction as that of the remaining flow. If the wheeling transaction reduces the net flow because its direction opposes the native flow, line losses are reduced because the loading on the line is smaller. In this circumstance, the marginal cost of wheeling is a negative 8 percent. This means that the wheeling utility is benefited by an 8 percent reduction in the line losses of its own native load. A payment of this amount from the wheeling utility to the customer is, strictly speaking, the economically efficient action. Eight percent of system lambda multiplied by the number of megawatt-hours wheeled is the (approximate) marginal generation cost saving in such a case. The negative 8 percent price provides the correct incentives to encourage a wheeling transaction that reduces line losses. The wheeling utility that paid such a negative price, pricing the savings from each kilowatt-hour wheeled at the marginal savings received from the last kilowatt-hour wheeled, would find that its incremental generation cost saving exceeds the payment made to the customer, so that the utility would still make a profit on the transaction. This is a general proposition that has been shown by the MIT group.

The rule of thumb that incremental losses are double average losses for a line cannot be simplistically applied to the entire network. The average line losses throughout the network of the wheeling utility are not the correct benchmark. Instead, the average loss along each line in the path used to wheel the electricity must be doubled, and then these losses must be algebraically added together. The addition is positive if the wheeling increases the loading on a line and is negative if it decreases it. It is possible (although unlikely) for the marginal cost of wheeling when calculated this way to be some 20 to 30 percent of system lambda where 10 to 15 percent energy losses occur on the principal lines carrying wheeled power from one border of a utility to another. Note that wheeling in the opposite direction in such a case would reduce losses by 10 to 15 percent and would be efficiently priced at a negative 20 to 30 percent of system lambda.

Payment for marginal line losses introduces an additional level of complexity with multiple wheeling transactions. The marginal line losses attributable to any load ought to be calculated as decrements to the same total load level. That is, it is incorrect to think of one transaction of 100 MW as being first, and another transaction of 100 MW as happening subsequently. The conclusion of such thinking might be that the marginal line losses of the second transaction are larger because it occurs later and therefore causes greater nonlinear losses. All demands occur at the same time and together result in an overall loading of the network and of particular lines. The savings from reducing any demand by one megawatt are the same.

To find the incremental flows and line losses associated with a particular wheeling transaction, the load flow study should be conducted in a decremental fashion. Begin with the total system load including all simultaneous wheeling arrangements and find the new flow pattern in the absence of a particular transaction. Each transaction is analyzed with reference to the same total load, not added sequentially. Marginal loss multipliers can be found for each transaction, for each utility, for a few representative loadings during the year. These loss factors can be multiplied, then, by the metered and possibly inferred MW flows described above to determine marginal losses. A wheeling customer would be responsible for marginal loss payments to all utilities affected by the transaction. If the wheeling customer is an investor-owned utility that frequently interchanges economy energy, the marginal loss payments could be collected in an account that accumulates positive and negative payments and is cleared periodically, perhaps once a year. If the wheeling customer is a municipality so that the direction of electricity flow is predominantly one way, the account could be cleared more frequently, perhaps monthly.

The important complicating feature of multiple wheeling transactions is the need to develop marginal loss factors in a mutually consistent way. The aggregate reference load must be the same for all transactions. Perhaps most importantly, a wheeling pricing policy to recover roughly twice the average losses is substantially different from current practice based on the average only. Such a policy is likely to be opposed by potential wheeling customers. Nonetheless, it is the case that a wheeling transaction (and all other transmission uses for that matter) creates incremental line losses of such a magnitude. An efficient pricing policy would recover the incremental losses.

Congestion Cost

The short-run marginal cost of wheeling includes marginal line losses plus a congestion component that depends upon the status of available generation and transmission capacity. When demand approaches the limits of capacity, the congestion component of pricing rises. In real time, rapid demand changes can result in very large, and possibly abrupt, changes in price.

Conceptually, a congestion charge is a component of the opportunity cost incurred when a particular customer uses a transmission line, thereby denying its use to another. If users have been correctly ordered, then the marginal user has a slightly higher willingness to pay than that of the particular customer who, of those denied service, has the highest willingness to pay. The opportunity cost would be the highest valued use foregone. The congestion charge is the component of price added so as to ration service to those most willing to pay.

The ideal way to institute such a policy would be through responsive pricing so that the price is adjusted frequently, perhaps in real time. This is the kind of market clearing pricing described by Schweppe, Bohn, and Caramanis.[2] With advances in sophisticated computational algorithms and control centers, such a pricing scheme could be devised for large utilities.

An alternative way of determining the congestion charge in practice would be an auction, among potential users of a transmission segment. Depending on how frequently the auctions were conducted, this is an excellent way of discovering the price needed in order to ration a limited transmission capacity to those who place the highest value on its use, which is precisely the notion of a congestion charge. The enormous number of

[2] Schweppe, Bohn, and Caramanis, Wheeling Rates: An Economic-Engineering Approach.

transmission lines would make it too difficult to hold a separate auction for each, but access to transmission corridors, or groups of lines, could be auctioned in a practical manner. The danger of an auction, discussed in chapter 8, is that utilities might pursue a policy of purposeful underinvestment in transmission so as to create monopoly profits--a price in excess of true short-run marginal cost, a cost based on the concept of optimal (although, not smooth) capacity expansion.

Yet another way of approximating a congestion charge would be to use long-run marginal capacity cost (adjusted for fuel savings) on line segments or corridors that are used nearly to capacity. That is, an administrative rule could be substituted for a market-based process of price determination. The rule would specify that price would include marginal capacity costs as well as marginal operating costs when the load on a line or corridor exceeds a specified level. Such a price would jump from a low to a high level at predetermined loadings. Another type of administrative rule could be fashioned that would add capacity costs more smoothly. An example might be to add 0 to 100 percent of capacity costs as line load factor increases from, say, 70 to 90 percent. Whatever the administrative rule, it would only approximate the congestion charge component of short-run marginal cost, which raises the price to the level needed to reduce demand temporarily back down to capacity in a network that has the long-run, optimal amount of transmission capacity.

The three alternatives proposed here, responsive pricing, auctions, and administrative capital cost recovery rules, approximate opportunity costs (or congestion charges) with varying degrees of accuracy, but all can correctly convey price signals that promote efficient resource use and good decision-making by users. In that sense, all three alternatives might have a niche in an overall transmission pricing policy. Responsive pricing might be appropriate and feasible for large IOUs. Auctions could be used for major corridors, and administrative rules could be incorporated into bulk power markets that are used too infrequently for an auction or are too small to implement responsive pricing. In any case, there are several practical ways of approximating the congestion charge component needed for transmission lines that are occasionally threatened with overload.

If prices are expressed in pre-set rates or tariffs, such prices must have a time-of-use dimension if they are to encourage good decision-making.

Prices that are the same during all hours of the year do not accomplish this, even if they happen to be calculated from some peak-responsibility method (such as the 12-coincident-peaks method) of cost allocation. That is, the use of peak allocation factors does very little to promote economic efficiency if the resulting prices themselves do not vary during the year. The three alternatives discussed in this section can be arranged so that prices during peak hours are higher than during off-peak hours, and as such they promote efficient resource use.

Capacity Measurement

The price for wheeling service must be expressed in terms of some sort of unit that measures transmission capacity. One possibility is the maximum MW loading (of a line or of a larger network of lines) carried during peak hours. Another is the rated capacity of a line or network. In the Texas experience, lines are typically loaded at perhaps 1/4 to 1/2 of their rated capacities.[3] Prices based on capacity are likely to be much smaller (1/4 to 1/2), then, than those based on maximum actual loadings.

It seems clear that a price to recover the capital costs of wheeling that mimics long-run marginal cost would be based on the rated capacity of a line or network. A price based, instead, on maximum loading has the characteristics of an average cost price (as opposed to a marginal cost price) because it declines as the system peak load (that is, maximum demand) increases. In addition, the congestion component of short-run marginal cost is based on rated capacity, not peak load. The concept of a congestion charge, which theoretically is the best way of recovering capital cost, is based on the opportunity cost of capacity needed to satisfy an increment of demand when load is at rated capacity.

The Texas Commission defines line capacity as 80 percent of the thermal rating of the line at 75°C conductor temperature, 25°C air temperature, 1.4 mph wind speed, for transmission lines with emissivity of 0.5 and nominal

[3] Sam F. Skinner, Transmission Systems Marketing Impediments to Expansion (Austin, TX: Public Utility Commission of Texas, October, 1985), presentation to Third NARUC Electric Research and Development Seminar, Chicaco, IL. See also Public Utility Commission of Texas, Section 23.67, Substantive Rules, December 1984 Edition, Revised 12-84.

voltage at least 60 kV when measured phase to phase.[4] Such a definition has a 20 percent built-in reserve factor to ensure reliability. In most instances this margin (or some similar fraction) should be adequate. Particular lines, however, may have been built for more complicated reasons. A line might serve a reliability purpose, providing access to backup generating capacity; that is, a utility might build a transmission line to a neighboring utility instead of building a peaking plant for the purposes of generation reliability. If so, the line would appear to have substantial unused capacity most of the time if capacity were measured as 80 percent of thermal rating. Such a line, in actuality, would have substantially less than 80 percent capacity for carrying firm loads such as occur in most wheeling arrangements because more than 20 percent is needed in reserve for generation reliability purposes. In such a case, it may be appropriate to identify such lines and determine their capabilities separately.

The discussion in chapter 3 makes clear that the power-carrying capability of a line may depend on factors other than the thermal rating standard used by the Texas Commission. For lines longer than 50 miles, for example, the voltage drop caused by reactance along a line limits the power that can be transmitted. Assessing capability can be quite involved; however, engineering studies can make these determinations in practice.

Apart from determining a line's capability, commissions also may need to determine its actual use during a proposed wheeling transaction. To do this requires the use of load flow analyses, as discussed previously. Disputes among customers as to whether or not adequate capacity is available for a transaction could be addressed in the context of a specific load flow model that the FERC or a state commission has decided is appropriate for such purposes. Similarly, a commission could issue guidelines regarding the appropriate structure of congestion charges, auctions, or administrative peak-pricing rules, and periodically review whether its guidelines are being followed. This would provide protection to wheeling customers from a utility abusing its monopoly position.

[4] See Skinner, Transmission Systems, appendix VI.

Long-Run Marginal Cost

Long-run marginal cost includes the capital costs associated with increasing the capacity of a transmission line. Enhancing the capacity of a particular portion of a network might require a new line, a second circuit on an existing set of poles or towers, or the addition of reactive power compensation equipment. The marginal capital cost is the cost increment divided by the capacity increment. The capacity increment was just discussed, and the cost increment, as set out in chapters 4 and 5, may depend on the length of the line segments used, the difficulty of the terrain, regulatory siting requirements, and so on. The data provided in part II of this report may be useful for estimating the marginal capital cost associated with a particular wheeling transaction, and the data base being assembled by EIA (as mentioned at the end of chapter 4) will, when completed in a few years, make it possible to do detailed analyses of incremental transmission costs and the associated additional system transfer capability developed. The marginal capital cost must be converted to an annual or monthly capital charge per megawatt or per megawatt-hour, in the usual manner familiar to retail ratemakers.

The purpose of an efficient price is to signal to a user the current resource cost consequences of his actions. Current, and not embedded costs, improve efficiency in this sense. A few, unrepresentative lines needing additional capacity may not reflect current costs, however. The capital costs along all routes where the energy flows would be a more appropriate measure. Ideally, prospective costs are best. In practice, these may be difficult to verify because the utility may have no investment plans in some parts of the network and would have to submit either tentative current cost estimates or historical costs. Handy-Whitman construction cost indices could be used to find current costs for each transmission project vintage, although we do not necessarily recommend this.

As described in chapter 7, the notion of long-run marginal cost of a transmission network involves a long-run equilibrium in which transmission capacity is optimally sized with respect to expected peak load. Marginal generation and transmission costs are equalized in some long-run sense in such an equilibrium. This means that an appropriate concept of long-run marginal cost involves the capital costs along each segment of the transportation route, and not merely those that are used to capacity in the current, perhaps nonoptimal, configuration of the network. Because the energy flow is fractured among many parallel paths, the transportation route could be quite complex. The marginal capital cost of each line segment would be weighted by the fraction of incremental power flowing along it. The calculations required to estimate long-run marginal cost of transmission are conceptually similar to those developed by the MIT researchers regarding short-run marginal costs. The use of tie line coefficients, in particular, correctly accounts for the multiplicity of paths chosen by the power. For long-run marginal cost calculations, peak-load tie-line coefficients could be used along with marginal capital cost estimates for the various routes.

In practice, wheeling rates based on long-run marginal costs could be aggregated and simplified for administrative purposes. Some of the dimensions for doing so are discussed in the next section. Importantly, substantial progress toward a goal of promoting good, long-run decisions would be made if the price of long-term, firm wheeling service were based on current costs and the peak power-carrying capability of transmission lines. Such a price would have a time-of-use dimension. In itself, this is the major improvement over time-averaged, embedded cost rates. Other refinements, discussed next, though significant, are minor by comparison.

Administration and Transaction Costs

The complexity of the enormous, interconnected transmission grids can result in some administrative complexity when trying to implement good pricing policy. Responsive, short-term pricing requires sophisticated software to calculate the prices, keep track of parallel flows, and account for the payments made to a large number of utilities. Less complex pricing mechanisms (peak and off-peak prices in pre-set periods, for example) would require use of large-scale load flow analyses. The conduct of auctions could be quite complicated depending on their frequency and the possible need for users to successfully piece together a contract path by bidding in multiple auctions because the path crosses several utility systems. In considering the appropriate degree of complexity to inject into the rate-setting process, regulators need to weigh the benefits of more accurate price signals and better decisions against the administrative expense of achieving them. If the transaction costs are greater, the more complex pricing mechanisms are not justified. This may be a difficult determination for regulators to make in practice, but it deserves some serious consideration in designing wheeling rates that may require measurements beyond those currently common in the industry.

An administrative simplification might be achieved by designating a principal or lead utility, most likely located on the contract path. This company could be given the responsibility of preparing load flow studies, arranging the transaction, collecting wheeling fees and then dispersing these to other utilities affected by parallel flows. Alternatively, the buyer or seller could play this role. It should be relatively easy to administer the collection of the capital cost component of the wheeling tariff. If this is a fixed portion of the wheeling customer's bill, the customer simply pays each utility on the contract path and each utility significantly affected by parallel flows according to a prearranged payment schedule. If the capital cost is collected through a demand charge, the wheeling customer's own maximum demand can be metered across specific tie lines, most likely on the contract path. Some parallel flows may be difficult to verify by direct metering if such secondary flows cannot be separated from other flows in the network due to coordination sales or other long distance energy movements. In such a case, it may be possible to devise a method that relies on the metering over a few specified tie lines and from these measurements then infer the remaining flows based on load flow studies. The capital cost portion of the bill is paid in accordance with the partly measured and partly inferred maximum MW load.

Certain types of wheeling transactions may be too small to justify the transaction costs of accounting and scheduling. An administrative rule to limit the size of wheeling deals priced in this way to those above a specified minimum is sensible on these grounds. Selecting the particular minimum is a matter for regulatory judgment. The Texas Commission requires a transaction to be at least 25 MW to qualify for mandatory wheeling, as an example.[5]

---

[5] See Skinner, Transmission Systems, appendix VI. The Texas rule mandates wheeling for PURPA Title II qualifying facilities.

Administrative complexity, in our view, does not prevent the adoption of a wheeling pricing policy designed to promote good decision-making. Such transactions costs could influence the details of the rate design, but do not constitute a reason for basing prices on embedded rather than current costs. It is possible to design relatively simple rates or tariffs from marginal cost principles that would not be administratively onerous. In the following section, several kinds of simplifications are discussed.

Designing Pre-set Rates

The discussion so far has made clear that the cost consequences of a wheeling transaction are complex in that the costs can be spread widely over a geographic area, not just along the contract path. Having dozens of transmission lines across the territories of several utilities makes the real-time computation of marginal transportation cost more difficult for wheeling than, say, for trucking. Large scale, real-time algorithms to find responsive pricing can handle the numerical complexity, but the administrative expense may not be justified in some cases.

Pre-set wheeling rates or tariffs can promote good decision-making too, although not as well as responsive pricing. Some ways of fashioning pre-set rates are discussed in this section. It should be pointed out that any averaging or other simplification for the purpose of deriving pre-set rates involves some loss of economic efficiency. In principle, it is possible to measure, or at least imperfectly estimate, the efficiency loss. Against this, regulators should weigh the gains in terms of administrative cost reduction. Rate design for wheeling services must involve a balancing of the efficiency benefits with costs of administering and overseeing more complicated rate structures.

Time-of-Use Wheeling Rates

In the absence of a real-time wheeling price system, prices can be set for short time periods and published in advance. These can be found using load flow analysis. Such pre-set prices could be based on averages of the spot prices that are estimated to prevail during the hours assigned to each pricing period. If spot prices are not available, efficient prices could be based upon the approximation that marginal running costs are mostly marginal line losses, which are about twice the average loss on any line in percentage terms. The aggregate line loss across a utility network is the algebraic addition (that is, losses associated with negative flows are subtracted) of those on each line, an exercise that can be conducted with load flow programs for several representative times of the year. The marginal line loss for any utility affected by the wheeling transaction is roughly twice the aggregate losses across a utility's lines. The efficient price for any period would be about twice the average line loss times the estimated system lambda for that period.

Long-term wheeling rates could have a similar time-of-use dimension. During the peak hours, the expected marginal capital cost and marginal operating cost can be found for a transmission network in which a long-term balance has been struck between the use of capital, the need to protect reliability, and the minimization of wheeling operating costs. Such a balance or long-run equalization of marginal costs across the grid is discussed in chapter 7. The off-peak price would consist primarily of expected marginal line losses during periods when load is expected to be lower than capacity. The pricing structure would have a time-of-use variation that corresponds to the variation of costs.

A difficulty encountered in long-distance transmission service may be that the peak periods may be different among utilities. Since a wheeling transaction may require facilities of several utilities, the wheeling price in any period aggregated over all lines may involve the averaging of an off-peak price of one utility with the peak price of another. This is mostly a curiosity, however, and poses no conceptual or practical difficulties. The appropriate price is a weighted average of the prices along each line segment. As long as the rate for each line is based on its own time-profile of loading, the subsequent averaging among several lines is appropriate. No additional computational problems should be encountered since there is a need to average the prices along parallel-flow links in any case.

The conclusion is that both interruptible and firm wheeling rates could be established that have a pre-set, time-of-use dimension. In addition, time-differentiated rates are an important ingredient in a policy to promote good decision-making in the absence of real-time pricing.

Incorporating Distance and Counterflow into Wheeling Rates

The cost of most transmission facilities increases directly with the distance involved. The investment cost of rights-of-way, towers, poles, conductors, and even the labor cost of maintaining a right-of-way all increase more-or-less proportionally with distance. There are some economies, such as engineering design costs, so that costs may increase somewhat less than proportionally, as suggested by the results in chapter 5. However, distance is clearly an important factor in transmission cost. This suggests that efficient wheeling prices would be based on mileage.

An alternative view is that the transmission network is a unified, integrated system that is operated in such a way so that particular paths and distances cannot be distinguished. Also, the flow along any portion of the network can change frequently as load rises and falls, and can change substantially as new generating units, loads, and lines are added to the system. This dynamic, unified concept of the network should be incorporated into any efficient rate design from this perspective.

There is no necessary conflict between these two views. Load flow studies can be made before and after a proposed wheeling transaction to determine line-by-line flow changes and thus determine the effect on each line in the integrated network. Such before-and-after studies can be conducted under several load scenarios to estimate the range (or variance) of possible line loadings as the load splits along the various network paths. The findings of such an incremental load flow analysis are easily combined with the mileage of each line to determine the product of incremental load and distance (megawatt-miles) for each flow path. Mileage-based prices, then, can be compatible with the integrated nature of the network.

The extent to which particular radial lines experience load changes during wheeling can be discovered or confirmed with load flow studies. A radial line is one not backed up by other network lines, such as a line used to transport mine-mouth generation to a substation connecting it to the main transmission network. A radial line also may serve isolated loads. Such lines probably would not be used as part of the wheeling transaction, a fact that load studies could confirm.

Note that the cost of such radial lines is of no consequence to wheeling rates if marginal cost pricing is in effect. The capacity of such lines would need no enhancement as a result of a wheeling transaction. The marginal capacity enhancement would be needed elsewhere in the main transmission network. An average embedded cost wheeling price, however, is affected by the cost of radial lines. If possible, the cost of such lines should be excluded from the calculation of wheeling prices if the lines clearly are not used.

A separate issue is how to treat wheeling that results in an incremental energy flow counter to the direction of the prevailing energy flow. In the Texas deliberations (see footnote 3), customers argued that negative loading reduces the need for facilities and therefore should result in a negative payment. The utilities argued that the power moved over the facilities regardless of its direction and therefore the utility should be compensated.

The short-run marginal cost concept provides a guideline to how efficient prices are fashioned in these circumstances. If short-run marginal costs could be charged, with its two major components--marginal line losses and a congestion charge, the marginal line loss costs associated with the unloading of a line are indeed negative. A variable pricing formula based on marginal line losses would indicate that the utility ought to pay the customer because total losses on the line are reduced by the wheeling transaction. As mentioned in chapter 7, the utility enjoys a total, positive surplus in such circumstances because the savings in aggregate losses outweigh the negative payment for marginal losses. The utility consequently does not lose if it pays the customer for the loss reduction. The first component, then, of the short-run marginal cost formula can result in negative payments at the margin but the utility benefits nonetheless.

The congestion charge component of the short-run marginal cost formula suggests the proper way to deal with the capital costs of negative line flow. Although it is true that a congestion charge is positive when capacity is short, and is zero otherwise, there is no implication that counterflow be priced at zero. Consider a situation where capacity is fully used, with customers wanting more than 100 percent of rated capacity so that some rationing is required. If a particular transaction causes an incremental reduction in such a line's loading because it runs counter to the predominate direction of energy flow, less rationing would be needed. Consequently, efficient pricing would encourage the counterflow transaction and discourage the larger set of positive flow transactions. The conclusion is that at the time of a capacity shortage, negative flows would be priced negatively.

An alternative way of grasping this principle is to argue by analogy that counterflow is conceptually the same as added capacity. In this sense, it is similar to the economic concept of supply, as opposed to demand. A sensible pricing policy for supply is one that encourages more supply at higher prices, in this case the supply of counterflow energy. If a positive price were charged for counterflow, larger prices would discourage it. On the other hand, if a negative price is used for counterflow, then the higher the positive price for flow in the prevailing direction, the higher the negative price for counterflow. This tends to encourage counterflow, as such supply should be encouraged. Hence, an efficient pricing policy would be for the utility to pay the prevailing congestion charge to customers whose actions reduce the load on a transmission line otherwise used to capacity.

The theory is clear--negative congestion charges are a part of an efficient wheeling pricing policy. The preceding argument is applicable for short-run conditions when capacity is actually rationed. Such a negative congestion price would prevail only occasionally, when capacity is short, and would not be continually applied.

In practice, designing rates to account for both distance and counterflow can be done in a variety of ways. Some of the ways are illustrated next in an extended example. Table 9-1 shows some hypothetical distributions of power among three parallel lines that wheel 10 MW a distance of 100 miles. The total load on lines and their direction of flow during the peak periods of a wheeling operation depend on the configuration of other loads and the pattern of generating units in use during these peak periods (reflecting in part the random nature of demand). In part I of the table, the loading on each line multiplied by the line's length is shown for four load configurations. For example, in configuration A the product of the incremental load and the distance it travels is 800 MW-miles for line 1, 100 MW-miles for line 2, and 100 MW-miles for line 3. In configurations B

TABLE 9-1

EXAMPLES OF WHEELING CHARGES FOR INCREMENTAL LOADS AND DISTANCES (MW-MILES) ALONG THREE PARALLEL LINES UNDER FOUR LOAD CONFIGURATIONS, INCLUDING COUNTERFLOW

Line	1	2	3	
Cost per MW-mile per month	$6	$5	$7	
I. Load Configuration	Number of MW-Miles and Monthly Cost			
A	800	100	100	
	$4800	$500	$700	
B	700	-100	200	
	$4200	-$500	$1400	
C	800	0	200	
	$4800	$ 0	$1400	
D	700	-200	100	
	$4200	-$1000	$700	
II. Billing Method	Billing Determinants and Monthly Bill			Total Bill
Average MW-Miles:	750	-50	150	
Bill:	$4500	-$250	$1050	$5300
Average of Positive MW-Miles:	750	25	150	
Bill:	$4500	$125	$1050	$5675
Average of Absolute MW-Miles:	750	100	150	
Bill:	$4500	$500	$1050	$6050
Maximum MW-Miles:	800	100	200	
Bill:	$4800	$500	$1400	$6700

and D, the power wheeled on line 2 flows counter to native load; this is expressed as a negative entry for the number of MW-miles. Immediately below each number of MW-miles is the monthly cost of the incremental load on the line, which is the product of the MW-miles and the monthly cost per MW-mile for the use of each line, given at the top of the table. Negative MW-miles appear as negative costs, or cost savings. These are the wheeling costs for one configuration of native loads; other configurations are possible.

Suppose the four configurations in the table are equally likely and we want to determine pre-set wheeling rates that take these into account. Four ways of doing this are considered, resulting in four possible billing determinants, as shown in part II of the table. These are the simple average of incremental MW-miles, the average of positive incremental MW-miles, the average of the absolute incremental MW-miles, and the maximum MW-miles. A case can be made for each of the four methods depending on circumstances.

The average MW-miles method is to take the average of the four MW-miles for each line given in part I to get a number of MW-miles to use for billing purposes. If the configurations were not equally likely, a weighted average should be used, but this situation is avoided here to keep the example simple. On line 1, the average number of MW-miles is 750, and the monthly bill for use of this line is \$4500 per month (750 MW-miles x \$6 per MW-mile per month). Because the incremental load on the second line is sometimes negative, the average MW-miles is a negative 50 MW-miles, meaning that unloading the line is the most common occurrence. If the average MW-mile measure is used, the utility that owns line 2 would pay the wheeling customer \$250 per month. Such a payment might be justifiable if all four load configurations occur when capacity is actually short and if these four situations are the only likely ones to occur in the future. The total monthly payment for wheeling over all three lines is \$5800.

An alternative billing determinant is the average of only the positive MW-miles. This causes no change in the bills for lines with no counterflow, but this method would require a positive payment from the wheeling customer to the owner of line 2 of \$125 per month. The Texas Commission uses essentially this method to determine payments made to utilities that are not on the contract path, that is, for determining payments for utilities that carry loop flows. The Commission justified its selection of this method, in part, as a compromise between the average method just described and the following method, advocated by wheeling utilities.

A third possibility is to base the customer's bill on the average of the absolute values of the MW-miles on each line. Again, this has no effect on the bills for lines with no counterflow. The resulting MW-miles used for billing purposes under this method are always the same as or higher than those found using either of the preceding methods. The reason for considering this method is that power flowing along a line is using the facilities whether it is with or against the prevailing flow. If the incremental power flows more or less on a direct route, the absolute MW-mile measure is likely to be approximately equal to size of the transaction in MWs multiplied by the distance between the supplier and customer along the route, assuming that some existing lines directly connect them. (The most direct route will be longer than the airline distance because of mountains or other terrain features.) The number of direct MW-miles involved is an indication of the smallest increment to existing facilities that could be newly constructed to accommodate the transaction. The number of absolute MW-miles is larger than the number of direct MW-miles if the power flows widely in the network thus creating parallel flows, or if the buyer and seller are not directly connected in the existing network (which seems unlikely in most parts of the U.S.). In this sense, the number of direct MW-miles multiplied by the cost per MW-mile is a crude indication of the cost of building new facilities as an alternative to using the existing network. The possibility of reverse flows affects the first two MW-mile measures discussed, either of which could be substantially less than the absolute MW-miles. Indeed, in the extreme, the entire wheeling transaction could run counter to the prevailing direction of flow, resulting in negative MW-miles using the average method, or in zero MW-miles according to the positive-only method. The absolute MW-mile method would show the number of MW-miles of newly constructed facilities needed to carry on the transaction, in such circumstances.

A fourth possible billing determinant is the maximum incremental load imposed by the wheeling transaction under any of the four possible configurations. This generally (but not necessarily) would result in the highest payment of the four methods. The aggregate payment is $6700 under this method in table 9-1, compared to $5675 for the positive-only method and

$5300 for the average-load method. The rationale for this method is that the wheeling customer needs to reserve enough capacity on each line so that power can be transmitted under any of the likely circumstances. The circumstance that loads line 1 most heavily is not necessarily the same as the one that loads line 2 most heavily. Having enough capacity on all lines would require reserving capacity for the maximum incremental load on each.

In the context of responsive pricing, the analog to what is called the average MW-mile method in table 9-1 would be the economically efficient pricing scheme because each load configuration would be evaluated and priced in real time. When prices must be set beforehand, however, none of the four methods has such a clear advantage over the others. Because all of the methods are used to calculate pre-set rates, all implicitly correspond to a particular notion of reliability. The highest reliability standard is incorporated into the maximum MW-mile method. If a long-term wheeling arrangement is intended to be very firm with little or no chance of interruption, the maximum MW-mile method yields a price that is similar to one that would be needed to partially own or permanently reserve capacity on a transmission link. The average MW-method, on the other hand, corresponds to a more conventional standard of reliability, which is the average of the loads that can be expected during ordinary peak periods. As the system and its loadings evolve over time, the average peak loading would change, as would a wheeling price based on the average method. Utilities that are responsible for making negative payments in one year might receive them, instead, in another year if circumstances change negative flows into positive ones.

The positive-only MW-miles method, and the absolute MW-mile method can be thought of as intermediate approaches that might represent a good compromise in some cases. While either of these two intermediate methods may be useful as a practical compromise, it should be noted that the theoretical justification of both is somewhat weak if capacity is fully utilized. That is, the positive-only MW-mile method substitutes a zero for any negative MW-miles in a somewhat ad hoc fashion. Likewise, changing the sign of the negative numbers to be positive has a similar arbitrariness to it. If the flow is truly negative and could be expected to remain negative under any likely conditions, the simple average of the MW-miles arguably would promote economic efficiency the best of the four methods when transmission capacity is fully used.

If capacity is not fully utilized, the positive-only method is somewhat more justified since the short-run marginal cost formula suggests a zero capacity charge in times of excess capacity. Such an argument does not carry us far, however, since a short-run marginal cost pricing policy also would impose no capital charge on the positive MW-miles segments, if the capacity were underutilized.

In the final analysis, it should be recalled that the efficiency argument supporting a long-run marginal cost pricing policy for firm wheeling service is based upon the objective of minimizing the distortions to the customer's long-run electricity-using investment decisions. Sending him a correct price signal means to convey to him the resource cost of his action. Any of the four methods accomplishes this fundamental objective when the wheeling price must be pre-set for expected peak and off-peak periods. The simple average MW-mile method has the strongest theoretical foundation, in our opinion, but its advantage over the others is only modest.

The alternative to mileage-based wheeling rates would be a postage stamp tariff or zonal rates. A postage stamp rate is a fixed rate per kilowatt-hour for using a utility's transmission system. A postage stamp rate does not promote good decision-making by users, unless all wheeling must take place in the same direction and over the same distance so that distance is implicitly incorporated into the rate. Otherwise, such rates do not reflect cost differences by time-of-use or distance, both of which affect costs importantly. A simplification of mileage rates would be to establish rate zones, such as a price per kWh for each 50 miles of wheeling. Alternatively, geographical zones could be set up with prices for each zone that reflect zonal costs. In some heavily used and densely built Eastern corridors, for example, the distance that a MW could be transmitted for one mill may be short compared to that along some high-voltage routes in the West. Such zonal rates could differ by time-of-use. A simplification such as rate zones based on incremental cost principles could be a useful way of reducing the administrative and transactions costs of ratemaking without sacrificing much of the good signal aspects of rates that encourage users to make good decisions. The Florida brokerage system uses zonal rates.

Transmission Corridors

A major complicating feature of many wheeling transactions is the multiplicity of lines that carry the power. As explained elsewhere in this report, efficient wheeling rates for groups of lines are weighted averages of the unit costs associated with each line. The weights are the fractions of power flowing over each line as determined by load flow studies, and the costs are long-run or short-run marginal costs, as appropriate. Because the prices are formed as weighted averages, it is possible to aggregate the appropriate costs in stages. This can be an advantage in developing rates for major transmission corridors.

The idea of a transmission corridor, as the term is used here, is a single group of lines connecting a power supplying area with a power-consuming area. These areas may consist, for example, of control areas, as illustrated in figure 9-1. It shows five control areas connected by transmission lines. Within a control area are many transmission lines, and between control areas are possibly many connecting lines, each shown for simplicity as a single line, or corridor, in the figure.

In circumstances where such corridors are important features of the grid, a wheeling rate could be developed for the corridor as a whole. For example, a rate could be developed for the corridor between C_1 and C_2 by performing a load flow study of the interconnected network of lines in and near that corridor. In this context, "near" means those lines close enough to be affected by the transaction. For a power flow from C_2 to C_1, the corridors linking C_2 to C_4 and C_5 could be excluded, although those connecting to C_3 would need to be included. Similarly, a wheeling price could be developed for C_1-to-C_3 and C_3-to-C_2 transfers. The corridors from C_2 to C_4 and also from C_4 to C_5 are isolated, and hence a load flow study of either could neglect the remaining portions of the grid and concentrate on sorting out the flows along the many lines in each corridor, shown in the diagram as a single connecting line. In this way, wheeling prices can be developed for power transfers between major connected control areas using load flow programs developed for these particular regions smaller than the entire grid. With prices established for each major corridor, a wheeling

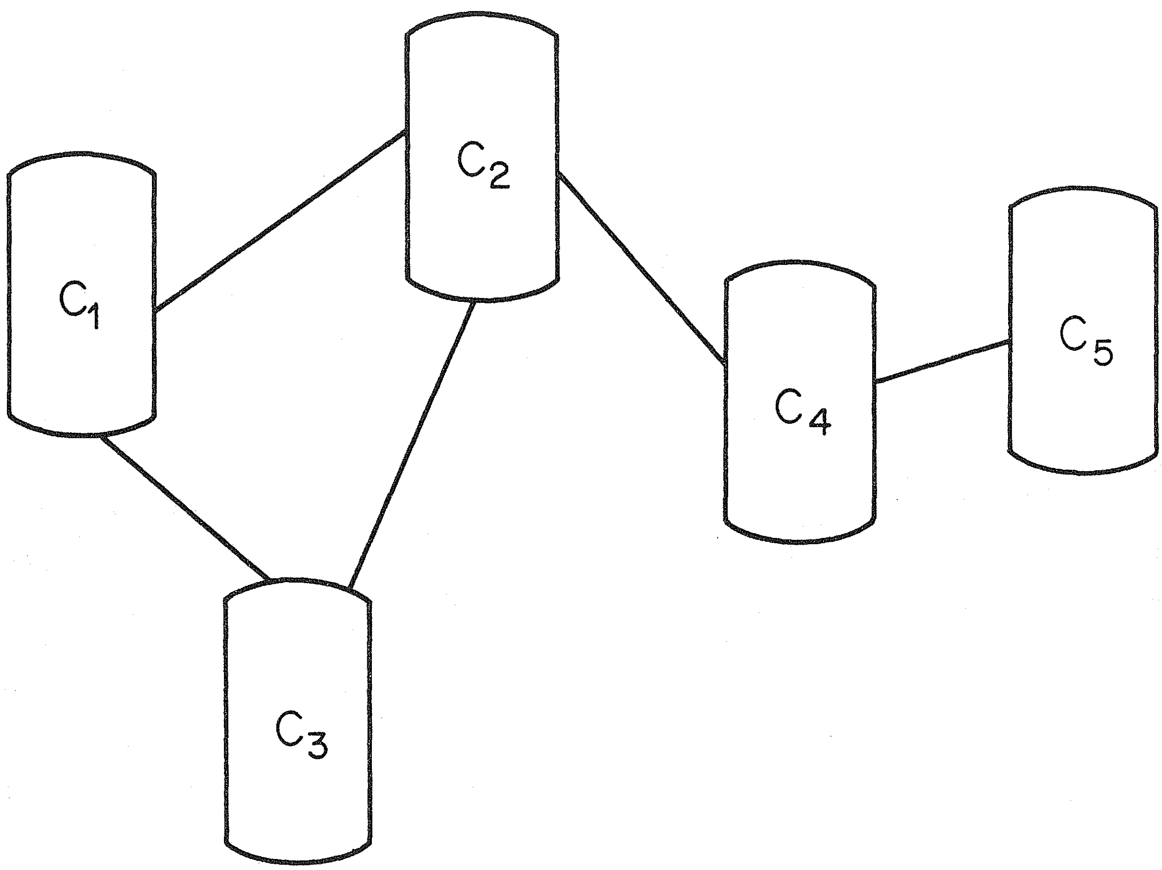


Fig. 9-1 Transmission corridors between control centers

price for a transaction between C_5 and C_1 is the algebraic sum of the prices along each corridor. Between C_2 and C_1 it would be necessary to know the fraction of the power moving directly from C_2 to C_1, and that moving towards C_3 and then on to C_1.

The load flow program used to formulate wheeling rates may not need to encompass the entire network connecting a buyer and seller if the results of load flow studies for intermediate segments of the network are available. The programs used by the reliability councils could be linked, perhaps, using this principle. This would avoid the expense of developing and running load flow programs for the entire, interconnected Eastern region of the U.S., for example.

Once a price for the use of a corridor has been established, wheeling revenues could be divided among the owners of the lines within the corridor according to some standard formula. The formula should be based on an analysis of flows within the corridor and updated periodically, as needed, to capture major changes in corridor flows. To best promote good decision-making, the entire exercise of formulating and dividing corridor rates would be based on time-of-use.

In practice, identifying major corridors and establishing rates for each would require careful study of current and projected power flows. Some transfers might be defined as traveling along a single corridor if the amount of power that flows along other paths is small enough to be ignored. As such small flows enlarge and are no longer minor, the idea that the transaction is confined to a corridor becomes less sensible, and larger load flow programs must be used. For many purposes, however, it should be possible to identify corridors and so simplify the ratemaking process.

CHAPTER 10

SUMMARY AND COMMENT

The wheeling of electricity by a utility located between a buyer and a seller is one of many kinds of transactions that enable the trading of bulk power among investor-owned utilities (IOUs), municipal and cooperative utilities, and other power authorities. The three high-voltage transmission networks in the United States provide the connections needed to transfer the power. The interties among utilities help to improve overall reliability and also create the opportunity to supply the nation's demand for electricity with the most efficient and least costly sources of generation, provided the interties are strong enough. Production efficiency, that is, supplying a given level of demand at least cost, is characterized by an equalization of marginal costs, including generation and transmission costs, throughout each network. Economically efficient prices encourage decisions by utilities that promote the equalization. In this report, marginal cost equalization across the grid is the standard under which pricing policy for wheeling is evaluated. The evaluation of each pricing policy discussed in this report is based upon whether it leads to good decisions in this sense.

Two concepts of marginal cost equalization are presented in this report. The first is short-run marginal cost equalization which requires that generation levels be adjusted among utilities so as to equalize system lambda plus marginal line losses (plus congestion costs if any generation or transmission constraints are encountered). In effect, all generating units in the network are economically dispatched and system fuel costs are minimized in serving the current network load. The concept is an old one, but its implications for wheeling prices have been developed only recently by Schweppe, Bohn, and Caramanis. The second concept of production efficiency is long-run marginal cost equalization. This is an equilibrium in which generation and transmission capacity are adjusted among utilities so as to minimize total incremental electricity production costs throughout a network as network load grows. These costs include incremental capital costs plus marginal running costs (fuel cost and line losses). Such an equilibrium requires that transmission capacity be optimally and fully utilized at planned peak-load levels. Wheeling prices encourage good bulk power supply decisions on the part of utilities if the resulting adjustments in generation levels and also in generation and transmission investment plans lead toward both kinds of marginal cost equalization.

It is not our purpose in this report to evaluate whether the current levels of transmission capacity within and among the U.S. networks are optimal. We do not know, for example, whether strengthening ties across the Rocky Mountains to integrate the western and eastern synchronous areas is a good idea, whether incremental benefits are as large as incremental costs. Our purpose is to design wheeling prices that would not be an obstacle to such construction when the benefits are larger and that would not promote it when the costs are larger.

Wheeling prices that encourage good decisions of this sort can promote marginal cost equalization, but cannot accomplish it if obstacles other than poor pricing intrude. An important obstacle is the wheeling revenue requirement, which tends to result in wheeling prices based on embedded average costs. Embedded cost pricing does not encourage, except by accident, bulk power supply decisions that fully reduce marginal cost differentials among utilities and thereby minimize the aggregate cost of electricity supply. Ideally, from the viewpoint of good decision-making the preferred policy would be to have no revenue requirement for wheeling service. Any such policy should be explicit about how to calculate prices in the future if marginal costs are lower than average embedded costs. If marginal cost pricing should fail to cover costs, the policy may need to be adjusted to meet the revenue requirement. Other obstacles include the existence of low-priced preference power and the pattern of rules governing access to the transmission system by requirements customers, cogenerators, and some large industrial customers. Some utilities are reluctant to give up their participation in simultaneous buy-sell transactions in order to substitute wheeling transactions that may be financially less lucrative.

There are also technical questions as to how best to protect the reliability of the system if long-distance power transfers become more important.

In the context of all of these obstacles, this report suggests some policy guidelines that would improve the tendency of wheeling prices to encourage good decisions. No simple pricing rule or formula will suffice under changing laws, regulations, and conditions of competition in the industry. Differing circumstances require different approaches. In particular, designing a single price to promote both short-run and long-run marginal cost equalization is difficult. All avenues that promote economically efficient use of the network, however, are based upon incremental pricing principles.

The method developed at MIT provides the best way of equalizing short-run marginal costs by calculating responsive wheeling prices, updated hourly or perhaps every five minutes. Computer technology now may be close to a point where such an elaborate system might be practical for use by large IOUs as a way to price interchange power that requires wheeling. Such pricing automatically has a time-of-use dimension. In the absence of responsive pricing, a frequent auction of transmission capacity can provide market-based signals about the appropriate size of congestion charges, and hence can also help to equalize short-run costs.

Long-run marginal cost equalization can be facilitated by long-term firm contracts for wheeling services priced at long-run marginal costs. These costs include the incremental costs of transmission capacity, as well as marginal line losses. A time-of-use rate structure is preferred for pre-set firm contract rates in order to place most of the capacity cost recovery on peak prices. Fuel cost savings with reduced line losses are a part of the capital cost calculation. Such pricing of firm power wheeling would promote an equalization of long-run incremental costs across the network and would promote electricity service at the least aggregate cost in the long term.

To encourage both short-run and long-run cost equalization, it is best to divide all wheeling services into interruptible and firm categories. Interruptible wheeling would be priced at short-run marginal cost, firm wheeling at long-run marginal cost, and the customer would have the option of selecting the service category. The interruptible price could be set by responsive pricing, by an auction, or in pre-set rates and tariffs. The best pricing structure for each category would have a time-of-use dimension if pre-set rates or tariffs are used. In the case of interruptible wheeling, short-run marginal cost (averaged over a few representative times of the year so that pre-set prices vary by time of use) is a pricing standard that would encourage efficient trading and would tend to reduce unwanted differentials in marginal energy costs. In the absence of any transmission or generation constraints, such prices are mostly marginal line losses, which are higher during peak periods. Congestion charges are a part of short-run marginal cost pricing any time there is a transmission or generation capacity constraint. In the case of interruptible wheeling prices set in advance, congestion charges become part of peak-period prices and are not normally included in off-peak rates. Pre-set firm rates would be more efficient with a two-part structure, charging separately for transmission capacity reservation and energy transportation.

The wheeling of electricity involves loop flows that can be sorted out with load flow models. A wheeling price structure can be fashioned that accounts for such flows under all the pricing approaches just described--responsive, pre-set interruptible, and firm wheeling rates. The arithmetic is complicated and undoubtedly could be disputed in regulatory forums. The fact that reasonable people may choose different methods for estimating a complex phenomenon should not obscure the need to estimate it at all, however.

Pricing firm wheeling contracts at long-run incremental costs does not seriously disturb the equalization of the short-run incremental costs with nonfirm service, provided the transmission network is sized more or less appropriately. If large amounts of excess transmission capacity are available year after year, however, for reasons unrelated to cost minimization, the time-average of short-run marginal costs may be substantially less than the time-average of long-run incremental costs. Firm customers would pay substantially more than would be justified by the quality-of-service differences, in relation to interruptible users. Said differently, interruptible users would be interrupted seldom, if ever, in such circumstances and would receive about the same quality of service as firm users for a lower price. To avoid this, firm users can always exercise the option to participate instead in the interruptible wheeling market, but there may be high transaction costs to this option for some firm customers.

Another danger is that wheeling utilities could unduly restrict capacity to sustain a price in the interruptible market at a level above the cost of capacity expansion, and so earn monopoly profits. In this case, all wheeling customers would seek firm contracts at the fixed, long-run marginal cost price, in effect paying for capacity expansion that might never occur. Competition among customers would likely take the form of bidding in terms of contract duration in this case. These concerns suggest that, even with efficient pricing, strong regulatory oversight of transmission investment programs is required.

These observations conclude the summary of our pricing policy conclusions, and a few comments--not central to our theme--about pricing policy consequences and implementation may be appropriate. An institutional difficulty is that wheeling pricing policy is established at the FERC, while state authorities certify transmission facilities. The interrelation, just described, between appropriate pricing and optimal investment creates a need for more federal-state cooperation. This need will increase as developments in transmission technology, perhaps including the use of superconductors to reduce line losses dramatically, continue to lower the cost of long-distance power transfers, thereby making interregional coordination of generation and its dispatch economical over a greater range. Perhaps such cooperation could occur through a joint board of federal and state regulators.

If wheeling prices are effective in minimizing bulk power supply costs, generating units may be far from the load centers they supply. The situation would be quite different from the typical current arrangement of local generating stations serving local loads within a franchise area. In many cases, the least cost approach would be to construct out-of-state generation to meet in-state needs.

From the perspective of state regulators, jurisdictional utilities could come to rely increasingly on nonjurisdictional sources of supply, probably through long-term bulk power supply contracts. The ultimate impact on state regulation of electric utilities is unclear. Already, there are difficulties with holding companies that form least-cost generation and transmission capacity expansion plans outside the purview of any one state regulatory commission. Such difficulties can be expected to multiply if efficient wheeling prices are effective in minimizing interregional network costs. There is no technical or economic reason why state political boundaries should form the natural boundaries of cost-minimizing power pools, brokerage systems, or other associations of trading partners.

These concerns suggest that greater interstate cooperation in electric utility regulation is needed if federal pre-emption of some state regulatory functions is to be avoided. Also, as mentioned, a stronger federal-state alliance seems appropriate today in any case.

If efficient pricing for wheeling is to be implemented by the FERC, there are several approaches for implementing a new pricing system, depending in part on whether wheeling is to be voluntary or mandatory. It is interesting to note that in the natural gas industry, through Order 436, the FERC was able to offer natural gas pipelines expedited certification of pipeline facilities in exchange for their agreement to transport gas for others on a nondiscriminatory basis. The FERC is not able to fashion a similar program in the electricity industry because the states, and not the FERC, certify transmission lines.[1] Although the particular source of the incentive in Order 436 is unavailable in electricity regulation, another might be substituted. The key idea behind Order 436 is to exchange some policy of value to a regulated utility for a policy of nondiscriminatory access. In the case of electricity, the valuable policy could be some variation of marginal cost pricing. The suggestion is to institute some form of marginal cost pricing in exchange for an agreement to provide nondiscriminatory transmission service. Each utility could be given an option of either (a) becoming a nondiscriminatory provider of transportation service and having its jurisdictional transportation rates based upon a marginal cost policy (which could take any number of forms), or (b) remaining a voluntary provider of transmission services to others and having its transportation rates based on embedded costs.

A major difficulty with this proposal is that power flows can be widely dispersed across the high-voltage network. If some utilities were to provide nondiscriminatory access and others opted for the status quo, the FERC would have to deal with unintended parallel flows along the lines of

---

[1] For a more thorough discussion of the differences in the FERC legal authority over the gas and electric industries, see Robert E. Burns, "'Access to the Bottleneck': Legal Issues Regarding Electric Transmission and Natural Gas Transportation," in Natural Gas Restructuring Issues, ed. J. Stephen Henderson (Columbus, OH: NRRI, 1986), pp. 37-61.

nonparticipating utilities. A possible approach to the problem would be to allow only transactions for which a contract path can be established with small loop flow effects imposed on nonparticipating companies. The definition of "small" would require careful consideration. (A possible approach to determining such allowable loop flows is to examine the size of the loop flows that accompany some present voluntary wheeling arrangements, which may be presumed not to be unduly burdensome since the utilities voluntarily allow them.) In any event, a utility would always be compensated for substantial loop flows over its transmission lines. As an added incentive to adopt the nondiscriminatory access option, the FERC might wish to set the compensation for loop flows at embedded cost for voluntary providers of wheeling services and at marginal cost for those that accept the open access option.

This suggestion might be combined with a policy suggested by National Economic Research Associates in its comments on Phase II of the FERC electric transmission inquiry. As described in chapter 8, this is to phase-in marginal cost pricing for generation over a period of years. The combined effect would be to move from embedded to marginal cost pricing for bulk power supply. If this suggestion were adopted, the FERC would want to develop an explicit plan for completing the transition in an announced time.

It is not the purpose of this report to develop the details of such a policy compromise. Indeed, the suggestion just outlined is not a recommendation of this report. We prefer marginal cost pricing for transmission even if open access is unavailable and would not want to see the proposed compromise result in a continuation of the status quo, voluntary wheeling at embedded cost prices. Its discussion here is intended to broaden the scope of the policy dialogue and is one of several ways that could lead to the implementation of the pricing policies presented in this report.

The issue addressed in this report is basically how to set wheeling prices that create incentives for the best use and development of the nation's electric bulk power supply resources. Whether good wheeling pricing in itself can accomplish this depends on the non-price impediments to power transfers that may exist, the subject of a forthcoming NRRI report. These impediments relate to other issues that are important and must be dealt with by policy makers. In all of these matters, the goal of good decision-making that equalizes marginal costs across the grid can be a constant guide to regulators in their deliberations about good pricing rules.

APPENDICES AND BIBLIOGRAPHY

APPENDIX A

GLOSSARY

This glossary of terms is intended to draw together in one place a nontechnical explanation of the technical terms in this report that relate to power transmission and wheeling. It is an extension of part of an earlier NRRI document, "An Information Package on Electric Power Transfers and Wheeling" (1984). Sources consulted in compiling this glossary include principally (1) the Glossary of Electrical Utility Terms, Financial and Technical, Edison Electric Institute, 1961 and (2) IEEE Standard Dictionary of Electrical and Electronics Terms, ANSI/IEEE Std 100-1984, Institute of Electrical and Electronics Engineers, Inc., 1984, as well as (3) other technical references in the bibliography.

While much of the glossary relies on the first two sources, many definitions and explanations are modified and simplified to make them clearer to a wide audience. Even so, the reader with little or no background in electric circuits or electric power transmission should not begin by studying this glossary, but by reading appendices B, C, and D and part I of this report. Afterwards, the glossary will be a handy, quick-reference reminder of terms learned.

Alternating Current - An electric current that reverses its direction of flow periodically. In the U.S. 60 cycles per second is the standard.

Ampere - The unit of measurement of electric current. It is proportional to the number of electrons flowing through a conductor past a given point in one second.

Apparent Power - The apparent power of a circuit or device, in volt-amperes, is the product of the current in amperes and the voltage in volts of the circuit or device. A practical unit is often the kilovolt-ampere (kVA), which is 1,000 volt-amperes.

Automatic Generation Control - The regulation of the power output of electric generators within a prescribed area in response to changes in system frequency, tie-line loading, or the relation of these to each other, so as to maintain the scheduled system frequency or the established interchange with other areas within predetermined limits or both.

Bundled Conductors - An assembly of two or more conductors used as a single conductor and employing spacers to maintain a predetermined configuration. They provide an economical way to mitigate corona problems and reduce line reactance.

Bus - An electrical conductor that serves as a common connection for two or more electrical circuits. A bus may be in the form of rigid bars, either circular or rectangular in cross section, or in the form of overhead cables held under tension. In particular, bus often refers to the connection between electric generators and transmission lines.

Capacitance - The property of a group of conductors and insulators to store an electric charge when a voltage is applied across the conductors.

Capacitive Reactance - A phenomenon associated with AC power in which variations in voltage fall behind variations in current, impeding power delivery.

Capacitor - A device that introduces capacitance in an electric circuit.

Circuit - A circuit is a conductor or a system of conductors forming a closed loop through which an electric current flows.

Circuit Breaker - A device designed to open and close a circuit, and to open the circuit automatically with a predetermined current overload.

Circuit-mile - The total length in miles of separate circuits regardless of the number of conductors used per circuit.

Compensation Equipment - A device that supplies or consumes reactive power. (See also "Power Factor Correction.")

Condenser - Another name for a capacitor, and therefore, a device that supplies reactive power to an AC circuit.

Conductor - A wire or combination of wires not insulated from one another that are suitable for carrying an electric current.

Connected Load - The sum of the maximum continuous power consumption ratings of the electric power consuming devices connected to a supplying system, or any part of the system under consideration.

Contract Path - The portion of a transmission network legally designated as the path along which wheeled power is intended to flow. The actual path of power flow can differ from the contract path.

Control Area - A part of a power system or a combination of systems to which a common generation control scheme is applied.

Control Center - A place where coordination, dispatching, and communication duties are performed generally for utility members of a control area.

Corona - A luminous discharge due to ionization of the air surrounding a conductor caused by a voltage difference between two nearby points in the air exceeding a critical value.

Coordination Service - Coordination service generally involves the sale, exchange, or transmission of electricity between two or more electric utilities that typically have sufficient generation and transmission capacity to supply their own load requirements under normal conditions.

Coordination Service Pricing - The typical price components of a bulk power coordination sale are an energy charge, a capacity, or reservation charge, and an adder. The price for a particular sale may embody some or all of these components. The energy charge is made on a per-kilowatt-hour basis and is intended to recover the seller's system incremental variable costs of making a sale. Since the nonfuel expenses are usually hard to quantify and small relative to fuel expense, energy charges quoted are usually based on fuel cost. A capacity charge is set at a certain level per kilowatt and is normally paid whether or not energy is taken by the buyer. An adder is added to the energy charge to recover the hard-to-quantify nonfuel variable costs. There are three types of adders: percentage, fixed, and split-savings. A percentage adder increases the energy charge by a certain percentage. A fixed adder adds a fixed amount per kilowatt-hour to the energy charge. Split-savings adders are used only in economy energy transactions. They split production cost savings between the seller and the buyer by adding one-half of the savings to the energy cost.

Direct Current - Electricity that flows continuously in one direction.

Disconnect Switch - A switching device for disconnecting circuit elements from a voltage source. They are often used in series with circuit breakers for disconnecting or connecting system equipment after current has been interrupted by circuit breakers.

Dispatching - The operating control of an integrated electric system involving operations such as (1) the assignment of load to specific generating stations and other sources of supply to effect the most economical supply as the total or the significant area loads rise or fall; (2) the control of operations and maintenance of high-voltage lines, substations, and equipment, including administration or safety procedures; (3) the operation of principal tie lines and switching; and (4) the scheduling of energy transactions with connecting electric utilities.

Distribution System - The portion of an electric power system that delivers energy from the bulk power supply system to ultimate customers.

Diversity Exchange - An exchange of capacity or energy, or both, between systems whose peak loads occur at different times.

Double-circuit Line - A transmission line having two separate circuits. Since each carries three-phase power, at least six conductors, three per circuit, are required.

Economy Energy - Energy produced and supplied from a more economical source in one system, substituted for that being produced or capable of being produced by a less economical source in another system.

Electric Current - The number of electrons per unit time moving past a point in a conductor.

Electric Energy - The ability of an electric current to produce work, heat, light, or other form of energy. It is measured in kilowatt-hours. (See also "Electric Power.")

Electric Power - The rate at which electric energy is generated, transmitted, or consumed. Electric power is measured in watts or kilowatts.

Energy Broker System - Introduced into Florida by the Public Service Commission, the energy broker system is a system for exchanging information. It allows utility systems to efficiently exchange hourly quotations of prices at which each is willing to buy and sell electric energy. For the broker system to operate, utility systems must have in place bilateral agreements between all potential parties and must have transmission arrangements which allow the exchanges to take place.

Firm Obligation - A commitment to supply electric energy or to make capacity available at any time specified during the period covered by the commitment.

Firm Power - Power or power-producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions; that is, power supplied under a firm obligation.

Flashover - A disruptive discharge through air around or across the surface of an insulator, between conductors of different voltage, where the path of the discharge is ionized and can maintain an electric arc.

Generator - A machine that transforms mechanical energy into electric energy.

Generating Station - A station which consists of electric generators and auxiliary equipment for converting mechanical, chemical or nuclear energy into electric energy.

Hybrid Transmission Line - A double-circuit line with one AC and one DC circuit. The AC circuit usually serves local loads along the line.

Impedance - The opposition to power flow in an AC circuit. Also, any device that introduces such opposition, in the form of resistance, reactance, or both. The impedance of a circuit or device is measured as the ratio of voltage to current, where a sinusoidal voltage and current of the same frequency are used for the measurement; it is measured in ohms.

Inadvertent Power Exchange - An unintended power exchange among utilities that is either not previously agreed upon or in an amount different from the amount agreed upon.

Inductance - The property of an electric circuit to induce an opposing voltage in the circuit, or in a neighboring circuit, when it carries a changing current.

Inductive Reactance - A phenomenon associated with AC power in which variations in current fall behind variations in voltage, impeding power delivery.

Inductor - A device that introduces inductance in an electric circuit.

Insulator - A material that is a very poor conductor of electricity. Insulating material, usually a ceramic or fiberglass when used in a transmission line, designed to support a conductor physically and to separate it electrically from other conductors and supporting structures.

Interchange Energy - Electric energy (kilowatt-hours) delivered to or received by one electric utility system from another for economy purposes. It may be returned in kind at a later time or may be accumulated as energy balances until the end of a stated period. Settlement may be by payment or on a pooling basis.

Interconnected System - A system consisting of two or more individual power systems normally operating with connecting tie lines.

Inverter - A machine, device, or system that changes direct current to alternating current.

Line Losses - Power (kilowatts), and associated energy in kilowatt-hours, lost in transmission and distribution lines under specified conditions. See also Transmission Losses.

Load - A device that uses electric power; an installation or system at the receiving end of an energy source or energy conversion device; also, (loosely) the power delivered to such a device.

Load Center - A point at which the load of a given area is assumed to be concentrated.

Load Curve - A graph of kilowatt demand over a specified period of time, generally a day.

Load Factor - The ratio of the average load over a designated period of time to the peak load occurring in that period.

Load Flow - The flow of power on an electric system from generation to load.

Load Flow Study - A study, usually done today on a computer, that determines the electrical conditions, especially the amount of power carried, along various delivery paths connecting generators and loads for a specified set of system parameters.

Loop Flow - The movement of electric power from generator to load by dividing along multiple parallel paths; it especially refers to power flow along an unintended path that loops away from the most direct geographic path, or contract path.

Multiparty Wheeling - When four or more utilities engage in the selling, buying, and wheeling of power; a wheeling arrangement with two or more wheelers.

Net System Capability - The generating station capability of a system at a stated period of time (usually at the time of the system's maximum load) plus capability available at such time from other sources through firm power contracts less firm power obligations at such time to other companies or systems.

Non-Firm Power - Power or power-producing capacity supplied or available under an arrangement that does not have the guaranteed continuous availability feature of firm power.

Nonspinning Reserve - That generating capacity not currently running, but capable of being connected to the bus and loaded within a specified time.

Ohm - A unit of measurement of electric resistance.

Phase-Shifting Transformer - A transformer that can either advance or retard the voltage variations in one circuit with respect to another circuit, thereby affecting the power flow in the line. It can be used in some circumstances to limit undesirable loop flow.

Pole-mile - A unit for measuring the simple length of a transmission line carrying electric conductors, without regard to the number of conductors or circuits carried.

Power Factor - The ratio of real power to apparent power. A power factor of one implies the absence of reactive power.

Power Factor Correction - Any action or device that increases the power factor, ideally to unity.

Power Pool - A power pool is two or more electric systems interconnected and coordinated to supply power in a more economical manner.

Power System - One or more generating stations and connecting transmission lines operated under common management or supervision to supply load.

Power Transfer Limit - The maximum power that can be transferred from one electric utility system to another without overloading any facility in either system.

Protective Relay - A type of switchgear that detects defective lines or other power system conditions of an abnormal or dangerous nature, and initiates appropriate action.

Purchased Power - Power purchased or available for purchase from a source outside the system.

Reactance - A phenomenon associated with AC power characterized by the existence of a time difference between voltage and current variations.

Reactive Power - The rate at which energy stored in an electrical circuit is exchanged between inductive and capacitive elements of the circuit, measured in kilovars.

Real Power - The rate at which electric energy is delivered to a load or loads, measured in kilowatts. (Sometimes called "active" power.)

Rectifier - A device for converting alternating current to direct current.

Relay - An electrically controlled device that opens and closes electrical contacts to effect the operation of other devices. (See also "Protective Relay.")

Reliability - The degree of assuredness with which the utility provides uninterrupted service to customers.

Reserve - The generating or transmission capability in excess of that required for the expected system load.

Resistance - The property of a circuit element that is a measure of the permanent power loss the element causes due to heat dissipation, radiation, or other permanent electromagnetic energy loss. It equals the power lost divided by the square of the current and is measured in ohms.

Right of Way - The land, and legal right to use and service the land, along which a transmission line is located.

Scheduled Outage Service - Power received by a system from another system to replace power from a generating unit taken out of service for scheduled maintenance.

Service Area - The territory in which a utility system is required or has the right to provide electric service to ultimate customers.

Shield Wire - An overhead wire used to protect phase conductors from lightning strokes. In most cases, the wire reduces the effects of strokes, conducting the electrical discharge into the ground through (in most cases) the grounded transmission line support structure.

Single-circuit Line - A transmission line with one electric circuit. For three-phase supply, a single circuit requires at least three conductors, one per phase.

Spinning Reserve - That reserve generating capacity running at a zero-load or partial-load level, which is synchronized, connected to the bus, and ready to take load.

Stability - The ability of an electric power system to maintain standard alternating current frequency under various small to large system disturbances.

Stability Study - A study, usually done today by computer, to evaluate how well a system maintains stability following a disturbance.

Static VAr Generator - A device that uses a thyristor and compensation equipment to automatically either supply reactive power or consume reactive power as needed.

Substation - An assemblage of equipment that either transforms power from one voltage to another or switches electric power circuits.

Subsynchronous Resonance - Any of several undesirable electric wave phenomena, causing electrical oscillations along a transmission line at a frequency below the normal system frequency.

Subtransmission - A set of transmission lines of voltages between transmission voltages and distribution voltages. Generally, lines in the voltage range of 69 kV to 161 kV.

Supporting Structure - The main supporting unit (usually a pole or tower) for transmission line conductors, insulators, and other auxiliary line equipment.

Surplus Energy - Energy generated that is beyond the immediate needs of the producing system. This energy may be supplied by spinning reserve and sold on an interruptible basis.

Switchgear - The switching and interrupting devices used to control, meter, protect, and regulate electric power systems.

Switching Station - An assemblage of equipment for the primary purpose of tying together two or more electric circuits through switches that are selectively arranged to permit a circuit to be disconnected.

Synchronism - The state where connected alternating-current systems operate at the same frequency and voltage phase.

Synchronous Condenser - A synchronous machine running without load that supplies or absorbs reactive power.

Tap-changing Transformer - A transformer equipped with a voltage regulator and taps to maintain constant voltage output.

Thermal Limit - The maximum amount of power a transmission line can carry without suffering heat-related deterioration of line equipment, particularly conductors.

Three-party Wheeling - An arrangement in which a utility transmits power for two other utilities that are not physically connected, where the transmitting utility neither buys nor sells the power.

Three-phase Power - Power generated, and transmitted from generator to load, on three conductors.

Three-phase Reactor - A device that, as its primary purpose, introduces inductive reactance in a three-phase circuit. Among other uses, it can compensate the capacitive reactance of a three-phase circuit.

Thyristor - A solid-state switch that can turn on or off parallel circuit components.

Thyristor-controlled Reactor - A device, controlled by a thyristor, that absorbs reactive power on a transmission network.

Thyristor-switched Capacitor - A device, controlled by a thyristor, that supplies reactive power to a transmission network.

Tie Line - A transmission line connecting two or more power systems.

Transformer - An electromagnetic device that changes voltage and current for the purpose of AC power transfer.

Transmission Line - A set of conductors, insulators, supporting structures, and associated equipment used to move large quantities of power at high voltage, usually over long distances between a generating or receiving point and major substations or delivery points.

Transmission Losses - The power lost in transmission between one point and another. It is measured as the difference between the net power passing the first point and the net power passing the second.

Transmission Network - A system of transmission or distribution lines so cross-connected and operated as to permit multiple power supply to any principal point.

Transmission System - An interconnected group of transmission lines and associated equipment for the movement or transfer of electric energy in bulk between points of supply and points of delivery.

Two-party Wheeling - An arrangement between two utilities in which one utility agrees to transmit power owned by the other.

Unscheduled Outage Service - Power received by a system from another system to replace power from a generating unit forced out of service.

Volt - The unit of electromotive force, or electric "voltage"; the amount which, if steadily applied to a circuit having a resistance of one ohm, produces a current of one ampere.

Volt-ampere - The unit of apparent power.

Voltage - The difference in electrical potential between any two conductors or between a conductor and ground. It is a measure of the electric energy per electron that electrons can acquire and/or give up as they move between the two conductors.

Voltage Regulator - A device attached to the customer side of a transformer that maintains a constant voltage to the distribution system.

Watt - The unit of measure for electric power.

Wheeling - The use of the transmission facilities of one system to transmit power of and for another entity or entities. The most common type of wheeling involves one utility transferring power generated by a second utility for sale to a third utility. (See also "Two-party Wheeling" and "Three-party Wheeling.")

APPENDIX B

SOME ELECTRICAL TERMS AND UNITS

In the main body of this report, the terms "current," "voltage," "energy," and "power" have been used without explanation since most people have a good intuitive sense of the meanings of these terms. This discussion examines these meanings, first for direct current, then for alternating current. It then goes on to develop an intuitive understanding of the concept of "reactive power," a concept needed to understand some limitations on transmission line capability for wheeling. Some common electrical units of measure are also explained.

Current is the flow of electrons through metal conductors. More precisely, it is the number of electrons passing any point in the conductor per second, that is, the rate of electron passage. With steady direct current, the electrons flow at a constant average speed in the same direction. The average speed is very small, typically a couple of feet per hour.

This may be surprising because electricity is well known for the speed at which a system is energized when an electrical circuit is completed. But what travels fast in an electrical conductor is not the electrons but changes in the voltage.

Voltage measures the electrical energy that each electron can acquire as it moves in the conductor. Thus, it determines the push or pull that forces the electrons to flow despite the conductor's resistance to such flow. When a circuit is first completed, electrons at the voltage source begin moving immediately. Electrons down the line begin moving a little later as the voltage travels through the circuit. The speed of the voltage propagation is so great that, under ideal conditions, it can travel across the United States in about 1/60 of a second. In a simple circuit only a few miles long, it appears as if all the electrons begin to move simultaneously.

Direct Current Circuits

Figure B-1 illustrates a simple direct current (DC) circuit in which a battery is connected by two wires to an appliance that can run on direct current. When the switch is closed (that is, the appliance is "turned on"), the voltage difference that exists between the two sides of the battery is communicated almost instantly along both wires, providing a voltage difference across the appliance. Electrons emerge from the lower terminal of the battery and travel to the right along the bottom wire. Electrons are forced through the appliance by the voltage, and electrons in the upper wire travel to left, the leftmost ones entering the upper terminal of the battery. All electrons around the circuit begin moving at about the same time, but may move only a few inches, or a small fraction of the way around the circuit, if the appliance is operated for only a few minutes.

If the wires resist the movement of electrons, as all real wires do to some degree, some heat develops in the wires and some of the electrical push, or voltage, is used up in this way. If the wires are good conductors, this resistance heating is quite small, and most of the battery voltage is used to push electrons through the appliance.

There are two principal types of appliances, those that produce heat and those that produce motion. The first type consists of a conductor that resists the flow of electrons and so gets hot; these include light bulbs, space heaters, water heaters, and electric irons, to name a few. The second type contains a motor, that is, a closely spaced pair of wire coils designed so that current flowing through one coil induces the other coil to spin; these appliances include electric fans, mixers, drills, washing machines, air conditioners, and heat pumps, as well as major industrial machinery. Most, but certainly not all, appliances are of one of these two types--or a combination of the two, like a hair dryer containing a heating element and a fan. The first type is called a resistance load and the other, an inductive load; a load is any appliance, device, or group of devices that consumes electric power.

Energy is required to push each electron through an appliance. The voltage across an appliance is a measure of the energy available to push an electron through it. The total amount of energy consumed by an appliance (that is, converted to heat energy or the energy of motion) depends on both

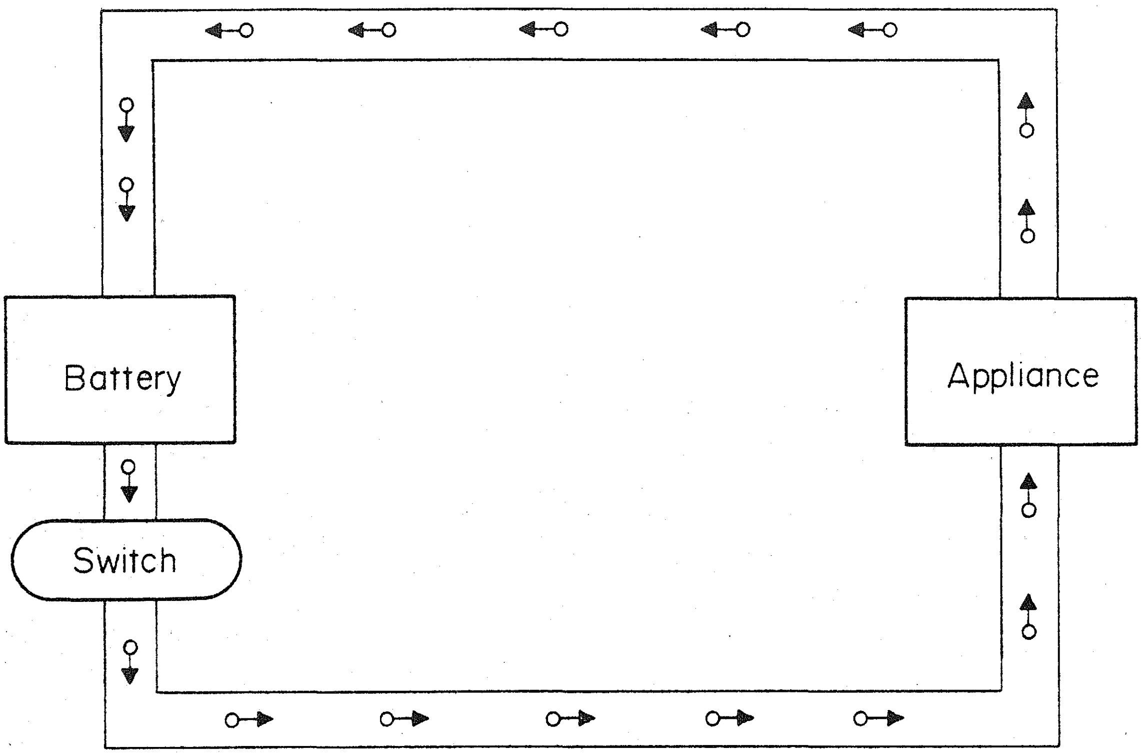


Fig. B-1 A simple direct current (DC) circuit. The small circles represent electrons, and the arrows show the direction of electron movement.

the voltage and the number of electrons pushed through. The rate at which energy is consumed depends on the voltage and the rate at which electrons pass through. In other words, it depends on both the voltage and current.

Power is the term used to describe the rate at which energy is generated, moved, or consumed. A DC appliance that takes a current I when a voltage V is applied across it has a power rating of P = VI.

Alternating Current Circuits

In some ways, AC circuits and appliances are similar. Consider the simple AC circuit with a resistance appliance such as an ordinary light bulb, shown in figure B-2. If the source of power is a 60-cycle AC generator, then the voltage reverses direction 120 times per second, that is, twice each cycle. During each of these 60 cycles, the voltage starts at zero, increases to a maximum in one direction, decreases back to zero, increases to a maximum in the opposite direction, and decreases back to zero, ready to begin the next cycle. For simple circuits of everyday size, these voltage variations are experienced everywhere throughout the circuit virtually simultaneously.

Electrons react instantaneously to these voltage variations. When the voltage is zero, each electron is at rest. As the voltage increases, each electron moves one way (say counterclockwise) around the circuit; it speeds up as the voltage rises--that is, the current increases along with the voltage. The electrons reach peak speed, that is, the current reaches its maximum just when the voltage peaks; then the current shrinks to zero as the voltage falls to zero. As the voltage rises and falls in the opposite direction, tending to push electrons now clockwise around the circuit, the current rises and falls in the clockwise direction in lock-step with the voltage.

Notice that electrons oscillate back and forth past their starting points, but do not actually travel through the circuit. In fact, electronsare displaced no more than a hairsbreadth in either direction. Still, there is resistance to even such small oscillations, and energy is constantly consumed in maintaining this back and forth motion. Little energy is consumed in good conductors, but a lot of energy is used in the resistive appliance.

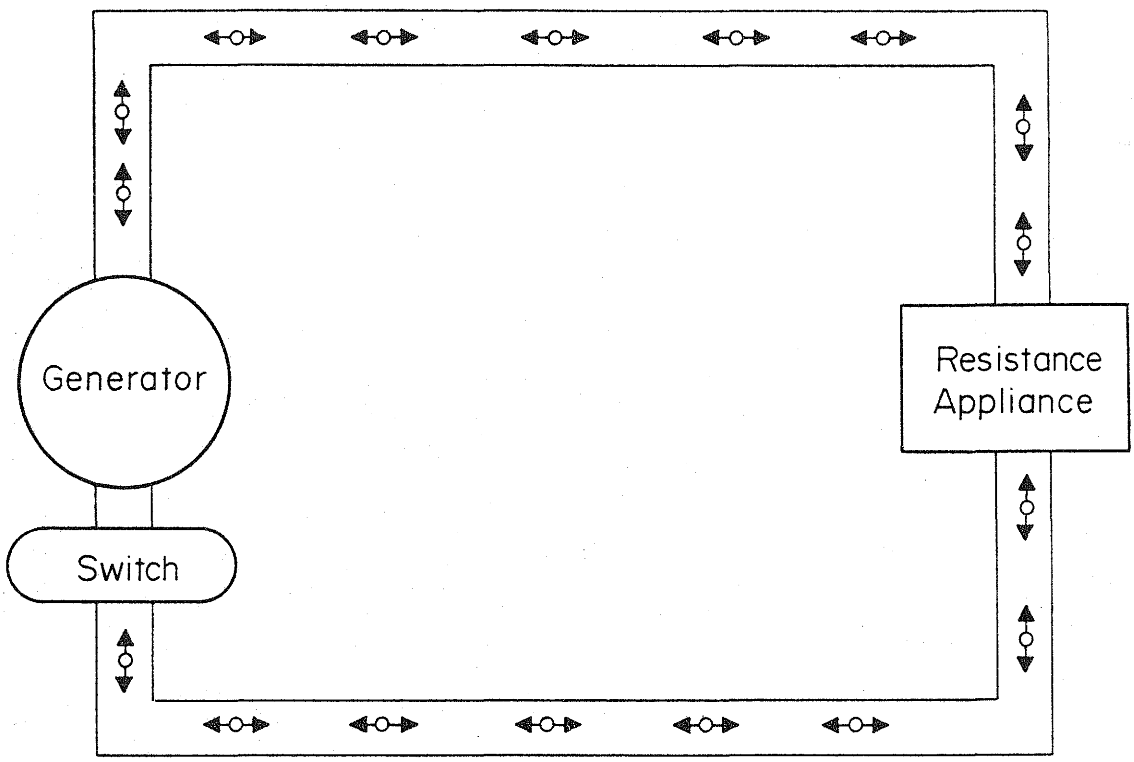


Fig. B-2 A simple alternating current (AC) circuit with a resistance appliance. The small circles represent electrons, and the two arrows with each electron are meant to show that the electrons move alternately forward and back, but experience no net movement. The back-and-forth movement of each electron is in step with the alternating directions of rising and falling generator voltage.

With a purely resistive appliance the variations in the voltage across the appliance are in synchronization with variations in the current through the appliance. That is, these two quantities peak at the same time and reach a value of zero and reverse direction at the same time. It is still true that the power delivered to the resistance appliance at any instant is given by P = VI. Since voltage and current rise and fall together, power is delivered in pulses. There are two power pulses during each cycle, one when the voltage pushes the electrons clockwise through the circuit and one when the push is counterclockwise.

This coordinated variation of voltage and current does not happen for all appliances, however, and this fact leads to the concepts of reactance and reactive power. Most appliances contain not only resistance material but also other large conductors and coils of wire, and these have the effect of getting the voltage and current variations at least slightly out of step.

In appliances containing coils of wire, especially motors, each coil acts as a mini-generator when AC current flows through it. It generates an internal voltage, which tries to push electrons in the opposite direction to that of the main power supply. The net result is to retard the electron oscillations, so that the alternating current variations fall a little behind the variations in the external voltage from the generator.

Large conductors in, or even near, AC circuits tend to have the opposite effect. The voltage cannot build up to its maximum value until electrons, which are free to move about in the large conductors, fully "charge up" these conductors. The full charge occurs when the incoming current has just ceased and is about to reverse itself. The result in this case is that voltage variations fall a little behind the current variations.

Materials and devices that cause these two non-resistance effects on AC circuits are said to produce "reactance," indicating that AC circuits react in a more complicated way than DC circuits when coils and large conductors are present. The reaction is either to retard current variations or to retard voltage variations. Any device that causes the first effect, current falling behind voltage, is called an inductive device and is said to introduce "inductive reactance" into the circuit. Devices that cause voltage to fall behind current are called capacitors or condensers (two names for the same thing) and are said to introduce "capacitive reactance."

It is useful to think of an alternating current as creating inductive reactance effects in appliances it passes through and to think of an alternating voltage as creating capacitive reactance effects in appliances to which it is applied. Whether a device contributes inductive or capacitive reactance effects to an electric circuit depends in part on its physical components and in part on the relative strengths of the current and voltage oscillating through it.

The voltage across an appliance is affected not only by its resistance but also by its reactance. For a given current, the voltage drop across an appliance with both resistance and inductance is greater than across one with only resistance. Also, the voltage drop across an appliance is greater if it has capacitance as well as resistance. The combined effect of the resistance and reactances of a device on the voltage drop across the device is called its impedance.

All real appliances have at least some small inductive and capacitive reactances, but these can often be ignored. In fact, since one reactance tends to get voltage ahead of current and the other tends to get it behind, these reactances tend to cancel one another, bringing current and voltage back into step with each other. If there is complete cancellation, no voltage drop occurs beyond that caused by ordinary resistance.

Reactive Power

The concept of reactance leads to the concept of reactive power. Consider a simple AC circuit with a coil of wire that is part of an AC motor. The coil has inductive reactance as well as resistance so that the current variation is a little "out of sync" with the voltage variation. Most of the time, as the voltage is pushing an electron in the coil to the right, that electron is moving to the right. The voltage is then acting so as to supply energy to the motor, causing it to turn.

Consider, though, what happens when the voltage reverses direction and begins pushing the electron to the left. Because the current is lagging, the electron has not yet completed its motion to the right, and so for a short time the voltage is acting as a brake on electron flow. During this short time the voltage is not supplying any push that causes the motor to turn. Only when the electron later reverses direction, and follows the voltage to the left, can the voltage be effective in delivering power to the motor.

The power that is supplied by the generator to the appliance when the voltage and the current are in the same direction is called "real power." Real power is power that accelerates electrons, pushing them through an appliance such as a motor or a light bulb, producing motion or heat as intended. By contrast, the power used in decelerating electrons during that part of each cycle when the voltage and the current are in opposite directions is called "reactive power." This power is not lost, but is stored in the circuit and exchanged between circuit elements; it is not immediately available to the load.

In an AC circuit, a load may have either inductive or capacitive reactance and in electric power systems the load is almost always inductive. An inductive load causes the alternating current variations to lag behind the alternating voltage variations, and this reduces the amount of real power that can be delivered to the load by the circuit. An industrial customer with motorized heavy machinery may compensate for the inductive reactance of the motors by installing devices in the circuit that add capacitive reactance, tending to bring voltage and current variations back into unison. This compensation, often called "power factor correction," helps the motors to maximize the real power that can be extracted from the delivered current and voltage.

Reactive power exists in a circuit when voltage and current do not vary in unison. One could say that the motor adds reactive power to the circuit and the compensating capacitor removes it, or vice versa. By convention, devices that tend to get voltage variations behind current variations are said to add reactive power to the circuit, or to be sources of reactive power. Hence, condensers or capacitors can be said to "generate" reactive power. By the same convention, devices that tend to get voltage variations ahead of current variations are said to remove reactive power from the circuit. Motors usually "consume" reactive power.

An alternate way of compensating for inductive load is to run the AC generator in such a way that the voltage lags the current at the generator output. Then the voltage-leading effect of the load may just cancel the generator action, so that power is effectively delivered to the load. Here the generator is said to generate both real power and reactive power and the load to consume real power and reactive power. The wires connecting generator and load are said to transmit both real and reactive power.

If the load were primarily capacitive, getting voltage behind current, then the generator could be run so that the generated voltage would lead the current. Then, it would be said that real power flows from the generator to the load and that the reactive power flows in the opposite direction, from the load to the generator. This is because of the convention that capacitive devices are sources of reactive power rather than absorbers. If the convention were reversed, of course, the direction of reactive power flow would be reversed.

This discussion suggests that reactive power is much less real than "real power"; and it is, in the sense that it cannot provide energy to appliances. But the effect of voltage and current being out of step, which is reactive power, is very important for several reasons. Unless there is an equal absorber of reactive power for every source, some electrical energy put into the circuit can find no outlet and can damage the generator or the load or both. If voltage and current become too much out of step (more than a quarter cycle of variation), the generator may run at the wrong speed--a disastrous result if maintenance of 60-cycle power is important. Then motorized machinery in the system would run at the wrong speed or even suffer damage. Also, as mentioned, a voltage drop occurs across reactive elements of a circuit, so reactive power compensation is important to eliminate voltage loss so that the maximum voltage difference can be applied to the intended load.

Further, unless the source of reactive power is located close to the absorber, reactive power must "flow" through the connecting wires. In practical terms, this means that the wires connecting the source and absorber must be large enough and insulated well enough to carry a large current and a large voltage, even though a small amount of real power may be carried by the wires. Thus, a large investment is required for a small benefit unless reactive power compensation is local. In addition, while the moving electrons cannot power an external appliance during that portion of the cycle when their direction of motion is opposite to the voltage direction, nevertheless the electrons are moving; they encounter resistance to their motion; and hence resistance heating losses of electrical energy accompany reactive power flows.

Units of Measurement

It might seem that a sensible way of telling the size of a current would be to give the number of electrons per second passing any point. But the number would be in the trillions of trillions. Instead, more practical measuring units have been made up that recognize the contributions of some early scientists in electricity and power studies: the Frenchman, Andre Ampere; the Italian, Alessandro Volta; the German, Georg Ohm; and the Englishman, James Watt. Current is measured in amperes, voltage in volts, resistance in ohms, and power in watts. Because impedance is analogous to resistance in causing a voltage drop, it is also measured in ohms. Since $P = VI$ in the absence of reactance, a watt is defined as a volt times an ampere.

Because the voltage and current are sometimes at odds, due to the reactance, with the voltage push applied against the direction of electron motion, the product of voltage across an appliance and current through it does not always give the real power consumption of the appliance. To avoid confusion, the unit "watts" is reserved for measuring the real power consumption. The product of voltage and current--which is a good single measure of the ability (or "rating") of the appliance to withstand large voltages and currents--is measured in volt-amperes, or VAs. Also to avoid confusion, reactive power is stated in terms of volt-amperes (reactive), or "VArs". Hence, a capacitive device that tends to make voltage lag behind current is not only described as a source of reactive power but may also be described as a device that "generates vars". From these units, of course, come kilowatts (thousands of watts, kW), megawatts (millions of watts, MW), thousands and millions of volt-amperes (kVA and MVA), as well as kilovars (kVAr) and megavars (MVAr).

Since power is the rate at which energy is transported (or generated or consumed) by a device, the amount of energy transported depends on both the power and how long it flows. This leads to energy units such as kilowatt-hours (kWh) and megawatt-hours (MWh). For example, if energy passes through a transformer for an hour at the rate of 20 megawatts, the total energy passing through the transformer is 20 megawatt-hours (20 MWh).

APPENDIX C

EVOLUTION OF TRANSMISSION SYSTEMS

Historically, electric utility systems evolved from small independent generators directly serving small local distribution systems. Eventually, the economics of large central station generation prevailed over that of the small isolated stations. Later, several central stations provided power to a high voltage transmission network from which many local distribution systems drew power. As the technology of still higher voltage transmission developed, small electric companies merged and the size of individual utility company transmission networks expanded. Also, transmission lines linking neighboring systems were often installed, sometimes capturing geographic economies of scale without corporate mergers.

Today, the level of neighboring utility cooperation can vary from a very loose informal arrangement among companies to a formal power pool. Pools may coordinate a little or a lot of their companies' capacity planning and generation dispatch activities. Members of a public utility holding company are usually operated as if they were a single large company.

The level of cooperation expanded with advances in the technology for moving electricity over long distances. The first electric utilities to serve the public, established January 1882 in London and September 1882 in New York, used low voltage direct current (DC). The size of the early systems was severely limited by energy losses over the power lines. At low voltage, the energy lost was high, mostly because of heat generated in the wires by the large current. By the mid-1880s, the practical use of alternating current (AC) for moving power at high voltage was demonstrated. While direct current consists of electrons flowing always in the same direction through a wire, alternating current consists of electrons flowing first one way, then the other--alternating directions many times each second.

Unlike DC, the voltage of AC can be easily increased or decreased, using a device called a transformer. Further, for a given amount of power to be moved, an increase in voltage reduces the current required and the associated energy loss. Hence, AC power can be sent over long distances by taking it from the generator, increasing the voltage with a transformer, sending it along a power line designed to carry high voltage AC current to a local distribution system, and decreasing the voltage with another transformer that connects the high voltage line to the low voltage local system.

The question of AC versus DC was hotly debated in the 1880s, but the invention of a good motor that could run on AC in the early 1890s helped decide the question. Germany installed the world's first large AC power line in 1891, and in the U.S. AC power became the standard in 1896 with the opening of an AC line running 22 miles from Niagara Falls to Buffalo.

Distance increased with voltage. By the turn of the century several AC lines about 70 miles long had been installed in the U.S. with voltages in the range of 30,000 to 40,000 volts, or 30 to 40 kilovolts (kV) to use the common unit. Longer distances and higher voltages were restricted for a time by the design and quality of insulators, the materials which prevent electricity from flowing through the wooden poles supporting the wire and into the ground. Insulator improvements prior to 1910 eased this restriction, however. This led to the development of hydroelectric power all over the world, as good dam sites could then be linked to population centers. The word "transmission" first came into common use in describing the long distance shipment of power from hydroelectric generators to cities, at voltages usually above 40 kV. By 1920, 132-kV transmission lines were common, and a few 150-kV lines were operating. Two major U.S. transmission lines operating at 220 kV were installed in 1922. The next major step forward in the U.S. occurred in 1934 when a 287-kV AC line carried power 270 miles from Boulder (now Hoover) Dam to Los Angeles. This was the highest voltage line in the U.S. for nearly 20 years.

At 220 kV and above, a new problem restricted how high AC voltage could go and hence how long the line could be. At higher voltages, air around the wire can become ionized and can form a visible glow, or "corona", as electricity is discharged directly from the wire into the atmosphere. This corona effect depends not only on the voltage, but on the size and surface properties of the wire, the humidity of the air, and other factors. It not only causes energy loss, but can be noisy and interfere with radio and television broadcasting, especially on rainy days. Large diameter wires provide some relief from the corona problem, but these add substantially to costs as the wires are larger than the current capacity requires.

Two solutions to this problem were pursued in the 1930s and 40s. One was to divide the current flow in each wire over several wires, properly configured, which led to the technology of extra-high voltage (EHV) AC transmission. The other was to revisit the possibility of DC transmission, for which corona is less of a problem. Experiments in Germany during World War II advanced both solutions considerably.

After the war, EHV AC transmission spread to many countries. Great Britain established a network of 275-kV lines (called a grid) to move large amounts of power around the country. In 1954, a 600-mile line operating at 380 kV was constructed in Sweden. Later, many industrialized countries, including the U.S., constructed AC lines operating at or around 345 kV, 500 kV, and 765 kV. Within any one country, lines are built at one of a few standard voltages so that no additional transformers are needed to connect similar lines together. Voltages in the EHV range, 345 kV to 765 kV, are now common in the U.S., and higher voltage transmission, called ultra-high voltage or UHV, has been the subject of active research.

DC transmission made a comeback with the development of an efficient device for converting power from AC to DC and vice versa. A device called a rectifier, which operated with an electrical discharge (arc) through mercury vapor, was used for converting AC generator output to high voltage DC power to be transmitted. A similar device, called an inverter, converted the transmitted DC power back to AC, as required by all the distribution systems and customer equipment that had developed since 1900.

In 1954, Sweden installed the world's first large commercial high voltage DC transmission line. It traveled 60 miles underwater, carrying 20 megawatts (MW) of power at 100 kV. Many other submarine DC lines followed in the 1960s, and in the 1970s several overhead lines were constructed for high voltage direct current (HVDC) transmission over long distances. In the mid-1970s, use of a solid state device, called the thyristor, replaced the mercury arc device in rectifiers and inverters for AC/DC conversions.

A DC line itself is less costly per mile than an AC line because fewer and smaller conductors are required. But, the entire DC transmission system must be long to be economical. This is because the fixed costs of the rectifier and inverter must be spread over many miles of line to bring the DC system cost per mile below that of the comparable AC system. At today's prices, an overhead DC line must be about 400 miles long or longer to cost less than an AC system. For underground and underwater transmission, because of electrical interactions between alternating current and nearby matter, DC lines are more economical at distances greater than 20 miles.

APPENDIX D

BULK POWER TRANSFERS, TRANSMISSION FACILITIES, AND THE GROWING DEMAND FOR WHEELING

Determining rate designs for wheeling services necessarily involves the consideration of numerous factors and costs. Important factors are wheeling technology and wheeling costs, which are discussed in parts I and II of this report. This appendix contains supplemental material on factors that could influence ratemaking decisions, including the current status of electric utility transmission facilities and the current institutional arrangements under which bulk power sales occur and wheeling services are provided. The first section of this appendix discusses the types of bulk power exchanges and the organizational means by which these transactions are arranged. Wheeling services may be needed in some instances to complete these exchanges. The second section describes current and planned North American transmission facilities. The third section relates this description to a discussion of where wheeling is presently occurring and where there is a demand for wheeling.

Arrangements for Bulk Power Transfers

Understanding arrangements for bulk power transfers involves understanding the degree of commitment between the parties, the types of exchanges that take place (such as economy exchanges and outage service), and the organizations that utilities form to arrange exchanges (such as power pools or brokerage systems). Every exchange involves a type and an organizational arrangement, such as outage service in a power pool.

Coordination and Requirements Sales

The utility industry distinguishes coordination sales and requirements sales. Coordination sales involve the exchange of power between two utilities that usually have enough generation and transmission capacity to meet their own needs. With requirements sales, the buyer depends on the seller for some or all of the generation and transmission needs.[1]

Requirements sales are transactions between a utility with its own generating capacity and a utility with insufficient capacity. Power is sold to the latter utility for resale to its retail customers. The seller commits itself to long-term firm service to the buyer. If the buyer obtains all its power from the seller, the buyer is called a full-requirements customer of the seller. Alternatively, the buyer may have other sources of power, including other sellers or its own generating capacity, and it may obtain only part of its power from any one seller. In this case, the buyer is a partial-requirements customer of any one seller. About one-third of wholesale power sales are requirements sales. The customers in these types of transactions are generally municipally owned or cooperative utilities.[2] In the discussion of types of exchanges that follows, it is assumed that all exchanges are coordination sales.

Types of Exchanges

About two-thirds of wholesale power sales are currently coordination sales.[3] These purchases may be made for various reasons, including reliability and cost savings. Reliability motivations may include satisfying a reserve capacity requirement or serving load that would otherwise be dropped because of a lack of generating capacity. Cost savings

---

[1] See Wilbur C. Earley, "Coordination Transactions among Electric Utilities," Public Utilities Fortnightly, September 13, 1984, pp. 31-37; see also Marie Mastin Newman and Bruce S. Edelston, The Vital Link: Electric Transmission and the Public Interest (Washington, D.C.: Edison Electric Institute, 1986), pp. 17-18.

[2] Newman and Edelston, The Vital Link, pp. 11, 17; and U.S., Department of Energy, Energy Information Administration, Interutility Bulk Power Transactions: Description, Economics, and Data, DOE/EIA-0418 (Washington, D.C.: U.S. Government Printing Office, 1983), p. vii.

[3] Newman and Edelston, The Vital Link, p. 17.

might result from short-term replacement of the buyer's own more expensive power with cheaper power available from the seller. Cost savings might also be long-term, affecting a utility's capacity expansion plans. Utilities may engage in coordination transactions either to take advantage of diversity in loads or to stagger maintenance schedules; either action can reduce the need for installing capacity. A utility may also want to share economies or reduce risks through joint ownership of generating units or through unit sales. Another long-term cost-savings motivation for a utility to engage in coordination transactions is to market its excess generating capacity.[4]

Several types of coordination transactions occur.[5] These may be grouped according to the motivations behind the utilities' participation in the transactions. As mentioned, these range from energy savings to capacity reservation.

A utility may want to obtain (or sell) cheaper energy. One way in which to do this is to purchase <u>economy energy</u>. An economy energy transaction enables a utility with higher power costs at a particular time to buy power from another utility with lower power costs at that same time. Economy energy is unconditionally interruptible and is usually supplied for one hour at a time.

A utility may also need to obtain <u>emergency energy</u>, for such reasons as a disruption in its fuel supplies. An emergency, such as a strike, may have cut off its fuel, or the government may have prohibited the use of a particular type of fuel. In such instances, the utility may enter into an agreement with another utility to procure the necessary power.

A third energy-related motivation for engaging in coordination transactions involves selling power from hydroelectric facilities, called <u>dump power</u>. A utility may be faced with the prospect of excess available hydroelectric energy: its reservoirs may be filled and it may want to avoid spilling water over its dams, not generating electricity in the process. The utility may then price the power at a low level needed to attract buyers.

---

[4] Earley, "Coordination Transactions," p. 32.
[5] Ibid., pp. 33-34. See also Newman and Edelston, <u>The Vital Link</u>, pp. 17-18; and Energy Information Administration, <u>Interutility Bulk Power Transactions</u>, pp. 13-18.

A fourth energy-related coordination transaction, which also involves a capacity-related motivation, is the diversity exchange agreement. A diversity exchange agreement provides for the exchange of capacity, energy, or both between utilities with peak loads occurring at different times of the day or seasons of the year. For example, a utility with peak demand during the winter and lower demand in the summer may place some of its unused summer capacity in the service of a utility with peak demand during the summer. Reciprocity is the basis for the agreement, and so the summer-peaking utility will place its unused winter capacity at the disposal of the winter-peaking utility. These exchanges are designed to reduce both capacity requirements and energy costs.

Capacity reasons for coordination transactions may be either temporary or longer-term in nature. Temporary shortages in capacity may arise for a variety of reasons, such as maintenance or an emergency. A utility might engage in a short- or limited-term power transaction to meet a temporary capacity shortage. Short- and limited-term power services are conditionally interruptible services purchased by a utility to cover temporary deficiencies in capacity, both planned and unplanned. Short-term power may be reserved for one day to one-week periods. Limited-term power may be reserved for one to twelve months. These are firm power services, and are given a fairly high priority (just under native load) by the seller. Other types of transactions deal specifically with maintenance or emergencies. For example, in a scheduled maintenance arrangement, the utilities involved agree to furnish backup power to each other for short periods during which maintenance or overhaul of facilities is occurring. Emergency service transactions allow for the provision of power to a utility when demand exceeds immediately available resources. These agreements usually cover 24 to 72-hour periods, during which the buyer is expected to do what is necessary (repair units, arrange other power purchases, etc.) to make up the deficiency in its power supply.

Bulk power exchanges to meet longer-term capacity requirements are also entered into for a variety of reasons. A utility may wish to avoid the expense of installing new capacity and may try to find a reliable alternative source of power instead of constructing its own. If a nearby utility has excess capacity, the two utilities may decide to enter into some type of coordination agreement. Three of these are described here.

Unit power agreements allow the buyer to purchase a specified portion of the output of one of the seller's generating units. This agreement provides both power and capacity without ownership. Service is dependent upon the availability of the particular unit. The buyer pays the unit's operating costs during the course of the agreement. Under a system power agreement, a utility purchases a specified portion of output or capacity from another utility's entire system or specified units of that system. Reliability is greater under this type of agreement than under a unit power agreement because more than one unit is involved. The third possible transaction discussed here is a reserve transaction. In a reserve transaction, two or more utilities share reserve generating capacity by making the group's capacity available to any utility (that is a party to the agreement) experiencing a capacity shortage due to unexpected occurrences.

Organizational Arrangements

The organizational arrangements under which bulk power exchanges occur can range from simple bilateral agreements to more complicated pooling arrangements.[6] Several types of arrangements are discussed here, including holding company systems, power pools, and multilateral and bilateral agreements.

Holding company systems consist of separate utilities under the control of a single holding company. A system may have interconnected generating and distribution utilities located in the same state or adjacent states. In such instances, the holding company system may be highly coordinated and, using central dispatch, may operate as a single system, similar to a tight power pool (discussed below). In other cases, however, the subsidiaries of the holding company are located in different parts of the country and thus are not interconnected. These subsidiaries operate independently of each other and do not form a single integrated system. Table D-1 lists the major holding companies that operate with central dispatch or as part of a

[6] See U.S., Federal Energy Regulatory Commission, Office of Electric Power Regulation, Power Pooling in the United States, FERC-0049 (Washington, D.C.: U.S. Government Printing Office, 1981), pp. 3, 33-35.

TABLE D-1

MAJOR HOLDING COMPANY POOLS
IN THE UNITED STATES

Holding Companies with Central Dispatch	Holding Companies that Belong to Large Pool
Allegheny Power System, Inc. (APS)	General Public Utilities (belongs to PJM)
American Electric Power System (AEP)	New England Electric System (belongs to NEPOOL)
Central and Southwest Corporation (C&SW)	Northeast Utilities (belongs to NEPOOL)
Middle South Utilities, Inc. (MSU)	
Southern Company System (SOCO)	
Texas Utilities Company (TUCO)	

Source: U.S., Federal Energy Regulatory Commission, Power Pooling in the United States (Washington, D.C.: U.S. Government Printing Office, 1981), p. 9.; Energy Information Administration, Interutility Bulk Power Transactions, pp. 24-25; personal communications with holding company officers, July 1987. Note: table D-2 explains the pool acronyms.

larger power pool.[7] An important characteristic of a holding company system and of all of the more complex institutional arrangements discussed here is that these agreements usually cover more than just the exchange of extra bulk power supplies. Provisions of these agreements cover common operation of facilities and joint planning of system expansion.

A power pool may be as little as an informal agreement among a group of utilities to establish principles and criteria to facilitate the coordination of planning or operations. The principles could cover a variety of coordination activities and compliance with them would be voluntary. Alternatively, a pool may be a formal contractual agreement in which two or more systems coordinate the planning and/or operation of their

[7] Technically, the holding companies do not belong to pools; their subsidiary operating companies do.

bulk power facilities and in which the responsibilities of the individual systems are stated explicitly. Agreements establishing formal pools must be approved by the FERC. They may be classified as either tight or loose.[8]

In a tight pool, extensive requirements are made of the member utilities. These include capacity requirements, central dispatch of generating plants as a single system, and coordinated scheduling of maintenance and unit commitment. Penalties may be used to enforce the requirements. A tight pool may operate almost as a single system as individual utilities surrender much of their autonomy to the pool.

A loose pool is an extension of a multilateral agreement (discussed below) in that it adds provisions for coordinated capacity planning and operation in addition to bulk power exchange. In a loose pool, members coordinate their planning and operation, but central dispatch may not be required. Members continue to operate their own generation and transmission systems while the pool plans for long-term expansion of these facilities and sets standards for reliability and uniform operating procedures. Penalties are not usually employed to enforce the agreement. A loose formal pool is thus a middle position between the highly coordinated tight formal pool and the informal pool that operates with no contract at all.

Utilities engage in pooling and other types of coordination to obtain the economies possible for large systems. Pooling can be thought of as a substitute for horizontal integration, in that it requires the utilities involved to agree to numerous operational and financial relationships.[9] Members of tight pools, for example, must agree on such areas as transmission access rights and capacity obligations of pool members, compensation arrangements for use of transmission facilities owned by individual pool members, economy exchanges of power and compensation for those exchanges, generating unit commitment, and compensation for that

---

[8] See Charles F. Phillips, Jr., The Regulation of Public Utilities: Theory and Practice (Arlington, VA: Public Utilities Reports, Inc., 1984), pp. 543-545; see also Paul L. Joskow and Richard Schmalensee, Markets for Power: An Analysis of Electric Utility Deregulation (Cambridge, MA: MIT Press, 1983), pp. 66-76; and Energy Information Administration, Interutility Bulk Power Transactions, pp. 22-24.
[9] Joskow and Schmalensee, Markets for Power, p. 71.

commitment. Inability to agree on these types of issues can result in the breakup of the pool.

Potential problems facing pooling include large utilities not deriving as much benefit from pooling as small utilities, or vice versa. Large systems may thus not be interested in pooling unless they can share in the benefits that the small systems receive. In addition, changing economic conditions may necessitate frequent renegotiation of the pooling agreement, endangering its stability.[10] Pools are sometimes constrained by their members' transmission networks. While a pool tries to keep its generation costs to a minimum, high-cost generating units may have to be used because of a lack of adequate transmission facilities from lower-cost generators to load centers. Other problems hindering pooling include the imposition of additional risks on a pool's members by the obligations of membership in the pool and the diverse interests of the pool's members interfering with collective decision making.[11] Table D-2 lists U.S. power pools and coordination groups as identified by Electrical World and others.

While utilities may begin to coordinate their operations with other utilities through simple arrangements such as bilateral agreements and may proceed to more elaborate arrangements such as pooling, the move from simpler to more complex coordination is not necessarily assured. Binding agreements, such as pooling contracts, may secure benefits for the utilities involved, but as noted earlier they may also expose the utilities to additional risks, impose additional obligations, and lessen a utility's ability to make its own decisions. Thus, multilateral arrangements or simple bilateral agreements may sometimes be preferred by utilities.[12]

Multilateral arrangements include different types of agreements. Multilateral agreements are a means by which utilities can try to achieve benefits for themselves through voluntary coordination while avoiding the requirements of more formal contractual arrangements such as tight power pools. Three of these, the Florida Brokering System, the Southwest Bulk Power Experiment, and the proposed Western Systems Power Pool, are discussed below. These three arrangements are concerned mainly with the exchange of

---

[10] Ibid., p. 76.
[11] Phillips, Regulation of Public Utilities, p. 545.
[12] Ibid., pp. 7, 9.

TABLE D-2

POWER POOLS IN THE UNITED STATES, OTHER THAN HOLDING COMPANY POOLS

Central Area Power Coordination Group (CAPCO)

Connecticut Valley Electric Exchange (CONVEX)

Florida Electric Coordinated System

Michigan Electric Coordinated Systems

Mid-Continent Area Power Pool (MAPP)

Missouri Basin Systems Group, Inc. (MBSG)

MOKAN (Missouri-Kansas) Pool

New England Power Pool (NEPOOL)

New Mexico Power Pool

New York Power Pool (NYPP)

Northwest Power Pool Coordinating Group

Pennsylvania-New Jersey-Maryland Interconnection (PJM)

Rhode Island-Eastern Mass-Vermont Energy Control (REMVEC)

Southern California Utility Power Pool

Wisconsin Power Pool

Source: Electrical World, Electrical World Directory of Electric Utilities, 1984-1985, 93d ed. (New York: McGraw-Hill Publications Co., 1984), pp. 943-944; amended through personal communication with L. MacGregor of the Michigan Public Service Commission and officers of NEPOOL, June-July 1987. Note: sometimes NEPEX and NEPLAN are mistakenly listed as power pools in New England. However, NEPOOL is New England's only power pool. It has three major divisions: NEPEX, which is the operations center and actually coordinates the bulk power exchanges; NEPOOL Billing, which accounts for costs and then bills the utilities for the pool's services; and NEPLAN, which plans for expansion of generation and transmission capacity and does load and economic forecasting for the region.

power and not with long-term capacity planning.

The Florida Brokering System coordinates economy energy transactions among its members. The utilities involved include the Florida Power and Light Company, the Florida Power Corporation, and the Florida Public Utilities Company. Several other investor-owned, municipal, and cooperativeutilities also participate.[13]

Each member submits buy/sell quotations hourly to the System's computer. The quotation states the price at which the utility is willing to buy power, the higher price at which it will sell power, and the quantities of power involved. The quotations are based on each potential seller's incremental cost of generating power and each potential buyer's decremental cost (i.e., the amount of own-generation cost that the buyer would save by buying instead of generating power). Transmission costs, including third-party transmission, are also included in the quotations and are taken from existing transmission agreements and price schedules. The computer matches the buyer having the highest decremental cost with the seller having the lowest incremental cost. The next highest decremental cost is matched with the next lowest incremental cost, and so on. The matching concludes when a preset cost difference is reached. Sales are voluntary and are based on existing bilateral contracts and transmission agreements among the utilities.

The Southwest Bulk Power Market Experiment was a study by the FERC to determine whether certain changes in bulk power markets, such as more competition, necessitated changes in the Commission's regulation of coordination transactions. The FERC approved the two-year experiment in December 1983.[14]

Six utilities in Arizona, New Mexico, and Texas participated voluntarily in the experiment. Four of the utilities were investor-owned and two were publicly-owned.

---

[13] Energy Information Administration, Interutility Bulk Power Transactions, pp. 26-27; and Federal Energy Regulatory Commission, Power Pooling in the United States, pp. 86-87.

[14] A. Stewart Holmes, "The Southwest Bulk Power Market Experiment: First-Year Results," paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 20-22, 1985.

Two types of transactions were involved. Economy energy was purchased on an hourly basis (or for longer periods). Block energy transactions involved negotiated amounts or blocks of energy delivered over a period of thirty days or longer.

Major features of the experiment were pricing flexibility, profit retention by sellers, and wheeling access. Pricing flexibility (and sending price signals) was considered necessary for the operation of a competitive market. The utilities were allowed to charge any price within a zone of acceptability. The floor for prices was one-half of the average of each participant's estimated 1984 incremental energy costs for those energy sources most likely to be used for the experiment's transactions. The ceiling was two times the average of the participants' fully allocated costs of supplying firm, partial requirements service. The requirements service rates of only the four investor owned utilities were used because the other two participant utilities did not offer such service.

The experiment also allowed some profits earned from the transactions to be shared with the utilities' stockholders instead of being passed through to wholesale requirements customers in lower rates (as is the usual case). The FERC allowed the participants the opportunity to keep 25 percent of the profits earned from the experiment's transactions for their stockholders with the remaining 75 percent going to wholesale customers.

Experiment participants agreed to provide wheeling services for each other. The utilities were to furnish the service even if they lost sales (by having to provide wheeling instead of being able to sell power to customers themselves) in the process.

The Western Systems Power Pool (WSPP) is a proposal by fourteen western utilities that would cover all major types of coordination transactions. Four service schedules, one each for economy energy, unit commitment, firm system capacity/energy sale or exchange, and transmission, would be employed. Transactions would be voluntary.[15]

[15] See William J. Kemp and Thomas S. Karwaki, "The Western Systems Power Pool: Flexible Pricing in Action," in Proceedings of the Fifth NARUC Biennial Regulatory Information Conference, vol. 2, ed. Robert E. Burns (Columbus, Ohio: The National Regulatory Research Institute, 1986), pp. 933-943.

The main features of this power pool include an information exchange. Participants would voluntarily submit bids and offers for services to the pool's Hub computer. All participants would have access to the Hub. The potential buyers and sellers would contact each other independently of the Hub to negotiate the terms and prices of the transactions. Third parties (participants in the WSPP) may need to be contacted for transmission service. Prices would be set flexibly by market conditions, subject to the agreement of the negotiating parties and to ceilings based on the highest poolwide costs, instead of using traditional embedded cost-based rates.

Bilateral agreements, the simplest means of arranging bulk power transactions, generally specify the objectives of each party and may contain other provisions such as provision for arbitration of disputes. The agreements may also describe any facilities that need to be built to make the connection between the parties, specifying progress and completion dates. Penalties may be used to enforce these target dates. The costs of interconnecting may be assigned to each party based on the benefits that each expects to derive. Bilateral agreements are usually designed to coordinate day-to-day operations instead of long-term expansion planning. A committee with representatives from each utility may oversee the agreement.[16]

Emergency power, firm power, and economy energy are examples of the types of services covered by bilateral agreements. While the transactions may or may not take place (the agreement's existence does not force the utilities to proceed with the transactions), the agreement does provide the framework through which the utilities can execute the transactions if they decide to do so. Bilateral agreements also generally specify how transactions are to be priced, measured, and coordinated.[17]

Bilateral agreements may also cover transmission services, including wheeling power over the lines of intervening utilities. In Texas, the PUC has developed a rule that requires this last type of bilateral agreement for the transmission of a cogenerator's power. The rule specifies that a utility that would otherwise have been required to buy a qualifying

---

[16] Federal Energy Regulatory Commission, Power Pooling in the United States, pp. 33-34.
[17] Energy Information Administration, Interutility Bulk Power Transactions, p. 21.

facility's power or capacity must transmit the cogenerator's power to any other utility designated by the qualifying facility. The intermediate utility is also required to construct any additional facilities needed to transmit the power if the qualifying facility requests it to do so. The cogenerator would pay for the interconnecting facilities, and the affected utilities would pay for additional facilities.[18] The rule applies to cogenerators with a rated capacity of greater than ten megawatts. The intermediate utility is not required to transmit the power if, in doing so, it would become subject to the Federal Power Act or the transmission would violate federal or state law.[19]

Growth of Power Sales

U.S. electric utilities have engaged increasingly in bulk power exchanges over the past few decades. In 1945, for example, sales for resale by privately owned utilities totalled 39.2 billion kWh. By 1984, these sales had increased to 335.8 billion kWh, a growth of 757 percent.[20] Another way of viewing bulk power transactions, in addition to documenting their increasing amount, is to examine them as a fraction of the amount of power generated by utilities. This is done in table D-3.

The table gives information on the changes in sales for resale and in interchanges from 1945 through 1984. Interchanges are short-term economy energy transactions among utilities. The energy may be returned in kind or accumulated as an energy balance for eventual payment. Sales for resale, also called wholesale sales, are all other power sales, including coordination sales for resale and requirements sales for resale. While the

---

[18] Substantive Rules of the Public Utility Commission of Texas, September 1, 1986, p. 86.

[19] Texas Register, September 23, 1985. The rule is also reprinted as appendix V in Sam F. Skinner, "Transmission Systems Marketing: Impediments to Expansion," paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 1985.

[20] These data were taken from Energy Information Administration, Interutility Bulk Power Transactions, p. 3; and U.S., Department of Energy, Energy Information Administration, Financial Statistics of Selected Electric Utilities 1984, DOE/EIA-0437(84) (Washington, D.C.: U.S. Government Printing Office, 1986), p. 20. The percentage was calculated by the authors.

TABLE D-3

SALES FOR RESALE AND INTERCHANGES (IN)
AS A PERCENTAGE OF POWER GENERATED
BY PRIVATELY OWNED ELECTRIC UTILITIES,
1945 TO 1984[a]

Year[b]	Sales for Resale as a Percentage of Generated Power[c]	Interchanges (In) as a Percentage of Generated Power[c]
1945	22	7
1946	21	7
1947	22	6
1948	21	6
1949	20	6
1950	19	6
1951	17	5
1952	16	6
1953	15	5
1954	14	6
1955	15	6
1956	15	6
1957	14	6
1958	14	-[d]
1959	13	-[d]
1960	14	-[d]
1961	14	7
1962	15	7
1963	15	7
1964	15	7
1965	15	7
1966	16	8
1967	17	9
1968	17	10
1969	18	12
1970	17	14
1971	17	15
1972	16	16
1973	16	18
1974	17	19
1975	17	19
1976	19	19
1977	17	19
1978	18	19
1979	17	21
1980	18	21
1981	19	22
1982	20	24
1983	19	22
1984	19	22

Source: The calculations for 1945 to 1980 were based on data taken from U.S., Department of Energy, Energy Information Administration, Interutility Bulk Power Transactions: Description, Economics, and Data, DOE/EIA-0418 (Washington, D.C.: U.S. Government Printing Office, 1983), p. 3. The calculations for 1981 to 1984 were based on data taken from U.S., Department of Energy, Energy Information Administration, Financial Statistics of Selected Electric Utilities 1984, DOE/EIA-0437(84) (Washington, D.C.: U.S. Government Printing Office, 1986), p. 34. Calculations were done by the authors.

[a]The data for 1945 to 1980 are from Class A and Class B utilities. Class A utilities had an annual electric operating revenue of $2.5 million or more. Class B utilities were those utilities that had an annual electric operating revenue of $1 million or more, but less than $2.5 million. The Class A-Class B categorization has been replaced by the classification of "major electric utilities." The data from 1981 to 1984 are from major utilities. A major electric utility is one that, in the previous three consecutive calendar years, has had sales or transmission in excess of one of the following: 1,000,000 MWh of total annual sales, 100 MWh of annual sales for resale, 500 MWh of annual gross interchange out, or 500 MWh of wheeling for others. Regardless of which classification scheme is used, the Department of Energy states that on the basis of assets and revenues nearly 100 percent of the privately owned sector of the electric utility industry is covered.

[b]The data for 1945 to 1959 do not include Alaska and Hawaii. Alaska is also excluded from the 1961 data.

[c]The calculations for 1945 to 1960 are based on total generation, the only data reported by the government. Thereafter, only net generation data were reported, and these are used in the calculations.

[d]For 1958-1960, only net interchange, instead of interchanges in and out, was reported.

amount of power involved in sales for resale has increased substantially since 1945, the amount expressed as the percentage of power generated has remained relatively stable over the period. The high point of 22 percent was reached in 1945 and in 1947, and the low point of 13 percent was in 1959. In 1984, approximately one-fifth (19 percent) of generated power was involved in sales for resale.

While sales for resale as a percentage of power generated has been somewhat stable, the amount of electricity sold in economy interchanges hasgrown considerably (from 7 to 22 percent with a low point of 5 percent and a high point of 24 percent) in relation to power generated. Table D-3 shows that interchange energy has increased greatly in importance. In fact, since 1972 interchanges have exceeded sales for resale and thus are an important factor behind the overall increase in bulk power sales.

The growth in bulk power exchanges is not confined to the United States. The transmission systems in most International Energy Agency (IEA) member western European countries are closely interconnected.[21]

In Europe, there are two frequency blocks that transmit energy, via direct current, across national boundaries. One of these arrangements is The Union for the Co-ordination of Production and Transport of Electricity (UCPTE), which includes utilities in Austria, Belgium, France, Germany, Italy, Luxembourg, the Netherlands, and Switzerland. Four additional countries, Greece, Portugal, Spain, and Yugoslavia, are associates of the UCPTE. The second frequency block is the Nordel and includes the utilities of Denmark, Norway, Sweden, Finland, and Iceland (the latter does not take part in any electricity exchanges). Regional arrangements include the Franco-Iberian Union (UFPTES) and SUDEL, which consists of utilities in Austria, Italy, and Yugoslavia. Separate frequency blocks have been formed by utilities in the United Kingdom and Ireland.

The UCPTE and Nordel do not have executive powers. Their main functions are information exchange, giving advice, and making recommendations in order to facilitate cooperation among the member

---

[21] This discussion is based on material in International Energy Agency, Electricity in IEA Countries: Issues and Outlook (Paris: International Energy Agency, 1985), pp. 87-92.

utilities. The members themselves are responsible for the purchase and sale of electricity.

While most electricity consumed in each of the International Energy Agency's European member countries is produced within that country, there are some major power exchanges between countries. In 1983 the twelve UCPTE countries (including the four associates) exchanged 74,200 gigawatt-hours, 6.6% of total consumption, between themselves and other countries. Hydropower from Austria and Switzerland and thermal power from various other countries were especially important. In 1983, the Nordel countries exchanged 20,200 gigawatt-hours representing 8% of total consumption.

Surplus nuclear generating capacity in France may provide the main opportunity for increased international power transmission in the future. In 1984 Italy and the Netherlands imported power from the French. In the long-term (in the 1990s) the French expect to export sizeable amounts of power, 30,000 to 50,000 gigawatt-hours per year, to neighboring countries. Transmission lines to accomplish this are currently being constructed. Exports of French electricity to Italy, Portugal, and Spain would be important because those countries are highly dependent on oil-fired generation. Exports to Portugal assume that transmission through Spain is possible. A link between France and the United Kingdom, a 2000-MW undersea cable, is scheduled to be energized in 1985 or 1986 and will allow additional power exchanges.

Short-term power exchanges among utilities in different countries have assumed great importance in Europe. These exchanges take advantage of differences in the marginal costs of production and allow the utilities to maintain control over their long-term supply. Regulators in some countries have also been unwilling to approve the operation of power plants that will not serve their own people. Local power production is preferred to a long-term strategy of importing power.

Prices in the power transactions are usually negotiated in individual agreements. Nordel members, however, use set pricing formulas in short-term exchanges. Sweden and Denmark employ a system in which any savings are split equally between the parties. Norway and Sweden's formula leads to an approximately equal split of savings. For transactions between Norway and Denmark, Norwegian power exports are priced at 75 percent of marginal Danish production costs while Danish exports are priced at 110 percent of marginal Danish production costs.

The IEA states that buyers and sellers must agree to longer-term supply contracts, resolve questions of pricing policy and back-up power, and provide incentives for building new transmission facilities in order for more bulk power trading to occur in Europe.[22]

Current and Planned U.S. Transmission Facilities

This section provides an overview of the transmission facilities, both current and planned, needed for bulk power transfers and for wheeling. The previous discussion of the institutional arrangements shows that electric utilities do not operate as isolated entities. But the extent of their interaction is limited by the degree of connectedness of their transmission and generation facilities.

The U.S. presently has over 140 control areas for the purposes of coordinating utility operations. A control area may include one utility or many utilities bound together by contract. The utilities within a control area operate, for some purposes, as if they were in one system, controlling generation to meet their combined loads and coordinating imports of power from and exports of power to other control areas. Each control area has an electrical and a geographic boundary, and it operates in synchronization with the other control areas located within the same interconnected network. The control areas, as of 1981, are shown in figure D-1.[23]

There are four major interconnected areas in the continental United States and Canada: the Eastern Interconnection, the Western Systems Coordinating Council, the Electric Reliability Council of Texas, and Hydro-Quebec. These are shown in figure D-2. Because the utility systems within an interconnected area are synchronized, the AC frequency is approximately the same at all points within each interconnected area. Transfers of power from one system to another within the interconnected area occur over transmission lines that are not necessarily along the flow's most direct

[22] Ibid., p. 92.
[23] Federal Energy Regulatory Commission, Power Pooling, p. 26; and Newman and Edelston, The Vital Link, pp. 10-11, 13.

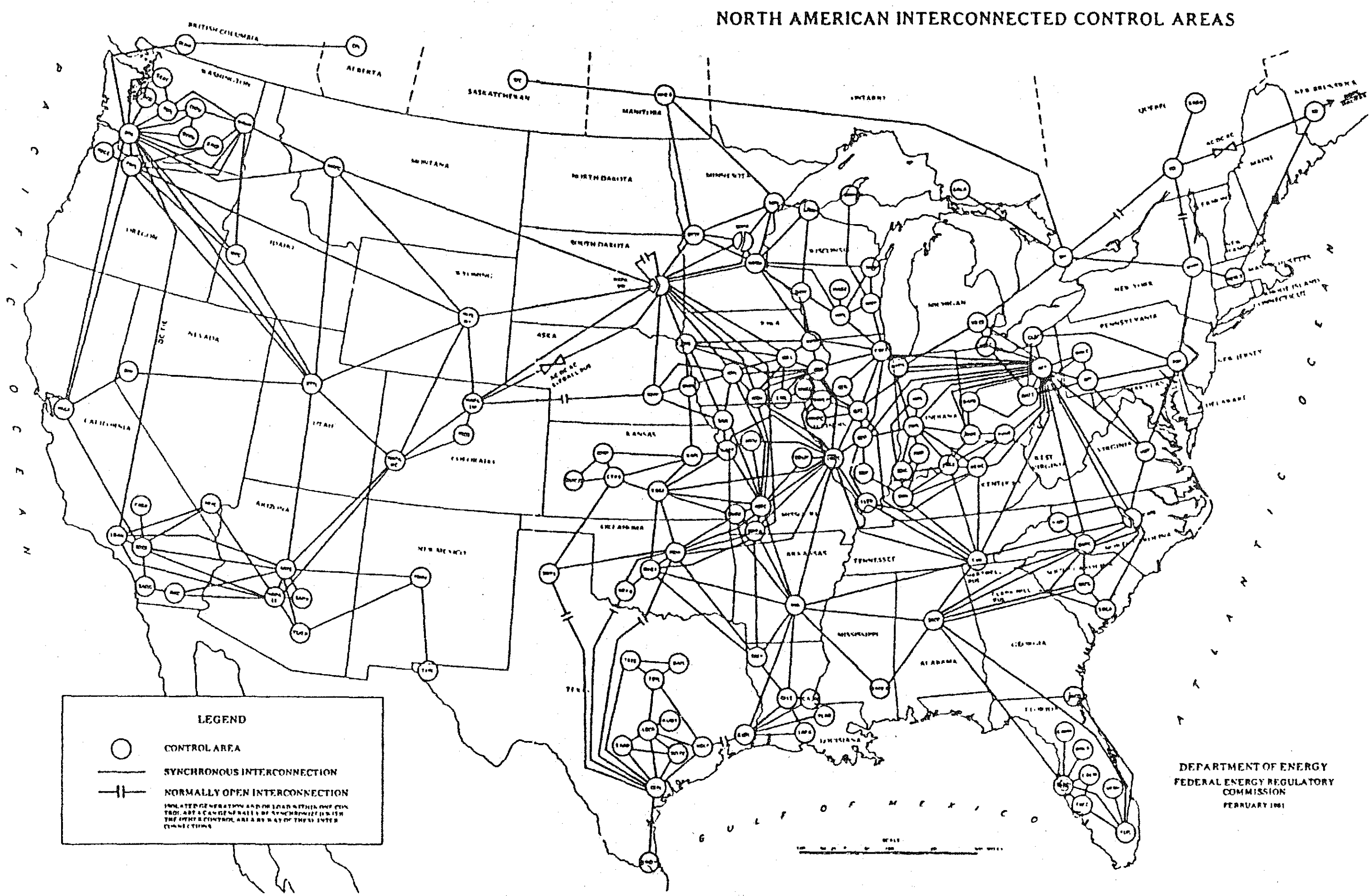


Fig. D-1 North American Interconnected Control Areas. Source: U.S., Federal Energy Regulatory Commission, Power Pooling in the United States (Washington, D.C.: U.S. Government Printing Office, 1981), pp. 28-29. Note: control area labels deleted.

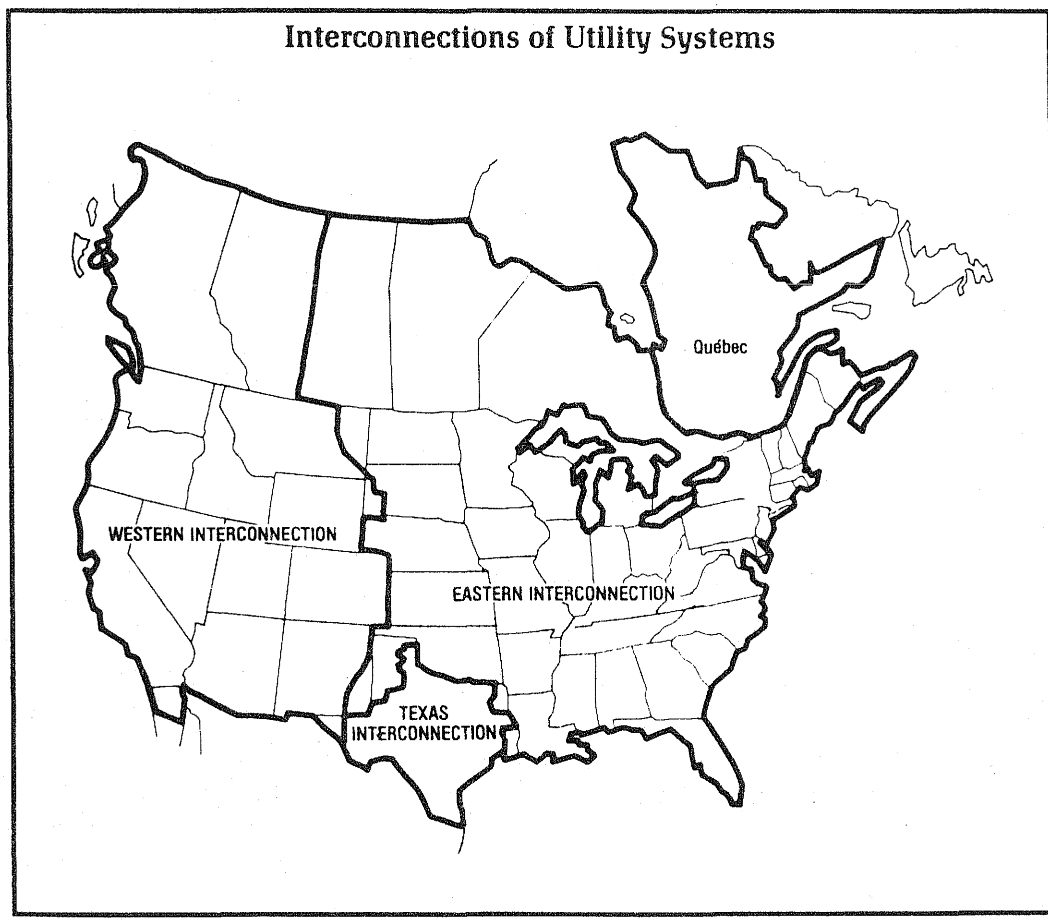


Fig. D-2. Interconnected Areas of the United States and Canada

Source: North American Electric Reliability Council, 1986 Reliability Review: A Review of Bulk Power System Reliability in North America (Princeton, NJ: North American Electric Reliability Council, 1986), p. 26.

path.[24] Control areas within interconnections are important means by whichutilities coordinate and execute bulk power transactions.

The nine regional reliability councils are also important for these purposes. Each council consists of representatives of the major utilities in a particular region. The councils cover the United States (except Alaska and Hawaii), Canada, and part of Baja, Mexico. Table D-4 gives an overview of the councils and their memberships. The council regions are shown in figure D-3. In 1968 the National (later renamed North American) Electric Reliability Council (NERC) was formed to promote further the goal of reliability in bulk power supply.[25]

The high voltage transmission network under NERC, including the member systems in the U.S., Canada, and Mexico, consists (as of early 1986) of over 180,000 circuit-miles of lines that are 230 kV or above. This includes 140,691 miles in the U.S.; 38,894 miles in Canada; and 626 miles in Baja, Mexico. Approximately 3,400 miles (2,234 miles in the U.S. and 1,186 miles in Canada) of the network are direct current lines. Additions to the high voltage transmission system planned for the end of 1995 will increase the circuit mileage from 180,000 to approximately 203,700.[26] Tables D-5, D-6, and D-7 display data on the current mileage and planned additions by 1995, by NERC region.

One can see from the data that about half the high voltage transmission system in the lower forty-eight U.S. states consists of 230-kV lines. Of the 140,691 circuit-miles (AC and DC) of high voltage transmission lines in the forty-eight states, 68,248 miles (48.5 percent) are 230-kV lines. The comparable percentages for the other voltages are 345-kV lines, 32.3 percent; 500-kV lines, 16.0 percent; 765-kV lines, 1.6 percent; 250-300-kV DC lines, 0.3 percent; 400-kV DC lines, 0.3 percent; and 500-kV DC lines, 0.9 percent. For the entire NERC system, including Canada and Mexico as well, the percentages are as follows: 230-kV lines, 49.6 percent; 345-kV lines, 28.5 percent; 500-kV lines, 15.2 percent; 765-kV lines, 4.8 percent;

---

[24] North American Electric Reliability Council, 1986 Reliability Review: A Review of Bulk Power System Reliability in North America (Princeton, NJ: North American Electric Reliability Council, 1986), p. 26.
[25] Ibid., p. 4; see also Newman and Edelston, The Vital Link, p. 13.
[26] North American Electric Reliability Council, 1986 Electricity Supply & Demand for 1986-1995 (Princeton, NJ: North American Electric Reliability Council, 1986), p. 55.

TABLE D-4

NERC REGIONAL COUNCILS

East Central Area Reliability Coordination Agreement (ECAR)	18 member systems in Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland, and Tennessee
Electric Reliability Council of Texas (ERCOT)	20 municipalities, 48 cooperatives, 6 investor-owned utilities, and 1 state agency in Texas
Mid-Atlantic Area Council (MAAC)	11 member systems and 5 associates in Delaware, the District of Columbia, Pennsylvania, New Jersey, Maryland, and Virginia
Mid-America Interpool Network (MAIN)	13 members and 1 associate in Illinois, Missouri, Wisconsin, and Michigan
Mid-Continent Area Power Pool (MAPP)	27 participants and 17 associate participants in Iowa, Minnesota, Nebraska, North Dakota, Illinois, Michigan, Montana, South Dakota, Wisconsin, Manitoba, and Saskatchewan
Northeast Power Coordinating Council (NPCC)	22 member systems in New York, Vermont, New Hampshire, Maine, Massachusetts, Rhode Island, Connecticut, Ontario, Quebec, New Brunswick, and Nova Scotia
Southeastern Electric Reliability Council (SERC)	28 member systems in Kentucky, Virginia, Tennessee, North Carolina, Mississippi, Alabama, Georgia, South Carolina, and Florida
Southwest Power Pool (SPP)	38 member systems in Kansas, Oklahoma, Missouri, Arkansas, Mississippi, Louisiana, Texas, and New Mexico
Western Systems Coordinating Council (WSCC)	60 member systems and 4 affiliates in Washington, Oregon, Idaho, Montana, Wyoming, South Dakota, California, Nevada, Utah, Colorado, Arizona, New Mexico, Texas, British Columbia, Alberta, and Mexico

Source: North American Electric Reliability Council, 1986 Reliability Review: A Review of Bulk Power System Reliability in North America (Princeton, NJ: North American Electric Reliability Council, 1986).

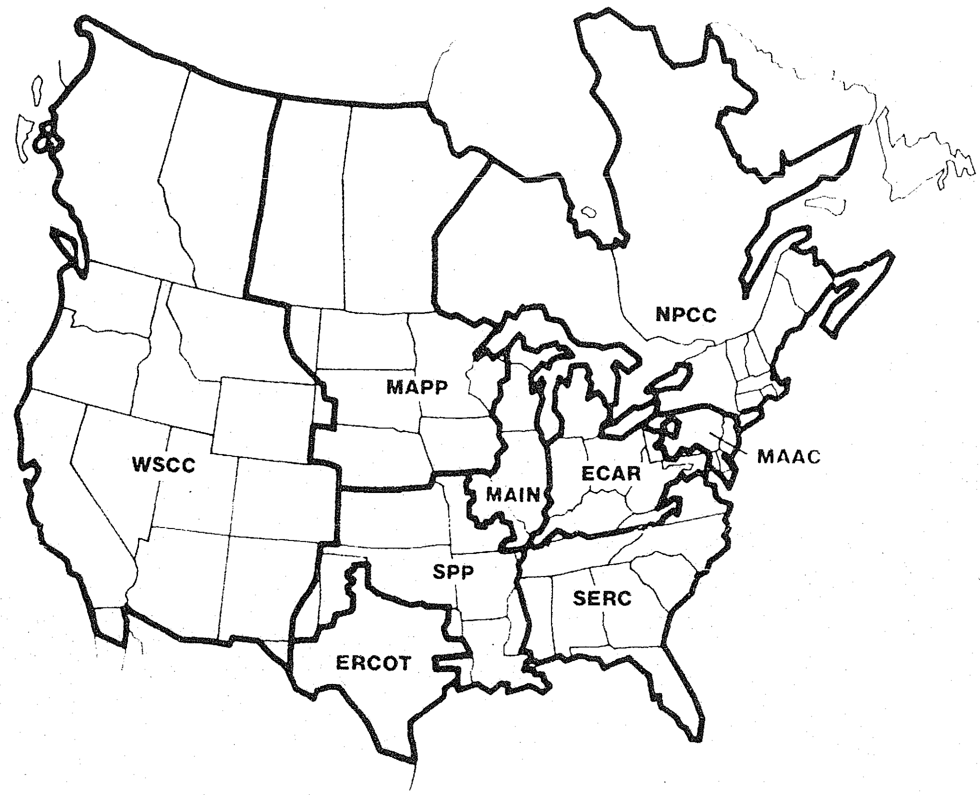


Fig. D-3. The Regional Reliability Councils of the North American Electric Reliability Council

Source: North American Electric Reliability Council, 1986 Reliability Review: A Review of Bulk Power System Reliability in North America (Princeton, NJ: North American Electric Reliability Council, 1986).

TABLE D-5

HIGH VOLTAGE TRANSMISSION LINES BY NERC REGION, AS OF JANUARY 1, 1986
(In Circuit-Miles)

	Alternating Current				Direct Current			
Voltage kV	230	345	500	765	±250-300	±400	±450	±500
Region								
U.S.:								
ECAR	1,083	11,747	847	1,923	0	0	0	0
ERCOT	0	6,371	0	0	0	0	0	0
MAAC	4,640	170	1,630	0	0	0	0	0
MAIN	262	5,051	0	90	0	0	0	0
MAPP	7,058	5,009	642	0	465	436	0	0
NPCC	1,534	4,023	5	252	0	0	0	0
SERC	19,230	2	6,673	0	0	0	0	0
SPP	3,978	4,450	2,079	0	0	0	0	0
WSCC	30,463	8,569[a]	10,676	0	0	0	0	1,333
Total	68,248	45,392	22,552	2,265	465	436	0	1,333
Canada:								
MAPP	4,113	924	130	0	0	0	1,139	0
NPCC	11,685	4,710[b]	1,381	6,315[c]	0	0	0	0
WSCC	4,787	264[a]	3,399	0	47	0	0	0
Total	20,585	5,898	4,910	6,315	47	0	1,139	0
Mexico:								
WSCC	626	0	0	0	0	0	0	0
NERC:								
Total	89,459	51,290	27,462	8,580	512	436	1,139	1,333

Source: North American Electric Reliability Council, 1986 Electricity Supply and Demand for 1986-1995 (Princeton, NJ: North American Electric Reliability Council, 1986), p. 57.

[a]Includes some 287-kV and 360-kV lines.
[b]Includes 315-kV lines.
[c]Includes 735-kV lines.

TABLE D-6

PLANNED HIGH VOLTAGE TRANSMISSION LINE ADDITIONS
BY NERC REGION, 1986 TO 1990
(In Circuit-Miles)

	Alternating Current				Direct Current			
Voltage kV	230	345	500	765	±250-300	±400	±450	±500
Region								
U.S.:								
ECAR	47	141	0	97	0	0	0	0
ERCOT	0	997	0	0	0	155	0	0
MAAC	216	0	25	0	0	0	0	0
MAIN	0	198	0	0	0	0	0	0
MAPP	199	180	0	0	0	0	0	0
NPCC	0	504	0	64	0	0	192	0
SERC	1,205	0	757	0	0	0	0	0
SPP	776	298	179	0	0	0	0	0
WSCC	1,573	1,581[a]	709	0	0	0	0	0
Total	4,016	3,899	1,670	161	0	155	192	0
Canada:								
MAPP	658	0	0	0	0	0	0	0
NPCC	212	381[b]	347	72[c]	0	0	748	0
WSCC	1,271	0	247	0	0	0	0	0
Total	2,141	381	594	72	0	0	748	0
Mexico:								
WSCC	0	0	0	0	0	0	0	0
NERC:								
Total	6,157	4,280	2,264	233	0	155	940	0

Source: North American Electric Reliability Council, 1986 Electricity Supply and Demand for 1986-1995 (Princeton, NJ: North American Electric Reliability Council, 1986), p. 58.
[a]Includes some 287-kV and 360-kV lines.
[b]Includes 315-kV lines.
[c]Includes 735-kV lines.

TABLE D-7

PLANNED HIGH VOLTAGE TRANSMISSION LINE ADDITIONS
BY NERC REGION, 1991 TO 1995
(In Circuit-Miles)

	Alternating Current				Direct Current			
Voltage kV	230	345	500	765	±250-300	±400	±450	±500
Region								
U.S.:								
ECAR	10	412	126	0	0	0	0	0
ERCOT	0	546	0	0	0	0	0	0
MAAC	78	0	86	0	0	0	0	0
MAIN	0	83	0	0	0	0	0	0
MAPP	206	363	225	0	0	0	0	0
NPCC	0	115	0	0	0	0	0	0
SERC	684	0	132	0	0	0	0	0
SPP	462	252	183	0	0	0	0	0
WSCC	499	549[a]	1,256	0	0	0	0	455
Total	1,939	2,320	2,008	0	0	0	0	455
Canada:								
MAPP	519	0	0	0	0	0	0	0
NPCC	464	209[b]	648	0	0	0	0	0
WSCC	281	79[a]	526	0	0	0	0	0
Total	1,264	288	1,174	0	0	0	0	0
Mexico:								
WSCC	31	0	0	0	0	0	0	0
NERC:								
Total	3,234	2,608	3,182	0	0	0	0	455

Source: North American Electric Reliability Council, 1986 Electricity Supply and Demand for 1986-1995 (Princeton, NJ: North American Electric Reliability Council, 1986), p. 59.
[a]Includes some 287-kV and 360-kV lines.
[b]Includes 315-kV lines.

250-300-kV DC lines, 0.3 percent; 400-kV DC lines, 0.2 percent; 450-kV DC lines, 0.6 percent; and 500-kV DC lines, 0.7 percent. (In both sets of calculations, percentages do not sum to 100 percent because of rounding.) The planned additions to the NERC system do not drastically alter it in terms of its voltage makeup, as shown in table D-8.

The discussion of transmission facilities thus far has dealt mainly with the continental United States and Canada. A few comments can also be made about Alaska and Hawaii. In 1985 Alaska had 472.3 circuit-miles of 115-kV line, 535.2 circuit-miles of 138-kV line, and 141.5 circuit-miles of 230-kV line. Most of these transmission lines (442.3 miles of 115-kV line, 242.5 miles of 138-kV line, and all of the 141.5 miles of 230-kV line) are located around Anchorage. Alaska also has 186 miles of 34.5-kV line and 354 miles of 69-kV line.[27]

Data from the Hawaiian Electric Company in the Energy Information Administration's Financial Statistics of Selected Electric Utilities show that in 1984 the utility had 170 circuit-miles of 132-kV to 143-kV line. Hawaiian Electric also had 467 structure-miles of 41-kV to 50-kV overhead line. Hawaiian Electric was the only Hawaiian electric utility included in the report.[28]

The Growing Demand for Wheeling

The discussion above shows that electric utilities have a variety of motivations for engaging in bulk power transactions and that those transactions have increased in terms of the absolute amount of power involved and, for interchanges, the percentage of power generated. Increases in bulk power exchange opportunities naturally lead to increased demands for wheeling services, and hence for increased transmission capacity.

Much of the North American high voltage transmission system consists of extra-high voltage lines (345 kV and above) that can facilitate large scale bulk power transactions and wheeling. While the map of control areas in

[27] Alaska Power Authority, Alaska Electric Power Statistics, 1960-1985, 11th ed. (Anchorage: State of Alaska, 1986), p. 59.
[28] Energy Information Administration, Financial Statistics of Selected Electric Utilities 1984, p. 656.

TABLE D-8
VOLTAGE COMPOSITION OF NERC SYSTEM
AFTER PLANNED ADDITIONS ARE MADE

Voltage	Circuit-Miles Projected for 12/31/95	Percentage of NERC System Accounted for by this Voltage
U.S.:		
230 kV AC	74,203	47.1
345 kV AC	51,611	32.8
500 kV AC	26,230	16.6
765 kV AC	2,426	1.5
±250-300 kV DC	465	0.3
±400 kV DC	591	0.4
±450 kV DC	192	0.1
±500 kV DC	1,788	1.1
Total	157,506	99.9
Canada:		
230 kV AC	23,990	52.7
345 kV AC	6,567	14.4
500 kV AC	6,678	14.7
765 kV AC	6,387	14.0
±250-300 kV DC	47	0.1
±400 kV DC	0	0.0
±450 kV DC	1,887	4.1
±500 kV DC	0	0.0
Total	45,556	100.0
NERC:		
230 kV AC	98,850	48.5
345 kV AC	58,178	28.6
500 kV AC	32,908	16.2
765 kV AC	8,813	4.3
±250-300 kV DC	512	0.2
±400 kV DC	591	0.3
±450 kV DC	2,079	1.0
±500 kV DC	1,788	0.9
Total	203,719	100.0

Source: North American Electric Reliability Council, 1986 Electricity Supply & Demand for 1986-1995 (Princeton, NJ: North American Electric Reliability Council, 1986), p. 60. Percentages were calculated by the authors, and may not sum to 100 percent because of rounding error.

figure D-1 would seem to suggest that the country is extensively interconnected, the map of the extra-high voltage system in figure D-4 shows a more limited capability to move large amounts of power. Despite this limitation, there are pressures building for increased wheeling and access to transmission. These demands are arising all over the country, and they may tax the ability of the current (and planned) EHV transmission system to meet all the needs in some areas. In framing policy on pricing wheeling services, one needs to be aware of the limitations of the nation's transmission system as illustrated in figure D-4.

Table D-9 presents a list of instances in which wheeling services are being negotiated, wheeling is demanded or sought by some party, or wheeling is being denied to a particular party. These examples have been taken from a two-year sampling of Electric Utility Week, covering January 1985 through December 1986.

The table shows a variety of trends and developments. These include the following: disputes over access to transmission facilities and wheeling services, wheeling for cogenerators and small power producers, wheeling to leave one utility system in favor of another or to bypass a utility, bottlenecks due to a lack of adequate transmission facilities, moving power from areas with a capacity surplus to areas with scarcity, and the increasing activity of brokers.

Examples of wheeling for cogenerators and small power producers are Houston Lighting & Power's wheeling of power from a Dow Chemical plant (items 6 and 26), the New York PSC ordering Niagara Mohawk to buy power from a trash plant (item 8), the wheeling of power by three utilities from a wood-fired plant to the Newport (Rhode Island) Electric Corporation (item 9), Texas Utilities Electric Company agreeing to buy firm capacity from a cogeneration plant yet to be built (item 10), the promulgation of cogeneration wheeling rules by the Texas PUC (items 12, 18, and 25), Montana Power agreeing to buy power (which will have to be wheeled 300 miles) from a Wyoming wind power developer (item 14), a Florida PSC ruling that utilities must wheel cogenerated power to other facilities owned by the cogenerator (item 19), the wheeling of power by three utilities from a wood-fired facility to Central Maine Power (item 37), and Idaho Power's agreement to build transmission facilities to wheel power from a hydro project near Boise to the city of Seattle (item 49).

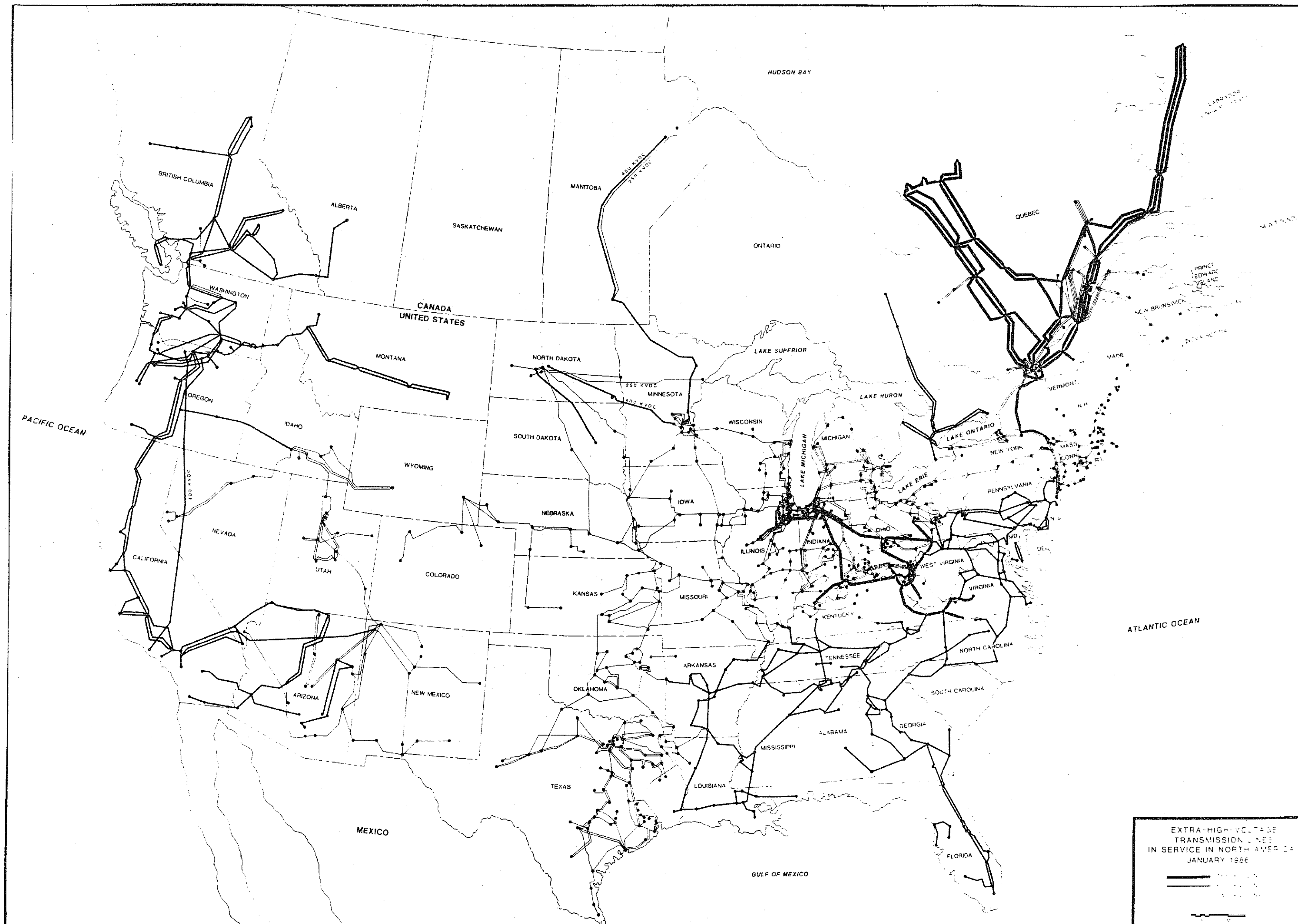


Fig. D-4 EHV Transmission Lines in Service in North America, January 1986. Source: American Electric Power Service Corporation.

TABLE D-9

EXAMPLES OF INSTANCES IN WHICH WHEELING IS OCCURRING OR WHEELING IS SOUGHT, 1985-86

---

1. Utah Power & Light (UP&L) and Deseret Generation & Transmission Cooperative engage in negotiations to settle a dispute over wheeling of power from Deseret's 400-MW Bonanza plant to several municipal systems in southwest Utah. UP&L later agrees to wheel nonfirm power from the Bonanza plant to out-of-state customers and says that it is willing to negotiate to wheel firm power from plants within Utah to in-state customers, subject to available transmission capacity. (Electric Utility Week, February 11, 1985, p. 7; Electric Utility Week, March 4, 1985, pp. 5-6.)

2. Western Area Power Administration officials support a proposal to build a 815-mile, 750-kV DC line between Oregon and Hoover Dam. A study by the Salt River Project, a quasi-governmental utility in Phoenix, Arizona, said that the line would facilitate bulk power exchanges, on a seasonal basis, between the Pacific Northwest and the Southwest. (Electric Utility Week, February 25, 1985, pp. 9-10.)

3. Canadian National Energy Board issues two licenses to Hydro-Quebec for power exports to the Vermont Department of Public Service. One license authorizes the export of 150 MW of firm power over 10 years. The second license authorizes the export of up to 200 MW of interruptible capacity and 1,752 gigawatt-hours of nonfirm energy every year for 10 years and 6 months. Exports made under the first license would be subtracted from the second license's annual maximum exports. The licenses must still be approved by the federal cabinet. (Electric Utility Week, March 11, 1985, pp. 5-6.)

4. The Salt River Project applies to the Arizona Power Plant and Transmission Line Siting Committee for a certificate to begin building a 500-kV DC line between Hoover Dam and Phoenix in 1988. The line will aid in the transfer of power between southern Nevada and Phoenix. Its initial capacity will be 1,600 MW with eventual capacity of 2,200 MW. (Electric Utility Week, April 15, 1985, p. 13.) Permit issued to build line. (Electric Utility Week, September 16, 1985, p. 15.)

5. Vermont Electric Power (VELCO) and the developers of a 25-MW hydro project, Missisquoi Associates, are attempting to resolve a dispute over the cost of upgrading VELCO facilities affected by the hydro project. One issue yet to be settled is how to set charges for wheeling power over VELCO lines. Missisquoi would like the charges to be based on the actual output of the plant. It is not clear if VELCO will use that method or set its charges as if the plant was transmitting power at peak capacity year-round. (Electric Utility Week, April 22, 1985, pp. 5-6.)

TABLE D-9 (continued)

EXAMPLES OF INSTANCES IN WHICH
WHEELING IS OCCURRING OR
WHEELING IS SOUGHT, 1985-86

---

6. Houston Lighting & Power (HL&P) agrees to wheel up to 300 MW/day of firm power during summer 1985 from a Dow Chemical complex at Freeport, Texas to Texas Utilities Electric. The contract is for four months and is renewable. Dow and HL&P had also recently signed a 10-year, 300-MW contract. HL&P is wheeling power from the Capitol Cogeneration facility near Houston to Texas-New Mexico Power. (Electric Utility Week, April 29, 1985, p. 9.) (See no. 26 below.)

7. Utah Power & Light (UP&L) is earning substantial profits brokering power between the Pacific Northwest and the Southwest. In 1984, UP&L cleared $38 million on power sales of $86 million. The utility buys surplus cheap hydro power in wet years from the Pacific Northwest and sells its own coal-generated power to the Southwest. In dry years, UP&L sells its excess power to both the Northwest and the Southwest. (Electric Utility Week, May 6, 1985, p. 8.)

8. The New York Public Service Commission orders Niagara Mohawk Power to buy 14 MW of power from a proposed trash plant in Erie, Pennsylvania if the developer can have the power wheeled to Niagara Mohawk. Pennsylvania Electric would have to agree to wheel the power. (Electric Utility Week, May 6, 1985, p. 9.)

9. Burlington (Vt.) Electric Department sells 8 MW of its 50% share of the 53-MW wood-fired McNeil power plant to the Newport (Rhode Island) Electric Corporation. Three investor-owned utilities are wheeling the power across Vermont and Massachusetts to Newport Electric. (Electric Utility Week, May 13, 1985, pp. 13-14.)

10. Texas Utilities Electric Company signs a 12-year contract to buy firm capacity to be wheeled from a 430-MW cogeneration plant to be built and operated by InterNorth Inc., an interstate gas pipeline. The power will be wheeled to TUEC through Houston Lighting & Power's service area. (Electric Utility Week, July 8, 1985, pp. 9-10.)

11. The New York Power Authority (NYPA) claims that Consolidated Edison is charging excessive rates to wheel NYPA nuclear power to two large industrial customers. The New York PSC will allow Con Ed's tariffs to go into effect, subject to refund with interest while it investigates. (Electric Utility Week, July 15, 1985, pp. 8-9.)

12. The Texas PUC issues cogeneration wheeling rule proposals. Commission staff recommend a "boundary" pricing mechanism, basing rates on the crossing of utility service territories instead of a mile-by-mile measurement. (Electric Utility Week, July 22, 1985, p. 13.)

TABLE D-9 (continued)

EXAMPLES OF INSTANCES IN WHICH
WHEELING IS OCCURRING OR
WHEELING IS SOUGHT, 1985-86

13. The Manitoba Energy Authority (MEA) is holding discussions with utilities in fifteen states (as well as with Ontario Hydro and Saskatchewan Power Corporation) as it tries to market up to 5,000 MW of power from the Nelson River hydro project. Power will be generated beginning around 1993. Talks are also being held with the Western Area Power Administration and the Minnesota-Wisconsin Power Suppliers Group. A 500-MW, 12-year contract has been signed with Northern States Power. (Electric Utility Week, July 29, 1985, pp. 13-14.)

14. Montana Power is negotiating a contract to buy 20 MW of power from Wyoming Wind Power, a wind farm developer in southern Wyoming. The power would have to be wheeled 300 miles to the utility. (Electric Utility Week, August 19, 1985, p. 11.)

15. Western Farmers Electric Cooperative of Oklahoma, which supplies power to nineteen cooperatives serving two-thirds of Oklahoma and part of Kansas and Texas, purchased the 138-kV Western Loop system from the Southwestern Power Administration. The purchase will enable Western to avoid wheeling charges it incurs in moving some of its power to the co-ops. (Electric Utility Week, August 19, 1985, p. 16.)

16. Utilities continue to study a 300-mile, 500-kV DC line between Los Angeles and Lake Mead near Boulder City, Nevada. The line is a proposed extension of the planned Mead to Phoenix 300-mile, 500-kV project from the Mead substation near Hoover Dam to Phoenix. (Electric Utility Week, August 19, 1985, pp. 15-16.)

17. The Bonneville Power Administration plans to propose rates to encourage Pacific Northwest utilities to buy power from the Administration and then resell it to California and the Southwest. (Electric Utility Week, August 26, 1985, pp. 1, 4.)

18. The Texas PUC proposes cogeneration wheeling rules requiring utilities to pay for upgrades in transmission facilities required for wheeling. The rules also include a "contract path" method for calculating wheeling charges under which the most direct path for a particular wheeling transaction would be found and developers would pay a higher rate to those utilities on this path than they would to other involved utilities not on that route. (Electric Utility Week, September 2, 1985, pp. 7-8.)

19. The Florida Public Service Commission rules that utilities must wheel cogenerated power to other facilities owned by that particular cogenerator. This is known as "self-service" wheeling. (Electric Utility Week, September 16, 1985, pp. 11-12.)

TABLE D-9 (continued)

EXAMPLES OF INSTANCES IN WHICH
WHEELING IS OCCURRING OR
WHEELING IS SOUGHT, 1985-86

---

20. Utah Power & Light (UP&L) and Utah Associated Municipal Power Systems (UAMPS) offer competing plans to build 345-kV transmission lines from central to southwest Utah. UAMPS argues that UP&L has a monopoly on high-voltage transmission in Utah. UP&L argues that it already has authority to build its line and further hearings are not needed. (Electric Utility Week, September 16, 1985, pp. 15-16.)

21. B.C. Hydro announces plans to build a 900-MW hydro project with all power to be exported to the U.S. The plan would compete with the Bonneville Power Administration's plan (see no. 17 in this table) to market power to Pacific Northwest utilities for resale to California and the Southwest. (Electric Utility Week, September 23, 1985, pp. 1, 2, 3, and Electric Utility Week, November 4, 1985, pp. 7-8.)

22. Utah Power & Light (UP&L) files suit against Utah Associated Municipal Power Systems (UAMPS) in their transmission line dispute (no. 20 above). UAMPS seeks to wheel power from the Intermountain Power Project, under construction, to municipal utilities. UP&L wants to stop UAMPS from proceeding with its plans. (Electric Utility Week, September 23, 1985, p. 7.) Former Secretary of Energy James Schlesinger files affidavit in support of UP&L. (Electric Utility Week, October 7, 1985, p. 8.)

23. Vermont Public Service Board, asked to resolve the dispute between Vermont Electric Power (VELCO) and Missisquoi Associates (see no. 5 above), criticizes VELCO for not dealing with potential problems in Vermont's links with the New York Power Authority. The Board ordered that Missisquoi should pay the lesser of either $50,000 or the portion of costs needed to upgrade a tie necessary to transmit Missisquoi's power. (Electric Utility Week, October 7, 1985, pp. 7-8.)

24. Utah Power & Light (UP&L) was not able to convince a Federal Energy Regulatory Commission administrative law judge that two long-term fixed-rate wheeling agreements, signed with the Western Area Power Administration twenty-three years previously, should be annulled. The ALJ said that the wheeling rates could not be increased and that UP&L had to live with its decision despite estimated revenue losses in 1984 of $7.5 million. Of the $7.5 million in losses, UP&L must absorb $900,000 with the remainder passed on to retail customers. (Electric Utility Week, October 14, 1985, pp. 8-9.)

TABLE D-9 (continued)

EXAMPLES OF INSTANCES IN WHICH
WHEELING IS OCCURRING OR
WHEELING IS SOUGHT, 1985-86

---

25. The Texas PUC issues its cogeneration wheeling rules, requiring utility wheeling of cogenerated power at rates of 3 to 4 mills/kWh. Support from both utilities and cogenerators was apparent from written comments on the rules. See nos. 12 and 18 above for previous stories. (Electric Utility Week, October 14, 1985, pp. 9-10.)

26. Texas Utilities allows cogeneration pact with Dow to expire. The contract was a 300-MW agreement. Dow says that the power will be used in-house while other markets are explored. (Electric Utility Week, October 14, 1985, p. 11.) See no. 6 above for previous story.

27. Eight Pacific Northwest and four Southwest utilities would like to build an electric power intertie that could cost up to $800 million, and be in service by 1995 or 1997. The southwestern utilities say that the tie is needed to get more northwestern surplus power to them. Very little arrives currently, they claim. The tie would have a 1,500- to 2,000-MW capacity and would run 1,100 miles from Twin Falls in southern Idaho to Mead, Nevada near Las Vegas. (Electric Utility Week, November 4, 1985, p. 7.)

28. Citizens Energy plans to become an independent electricity broker and asks the FERC for a declaratory order that its transactions not be subject to the Federal Power Act. If the FERC decides that it does have jurisdiction, Citizens asks that the Commission waive several of its regulations. (Electric Utility Week, November 4, 1985, pp. 5-6.)

29. Governors Arch Moore, Jr. of West Virginia and John Sununu of New Hampshire propose to transmit surplus power from the Midwest to the Northeast to compete with Canadian power imports. The plan includes building additional generation facilities in the Midwest; building a new transmission line to carry 2,000 MW of electricity from West Virginia to New England; and splitting any savings between the buyers and sellers, the states through which the line would run, and the exporting Midwest utilities. The utilities could use their share of the earnings to finance pollution control equipment. (Electric Utility Week, November 18, 1985, pp. 7-8.) Moore and Sununu say they will move ahead with their plan. (Electric Utility Week, November 25, 1985, p. 5.)

TABLE D-9 (continued)

EXAMPLES OF INSTANCES IN WHICH
WHEELING IS OCCURRING OR
WHEELING IS SOUGHT, 1985-86

30. The New Jersey Board of Public Utilities is developing a statewide wheeling policy. An objective is to wheel cogenerated power from the Public Service Electric & Gas (PSE&G) area to the Jersey Central Power & Light (JCP&L) area. PSE&G does not need the cogenerators' power but JCP&L has a capacity shortage. A "postage stamp" rate is likely to be mandated in the regulations. (Electric Utility Week, December 9, 1985, p. 14.)

31. The city of Geneva, Illinois claims that Commonwealth Edison has abused its monopoly power by proposing a wheeling rate that the city says would prevent it from buying cheaper power from Wisconsin Electric Power and thus leaving the Commonwealth Ed system. The city requests that the FERC hold a hearing. The FERC subsequently rules in favor of the city and orders Commonwealth Ed to replace the marginal cost based rate with an embedded cost based rate and no standby charge. (Electric Utility Week, January 20, 1986, pp. 1-2; and Electric Utility Week, February 3, 1986, pp. 1, 10-11.)

32. An FERC administrative law judge rejects a request by the city of Manti, Utah to order Utah Power & Light to wheel power on behalf of the city. (Electric Utility Week, February 3, 1986, p. 11.) Manti files second request for the FERC to order UP&L to wheel. (Electric Utility Week, February 24, 1986, pp. 10-11.)

33. The Bonneville Power Administration (BPA) proposes to sell Southern California Edison 550 MW of surplus firm power over the next 20 years. The contract is likely to be signed and is an important step in the plans of BPA to wheel its surplus power to California or to the Southwest. (Electric Utility Week, February 10, 1986, pp. 1-2.)

34. Howard Allen, chairman and chief executive officer of Southern California Edison, argues against mandatory wheeling. The National Governors' Association backs away from a resolution calling for mandatory wheeling in favor of a resolution for a "strong national electricity transmission policy." (Electric Utility Week, March 3, 1986, pp. 13-14.)

35. Pennsylvania Power & Light's limited transmission capacity may hinder the development of up to 1,600 MW of waste coal-fired cogeneration and small power, as well as obstruct the wheeling of power to other utilities. (Electric Utility Week, March 10, 1986, pp. 12-13.)

TABLE D-9 (continued)

EXAMPLES OF INSTANCES IN WHICH
WHEELING IS OCCURRING OR
WHEELING IS SOUGHT, 1985-86

---

36. Arkansas Power & Light (AP&L) asks the FERC for a declaratory order saying that it does not have to wheel power for the City Water & Light Plant of Jonesboro, Arkansas or Farmers Electric Cooperative Corporation. A requirement to wheel would result in the utility losing all sales that it now makes to Farmers. (Electric Utility Week, March 17, 1986, pp. 11-12.) The FERC denies the AP&L request. (Electric Utility Week, July 21, 1986, p. 4.)

37. Maine Public Service, the New Brunswick Power Commission, and Maine Electric Power plan to wheel power from an independent producer, a 30-MW wood-fired facility near Fort Fairfield, Maine, to Central Maine Power. (Electric Utility Week, March 17, 1986, p. 12.)

38. Citizens Energy concludes its first electric power agreement. It involves the Utah Municipal Power Association (UMPA) and the Los Angeles Department of Water & Power. An earlier request by Citizens to the FERC to exempt its brokerage deals from federal regulation is still pending (see no. 28 above) and Citizens plans to make an additional filing with the FERC for the Los Angeles-UMPA deal. (Electric Utility Week, April 7, 1986, pp. 8-9.)

39. The owner of three geothermal projects, Oxbow Geothermal Corporation, proposes building a 210-mile, 230-kV line from Nevada to California to deliver power to Southern California Edison. Oxbow claims that Nevada utilities do not have the transmission capacity to wheel the power from the projects, located in Dixie Valley, Nevada, to Southern California Edison. (Electric Utility Week, April 14, 1986, pp. 11-12.)

40. Washington Water Power (WWP) and B.C. Hydro may construct a 100-mile transmission line so that WWP could receive Canadian power directly and avoid the need to use the Bonneville Power Administration's transmission facilities. The line would be 230 kV and either 500 MW or 1,500 MW. (Electric Utility Week, April 21, 1986, p. 9.)

41. Citizens Energy files UMPA-LADWP agreement (see no. 38 above) with the FERC. (Electric Utility Week, May 12, 1986, p. 6.) The FERC approves Citizens' request for a declaratory order exempting it from the Federal Power Act when it functions as a broker (see no. 28 above). The Commission also ruled, however, that Citizens is subject to its jurisdiction when it functions as a marketer. (Electric Utility Week, May 19, 1986, pp. 1, 4.)

TABLE D-9 (continued)

EXAMPLES OF INSTANCES IN WHICH
WHEELING IS OCCURRING OR
WHEELING IS SOUGHT, 1985-86

---

42. Pennsylvania Power & Light and sixteen developers agree on how to pay for upgrades in transmission capacity necessitated by the development of waste coal-fired projects in the utility's service area. (See no. 35 above for previous story.) (Electric Utility Week, May 26, 1986, pp. 5-6.)

43. The Southwestern Power Administration (SWPA) and the city of Clarksville, Oklahoma sign a contract that will enable them to avoid substantial ($500,000/year) wheeling fees that they currently pay to Oklahoma Gas and Electric. Clarksville will build new transmission lines and SWPA will work on a substation. SWPA will then sell Clarksville some of its power and also transmit power to the city from the Western Farmers Electric Cooperative in Anadarko, Oklahoma. (Electric Utility Week, May 26, 1986, pp. 14-15.)

44. The Western Area Power Administration and eleven private utilities in the Southwest and Pacific Northwest are undertaking a 32-month study to determine the feasibility of a 500-kV DC line between the two regions. (Electric Utility Week, June 16, 1986, pp. 13-14.) Sixteen additional utilities join the study. (Electric Utility Week, September 22, 1986, p. 6.)

45. The FERC orders Utah Power & Light and the city of Manti, Utah to negotiate a transmission contract within forty-five days. (See no. 32 above for previous stories.) (Electric Utility Week, August 4, 1986, pp. 13-14.)

46. Four cogenerators plan to build a 42-mile, 115-kV line to connect to a Pacific Gas & Electric (PG&E) substation in the San Joaquin Valley in California. Inadequate transmission capacity made the new line necessary. Projects totaling 2,500 MW are waiting for access to the PG&E northern service territory. (Electric Utility Week, September 1, 1986, pp. 7-8.)

47. Citizens Energy arranges second power transaction. This arrangement involves the sale of power from the Utah Municipal Power Agency (UMPA) to the city of Pasadena, California. (Electric Utility Week, September 15, 1986, pp. 7-8.) The FERC approves the first transaction arranged by Citizens, involving the UMPA and the Los Angeles Department of Water and Power (see nos. 38 and 41 above). (Electric Utility Week, September 29, 1986, p. 12.)

TABLE D-9 (continued)

EXAMPLES OF INSTANCES IN WHICH
WHEELING IS OCCURRING OR
WHEELING IS SOUGHT, 1985-86

---

48. Illinois establishes the Illinois Energy Board, modeled after Citizens Energy, to function as broker and marketer and facilitate power sales within and outside the state. (Electric Utility Week, October 13, 1986, pp. 1 & 2.)

49. Idaho Power agrees to build transmission facilities to wheel power from a hydro project under construction near Boise to the City of Seattle Department of Lighting. The facilities to be constructed include a switchyard at the project site, and four miles of new 138-kV line. Seven miles of existing line will also be upgraded. (Electric Utility Week, October 20, 1986, pp. 10-11.)

50. Utah Power & Light (UP&L) agrees to wheel power for two Utah cities, Provo and Manti. (See nos. 32 and 45 above for previous stories.) UP&L agreed to wheel power to or from the cities. (Electric Utility Week, November 24, 1986, p. 5.)

51. Sho-Me Power Corporation, a Missouri generation and transmission cooperative, proposes to wheel power and provide retail service to customers off limits to its member cooperatives. Under state law, co-ops cannot serve new load in towns with more than 1,500 residents. Sho-Me proposes to wheel power over its members' systems, receive the power at the end of the line, and provide retail service to customers as a public utility. (Electric Utility Week, December 8, 1986, pp. 7-8.)

52. Airco Industrial Gases would like cheaper Hydro-Quebec power for its plant in Kittery, Maine. Public Service New Hampshire, which formerly served that area, is willing to wheel the Canadian power to the plant. The plan is opposed by Central Maine Power, which currently serves the plant, and the Maine Public Utilities Commission. (Electric Utility Week, December 15, 1986, pp. 1-2.)

Sources: Various editions of Electric Utility Week, as cited in the table.

Cases involving wheeling to leave one utility system in favor of another or to bypass a utility include the FERC ruling in favor of the city of Geneva, Illinois, which had claimed that Commonwealth Edison had proposed an excessive wheeling rate in order to prevent the city from buying cheaper power from Wisconsin Electric Power and thus leaving the Commonwealth Ed system (item 31), the FERC denying Arkansas Power & Light's request for an order that it does not have to wheel power for (and risk losing) one of its customers (item 36), the Southwestern Power Administration and Clarksville, Oklahoma bypassing Oklahoma Gas and Electric by building new facilities and wheeling power from a cooperative (item 43), and Airco Industrial Gases of Maine attempting to obtain cheaper Hydro-Quebec power (via wheeling by Public Service New Hampshire) and bypass Central Maine Power (item 52).

Using wheeling specifically (or bulk power exchange generally) to move power from areas of surplus to areas of scarcity includes the Canadian National Energy Board issuing licenses to Hydro-Quebec to export power to the Vermont Department of Public Service (item 3), a planned transmission line between Hoover Dam and Phoenix (item 4), Manitoba Energy Authority negotiations to market bulk power (item 13), the Bonneville Power Administration's proposed rates to encourage Pacific Northwest utilities to buy its power for resale in California and the Southwest (item 17), B.C. Hydro's planned 900-MW hydro project (item 21), a proposal by Governors Arch Moore of West Virginia and John Sununu of New Hampshire to move power from the Midwest to the Northeast (item 29), development by the New Jersey Board of Public Utilities of a wheeling policy to move power from the Public Service Electric and Gas service area to the Jersey Central Power & Light area (item 30), and a planned sale by the Bonneville Power Administration of bottlenecks due to a lack of adequate transmission facilities. Disputes over access include a dispute between Utah Power & Light (UP&L) and Deseretsurplus firm power to Southern California Edison (item 33). The activity of brokers includes Utah Power & Light (item 7), Citizens Energy (items 28, 38, 41, and 47), and the establishment of the Illinois Energy Board, modeled after Citizens Energy (item 48).

The general question of where wheeling service is wanted includes disputes over access to transmission facilities and wheeling services, and Generation and Transmission over wheeling of power from Deseret's power plant (item 1), a dispute between Vermont Electric Power and Missisquoi

Associates over upgrading the utility's facilities to handle power from the cogenerator (items 5 and 23), a confrontation between UP&L and the Utah Associated Municipal Power Systems over wheeling of power from the latter's facility (items 20, and 22), and a dispute between UP&L and the city of Manti, Utah over the wheeling of power for the city (items 32, 45, and 50). Bottlenecks due to a lack of adequate transmission facilities include the problem of moving surplus power from the Pacific Northwest to California and the Southwest (items 2, 16, 27, and 44), the need for more transmission facilities in Pennsylvania Power & Light's area to encourage development of cogeneration (items 35, and 42), a proposal by the owner of three geothermal projects in Nevada to build a transmission line to California because of insufficient available transmission capacity to wheel the projects' power (item 39), a proposal by Washington Water Power and B.C. Hydro to construct a transmission line enabling the former to receive power directly from the latter instead of having to go through the Bonneville Power Administration's system (item 40), and a plan by four cogenerators to build a transmission line because of inadequate available capacity to connect with a Pacific Gas & Electric substation (item 46).

APPENDIX E

CONFIDENCE INTERVALS FOR ESTIMATED LINE COSTS

The regression technique used in chapter 5 to estimate transmission line costs not only yields coefficients for the estimated equation, but also measures the probability and extent of any difference (called "error") between actual costs and estimated costs. Confidence intervals relate the probability of an error to the size of that error by forming cost intervals around each cost estimate. The size of a 90-percent confidence interval, for example, is set so that actual cost has a 90 percent likelihood of being somewhere within the interval. The formula, $\exp[\ln C \pm ts]$, generates a confidence interval around the logarithmic cost estimate $\ln C$, where C is cost per mile, t is the number of standard errors needed to achieve the analyst's chosen confidence level, and s is the standard error of the regression, which is 0.42 in chapter 5. Increasing the t-value increases the confidence level by widening the interval's range. Table E-1 reproduces the estimated costs in table 5-11 and presents the 90-percent confidence intervals in parentheses below each estimate.

The regression error is due partly to the use of simple representations of the variables affecting cost. The variables measuring the number of circuits, terrain type, population density, and region can explain cost only imperfectly and consequently the confidence intervals for costs are wide. Structure, for example, is measured as either poles or towers; however, many types of poles and towers with differing cost characteristics exist, as discussed in chapter 2. Poles can be made of wood, prestressed concrete, or steel. The category includes simple poles and more elaborate designs like H-frames. Towers also vary in configuration, size, and material. A simple dichotomy does not capture such distinctions, nor their impact on cost. Other variables that can affect cost, such as average humidity, frequency

TABLE E-1

ESTIMATED COSTS PER MILE AND 90-PERCENT CONFIDENCE INTERVALS
FOR TYPICAL SINGLE-CIRCUIT LINES, 50 POLE-MILES
IN LENGTH, BY REGION AND VOLTAGE
(in Thousands of 1985 Dollars per Pole-Mile)

Voltage	Handy-Whitman Regions					
	PL	NC	SA	SC	PC	NA
115 kV	90 (50-190)	120 (60-240)	130 (70-260)	140 (70-280)	150 (70-300)	180 (90-360)
138 kV	100 (50-200)	140 (70-260)	140 (70-280)	150 (80-310)	160 (80-320)	190 (100-390)
161 kV	110 (60-220)	140 (70-280)	150 (80-310)	170 (80-330)	180 (90-350)	210 (110-420)
230 kV	150 (80-300)	190 (100-390)	210 (110-420)	230 (110-450)	240 (120-480)	290 (140-570)
345 kV	220 (110-440)	280 (140-570)	310 (150-610)	330 (170-660)	350 (180-700)	420 (210-830)
500 kV	290 (150-570)	370 (190-740)	400 (210-800)	430 (220-860)	460 (230-910)	550 (270-1090)
765 kV	410 (210-820)	530 (260-1050)	570 (290-1140)	620 (310-1230)	650 (330-1290)	780 (390-1550)

Source: Estimated cost equation of chapter 5.

of lightning strokes in the area, amount of compensation equipment, conductor type and bundling, and so on, are either not represented or only partially represented by the variables in the cost equation of chapter 5.

The consequence of using simple measurements in place of detailed line design data is that the error can be large. The wide confidence intervals in table E-1 bear this out, suggesting that, while the estimated cost results are useful for determining typical costs and cost ranges, by region and voltage, they cannot, of course, replace engineering studies for determining actual costs of particular new lines.

APPENDIX F

CURRENT WHEELING RATES

This appendix provides an overview of the structure of current wheeling rates, including those filed with the FERC, rates filed with some of the states, and rates set by other agencies. It is based on surveys recently published by others and summarized here. It should be mentioned early in this review that, as noted by the authors of the surveys, wheeling tariffs and rate schedules generally do not describe in detail the methods used to develop the rates. Thus, any observations on rate methodology reported in this appendix are mainly the survey authors' informed conclusions, based on their experiences, as to how those rates were developed.

Many different wheeling rate designs are in use. Reviews of wheeling rates filed with the FERC have found the postage stamp type of rate to be the most common.[1] The postage stamp rate is a fixed charge per unit of energy or power transmitted, irrespective of the distance that the power travels. Postage stamp rates can be based on energy (cents per kilowatt-hour), demand (dollars per kilowatt), or both demand and energy (a rate that includes a flat charge per kilowatt-hour delivered plus a charge based on metered kilowatt demand). Occasionally, a rate design may be of the postage stamp type for one component, usually energy, and based on

---

[1] Edison Electric Institute, Rate Regulation Department, Terms and Conditions of Existing Transmission Service Agreements and Tariffs (Washington, D.C.: Edison Electric Institute, 1984), pp. 5-10; and A. Stewart Holmes, "A Review and Evaluation of Selected Wheeling Arrangements and A Proposed General Wheeling Tariff," Staff Working Paper, Federal Energy Regulatory Commission, Office of Regulatory Analysis, September 1983.

mileage for the other (usually stated as dollars per kilowatt per circuit-mile).

In addition to postage stamp rates, other types of rates include formulary rates, fixed charges, and no compensation. Formulary rates involve the use of a formula that alters the monthly charge with changes in demand and in specified costs. Fixed charges are charges for the exclusive use of specific facilities, including transmission and/or substation facilities, by the wheeling customer. These charges may also be used to cover the use of jointly-owned or pooled facilities, and are usually stated in dollars per month. Wheeling with "no compensation" involves the provision of wheeling services without charge in return for which the recipient is expected to furnish similar services at a later date.

Two types of wheeling service are generally offered: firm and nonfirm. Firm wheeling service may be offered in long-term contracts (such as unit contracts), entitlements to jointly-owned units, and requirements service. A survey by the Edison Electric Institute found the terms of service of firm contracts to be generally long, usually 20 years, but sometimes as long as 40 years.[2] In general, firm wheeling is not interruptible simply because peak demand exceeds capacity. There is an implicit understanding that the wheeling utility will construct facilities if needed to carry firm wheeling plus native load. The postage stamp $/kW rate is the most common form used in firm wheeling contracts, particularly for requirements service. The dollar-per-kilowatt rates surveyed by EEI varied from $0.20/kW/month to $1.612/kW/month. The cents per kilowatt-hour postage stamp rate was found mainly among requirements and firm power wheeling customers of the federal power marketing agencies. The charges varied from 0.1 mills/kWh to 42 mills/kWh. Formulary or fixed charge rates were also used for firm wheeling services, especially for entitlements or unit power. Fixed charges are generally set on a dollars/month basis. Note, that contract lengths of 20 to 40 years do not mean that price is fixed for such a period. Wheeling rates are regulated by the FERC and are subject to recalculation according to cost of service principles in every rate case.

---

[2] Edison Electric Institute, <u>Terms and Conditions</u>, pp. 5-8.

Nonfirm wheeling arrangements are generally of shorter duration and less precise concerning operating procedures than firm wheeling arrangements. Nonfirm wheeling contracts can be as long as 10 to 20 years. Service is interruptible during this term for various contingencies, including peak demand exceeding capacity. The postage stamp cents-per-kilowatt-hour rate was the most common rate for nonfirm wheeling found by the EEI in its survey. The rates ranged from 0.15 mills/kWh to 5.25 mills/kWh, with most at or below 2 mills/kWh. Some rates also use a dollars-per-kilowatt structure. In some instances, no compensation is required, but reciprocal services are expected to be provided by the recipient of the wheeling services.[3]

An FERC staff analysis of sixteen wheeling tariffs or rate schedules on file at the Commission in 1983 offered some further observations about rates for wheeling services.[4] The sixteen tariffs or rate schedules (twelve of the former, four of the latter) were chosen so as to reflect the wide range of terms or conditions present in such arrangements.

As in the EEI survey, the majority (all but two) of the wheeling arrangements had postage stamp rates. Firm service generally uses monthly, weekly, or daily charges per kilowatt or megawatt, while interruptible rates generally are based on kilowatt-hours wheeled.

The two wheeling arrangements that did not use postage stamp rates employed cost savings in one instance and a fixed charges-distance charge combination in the other. The cost savings rate was for interruptible service. The charge for wheeling was fifteen percent of the customer's savings in power costs. The fixed charges-distance charge rate was a Bonneville Power Administration monthly charge per kilowatt. The distance charge was derived by multiplying by 1.15 the number of airline-miles between the receipt point and delivery point of the power that was wheeled.[5]

According to the FERC analysis, firm rates are usually based on the total embedded costs of the wheeler's transmission facilities, including the return on transmission rate base, depreciation of transmission

---

[3] Ibid., p. 9.
[4] Holmes, "A Review and Evaluation," pp. 5, 19-25.
[5] Ibid., pp. 19-20.

facilities, operation and maintenance expenses, allocated taxes, and some administrative and general expenses. The embedded costs are then divided by a measure of the system peak (such as a single annual peak or an average of the twelve monthly peaks) to obtain an annual charge per kilowatt; this can be adjusted to a monthly, weekly, or daily charge.[6]

Two utilities studied in the FERC staff analysis offered conditionally interruptible service. The rates (dollars per kilowatt per year) were based on embedded transmission costs, as discussed above, divided by the wheeling system's total transmission capability. System capability measures the peak load that could be transmitted during a given time; it is approximated as the generating capability of a utility's own generating units plus any additional transmission capacity available for importing power from other systems.[7]

Unconditionally interruptible rates were offered in six of the wheeling arrangements. These were usually stated as a charge per kilowatt-hour. Only one rate schedule in the survey specified the method used to derive the rate, and this method consisted of dividing the monthly firm rate (stated as a per-kilowatt charge) by 730 (the number of hours in a month). The resulting rate, known as a 100-percent-load-factor rate, represented the per-kilowatt-hour charge that would result in the same revenue as a specified demand charge per kilowatt, assuming that the same amount of power would be wheeled all the time.[8]

With respect to wheeling rates filed with commissions or agencies other than the FERC (such as federal power marketing agencies), a survey of 176 such rates was conducted (as part of a larger study) for the Department of Energy.[9] Over three-quarters (79 percent) of the non-FERC arrangements contained provisions for firm service. The usual compensation method was a single specific rate (69 percent of the arrangements), although multipart rates were also used in some of the agreements (20 percent). Nonmonetary compensation was used in a small number (2 percent) of the arrangements.

---

[6] Ibid., p. 22.
[7] Ibid., p. 23.
[8] Ibid., p. 24.
[9] Richard C. Tepel et al., Analysis of Power Wheeling Services, prepared for the U.S. Department of Energy, November 1984, appendix I.

Eight non-FERC agencies were included in the study. A brief overview of wheeling arrangements filed with each follows.[10] The Public Utility Commission of Texas specified certain requirements for firm service agreements.[11] The parties would file the agreements with the Commission only if there was some disagreement about the arrangements, however. In transactions involving more than 25 megawatts, the wheeling charge was derived by multiplying the actual cost of the transmission system (found in a cost-of-service study) by the changes in megawatt-miles of power flow caused by the provision of wheeling services, and dividing this product by the total megawatt-miles of the utility's power flow (determined by load flow studies during the peak). In transactions involving less than 25 megawatts, and if the buyer only had one interconnection with other utilities, the buyer could choose to multiply the annual cost of the wheeler-provided transmission service by the megawatts of wheeling service contracted for and divide this product by the wheeler's system peak megawatt load.

The Tennessee Valley Authority (TVA) wheels power received from Big Rivers Electric Power Corporation to Alabama Electric Cooperative, and South Mississippi Electric Power Association. At the time of the survey, the TVA was charging 20 cents per week per kilowatt of the maximum aggregate hourly amount of power scheduled for transmission and 0.22 cents per kilowatt-hour for miscellaneous energy that may also be transmitted. A customer charge of $1,000 per month was also being assessed.

The Alaska Power Administration (APA) markets hydroelectric power generated by two projects. The APA has arranged wheeling of the power, which it markets, by third parties to its preference customers. The customers receive long-term firm access to the power in order to satisfy their wholesale requirements. Rates at the time of the DOE study were being assessed in mills per kilowatt-hour.

The Bonneville Power Administration (BPA) at the time of the DOE-sponsored study used three rate schedules for wheeling services that it provided. The Formula Power Transmission (FPT-1) rate schedule was a

---

[10] Ibid., pp. I.8-I.23.
[11] Ibid. These Texas data predate the recently revised Texas system for compensating wheeling services.

multipart rate that consisted of a Main Grid Charge for use of facilities of greater than 115 kV, a Secondary System Charge for use of facilities of 115 kV or less, and an Intertie Charge for use of the Pacific Northwest-Pacific Southwest Intertie. The Main Grid and Secondary System rates included charges per kilowatt and a rate per mile ($0.135/mile for Main Grid and $0.036/mile for Secondary System). The Use-of-Facilities Transmission (UFT-1) rate schedule applied to the use of specific portions of the BPA transmission system (referred to as the Federal Transmission System). The monthly charge per kilowatt was set equal to one-twelfth of the annual cost per kilowatt of the capacity of the facilities. The Energy Transmission (ET-1) rate schedule covered transmission (using excess capacity of the Federal Transmission System) of nonfirm energy from other utilities. The rate varied depending on the portion (Main Grid, Secondary System, or Intertie) of the transmission system used. The range, at the time of the survey, was from 0.75 mills/kWh for the Main Grid to 1.25 mills/kWh for the Intertie.

The Southeastern Power Administration (SEPA) is responsible for marketing power from various reservoir projects, and it has negotiated contracts with investor-owned utilities to wheel power. The SEPA has no transmission facilities of its own. Transmission rates are mileage-based with the charge per kWh increasing as the distance between reservoir and delivery point increases. Three zones are established going out from each reservoir. The first zone covers a 100-mile radius from the project; the second, 101 to 150 miles; and the third, greater than 150 miles. Charges at the time of the survey increased from 1.00 mill/kWh for delivery in the first zone, to 1.75 mills/kWh for the second zone, to 2.5 mills/kWh for the third.

The Southwestern Power Administration (SWPA) markets power from hydro projects in the Southwest, and it is charged by the Flood Control Act of 1944 with wheeling nonfederal power over any excess transmission capacity that it may have. Wheeling service at the time of the DOE-sponsored study was being provided under Rate Schedule TDC-2, a postage stamp rate approved by the FERC. Under this schedule, charges were based on the specific facilities used. Rates differed by the voltage of the transmission line used and the amount of transformer service required.

Interruptible service was being provided at a rate 5 percent lower than firm service.

The Western Area Power Administration (WAPA) markets power from hydroelectric facilities and one coal-fired facility in the West. The WAPA has negotiated a series of agreements with investor-owned utilities and generation and transmission cooperatives. These utilities wheel full or partial requirements power to preference customers of the WAPA, charging (at the time of the survey) 1 mill/kWh for scheduled transmission. The WAPA markets power from four projects that also have their own transmission systems. Wheeling is provided for nonpreference customers over these systems. Rates have been set for nonpreference customers for one of those systems (the Parker-Davis System in Arizona). At the time of the DOE-sponsored survey, firm service was provided for $3.67/kW/month. Nonfirm service was provided for 1.3 mills/kWh. Charges for firm and nonfirm wheeling service in other parts of the WAPA system were negotiated by the parties involved. Some rates were 1 mill per kilowatt-hour for firm and nonfirm services in some instances, and $5.30 per kilowatt per year for firm service in other cases.

The New York Power Authority (NYPA) generates and markets power from hydroelectric, nuclear, and fossil fuel plants. The NYPA provides requirements power for municipalities and rural cooperatives and has entered into wheeling contracts with investor-owned utilities to supply the power to its customers. Each utility charges for the wheeling service that it provides, and the charges are paid by the Authority. The NYPA also purchases power from Hydro-Quebec in Canada for resale to seven New York investor-owned utilities and two preference customers on Long Island. The NYPA transmits the power to the Niagara-Mohawk Power Corporation, charging (at the time of the DOE study) 1 mill per kilowatt-hour.

A recent case in Florida provides a final example of non-FERC wheeling rates.[12] The Florida Public Service Commission approved in April 1986 Florida Power's and Tampa Electric's wheeling rates for cogenerated power. Florida Power's rate for firm service was approved as $1.148 per kilowatt per month. Its nonfirm service rate was approved as 1.57 mills

---

[12] "Florida PSC Okays Florida Power, TECO Wheeling Rates for Cogenerators," Electric Utility Week, April 21, 1986, pp. 14-15.

per kilowatt-hour. Tampa Electric's rates were $1.225 per kilowatt per month for firm service and 2.5 mills per kilowatt-hour for nonfirm service.

BIBLIOGRAPHY

This bibliography includes the reference works and specific sources used by the authors in the course of preparing this report, as well as some other works that those interested in wheeling or related topics may wish to consult. The bibliography is not intended to be comprehensive. Many valuable publications are omitted, such as those of CIGRE and the material published by the Federal Power Commission in the various National Power Surveys.

The authors are arranged alphabetically within seven categories: technology, costs, economics, gain sharing, pricing, laws and regulations, and transmission policy. Although some works could have been listed under more than one category, each title is listed only once, under that category that best reflects its content.

Technology

Albrecht, Paul F., and Fink, Jack L. "Availability and Reliability Overview." Electric Forum 9 (1984):10-14.

Allaire, Jacques F.; Durand, Claude; Fink, Jack L.; Haralampu, George S.; Holt, David L.; and Richardson, Leon M. "Challenges and Alternatives of the New England-Hydro-Quebec HVDC Project." Electric Forum 9 (1984):15-24.

Allentuck, J. Automated Poolwide Economic Dispatch of Electric Generating Units and the Concept of Natural Monopoly. Brookhaven National Laboratory, 1979.

Anderson, S. W.; Landgren, G. L.; and White, R. "A Reliability Approach to Interconnection Planning." IEEE Transactions on Power Apparatus and Systems PAS-94 (1975):1644-51.

Anstine, L. T.; Burke, R. E.; Casey, J. E.; Holgate, R.; John, R. S.; and Stewart, H. G. "Application of Probability Methods to the Determination of Spinning Reserve Requirements for the Pennsylvania-New Jersey-Maryland Interconnection." IEEE Transactions on Power Apparatus and Systems PAS-82 (1963):720-35.

Arrillaga, J. High Voltage Direct Current Transmission. London: Peter Peregrinus Ltd., 1983.

Bhavaraju, M. P.; Billinton, R.; and Thompson, P. R. "Power System Interconnection Benefits." CEA Transactions, March 1969.

Billinton, Roy, and Allan, Ronald N. Reliability Evaluation of Power Systems. Marshfield, MA: Pitman, 1984.

Billinton, R., and Jain, A. V. "Power System Spinning Reserve Determination in a Multi-System Configuration." IEEE Transactions on Power Apparatus and Systems PAS-92 (1973):433-41.

Billinton, R.; Kuruganty, P. R. S.; Thompson, P. R.; and Wee, C. L. "Interconnected System Reliability Evaluation--Applications." CEA Transactions 20 (1981): Paper No. 81-SP-145.

Billinton, R.; Kuruganty, P. R. S.; Thompson, P. R.; and Wee, C. L. "Interconnected System Reliability Evaluation--Concepts and Philosophy." CEA Transactions 20 (1981): Paper No. 81-SP-144.

Billinton, R. and Wee, C. L. "A Frequency and Duration Approach for Interconnected System Reliability Evaluation." IEEE Transactions on Power Apparatus and Systems PAS-101 (1982):1030-39.

Breuer, Glenn D.; Ewart, Donald N.; and Tice, James B. "Energy Transport: An Interim Option for Generation Planners." Electric Forum 10 (1984):8-13.

Breuer, Glenn D.; Flairty, Clarence W.; and Nozari, Farhad. "An HVDC Option: Multi-Terminal Systems." Electric Forum 9 (1984):32-37.

Chan, Shu-Park; Chan, Shu-Yun; and Chan, Shu-Gar. Analysis of Linear Networks and Systems. Reading, MA: Addison-Wesley, 1972.

Cohn, Nathan Control of Generation and Power Flow on Interconnected Power Systems. New York: John Wiley & Sons, 1961.

Cohn, N. "Techniques for Improving the Control of Bulk Power Transfers on Interconnected Systems." IEEE Paper 71 TP81-PWK, 1971.

Damsky, Ben L. "Advanced Thyristor Valve Project." Electric Forum 9 (1984): 38-42.

Degeneff, Robert C. "Advanced Study Techniques: Tools for HVDC Systems Design." Electric Forum 9 (1984):4-9.

Degeneff, Robert C., and Jordan, Gary A. "Software Aims at Power-Pool Operations." Electrical World, June 1986, pp. 91-92.

Dhar, S. B., and Pang, C. K. "Interconnected Power Systems Planning Criteria Evaluation." IEEE Paper A80 081-0.

Dhar, S. B., and Pang, C. K. "Reliability and Sensitivity Studies of Interconnected Power Systems." IEEE Paper A79 104-1.

Dunlop, R. D.; Gutman, R.; and Marchenko, P. P. "Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines." IEEE Transactions on Power Apparatus and Systems PAS-98 (March/April 1979): 606-17.

Edison Electric Institute. Ten-Year Report on Load Diversity, Based on 1962-71 Load Data. New York: Edison Electric Institute, 1972.

Edison Electric Institute. Statistical Committee. Glossary of Electric Utility Terms: Financial and Technical 1961. New York: Edison Electric Institute, 1961.

Electric Power Research Institute. Transmission Line Reference Book: 345 kV and Above. 2d ed. Palo Alto, CA: Electric Power Research Institute, 1982.

Elsliger, Raymond. "Constraints on Hydro-Quebec Transmission System Development." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 20-22, 1985.

Encyclopedia Britannica, Macropedia, 1980 ed. S.v. "Electricity," "Electric Motor," and "Electric Power."

Endrenyi, J. Reliability Modeling in Electric Power Systems. New York: John Wiley & Sons, Inc., 1978.

Ewart, Donald N. "New Directions in Electric Power Transmission." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 20-22, 1985.

Feldman, J. M., and Wilson, D. D. "Shunt Reactor Compensation on Present and Future Transmission Systems." Proceedings of the American Power Conference 31 (1969):842-53.

Gregory, J. M. Alternating Currents. London: Methuen Educational Ltd., 1971.

Guile, A. E., and Paterson, W. Electrical Power Systems. 2 vols. New York: Pergamon, 1977.

Hingorani, Narain G. "Transmission R & D--The Global Situation." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 20-22, 1985.

IEEE Power Engineering Society. Corona and Field Effects of AC Overhead Transmission Lines: Information for Decision Makers. New York: Institute of Electrical and Electronics Engineers, Inc., 1985.

Institute of Electrical and Electronics Engineers, Inc. IEEE Standard Dictionary of Electrical and Electronics Terms. 3rd ed. ANSI/IEEE Std. 100-1984. Ed. Frank Jay. New York: The Institute of Electrical and Electronics Engineers, Inc., 1984.

Jones, Brian. New Approaches to the Design and Economics of EHV Transmission Plant. New York: Pergamon Press, 1972.

Knight, U. G. Power Systems Engineering and Mathematics. New York: Pergamon Press, 1972.

Lindsey, William C.; Ghazvinian, Farzad; Hagmann, Walter C.; and Dessouky, Khaled. "Network Synchronization." Proceedings of the IEEE 73 (October 1985):1445-67.

Masters, William D. "Overview of Electric Power Transmission in North America." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 20-22, 1985.

Mikolinnas, T. A.; Puntel, W. R.; and Ringlee, R. J. "Application of Adequacy Assessment Techniques for Bulk Power Systems." IEEE Transactions on Power Apparatus and Systems PAS-101 (1982):1219-28.

Miller, T. J. E. Reactive Power Control in Electric Systems. New York: John Wiley & Sons, 1982.

Nasar, Syed A. Electric Energy Conversion and Transmission. New York: Macmillan Publishing Company, 1985.

Oak Ridge National Laboratory. Comparison of Costs and Benefits of DC and AC Transmission. ORNL-6204. Oak Ridge, TN: Oak Ridge National Laboratory, 1987.

Pai, M. A. Power System Stability. Amsterdam: North-Holland, 1981.

Pang, C. K., and Wood, A. J. "Multi-Area Generation System Reliability Calculations." IEEE Transactions on Power Apparatus and Systems PAS-94 (1975):508-517.

Pape, R., and Swencki, S. "Sharpen Your Static VAr Generator Specs." Electrical World, October 1985, pp. 71-72.

Powel, Charles A. Principles of Electric Utility Engineering. Cambridge: The Technology Press of the Massachusetts Institute of Technology, 1955. New York: John Wiley & Sons, Inc., 1955. London: Chapman & Hall, Ltd., 1955.

"Power Delivery: UHV Technology Coming of Age." Electrical World, July 1984, pp. 65-66.

"Power System Planning and Operations: Coping with Strained Systems." EPRI Journal 8 (August 1983):46.

Ranade, S. J., and Sullivan, R. L. "A Reliability Analysis Technique for Bulk System Planning." IEEE Transactions on Power Apparatus and Systems PAS-100 (1981):3658-65.

Rau, N. S.; Misra, R. B.; Necsulescu, C.; and Schenk, K. F. "Reliability of Interconnected Power Systems with Corrected Demands." IEEE Paper 82 WM 155-0.

"Regional Report: Device Depresses Harmful Waves." Electrical World, October 1985, p. 36.

Robinette, Gary O. Energy and Environment. Dubuque, IA: Kendall/Hunt Publishing Company, 1973.

Rustebakke, Homer M., ed. Electric Utility Systems and Practices. 4th ed. Prepared by the Electric Utility Systems Engineering Department, General Electric Company. New York: John Wiley & Sons, 1983.

Schott, F. W. "Letters: Power 'Wheeling' Not Understood, Says Member." The Institute, September 1985, p. 3.

Skrotzki, Bernhardt G. A., ed. Electric System Operation. New York: McGraw-Hill, 1954.

Slater, Kenneth J. "Computer Modeling of Wheeling Arrangements." Presented at the Electricity Consumers Resource Council Seminar on Wheeling, Washington, D.C., September 26-27, 1985.

Slepian, Joseph. "Energy Flow in Electric Systems--The Vi Energy-Flow Postulate." AIEE Transactions, December 1942, pp. 835-41.

Thanawala, H. L. "Power Delivery: Static Compensators = Fast VAr Control." Electrical World, October 1984, pp. 74-76.

Tibberts, N., and Vassell, G. S. "Analysis of Generating Capacity Reserve Requirements for Interconnected Power Systems." IEEE Transactions on Power Apparatus and Systems PAS-91 (1972):638-649.

"20th Annual T & D Construction Survey." Electrical World, August 1985, pp. 59-66.

"21st Annual T & D Construction Survey." Electrical World, August 1986, pp. S-10 to S-34.

U.S. Department of Energy. Economic Regulatory Administration. Office of Utility Systems. The National Power Grid Study. Vol. 1: Final Report. DOE/ERA-0056-1. Washington, D.C.: U.S. Government Printing Office, 1980.

U.S. Department of Energy. Economic Regulatory Administration. Office of Utility Systems. The National Power Grid Study. Vol. 2: Technical Study Reports. DOE/ERA-0056-2. Washington, D.C.: U.S. Government Printing Office, 1979.

Weedy, B. M. Electric Power Systems. 3rd ed. New York: John Wiley & Sons, 1979.

Westinghouse Electric Corporation. Electrical Transmission and Distribution Reference Book. East Pittsburgh, PA: Westinghouse, 1950.

Wood, Allen J., and Wollenberg, Bruce F. Power Generation, Operation, and Control. New York: John Wiley & Sons, 1984.

Woodward, T. Robert. "PJM Interconnection: A Fully Integrated Power Pool." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 21, 1985.

Zorpette, Glenn. "HVDC: Wheeling Lots of Power." IEEE Spectrum, June 1985, pp. 30-36.

Costs

Bloom, Jeremy A. "Modeling Economic Operations of Power Pools." Paper (preliminary draft) presented at the TIMS/ORSA Joint National Meeting, San Francisco, May 14-16, 1984.

Bloom, Jeremy A. "Probabilistic Production Costing with Interchange Accounting for Power Pools." Paper presented at the TIMS/ORSA Joint National Meeting, Boston, April 29-May 1, 1985.

Christensen, L. R., and Greene, W. H. "An Econometric Assessment of Cost Savings from Coordination in United States Electric Power Generation." Land Economics 54 (May 1978):139-55.

Miller, W. Joseph, and Happ, Harvey H. "Generator Voltage/VAr Control Cuts Fuel Bill." Electrical World, July 1986, pp. 45-46.

"Proposal for Determining Total Transmission Costs." Appendix C of Comments of the Electricity Consumers Resource Council and the American Iron and Steel Institute. Presented to the Federal Energy Regulatory Commission, Docket No RM85-17-000 (Phase I).

Tepel, Richard C.; Jewell, Ward; Johnson, Ruth; Maddigan, Ruth; Resource Consulting Group; and Applied Systems Institute, Inc. Analysis of Power Wheeling Services. Prepared for the U.S. Department of Energy, November 1984.

Tucker, J. D., and Miske, S. A., Jr. "Power Delivery: Mechanical Switching Cuts SVC Costs, Losses." Electrical World, November 1985, pp. 61-63.

U.S. Department of Energy. Energy Information Administration. Financial Statistics of Selected Electric Utilities 1984. DOE/EIA-0437(84). Washington, D.C.: U.S. Government Printing Office, 1986.

Whitman, Requardt and Associates. The Handy-Whitman Index of Public Utility Construction Costs, Bulletin No. 113. Baltimore: Whitman, Requardt and Associates, 1981; and updates.

Economics

Acton, Jan Paul, and Besen, Stanley M. The Economics of Bulk Power Exchanges. Rand Note N-2277-DOE. Prepared for the U.S. Department of Energy. Santa Monica, CA: Rand, May 1985.

Baughman, Martin L.; Joskow, Paul L.; and Kamat, Dilip P. Electric Power in the United States: Models and Policy Analysis. Cambridge: The MIT Press, 1979.

Baumol, William J. "Contestable Markets: An Uprising in the Theory of Industry Structure." The American Economic Review 72 (March 1982): 1-15.

Baumol, William J. "On the Proper Cost Tests for Natural Monopoly in a Multiproduct Industry." The American Economic Review 67 (December 1977):809-22.

Baumol, William J.; Panzar, John C.; and Willig, Robert D. Contestable Markets and the Theory of Industry Structure. New York: Harcourt Brace Jovanovich, Inc., 1982.

Bonbright, James C. Principles of Public Utility Rates. New York: Columbia University Press, 1961.

Evans, David S., and Grossman, Sanford J. "Integration." In Breaking Up Bell: Essays on Industrial Organization and Regulation, pp. 95-126. Edited by David S. Evans. New York: North-Holland, 1983.

Evans, David S., and Heckman, James J. "Natural Monopoly." In Breaking Up Bell: Essays on Industrial Organization and Regulation, pp. 127-56. Edited by David S. Evans. New York: North-Holland, 1983.

Henderson, J. Stephen. "The Economics of Electricity Demand Charges." The Energy Journal, Special Electricity Issue 4 (1983):127-40.

Henderson, J. Stephen; Guldmann, Jean-Michel; Hemphill, Ross C.; and Lee, Kyubang. Natural Gas Rate Design and Transportation Policy under Deregulation and Market Uncertainty. Columbus, OH: The National Regulatory Research Institute, 1986.

Johnston, J. Econometric Methods. 2d ed. New York: McGraw-Hill Book Company, 1972.

Joskow, Paul L., and Schmalensee, Richard. Markets for Power: An Analysis of Electrical Utility Deregulation. Cambridge: The MIT Press, 1983.

Kahn, Alfred E. The Economics of Regulation: Principles and Institutions. Vol. 1: Economic Principles. New York: John Wiley & Sons, 1970.

Kelly, Kevin A.; Henderson, J. Stephen; Guldmann, Jean-Michel; Burns, Robert E.; Shih, Jeffrey; Paul, Pran K.; Pryor, Timothy; Lee, Kyubang; Chen, Yea-Mow; Cristo, Martin N.; and Nagler, Peter A. State Regulatory Options for Dealing with Natural Gas Wellhead Price Deregulation. Columbus, OH: The National Regulatory Research Institute, 1983.

Lee, Li Way. "A Theory of Just Regulation." The American Economic Review 70 (December 1980):848-62.

Machlup, Fritz. The Economics of Sellers' Competition: Model Analysis of Sellers' Conduct. Baltimore: The Johns Hopkins Press, 1952.

Plott, Charles R. "Laboratory Experiments in Economics: The Implications of Posted-Price Institutions." Science, May 9, 1986, pp. 732-738.

Scherer, F. M. Industrial Market Structure and Economic Performance. Chicago: Rand McNally, 1970.

Sharkey, William W. The Theory of Natural Monopoly. Cambridge: Cambridge University Press, 1982.

Telser, Lester G. "A Theory of Innovation and Its Effects." The Bell Journal of Economics 13 (Spring 1982):69-92.

Walters, A. A. "Road Pricing." De Economist 116 (1968):545-60.

Walters, A. A. The Economics of Road User Charges. Baltimore: Johns Hopkins Press, 1968.

Williamson, Oliver E. Markets and Hierarchies: Analysis and Antitrust Implications. New York: The Free Press, 1975.

Williamson, Oliver E. "Transaction-Cost Economics: The Governance of Contractual Relations." Journal of Law and Economics 22 (October 1979):233-61.

Gain Sharing

American Academic Encyclopedia, 1980 ed. S.v. "Game Theory."

Davis, Morton D. Game Theory: A Nontechnical Introduction. New York: Basic Books, 1970.

Friedman, James W. Oligopoly and the Theory of Games. New York: North-Holland, 1977.

Gately, Dermot. "Sharing the Gains from Regional Cooperation: A Game Theoretic Application to Planning Investment in Electric Power." International Economic Review 15 (February 1974):195-208.

Hamlen, Susan S.; Hamlen, William A., Jr.; and Tschirhart, John T. "The Use of Core Theory in Evaluating Joint Cost Allocation Schemes." The Accounting Review 52 (July 1977):616-27.

Littlechild, S. C. "A Game-Theoretic Approach to Public Utility Pricing." Western Economic Journal 8 (June 1970):162-66.

Littlechild, S. C., and Thompson, G. F. "Aircraft Landing Fees: A Game Theory Approach." Bell Journal of Economics 8 (Spring 1977):186-204.

Luce, R. Duncan, and Raiffa, Howard. Games and Decisions. New York: John Wiley & Sons, 1957.

McDonald, John. The Game of Business. Garden City, N.Y.: Doubleday & Co., 1975.

Mossin, Jan. "Merger Agreements: Some Game-Theoretic Considerations." The Journal of Business (October 1968):460-71.

Nash, John F., Jr. "The Bargaining Problem." Econometrica 18 (1950):155-62.

Owen, Guillermo. Game Theory. Philadelphia: W. B. Saunders Company, 1968.

Rapoport, Anatol. N-Person Game Theory. Ann Arbor, MI: University of Michigan Press, 1970.

Schotter, Andrew, and Schwodiauer, Gerhard. "Economics and the Theory of Games: A Survey." Journal of Economic Literature 18 (June 1980):479-527.

Sharkey, W. W. "Suggestions for a Game-Theoretic Approach to Public Utility Pricing and Cost Allocation." The Bell Journal of Economics 13 (1982):57-68.

Shubik, Martin. "Game Theory Models and Methods in Political Economy." In Handbooks in Economics. Book 1: Handbook of Mathematical Economics, vol. 1, pp. 285-330. Edited by Kenneth J. Arrow and Michael D. Intriligator. Amsterdam: North-Holland Publishing Company, 1981.

Shubik, Martin. "Incentives, Decentralized Control, the Assignment of Joint Costs and Internal Pricing." Management Science 8 (1962):325-43.

Shubik, Martin, ed. Game Theory and Related Approaches to Social Behavior. New York: John Wiley & Sons, 1964.

Shubik, Martin, and Shapley, Lloyd S. "On Market Games." Journal of Economic Theory 1 (1969):9-25.

Shubik, Martin, and Shapley, Lloyd S. "Pure Competition, Coalitional Power, and Fair Division." International Economic Review 10 (October 1969): 337-62.

Telser, Lester G. Competition, Collusion, and Game Theory. Chicago: Aldine Atherton, 1972.

Vorob'ev, N. N. Game Theory: Lectures for Economists and Systems Scientists. New York: Springer-Verlag, 1977.

Pricing

Ahlstrand, Philip. "Real-Time Pricing: A DSM Alternative." Electrical World, December 1986, p. 61.

American Economic Association. Readings in Price Theory. Chicago: Richard D. Irwin, Inc., 1952.

Anderson, John A. "Comments of Dr. John A. Anderson, Executive Director, Electricity Consumers Resource Council." Presented to the 9th Annual Convention and Regulatory Symposium, National Association of Regulatory Utility Commissioners, New York, November 18, 1985. (Photocopy.)

Anderson, John A. "Marketplace Pricing Will Strengthen the Electric Transmission System." Public Utilities Fortnightly, May 29, 1986, pp. 33-38.

Anderson, John A., and Houck, Gerald W., Jr. "Comments of The Electricity Consumers Resource Council and The American Iron and Steel Institute." Presented to the Federal Energy Regulatory Commission, Docket No. RM85-17-000 (Phase II), November 4, 1985.

Bauer, Douglas C. "Comments of the Edison Electric Institute on the Notice of Inquiry Regarding Regulation of Electricity Sales-for-Resale and Transmission Service." Presented to the Federal Energy Regulatory Commission, Docket No. RM85-17-000 (Phase 1), August 9, 1985.

Blank, D. M.; Lester, H. J.; and Mavlans, E. H. "Power Pool Rates: A Comparison of the Terms and Provisions for Power Exchange among Fifteen Major Power Pools." Paper presented to the Rate Research Committee, January 24, 1972.

Bohn, Roger E.; Caramanis, Michael C.; and Schweppe, Fred C. "Optimal Pricing in Electrical Networks over Space and Time." Rand Journal of Economics 15 (Autumn 1984):360-76.

Caramanis, M. C.; Bohn, R. E.; and Schweppe, F. C. "Optimal Spot Pricing: Practice and Theory." IEEE Transactions on Power Apparatus and Systems PAS-101 (1982):3234-45.

Caramanis, M. C.; Bohn, R. E.; and Schweppe, F. C. "Optimal Spot Pricing: Practice and Theory." IEEE Paper No. 82 WM 115-4. Presented at the IEEE/PES 1982 Winter Meeting, New York, January 31-February 5, 1982.

Caramanis, Michael C.; Bohn, Roger E.; and Schweppe, Fred C. "The Costs of Wheeling and Optimal Wheeling Rates." IEEE Paper No. 85 SM 464-3. Presented at the IEEE/PES 1985 Summer Meeting, Vancouver, British Columbia, Canada, July 14-19, 1985.

"DOE, Industry Groups Laud FERC Market Efficiency Goals; Differ on Means." Electric Utility Week, August 19, 1985, pp. 12-14.

Earley, Wilbur C. "Coordination Transactions among Electric Utilities." Public Utilities Fortnightly, September 13, 1984, pp. 31-37.

Earley, Wilbur C. "FERC Regulation of Bulk Power Coordination Transactions." Staff Working Paper. Office of Regulatory Analysis, Federal Energy Regulatory Commission, July 1984.

Edison Electric Institute. Public Policy Analysis Department. Summary of Comments Filed in Response to FERC's Notice of Inquiry in Docket No. RM85-17 (Phase I). Washington, D.C.: Edison Electric Institute, 1985.

Edison Electric Institute. Rate Regulation Department. Terms and Conditions of Existing Transmission Service Agreements and Tariffs. Washington, D.C.: Edison Electric Institute, 1984.

"Establishment of an Electricity Futures Market Could Be Beneficial." Inside FERC, September 2, 1985, p. 8.

"FERC ALJ: Niagara Mohawk Wheeling Rate Should Use 'Rolled-In' Method." Electric Utility Week, October 7, 1985, p. 7.

"FERC Commissioner Looks to Industry to Help Design Wheeling Rates, Terms." Electric Utility Week, October 28, 1985, p. 8.

"FERC Move toward Marginal-Cost Pricing Gets Mixed Reviews from Industry." Electric Utility Week, November 11, 1985, pp. 12-14.

"Florida PSC Okays Florida Power, TECO Wheeling Rates for Cogenerators." Electric Utility Week, April 21, 1986, pp. 14-15.

Hahn, Robert W. "An Experimental Examination of Spot Markets for Electricity." School of Urban and Public Affairs, Carnegie Mellon University, Pittsburgh, November 30, 1985. (Photocopy.)

Hawthorn, Duane. "Some Aspects of Compensation for Wheeling Service." Presented at the Electricity Consumers Resource Council Seminar on Wheeling, Washington, D.C., September 26-27, 1985. (Photocopy.)

Holmes, A. Stewart. "A Review and Evaluation of Selected Wheeling Arrangements and a Proposed General Wheeling Tariff." Staff Working Paper. Federal Energy Regulatory Commission, Office of Regulatory Analysis, September 1983.

Jahn, Louis R. "Pricing and Risk Allocation in Wholesale Rate Making." Public Utilities Fortnightly, July 24, 1986, pp. 29-33.

Jordan, W. John. "Capacity Costs, Heterogeneous Users and Peak-Load Pricing." The Quarterly Journal of Economics 100 (November 1985):1335-37.

Jordan, W. John. "Heterogeneous Users and the Peak-Load Pricing Model." The Quarterly Journal of Economics 98 (February 1983):127-38.

Kelley, Frank J.; Keskey, Don L.; Rosewarne, Phillip J.; Eastman, Ronald D.; and Mounts, Lynda S. "Comments of the State of Michigan and the Michigan Public Service Commission." Presented to the Federal Energy Regulatory Commission, Docket No. RM85-17-000 (Phase II), October 4, 1985.

Kelly, Frank J.; Keskey, Don L.; Rosewarne, Phillip J.; Eastman, Ronald D.; and Mounts, Lynda S. "Comments of the State of Michigan and the Michigan Public Service Commission." Presented to the Federal Energy Regulatory Commission, Docket No. RM85-17-000 (Phase I), August 9, 1985.

Kemp, William J., and Karwaki, Thomas S. "The Western Systems Power Pool: Flexible Pricing in Action." In Proceedings of the Fifth NARUC Biennial Regulatory Information Conference, vol. 2, pp. 933-43. Edited by Robert E. Burns. Columbus, OH: The National Regulatory Research Institute, 1986.

Lindsay, William W. "Wheeling Rates: FERC Policies and Some Alternatives." Presented to the Electricity Consumers Resource Council Seminar on Wheeling, Washington, D.C., September 27, 1985. (Photocopy.)

Merrill, Hyde M., and Wolcott, David R. "Economically Efficient Pricing and Allocation of Access to an Electric Transmission and Distribution Network." (Photocopy.)

"NARUC Electricity Committee Gets Transmission Study Off the Ground." Electric Utility Week, October 28, 1985, p. 11.

"N.Y. PSC to Scrutinize 'Excessive' Con Ed Wheeling Rate for Cheap Power." Electric Utility Week, July 15, 1985, p. 8.

Pfeffer, Jerry L. "Policies Governing Transmission Access and Pricing: The Wheeling Debate Revisited." Public Utilities Fortnightly, October 31, 1985, pp. 26-33.

Pfeffer, Lindsay & Associates, Inc. "A Review of Current Practice and Emerging Issues in the Design of Rates for Transmission." Draft Final Report. Washington, D.C., June 20, 1985.

Rosenzweig, Michael B., and Bar-Lev, Joshua. "Transmission Access and Pricing: Some Other Approaches." Public Utilities Fortnightly, August 21, 1986, pp. 20-26.

Scherer, F. M. Industrial Pricing: Theory and Evidence. Chicago: Rand McNally College Publishing Company, 1970.

Schweppe, Fred C.; Bohn, Roger E.; and Caramanis, Michael C. Wheeling Rates: An Economic-Engineering Foundation. Report TR 85-005. Cambridge: Massachusetts Institute of Technology, School of Engineering, Laboratory for Electromagnetic and Electronic Systems, September 1985.

Schweppe, Fred C.; Bohn, Roger E.; Tabors, Richard D.; and Caramanis, Michael C. "Comments on Regulation of Electricity Sales for Resale and Transmission Services." Presented to the Federal Energy Regulatory Commission, Docket No. RM85-17-000 (Phase II), October 1, 1985.

"Southwest Power Experiment Analysis Sees Potential Market Competition." Inside FERC, October 28, 1985, p. 7.

"The Sky Did Not Fall in the First Year of FERC's Bulk-Power Experiment." Electric Utility Week, October 28, 1985, p. 3.

U.S. Federal Energy Regulatory Commission. Office of Electric Power Regulation. A Review of Selected Transmission Agreements. August 1984.

"Utilities Would Pay New Line Costs under Proposed Texas Wheeling Rules." Electric Utility Week, September 2, 1985, p. 7.

Vickery, William. "Counterspeculation Auctions and Competitive Sealed Tenders." Journal of Finance 16 (March 1961):8-37.

Vickery, William. "The Fallacy of Using Long-Run Cost for Peak-Load Pricing." The Quarterly Journal of Economics 100 (November 1985):1331-34.

Willig, Robert D. "The Theory of Network Access Pricing." In Issues in Public Utility Regulation: Proceedings of the Institute of Public Utilities Tenth Annual Conference, pp. 109-52. Edited by Harry M. Trebing. East Lansing, MI: Division of Research, Graduate School of Business Administration, Michigan State University, 1979.

Laws and Regulations

Burns, Robert E. "'Access to the Bottleneck': Legal Issues Regarding Electric Transmission and Natural Gas Transportation." In Natural Gas Industry Restructuring Issues, pp. 31-70. Edited by J. Stephen Henderson. Columbus, OH: The National Regulatory Research Institute, 1986.

Butler, Jack A. Cogeneration and Small Power Production in Florida. Tallahassee: Florida Public Service Commission, May 1985.

Cavagnaro, Walter. "The Marketing of Surplus Northwest Power to California." California Public Utilities Commission, San Francisco, January 30, 1985. (Photocopy.)

City of Groton v. Connecticut Light & Power Co. 662 F.2d 921 (2d Cir. 1981).

Clark, Blair W., and Bruder, George F. "Florida Power Corporation's Motion to Intervene." Presented to the Federal Energy Regulatory Commission, Docket No. EL84-27, July 26, 1984.

Clark, Blair W., and Bruder, George F. "Florida Power Corporation's Petition for a Declaratory Order." Presented to the Federal Energy Regulatory Commission, July 26, 1984.

Electric & Gas Department (Trapp, Hoffsis); Legal Department (Twomey); and General Counsel (Pruitt). Memorandum to Steve Tribble, Commission Clerk, Re Motions for Reconsideration and Clarification of Order No. 13247, Proceedings to Implement Cogeneration Rules. Florida Public Service Commission, Docket No. 830377-EU, October 2, 1984.

Federal Power Act. Secs. 202, 205, 210, 211, and 212. 16 USCA.

Fels, Nicholas W., and Heap, David N. "Compulsory Wheeling of Electric Power to Industrial Consumers." Fordham Law Review 52 (1983):219-33.

Harrold, William H.; Bouknight, J. A., Jr.; and White, Robert I. "Petition of Florida Power & Light Company and the Florida Public Service Commission for a Declaratory Order." Presented to the Federal Energy Regulatory Commission, July 23, 1984.

Kretschmer, Ruth K. Energy Utilities: Industries in Transition. Springfield: Illinois Commerce Commission, May 1985.

Lindsay, William W., and Pfeffer, Jerry L. Deregulation of the Electric Power Industry: Perspective of State Regulation. Columbus, OH: The National Regulatory Research Institute, 1983.

Meeks, James E. "Concentration in the Electric Power Industry: The Impact of Antitrust Policy." Columbia Law Review 72 (1972):64-130.

O'Connor, Philip R., and Case, J. Cale. The Transition to Competition in the Electric Utility Industry. Springfield: Illinois Commerce Commission, May 1985.

Poling, Robert. "Legal Aspects of a National Power Grid." In Proceedings of Workshop on the Evolving Structure of the Electric Utility Industry. Mitre Corporation, March 1978.

Reiter, Harvey L. "Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts." Land and Water Law Review 18 (1983):1-80.

Shapiro, David L. "Policy and Legal Conflicts in the Pacific Northwest Power Act." Public Utilities Fortnightly, November 14, 1985, pp. 19-25.

U.S. Federal Energy Regulatory Commission. Declaratory Order Granting Interventions and Consolidating Proceedings, Docket Nos. EL84-27-000, EL84-28-000, EL84-38-000, and EL84-39-000, 29 FERC para. 61,140.

U.S. Federal Energy Regulatory Commission. Opinion No. 198; Opinion and Order Denying Application for an Order to Compel Wheeling, 25 FERC para. 61,204.

U.S. Federal Energy Regulatory Commission. Opinion No. 198-A; Opinion and Order Denying Rehearing, 26 FERC para. 61,127.

Transmission Policy

Alaska Power Authority. Alaska Electric Power Statistics, 1960-1985. 11th ed. Anchorage: State of Alaska, 1986.

Bauer, Douglas C. "Impediments to Bulk Power Marketing." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles Illinois, October 20, 1985.

Bauer, Douglas C., and Edelston, Bruce S. "Mandatory Wheeling: Is Competition in the Nation's Best Interest?" Electric Perspectives, Spring 1985, pp. 2-11.

Calzonetti, F. J.; Choudhry, M. A.; Duval, R. D.; Elmes, G. A.; Hanham, R. Q.; Mann, P. C.; Torries, T. F.; and Witt, T. S. An Evaluation of Electricity Export as a West Virginia Coal Utilization Strategy. Morgantown, WV: West Virginia University, Energy Research Center, September 1985.

Cassaza, John A. "Interconnections Grow in Value." Electrical World, December 1984, pp. 79-80.

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

Cicchetti, Charles J., and Obeiter, Robert D. "The FERC's Recent Interest in Wheeling and Carriage." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 22, 1985.

"Competition Is Revising Transmission Access Policies." Electric Light and Power, June 1985, pp. 46-47.

Cramer, Curtis, and Tschirhart, John. "Power Pooling: An Exercise in Industrial Coordination." Land Economics 59 (February 1983):24-34.

Driscoll, John. "Releasing Electricity Markets with Regulation." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 20-22, 1985.

Edison Electric Institute. Rate Regulation Department. Survey of Transmission Services Provided by Investor-Owned Utilities. Washington, D.C.: Edison Electric Institute, 1984.

Edison Electric Institute. Rate Regulation Department. "Transmission Access and Utilization: Briefing Papers." December 11, 1984. (Photocopy.)

Electrical World. Electrical World Directory of Electric Utilities, 1984-1985. 93d ed. New York: McGraw-Hill Publications Co., 1984.

Electricity Consumers Resource Council. Wheeling: Options for Industrials. Washington, D.C.: ELCON, 1984.

Faikman, J. F., and Scott, J. C. "Transmission, Power Pools, and Competition in the Electric Utility Industry." Hastings Law Journal 28 (May 1977): 1159-1207.

Ferguson, John S. "Is Central Station Generation Becoming a White Elephant?" Public Utilities Fortnightly, March 21, 1985, pp. 32-34.

Florida Power Corporation. "Transmission Service Resale Rate Schedule T-1 for Municipalities, Rural Electric Cooperatives, and Other Electric Utilities." Third Revised Sheet No. 21, April 12, 1979.

Florida Public Service Commission. "In re: Proceedings to Implement Cogeneration Rules." Order No. 13247. Docket No. 830377-EU, May 1, 1984.

Florida Public Service Commission. "Re Cogeneration Rules." Order No. 14339. Docket No. 830377-EU (1985). 68 PUR 4th 112.

"Governors Set to Discuss Midwest-Northeast Transmission Link This Month." Electric Utility Week, November 18, 1985, p. 7.

"Governors View Nepool Needs." Electrical World, December 1985, p. 36.

Harris, Walter D. "Canadian Power Surges South." Public Power, November-December 1982, pp. 77, 80-81, 84.

Hobart, Lawrence. "Electric Transmission in the U.S.: Problems and Solutions." Presented to the Electricity Consumers Resource Council Seminar on Wheeling, Washington, D.C., September 27, 1985.

Holmes, A. Stewart. "The Southwest Bulk Power Market Experiment: First-Year Results." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 20-22, 1985.

International Energy Agency. Electricity in IEA Countries: Issues and Outlook. Paris: International Energy Agency, 1985.

Iveson, Robert W.; Balu, Neal J.; and Dougherty, J. J. "Transmission Access: The Technical Aspects." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 20-22, 1985.

Iwler, Louis. "Industry News: Economy Power Transfers Pose Risk to Reliability." Electrical World, December 1984, pp. 22, 24.

Jenkins, Joseph D. "Power Marketing: The Broker Approach." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 22, 1985.

Johnson, Kenneth M. "Hydro-Quebec: New England Hydroelectric Power Link." New England Journal of Business Economics 9 (1982):19-27.

Joskow, Paul L. "Transmission Issues." 1984. (Photocopied.)

Lambert, Jeremiah D., and Pedelty, Jay D. "Mandatory Contract Carriage: The Changing Role of Pipelines in Competitive Natural Gas Markets." Public Utilities Fortnightly, February 7, 1985, pp. 26-33.

Lantz, David. "Power Pooling for Indiana: Benefits and Costs." Hoosiers for Economic Development Committee, March 1985. (Photocopy.)

Lindsay, William W. "Interconnection and Pooling: The Role of the F.E.R.C." In Energy and Communications in Transition: Proceedings of the Institute of Public Utilities Eleventh Annual Conference, pp. 262-74. East Lansing, MI: Division of Research, Graduate School of Business Administration, Michigan State University, 1981.

Littell, Richard, and Neises, Kenneth J. "A Potential Solution for Power Pooling Roadblocks." Public Utilities Fortnightly, December 20, 1979, pp. 23-26.

Markley, I. Edward. "DOE Prepared Statement before the California Energy Commission on Inter-Utility Coordination: Pooling and Brokering." Sacramento, California, September 17, 1980.

Mozer, H. "National Grid: Some Amplifications and Updates." In Proceedings of Workshop on the Evolving Structure of the Electric Utility Industry. Mitre Corporation, March 1978.

National Economic Research Associates. "Comments on the FERC Notice of Inquiry on Bulk Power Transactions." Presented to the Federal Energy Regulatory Commission, Docket No. RM85-17-000 (Phase 1).

National Electric Reliability Council. Transfer Capability: A Reference Document. Princeton, N.J.: National Electric Reliability Council, October 1980.

National Regulatory Research Institute. "An Information Package on Electric Power Transfer and Wheeling." November 1984.

Nelson, P. A. "Effectiveness of Power Pools in Bulk Power Supply." In Proceedings of Workshop on the Evolving Structure of the Electric Utility Industry. Mitre Corporation, March 1978.

"NERC: Reliability Less in Next 10 Years; Plant, Line Construction Urged." Electric Utility Week, October 7, 1985, p. 5.

"Network Access and the Future of Power Transmission." EPRI Journal, April/May 1986, pp. 4-13.

New England Regional Commission. New England Power Pool: Descriptions, Analysis, Implications. March 1976.

Newman, Marie Mastin, and Edelston, Bruce S. The Vital Link: Electric Transmission and the Public Interest. Washington, D.C.: Edison Electric Institute, 1986.

North American Electric Reliability Council. "Impediments to Transfers." Report prepared for the National Association of Regulatory Utility Commissioners Committee on Electricity. Princeton, N.J., May 30, 1984.

North American Electric Reliability Council. "Impediments to Transfers: An Update." Princeton, N.J., June 5, 1985.

North American Electric Reliability Council. 1986 Electricity Supply & Demand for 1986-1995. Princeton, N.J.: North American Electric Reliability Council, 1986.

North American Electric Reliability Council. 1986 Reliability Review: A Review of Bulk Power System Reliability in North America. Princeton, N.J.: North American Electric Reliability Council, 1986.

"Office of Technology Assessment Asked to Study Impediments to Wheeling." Electric Utility Week, January 6, 1986, p. 6.

Penn, David W. "A Municipal Perspective on Electric Transmission Access Questions." Public Utilities Fortnightly, February 6, 1986, pp. 15-22.

Penn, David W. "Policy Session: Regulating Transmission: Taking Off the Blinders: Transition, Transmission, Transactions." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 20-22, 1985.

Phillips, Charles F., Jr. The Regulation of Public Utilities: Theory and Practice. Arlington, VA: Public Utilities Reports, Inc., 1984.

Power Technologies, Inc. "A Study of Transmission Interconnection as Practiced and Planned by Kansas Electric Utilities." Report No. R100-80, 1981.

Power Technologies, Inc. "An Assessment of Policies and Technical Factors Affecting the Degree of Interconnection of Electric Utilities in the United States." Final Report to the Energy Policy Project sponsored by the Ford Foundation, December 1974.

Reinemer, Vic. "The Other Side: Access to Transmission Crucial." Public Power, May-June 1984, p. 84.

Skinner, Sam F. "Transmission Systems Marketing: Impediments to Expansion." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 1985.

Slaughter, Jane. "Current Status of Wheeling Availability." Electric Division, Michigan Public Service Commission, September 1985. (Photocopy.)

Stalon, Charles G. "Wheeling and Deregulation of Electric Generation." Paper presented at the Third NARUC Electric Research and Development Seminar, St. Charles, Illinois, October 22, 1985.

Stockford, Chapman (Chip). "Transmission Lines Must Be Fairly Shared." Public Power, May-June 1984, pp. 10-16.

Stone & Webster Management Consultants, Inc. "A Feasibility Investigation of the Benefits and Constraints of a Power Pooling System among the Ohio Regulated Electric Companies--Segment I." Prepared for the Public Utilities Commission of Ohio, Columbus, Ohio, August 1985.

"Transmission's OK; Transfers Are Limited." Electrical World, July 1984, p. 21.

U.S. Congress. Congressional Research Service. National Power Grid System Study--An Overview of Economics. Regulatory and Engineering Aspects. Washington, D.C.: Library of Congress, 1976.

U.S. Congress. Congressional Research Service. The National Electric Grid--A Concept Whose Time Has Come? Washington, D.C.: Library of Congress, 1978.

U.S. Department of Energy. Regional Power Systems Planning: A State of the Art Assessment. Washington, D.C.: U.S. Department of Energy, 1978.

U.S. Department of Energy. The Florida Electric Power Coordinating Group: An Evolving Power Pool. Washington, D.C.: U.S. Government Printing Office, 1979.

U.S. Department of Energy. Economic Regulatory Administration. Office of Utility Systems. Power Pooling: Issues and Approaches. DOE/ERA/6385-1. Prepared by Resource Planning Associates, Inc. Washington, D.C.: U.S. Government Printing Office, 1980.

U.S. Department of Energy. Energy Information Administration. Interutility Bulk Power Transactions: Description, Economics, and Data. DOE/EIA-0418. Washington, D.C.: U.S. Government Printing Office, 1983.

U.S. Department of Energy. Energy Information Administration. U.S.-Canadian Electricity Trade. Washington, D.C.: Energy Information Administration, 1982.

U.S. Department of the Interior. Transmission Study 190. Washington, D.C.: U.S. Government Printing Office, 1968.

U.S. Federal Energy Regulatory Commission. Office of Electric Power Regulation. Power Pooling in the United States. FERC-0049. Washington, D.C.: U.S. Government Printing Office, 1981.

U.S. Federal Power Commission. National Power Survey. Washington, D.C.: U.S. Government Printing Office, 1964.

U.S. General Accounting Office. Expanding the Pacific Northwest/Southwest Intertie: Benefits and Impediments. Washington, D.C.: General Accounting Office, 1983.

Usry, Robert O. "Transmission Use and Impediments Put in Perspective." Paper presented at the meeting of the Southeastern Association of Regulatory Utility Commissioners, Lake Buena Vista, Florida, June 10, 1985.

Varley, Andrew. "Is the Electric Utility Industry Ready for Deregulation?" Public Utilities Fortnightly, September 19, 1985, pp. 17-20.

Vassell, Gregory S., and Maliszewski, Raymond M. "AEP 765-kV System: System Planning Considerations." IEEE Transactions on Power Apparatus and Systems PAS-88 (September 1969):1320-28.

"Wheeling Becoming Key Issue as Competition Grows in Utility Industry." Electric Utility Week, October 14, 1985, pp. 10-11.

Whitfield A. Russell & Associates. Colorado Power Pooling and Generation Dispatch Strategies. Prepared for the Colorado Public Utilities Commission. Columbus, OH: The National Regulatory Research Institute, 1978.

Willrich, Mason. "Why Not Regional Electric Power Generation Companies?" Public Utilities Fortnightly, June 9, 1983, pp. 25-30.