NRRI 90-10

ELECTRIC TRANSMISSION ACCESS AND PRICING POLICIES: ISSUES AND A GAME-THEORETIC EVALUATION

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May 1990

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

Opportunities for competition in electric generation have prompted policy makers to examine present electric transmission access and pricing policies. These policies are interrelated with other public policies involving transmission siting, transmission service reliability, and the coordination of federal and state regulation of transmission services.

Several new access and pricing policies have been proposed by various parties, including The National Regulatory Research Institute, as alternatives to the status quo. These are categorized into two general models of reform, which have been called by the Federal Energy Regulatory Commission staff the "Contract model" and the "Planning model."

This report first provides an overview of the interrelated economic, engineering, and regulatory issues arising in the national transmission policy debate and then concentrates on an in-depth analysis of the principal economic issues. It summarizes the proposals for reform and develops a framework for analyzing the strategic behavior of sellers, wheelers, and buyers of wholesale power under new transmission access and pricing rules. The effects of various new rules on regional electricity production costs are evaluated. Also, transmission policies are assessed in terms of their effects on the market power of suppliers, buyers, and wheelers of wholesale electricity.

These evaluations require a method suitable for small groups of utilities and power suppliers, possibly operating in circumstances that correspond neither to traditional regulation nor to deregulation. A secondary purpose of this study is to introduce such a method, game theory, to regulators and illustrate its use in the case of transmission access and pricing policy.

Proposals for change must be evaluated in terms of their consequences in both the long run and the near term. The desirable short-run outcome is an efficient coordination market for economy power that, in effect, results in the most economic dispatch of all generating units in a region. In the long run, the best transmission policy is one that facilitates selection of the least-cost set of new generating units and transmission facilities for firm power service in the region. Good policies encourage all good transmission transactions, that is, those that lower the aggregate regional production cost, and they discourage bad transactions, which raise this cost.

Most reform proposals distinguish between policies for long-run firm and short-run nonfirm transmission. The difference between firm and nonfirm service needs to be better defined in the industry to make this distinction useful for transmission policy. Our analysis indicates that existing policy (Status Quo) for nonfirm service is generally adequate, though utilities in a position to wheel can get a large share of the nonfirm trading profits simultaneously buying and selling power instead of wheeling. Trading is expected to occur largely through two-party transactions with nearest neighbors instead of through third-party wheeling; utility middlemen can buy low and sell high, making a profit on the mark-up. Specific versions of the Contract and Planning models were selected for analysis. Our Contract model would leave this nonfirm power market virtually unchanged. Under our Planning model much of the gains from good wheeling would be transferred to the buyer, but some uneconomic transactions ("bad wheeling") would also be encouraged.

Further, our Planning model discourages construction of adequate transmission for coordination market trading, where buyers cannot acquire firm transmission rights for use in pursuing nonfirm power sales opportunities. The Contract model is better at encouraging wheelers to undertake such construction. The level of construction investment is optimal under flexible pricing for nonfirm transmission with a moderately high price ceiling.

As for firm transmission, the Status Quo can eliminate much good wheeling because wheeling service is voluntary and firm wheeling rates provide no incentive to wheel. However, no bad wheeling should occur under existing rules, according to our analysis. Our findings for firm wheeling under the Contract model are similar to those for the Status Quo: because firm generation prices are based on embedded costs, potential wheelers have both opportunity and incentive to secure low-cost power for themselves even if wheeling would lower overall production costs more. So good wheeling can be blocked, even though bad wheeling does not occur under the Contract model. By requiring that all--including the most suitable buyers--have access to the grid, the Planning model facilitates almost all the good firm wheeling that is available, but can also force uneconomic transactions to occur because of its pricing provisions.

Deregulation of firm generation prices and nonfirm generation and transmission prices is being considered by some policy makers for situations where a transmission utility's market power has been substantially mitigated. Whether a particular market has the characteristics of a seller's market, a buyer's market, or a wheeler's market depends on several factors, not just the firm and nonfirm transmission access and pricing rules. Generation pricing policy has an important effect on the market power of potential power suppliers, purchasers, and wheelers. Market power is affected not only by the number of competing sellers and buyers but also by their relative production costs and the quantities of power they have available for sale at an attractive price. Market power in the nonfirm transmission market is also affected by firm transmission policies--a relationship not fully explored in our analysis.

A case study of market power under various access and pricing rules for eight actual utilities shows that market power can shift significantly under reasonable changes in market conditions and can change dramatically over time as the incremental costs and reserve margins of the utilities change.

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF FIGURES (continued)

LIST OF FIGURES (continued)

LIST OF TABLES

FOREWORD

Competition in electric generation has brought increased attention to existing transmission access and pricing policies. New policies have been proposed by several parties (including NRRI). This study summarizes the various proposals for reform, examines the issues they raise, and offers a way of analyzing the strategic behavior of sellers, wheelers, and buyers of wholesale power as they face new access and pricing rules. Finally, the study applies game theory as a way for regulators to evaluate behaviors and outcomes, both short run and long run.

We think you will find this a particularly useful research report.

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May 31, 1990
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ACKNOWLEDGEMENTS

The authors gratefully acknowledge the assistance of Pravin Maheshwari, who compiled the data and ran the linear program for the case study described in appendix B. The report benefited substantially from a careful review by Dr. Douglas N. Jones and Dr. Kenneth Rose of NRRI, Dr. Thomas Kennedy of the Illinois Commerce Commission, and Professor Curtis Cramer of the University of Wyoming. While they identified several errors in the first draft, any errors remaining in the final report are, of course, our responsibility, not theirs. We are especially appreciative of the assistance of Marilyn Reiss who compiled the bibliography and prepared the manuscript and of Wendy Windle who prepared most of the figures.

CHAPTER 1

ELECTRIC TRANSMISSION QUESTIONS AND ISSUES

The nation has been striving to set electric transmission policy. New policy is needed because the transmission system and institutional arrangements for its use and expansion are not adequate to take advantage of emerging opportunities for competition in power markets. The difficulty is partly due to the complexity of the technology. But we are struggling because many interrelated policy questions, which need to be answered together, are being considered piecemeal. This chapter outlines an integrated approach to resolving transmission policy issues, and the remainder of this report takes the first analytical steps in implementing this approach.

The chapter begins with a review of the main policy questions. The review is brief because these questions have been discussed adequately in prior NRRI reports and elsewhere. The main purpose of this chapter is to set out how these questions are interrelated, how the relationships create issues that impede progress in policy formulation, and how various contributors to the policy debate view these issues from quite different perspectives.[1] The chapter concludes with an overview of how this report and other NRRI transmission reports relate to the overall policy debate.

Transmission Policy Questions

The three key questions in the national debate on electricity transmission policy involve access, pricing, and siting.[2] Two other

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[1] This chapter evolved out of a presentation made by one of the authors to the NARUC Staff Subcommittees on Economics & Finance and Electricity at the NARUC Summer Meeting in San Diego, July 1988. An earlier version of its content was published in *The Electricity Journal*; see K. Kelly, "Why Transmission Questions Are So Hard To Answer," 2 no. 1, Jan./Feb. 1989: 26-38.

[2] These three questions were identified as key in an NRRI report: see K. Kelly, ed., *Nontechnical Impediments to Power Transfers*, NRRI-87-8 (Columbus, Ohio: The National Regulatory Research Institute, September 1987). Subsequently, these three questions were the subject of the NARUC Transmission Conference held in Washington, D.C., June 1988.

vitally important questions are the electric system reliability question and the question of the appropriate balance of federal and state regulatory authorities over electric systems.

Access

The central question concerns access: who should be allowed to use electric transmission lines upon demand to buy and sell electricity? Access is a difficult question that applies to three distinct cases. The question in each case is whether transmission service should be voluntary or mandatory on the part of the transmitting utility.

Supplier Access

One case involves supplier access, the eligibility of a power supplier to move electric power along a particular utility's transmission lines in order to sell this power to a buying utility. Should every supplier--whether a utility, an independent power producer (IPP), or a PURPA[3] qualifying facility (QF)--have equal access rights? This question arises because differences in electricity prices among utilities create opportunities for mutually beneficial trading and because nonutility generators are now able to compete with utilities as electric power suppliers. Many, including many investor-owned utilities, would answer "yes" to this question as long as the buyer is itself an independent utility, one that buys electricity to resell it to its own customers and is normally capable of generating on its own the electricity needed to serve these customers. Electricity sale involves both a buyer and a seller, of course, and transmission access policy may turn more on who the buyer is than who the seller is.

Requirements Access

The second access case arises when the buyer is a wholesale requirements customer. This is a utility that buys power from the host utility and resells it to its own retail customers. The requirements customer, such as a city-owned distribution system, depends on the host

[3] Public Utility Regulatory Policies Act of 1978.

utility for all or a large part of its electricity supply. Requirements customers are quite diverse in the nature of their requirements, ranging from fully dependent to semi-autonomous entities with considerable generation and transmission of their own. They are usually located inside the host utility's service territory. In many cases, the host utility has constructed new electric generating capacity to meet the needs of the requirements utility just as it has for its own retail customers. The access question is: when this buyer wants to purchase power from a supplier other than its host utility, should it be treated as a full-fledged utility entitled to buy from outside sources? Should it have no more right to access than a retail customer? Or is some special policy required--such as a period of transition for the requirements customer from quasiretail customer status to independent utility status?

Retail Access

A third access policy case, retail access, addresses the rights of the retail customer, the buyer who actually consumes the power. The retail access question concerns the eligibility of a retail electric customer to use the transmission lines of the utility in whose service area it resides in order to buy power from another supplier. Other utilities' lines may be used too if the supplier is not contiguous with the host utility. Some large customers, such as petrochemical companies, aluminum smelters, and United States government facilities, want to be able to shop around for low-cost power when they are unhappy with local electric company rates. Sometimes, the customer seeking access is an industrial consumer that wants the utility to transport power from a distant cogeneration facility owned by that consumer.

Pricing

Another key transmission policy question is how best to set the prices for transmission services. This question can be seen as a decision tree. The principal question, corresponding to the trunk of the tree, is whether the price of transmission service should be set by a market or by a price-regulating agency. Markets do a good job of setting prices if there are many competing service providers and many customers for the service. Regulators do better with monopolies.

If policy makers choose the market branch of the tree, there are follow-on questions about how to detect and prevent monopoly abuse in pricing transmission service. Choosing the agency branch usually means choosing cost-based rates;[4] this requires another decision between traditional embedded cost-based rates and prices based on marginal costs. Choosing the latter calls for another choice between long and short run marginal cost pricing, and each of these branches calls for additional decisions about pricing implementation.

Siting

A third important transmission policy question concerns the growth of the nation's transmission system, particularly the siting and certification of new lines. Historically, most transmission lines have been built to ensure service reliability and to minimize generation capacity needs. Now, however, demands are growing for new lines to enhance competition in the bulk power market.

Some electric utilities are experiencing great difficulty in acquiring rights of way for new transmission lines. This is particularly true for long multistate lines, for which the benefits of transmission are obtained at the sending and receiving ends of the lines but for which siting difficulties and environmental effects are encountered along the way. The policy question is, are new administrative procedures or agencies required to balance the need for protecting local interests against the regional need for planning, locating, and constructing new lines expeditiously? Who ultimately decides if new transmission lines are needed and where they go?

Reliability

The question most often asked by utility engineers in the transmission policy debate is: in a more competitive environment for generation, how will the transmission system be able to support increased competition and still deliver power reliably to customers? The nation's electric systems are tightly interconnected with one another and require careful planning

[4] Regulators can instead allow "flexible prices" subject to a "price cap." If the cap is set about as high as the market price will go, the result is simply market-based pricing. If the cap is set at the cost of providing service, this is, in effect, cost-based pricing.

and coordination for reliable operation. Decreasing reliability means more frequent brownouts and blackouts, perhaps over large geographic areas.

Federal/State Authority

The fifth and final policy question is the appropriate balance between federal and state regulatory authorities over electric utilities generally, and over transmission networks in particular. States have authority over generation and transmission facility need and siting, the obligation to serve retail customers, and pricing of retail electricity generation and transmission. The federal government has authority over the pricing of wholesale electricity generation and transmission between utilities. There is shared authority over pricing power purchased from a QF or IPP, and there is a regulatory vacuum on the question of the utilities' obligation to provide wholesale generation and transmission services. As competition over larger regions emerges in the electric power industry, is the old way for federal and state agencies to share authority the best way?

Transmission Issues

With so many policy questions, it can become difficult to sort them out and to see how they are related. The diagram in figure 1-1 may help. The principal objective of this chapter is to use this diagram (which may at first seem unduly complicated) as a tool for clarifying the relationships among policy questions. The policy questions appear as circles. Supplier access is appropriately at the center because the ability of some suppliers to produce electricity at lower costs than other suppliers, along with their inability to reach all potential buyers, is what raises all other transmission policy questions. The four questions nearest the center--pricing, requirements access, reliability, and authority--are among the most discussed and most contentious questions in the current debate. The siting and retail access questions are peripheral and receive less attention today in most transmission policy discussions.

In the diagram, lines are drawn between certain pairs of policy questions, indicating that these questions are related. For example, incentives for siting new transmission lines that would allow more competition in electricity generation depend on the revenues recoverable from transmission services. If siting policy is made without considering the effects of pricing policy, the goals of the siting policy may not be

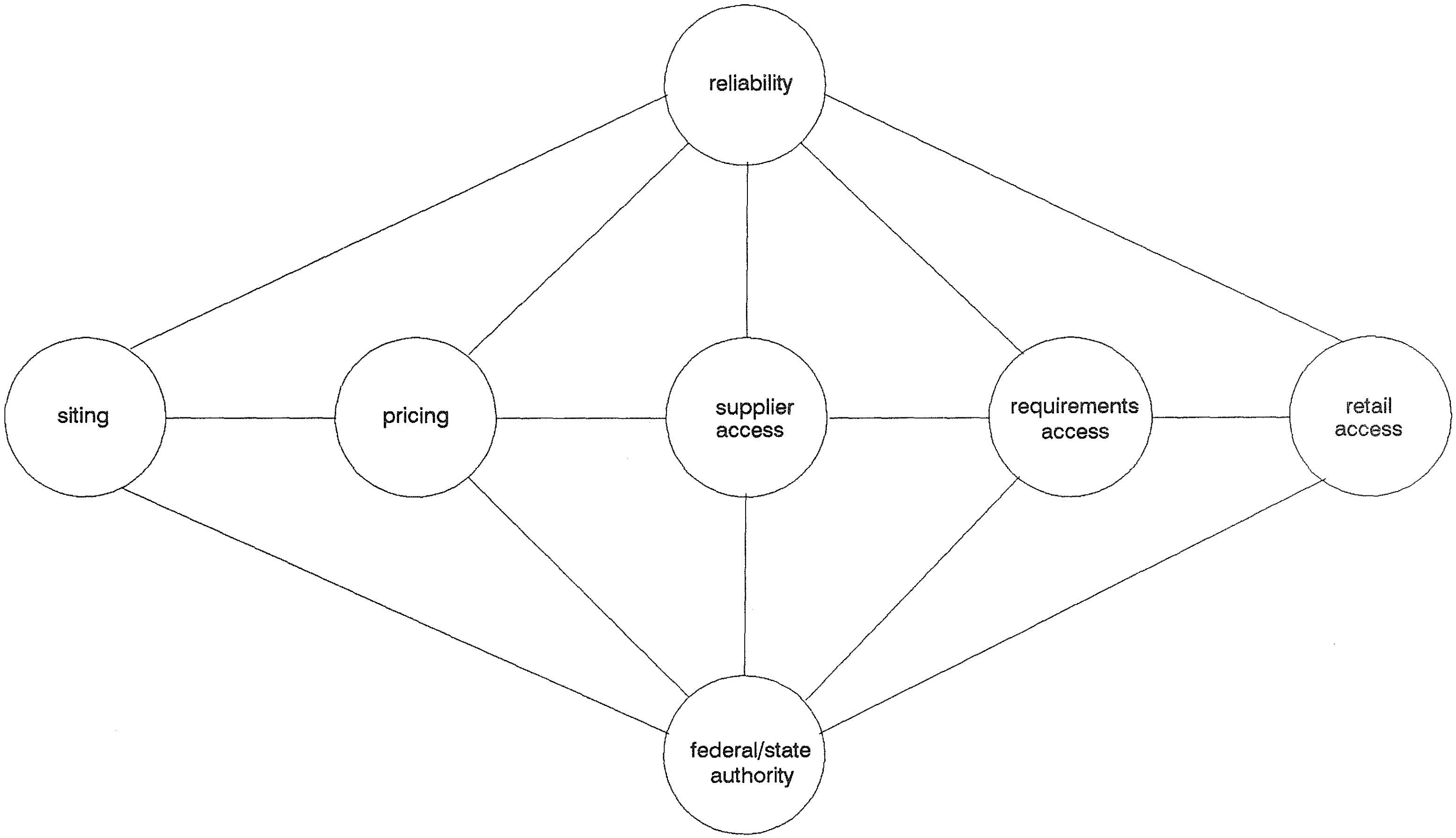

Fig. 1-1. Principal transmission policy questions.

achieved and even may be thwarted. Setting pricing policy in isolation can also yield poor results if the relation of pricing to other policies is ignored. (Pairs not shown as directly related, such as pricing and retail access, are not either current issues or issues likely to be salient in the near future.)

Because the policy questions in each pair are interrelated, it is hard to answer them separately, and an issue arises as one tries to do so. Each line in the diagram, therefore, represents an issue. The figure illustrates fourteen such issues. The four issues on the main horizontal axis of the diagram--which are the economic issues--relate the five key policy questions on this axis. At the top of the diagram, five other issues, referred to here as engineering issues, relate the reliability question to these five policy questions. At the bottom, five regulatory issues relate the authority question to the key policy questions.

Economic Issues

Four economic issues arise from the interplay between the five key economic questions, as shown in figure 1-2. These are the issues of incentives for new line construction, efficiency in setting prices to match the amount of transmission service provided with the amount needed, access equity among utilities, and the possible emergence of retail customer coalitions.

Incentives

The incentives issue relates the siting question to the pricing question. The term "siting" is used here as a shorthand label for the process of identifying the need for a transmission system addition, planning the system expansion, siting and certifying the new line, and obtaining all the necessary permits. Transmission service pricing links siting and access. Utilities will not voluntarily expand transmission capacity as needed to support more competitive and larger regional bulk power markets unless the prices they can charge for transmission services are high enough to give them the incentive to build.

A cumbersome siting process can provide a ready excuse for utilities unwilling to expand service at prices that are too low--even if access is mandatory. A weak effort to get the line certified, an acknowledgement that the environmental opposition raises valid concerns, an unwillingness

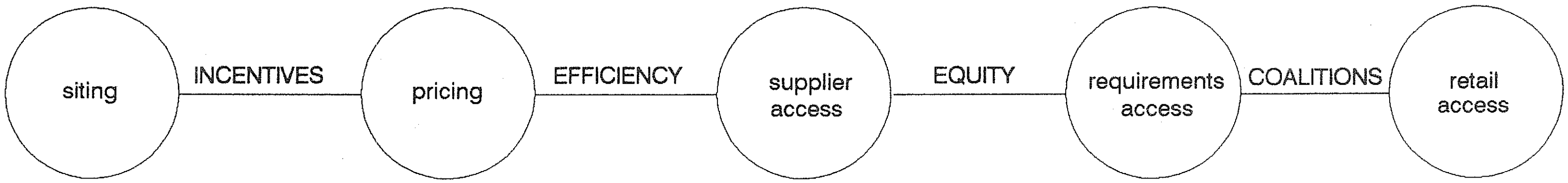

Fig. 1-2. Economic issues.

to "cave in" to landowners who demand exorbitant rent for a right of way can all substitute for a refusal to provide additional transmission service if transmission prices do not provide enough incentive to get the line built.

Cost-based prices simply reimburse the transmitting utility for its costs, providing little incentive for voluntary system expansion. Also, transmission at cost-based rates does little to influence local siting authorities, who see the gains from electricity trades accruing to distant buyers and sellers without benefiting the local economy at all. Further, cost-based prices may not adequately account for the risks involved. For example, there is a risk that fuel prices or other factors may change over the life of the transmission line, changing the relative costs of electricity suppliers. If the additional transmission capacity then is not used, costs may not be recovered after all or may be recovered from the wrong people. Risk to the transmitting utility can be reduced by arranging long-term take-or-pay contracts to cover the costs of new facilities, contracts which may themselves become impediments to open transmission access and competition.

Why would a utility try hard to build a line just to recoup a fraction of its costs? Yet, this is what utilities are expected to do under the current pricing formula where transmission prices are based on the average costs of all lines on the company's books, including some built decades ago. Embedded cost prices in particular are too low to motivate a utility to fight its way through a prolonged siting procedure. They artificially stimulate a demand for uneconomic transmission access but do not provide incentives for the utility to provide that access. Utilities would, in effect, give up valuable assets at discount prices and replace those assets at full current cost.

Traditional low prices and arduous siting procedures team up to discourage economically sound transmission investment decisions. Transmission pricing policy needs to be linked to line siting/system expansion policy.

Efficiency

Efficiency has to do with the effect of price on transmission service supply and demand. The efficiency issue arises as one tries to answer the access and pricing questions separately.

Right now, utilities have no obligation to provide wholesale transmission service, except perhaps under the antitrust laws, and the Federal Energy Regulatory Commission (FERC) apparently can approve only cost-based rates for transmission. Voluntary access at cost-based rates, especially traditional embedded cost-based rates, is a combination of policy answers that does not produce an adequate supply of transmission service.

Voluntary service at market-based rates would alleviate the supply problem but not eliminate it. As mentioned, these rates work well only if competition for transmission service could exist to control exorbitant pricing. Without competition, a transmission company's most profitable strategy is to restrict somewhat the amount of transmission capacity available to drive up the price of transmission service--or to protect its own generation sales.

Mandatory access at cost-based rates is the traditional United States answer to the access and pricing questions where competition is not possible. This combination of policies works well in protecting customers from high prices for the use of existing facilities. But the traditional utility "obligation to serve" includes the obligation to construct new facilities as needed, a factor often left out of the current transmission access policy debate. How hard utilities fight against mandatory access may well hinge on whether transmission rates are based on embedded or marginal transmission costs.

Examining the efficiency issues that relate transmission access and pricing policies is the purpose of the main body of this report.

Equity

The equity issue links the supplier access and requirements access questions. Many smaller utilities argue that allowing any supplier to market its power on the transmission grid and any utility to shop around on behalf of its customers for the cheapest power is sound economic policy. The wholesale requirements customer--though legally a utility--is normally confined to just one supplier. If "regular" utilities have access to a choice of competing suppliers, equity would seem to require that the smaller, mostly nongenerating utilities have equal access also. Is there a good policy basis for discriminating among utilities on access policy?

Regular utilities contend that there is, using another equity argument. These utilities have already invested in generating capacity to meet the needs of their requirements customers. This obligation is one that all parties agreed to in the past in a kind of implicit contract. It would be unfair now to break this contract, they assert, leaving them with large amounts of unproductive investment in idle capacity.

A compromise policy is to provide a period of transition for requirements buyers to change from customer status to independent utility status. During the transition, the generating capacity built to serve the requirements customer would be used to meet growing retail loads where new capacity would otherwise have to be constructed.

Is such a compromise itself a discriminatory practice? After all, most utility customers are free to turn off the lights any time without the electric company's permission. In short, should there be a policy of nondiscrimination among utilities that requires the supplier and requirements access questions to be answered either "yes" for both or "no" for both?

Coalitions

The requirements access question and the retail access question are usually addressed separately, but are linked by the coalition issue. If requirements customers have access and retail customers do not, a group of retail customers may form a coalition that declares itself to be a distribution-only utility. The new utility would then be free to hire an agent to shop around for power and could require the former host utility to provide transmission service from the supplier selected under the requirements access policy. The coalition could be a municipality, a new housing development, a group of commercial establishments in a shopping center, or a group of neighboring industrial plants that decide to interconnect electrically and form a wholly-owned joint venture corporation to find the cheapest power available.

The coalition issue would pit the franchise rights of the host utility against the antitrust rights of the coalition--a contest with an uncertain outcome. However, the idea of such coalitions emerging is far from fanciful. It is perhaps just one step removed from such recent developments as the joint action bulk power supply agency and the use of a municipal utility's service territory by industrial customers as a means to seek competitive power prices.[5]

If the formation of such coalitions is judicially sustained, must one be opposed to a requirements access policy if opposed to a retail access policy?

Engineering Issues

Five engineering issues emerge as we assess how answers to the five key policy questions affect the reliability question, or how reliability concerns may restrict the range of feasible answers to the policy questions. As illustrated in figure 1-3, these are the issues of transmission service adequacy and reserve margin, cooperation among utilities, control of generating units, and coordinated use of transmission systems.

Adequacy

Electric service reliability is ensured in part by constructing transmission lines in a grid-like system so that if one line fails other lines are available to carry power to customers. Reliability is also enhanced if distant generating stations can back up local stations that go out of service. In both cases, adequate transmission capacity is needed to move the power in an emergency. Some line capacity in effect is kept on standby because it costs less to construct extra standby transmission capacity than additional dispersed standby generation. New lines are often justified in part in terms of large regional reliability needs for meeting contingencies.

In siting and certification hearings, these regional needs can be hard to justify, both to the local utility that is asked to construct a portion of the line as well as to local siting authorities. Local siting approval is difficult if the benefits expected, though large, are spread over a wide region, whereas the negative aspects are felt directly and locally. Recent worries about possible health effects of electromagnetic fields exacerbate the problem.

[5] See the Wisconsin Wheeling and Stauffer Chemical case studies in Kelly, *Nontechnical Impediments to Power Transfers*, 221-230.

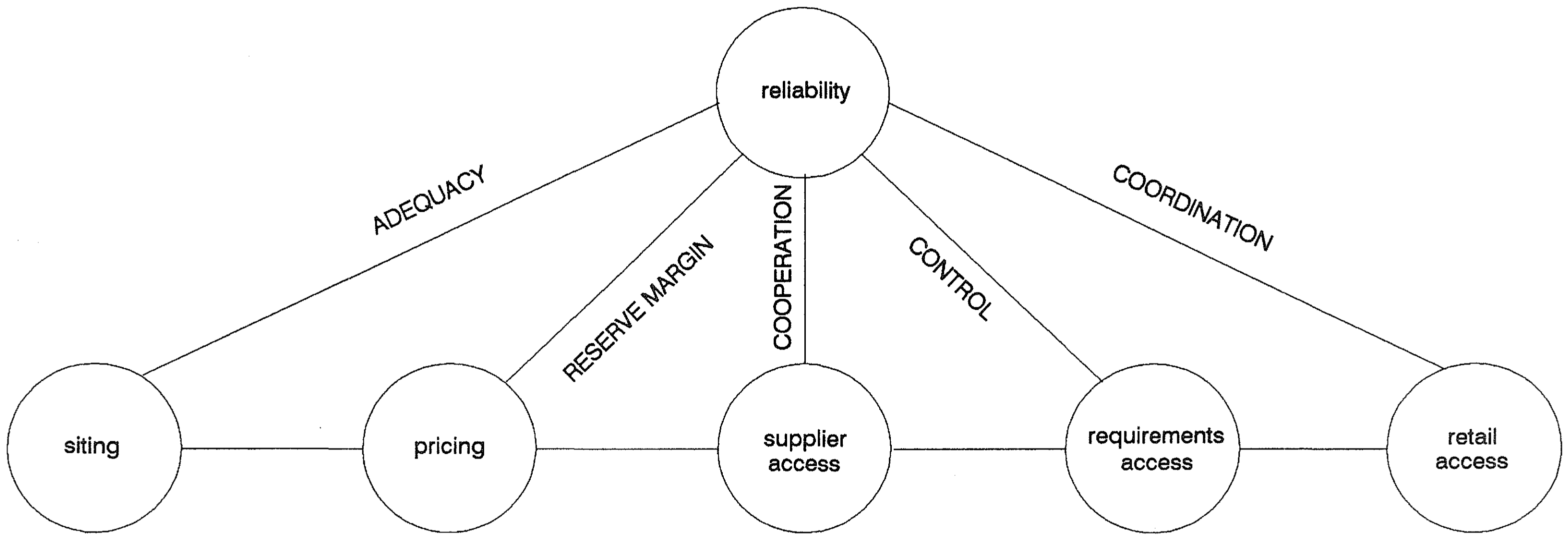

Fig. 1-3. Engineering issues.

Today's system of providing for additional transmission capacity does not always work well. The issue is how best to overcome expansion planning and siting difficulties to ensure reliability among neighboring systems.

Reserve Margin

Several economists have argued that the United States electric system is too reliable and too high priced.[6] Though they cast the argument in terms of excess generating capacity, it is possible that transmission capacity reserve margins are too large also. Here "too large" means that, given the choice, electric customers would select a somewhat higher frequency of service losses due to transmission inadequacy in exchange for lower electric rates. Regulated monopolies provide first-class service at high prices, so the argument goes, because they meet the reliability needs of the most demanding customer instead of the average customer's needs. (When given the choice, most telephone customers showed they prefer a fairly reliable $60 telephone to an indestructible $200 unit.)

An economically optimum pricing policy for transmission service would threaten this practice. The best prices, in the economist's view, would drive transmission line controllers to operate "on the margin" instead of with a large transmission reserve margin. On the margin, the benefits of carrying extra transmission line loads just equal the costs associated with interrupting existing loads more frequently. This cost-benefit test equates the benefits to all customers with the costs to all customers. In thus meeting the reliability needs of the average customer, the transmission system would not meet the needs of those customers who require highly reliable service. If economic pricing forces systems to operate "on the margin," somewhat more frequent brownouts and blackouts may be expected.

United States electric utility engineers are justifiably proud of having "the most reliable electric system in the world" and oppose any lowering of service quality standards. Economists see maintaining adequate reliability mostly as a necessary constraint on policy options. If reliability in fact turns out to be uneconomically high, a direct conflict will emerge between reliability policy and pricing policy.

[6] See, for example, A. Kaufman, L. T. Crane, and B. Daly, *Are Electric Utilities Gold Plated?* (Washington, D.C.: U.S. Library of Congress, Congressional Research Service, April 1979).

Cooperation

A policy favoring supplier access, for both utility and nonutility suppliers, will usher in an era of greater competition among utilities and others to win supply bids. Is it possible for utilities to compete in generation and cooperate in transmission?

Historically, utilities have cooperated with one another to provide a reliable electric supply. Cooperation among the large utilities to ensure reliability takes place within and among control areas and through the reliability councils. Cooperating utilities dispatch generating units as needed to match variations in area loads, and in doing so provide frequency control, voltage support, and stability for reliable transmission system operation. The dispatching order is based first on assuring reliability and second on minimizing costs.

As utilities enter an era of generation price competition, cooperation for reliability may suffer. In a competitive environment, dispatch may be dictated by contract terms, and revealing costs for economic dispatch would work against the interests of utilities trying to sell their own power in the market at a price as high above cost as possible.[7]

Reliability councils are a forum for centralized cooperative regional planning of facilities to ensure reliability: a generating unit of a certain size, if located here, would meet the reactive power needs and back-up generation needs of several companies in the region; a new transmission line, if located there, would strengthen the integrity of the grid if a neighbor's line should go down. Would this kind of fraternal cooperation survive if council members are strategically siting generating units and transmission lines to increase generation market share at the expense of their neighboring competitors? There may be a danger that stronger members of the reliability councils would collude under the guise of reliability planning to site new facilities in an anticompetitive fashion. If markets replace regulation, will utilities be allowed legally to cooperate at all under the antitrust laws?

[7] For one insight about how competition can eliminate cooperation, see "Spying on Competitors," *Electrical World*, November 1988, 23. For an opposite view regarding how competition for financing of new investment is compatible with cooperation among generating unit owners, see T. Paynter, "Coordinating the Competitors," Illinois Commerce Commission, May 1990.

Control

If requirements customers shop around for the cheapest power, it will be more difficult--but not impossible--to ensure the reliability of electric service. Service interruptions are avoided not only by having an adequate amount of generation and transmission capacity, but also by implementing a plan for controlling all the on-line generators in an interconnected system.

There are over two-hundred investor-owned utilities (IOUs) in the United States and several large federal utilities, such as the Tennessee Valley Authority. But there are only some 143 control areas. Some smaller IOUs give up control of their generating units to a large utility that operates all the generation and transmission facilities in the control area. The utility in control must respond rapidly to constant fluctuations in customers' electricity usage, raise and lower the outputs of many generating units, keep generating units rotating synchronously at standard frequency, make up for the unexpected failure of a generating unit or loss of a transmission line, and if necessary, call for emergency back-up power from outside the control area. Failure to perform these functions could mean that customers suffer a power failure. It may be momentary or last for hours; it may affect a portion of a city or most of a state depending on the configuration of the facilities and the nature of the incident. The key to performing the control functions is to have many interconnected generators under the immediate control of one center.

There are about 3,200 municipal, local, and cooperative utilities in the United States, most of which are full or partial requirements customers of an IOU. Requirements access policy may be to treat these as legally independent utilities entitled to purchase power from outside suppliers. But most still have the technical characteristics of customers in that they have little or no generation with which to perform their own control functions. With today's technology, it is unrealistic to expect an outside supplier to follow the moment-to-moment variations in a buyer's retail load. If both the outside seller (perhaps a single-unit nonutility generator) and the requirements buyer have limited control capability, reliability is threatened not only for service to this buyer, but also to the retail customers of the host utility surrounding the buyer.

Ensuring reliability requires that some control must be provided, probably by the host utility's control center. This raises a number of control issues. Will the host utility control the nonutility supplier's generators? If not, the host utility will want to be compensated for dispatching its own generators to follow variations in the requirements customer's load. It may want to be able legally to prohibit an arrangement between an outside supplier and a requirements customer that has significant adverse effects on its own system cost and reliability.

Interrelated policies on requirements access and system reliability are needed. New institutions may be required to ensure reliability if the number of independent decision-makers using the transmission grids goes from 143 to 3,400. As the number increases, the problem of coordinating overlapping control efforts becomes more complex.

Coordination

The coordination problem could become exceedingly complex if tens of thousands of retail customers also become independent users of the transmission system. Many small buyers each may contract for only a portion of a large generating unit's output. A single large buyer may get power from several small generating units. Buyers and sellers could be scattered throughout several utilities' service areas. The possibility of loss of frequency control and consequent shutdown of the system is real unless the system is tightly controlled by a strong "traffic cop" to police the behavior of so many independent and often technically untutored users.

The transmission system can handle more independent entities than it has now, perhaps up to a few hundred more, if all obey the rules of the road. But it cannot handle thousands more without developing new control technology and institutional arrangements for ensuring system reliability. It may be that these can be developed so that retail access would be possible technically. But it is unclear whether such a policy passes a cost-benefit test.

Regulatory Issues

Five regulatory issues emerge as we consider how answers to the five key policy questions affect the federal/state authority question, or how jurisdictional rigidity may constrain workable answers to the policy questions. As depicted in figure 1-4, these are the issues of state authority constraining federal policy regarding interstate commerce in

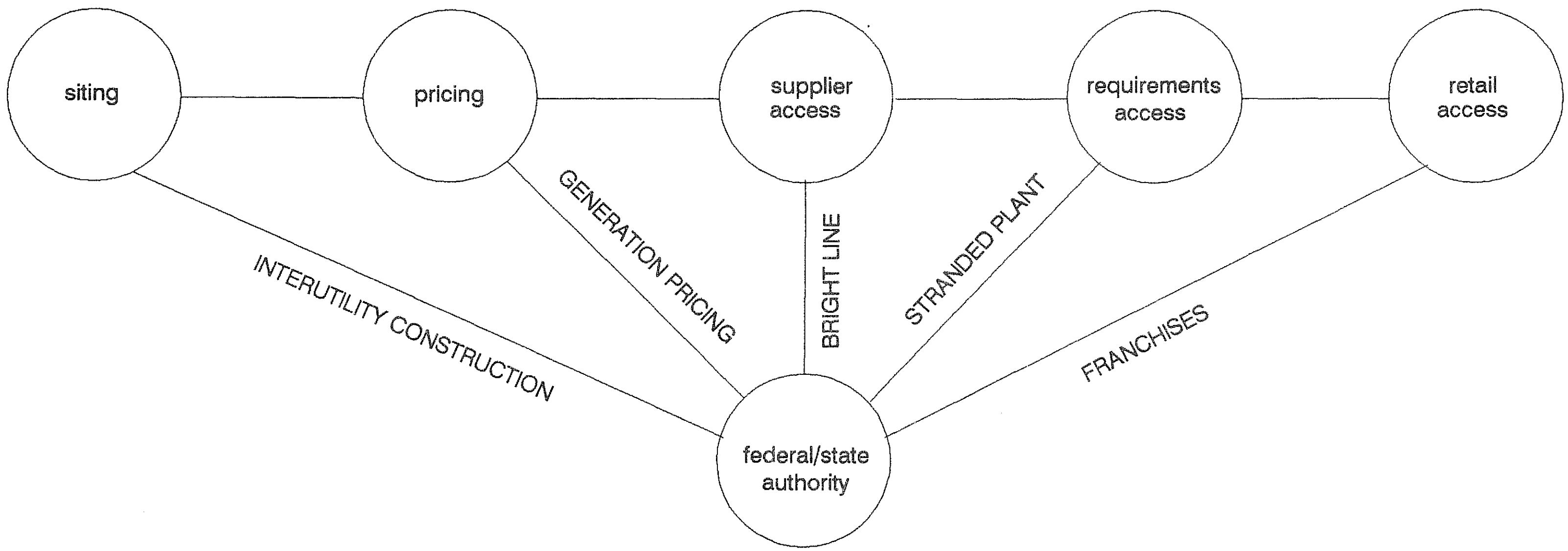

Fig. 1-4. Regulatory issues.

electricity and bulk power pricing, and the potential for federal policies to constrain traditional state authority over the prudence of utility decisions, stranded plant, and utility franchises.[8] Some of these issues have already been raised in the policy debate. Others are issues likely to emerge as competition increases in the industry.

Interutility Construction

A strong tension is emerging between state and local authority over interutility transmission planning, siting, and certification on the one hand and the inherent interstate commerce character of the transmission system on the other hand. Nothing could be more interstate, even international, in character than a single device connecting generators rotating in unison in Maine, Florida, Oklahoma, and New Brunswick. Strengthening this device to meet national needs by erecting new lines requires local approval where local, not national, cost-benefit tests are often applied.

Regulating any monopolistic industry requires close coordination in the use of two important regulatory powers: the power to enforce the obligation to provide service and the power to set service rates. Neither power alone can adequately control monopoly behavior. Yet in the case of electric wholesale transmission the ratemaking power is clearly at the federal level, while partial authority over transmission system expansion--to limit expansion if not to order it--is at the state level. This division of authority either will create a need for closer coordination of federal and state regulatory powers or will lead eventually to a regulatory tug-of-war as one side seeks to unify the two powers needed to regulate effectively.

Right now there is a vacuum in authority over the construction of multistate lines. One could argue that the federal government under the interstate commerce clause should have the authority to site new interstate, if not all interutility, lines. But this is an authority that it currently neither seeks nor wants and that no one, it seems, wants it to have.

[8] See K. Kelly, R. Burns, and K. Rose, *An Evaluation for NARUC of the Key Issues Raised by the FERC Transmission Task Force Report*, NRRI-90-7 (Columbus, Ohio: The National Regulatory Research Institute, January 1990).

Generation Pricing

The tug-of-war over generation pricing authority is already being waged. At issue is whether the price of delivered bulk power should be separated into its component parts, the price for generating the power and the price for transmitting the power. If these two prices continue to be set separately, a utility that both generates and transmits power may be able to price either generation or transmission service to its own strategic advantage. For example, a company that wants to sell its own power could try to set a high transmission price for moving a competitor's power, if its physical location permits, so that the delivered price of the competitor's power is too high. Or this company could try to set the transmission price high enough to capture most of the profits available from the three-party transaction. Uncertainty about transmission prices makes it difficult, of course, for some distant supplier to bid competitively.

Neither federal nor state authorities have exclusive jurisdiction over delivered price. The FERC asserts jurisdiction over virtually all transmission pricing as well as generation pricing for wholesale sales by utilities. However, states have the authority to set generating prices for sales by QFs, subject to FERC oversight, and states apparently will have jurisdiction over the use of competitive bidding to determine IPP generation prices, probably also subject to FERC oversight. The FERC allows split-the-difference pricing for generation in some circumstances, which may be different from--and often higher than--the price a competitive market would yield. States too have sometimes set rates for QF power above market rates, a practice the FERC is determined to eliminate. States worry that recent FERC interest in competitive bidding to set generation prices for IPPs will further limit their generation ratemaking authority.

The policy issue is whether federal and state ratemaking can be coordinated well enough to result in delivered prices for bulk power that eliminate the possibility of anticompetitive pricing strategies. If coordination is ineffective, states are likely to want exclusive control over intrastate transmission pricing, and the FERC is likely to use its oversight authority to delimit state generation pricing approaches to a single FERC-approved method.

Bright Line

Increasing supplier access will create new areas of uncertainty about the so-called "bright line" between federal and state authorities over nonretail electricity transactions. The FERC, for example, might allow utilities to earn some measure of profit on either generation or transmission service in order to encourage an open access policy. States would be in a position to eliminate these profits through retail rate reductions, creating a possible case for redrawing the bright line.

The FERC may act to protect the interests of power suppliers that win competitive bids. As a result, states could become increasingly limited in their ability to oversee the prudence of utility supply decisions. Some contend that competitive bidding will become the principal way by which electric utilities make new generating unit choices. If it does, state regulatory authority over such areas as certification of need, nonprice factors in supplier selection, contract provisions, fuel type, and oversight of fuel cost adjustment could be eroded gradually by a series of federal administrative and judicial decisions designed to enhance fairness or uniformity.

A policy of open competitive bidding and open supplier access to transmission would increase the trend toward utilities having power suppliers located out of state. This trend could be enhanced if some states were known to offer contract terms that transferred more supplier risks to utility retail customers and if federal rules prohibited favoring home-state suppliers. This too would gradually shift major regulatory responsibilities from the state to the federal arena.

Stranded Plant

The requirements access question has been thoroughly debated at the federal level, especially in comments filed with the FERC. Yet the consequences of permitting access to requirements customers may have to be dealt with more at the state than the federal regulatory level. If federal policy gives requirements customers access to suppliers, depending on the terms of the policy this action may result in host utilities having excess generating capacity--so-called stranded plant--constructed to meet requirements customers' needs.

Who should pay for the sunk costs of stranded plant? The state public utility commissions would probably have to decide. Utilities and others often say that retail customers must pay for any such costs through retail rate increases: the only issue is how to allocate the costs among residential, commercial, and industrial customers. But it is by no means certain that retail customers would pay for all or any of these sunk costs. Issues of what constitutes retail and wholesale rate base would have to be decided first--that is, which investments are state regulators responsible for deciding on and which are for federal regulators?

In a competitive environment, utilities presumably would be expected to offer their excess capacity for sale at market rates. These rates might or might not recover all of the capital costs of the stranded plant. Unrecovered costs would then be seen more as stockholder liabilities than retail customer liabilities. An abrupt change in federal law or regulation has the capacity to alter stock values in many industries. Electric utility stockholders, more so than retail ratepayers, could be affected by a federal requirements customer access policy. This may depend on whether federal implementation of this policy spells out who, if anyone, is left holding the bag.

Franchises

Like requirements access, the retail access question is debated more often at the federal policy level but would have its greatest effect at the state regulatory level. Many electric utility observers think federal support for retail access is unlikely. But gas industry observers know that the FERC proposed a rule that "leans on" local gas distribution companies to provide their retail customers open access to transmission pipelines. For federal policy makers to permit retail electric access would have a profound effect on the states' franchise authority.

In granting an electric utility an exclusive franchise to provide electric service to an area, the state strikes a bargain with the company. It becomes a legal monopoly, and the state requires that all customers be served and restricts monopoly abuse in pricing. The utility cannot "skim the cream off the top" of the market, choosing to serve only the more profitable customers. It must serve all comers. It cannot unduly discriminate in pricing--no sweetheart rates for favored customers or exorbitant rates to undesirable customers. It cannot make a real profit on its sales, but only earns a "normal" profit reflecting the low capital costs of its noncompetitive environment.

What it gets in return for agreeing to these restrictions is freedom from competition. No other power supplier can come in to cream skim, to set prices selectively for favored customers, or to increase capital costs by increasing the risk of sales loss to competitors.

Retail access changes all this, of course. The state's franchise loses its value. The issue here is not only who pays for stranded plant and who serves the less profitable customers, but who really ought to decide the retail access question.

Three Perspectives

The seven policy questions corresponding to the seven circles shown in figure 1-5 are placed at three different levels in that diagram. The access, pricing, and siting questions are at the center, with the reliability and the federal/state jurisdictional questions at the two other levels. The three levels are intended to indicate three perspectives on transmission policy.

Access, pricing, and siting receive the most attention from those with an economic policy perspective, such as economists and public policy analysts. Engineers and many customers worry about how the outcome of the policy debate will affect the reliability of electric service. How the outcome will change federal and state authorities over electric utilities is the most important question to those with a political or legal perspective.

Those with the economic policy perspective often view reliability concerns suspiciously, suspecting that utility engineers use reliability as a bugaboo to discourage competition in the industry. In fact, they sometimes have. This is unfortunate because electric transmission network reliability is indeed a serious concern. Achieving reliability in a more competitive environment is possible, but requires greater attention and more planning as the number of independent users of transmission systems grows. It is not yet clear who would be responsible for making the effort. The engineering perspective is often not represented effectively in the debate.

Those with an economic policy perspective also often give scant attention to the shifting line between state and federal authorities. Yet, an otherwise economically sound policy for reorganizing the electric

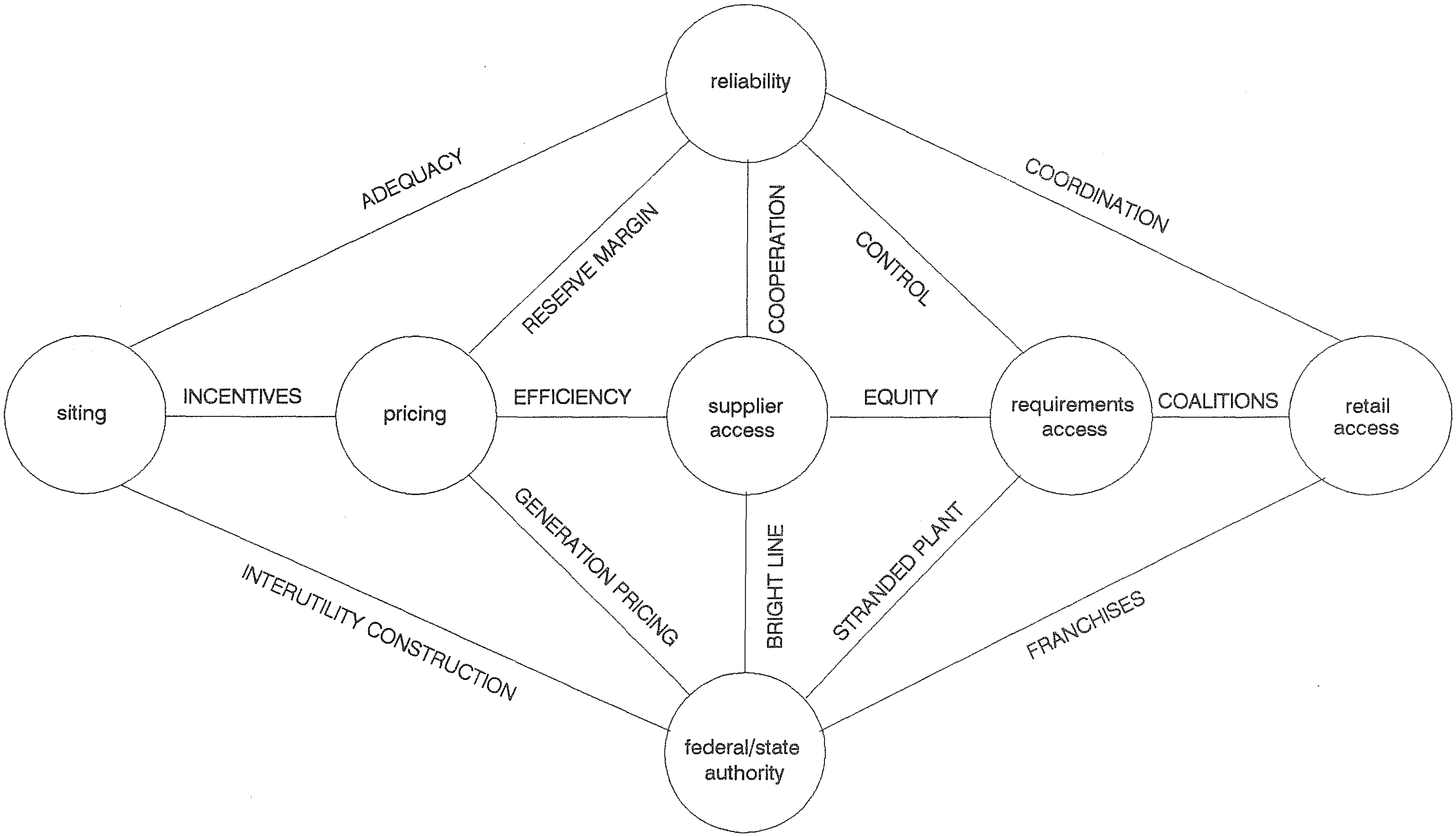

Fig. 1-5. Transmission policy questions and issues.

industry can be thwarted by a system of regulatory organizations that does not match the industry's new structure.

Those with either an engineering perspective or a legal perspective are often unappreciative or even unaware of each other's concerns. Both view with apprehension the effect that the debate taking place on the economic policy level may have on their own interests. Engineers in particular look askance at the efficiency concerns of economists, arguing that textbook market theories cannot perform as well in practice as sound technical planning. Yet, on the whole, markets are known to generally outperform centrally planned systems.

One difficulty we face in developing a national transmission policy is that the major policy questions are being addressed individually, based on the merits of the pros and cons of each question considered in isolation. The issues that arise from the interplay among questions are largely ignored. Recognizing these relations at first may lead to policy paralysis, however. For example, we do not know how best to set prices until access policy is decided, but we cannot determine a fair access policy until we know how prices will compensate for access. What is needed, of course, is a global view of the issues so that appropriate policies can be adopted in tandem. Development of a consensus on transmission policy, then, requires consideration of all the questions, their interrelatedness, and the legitimacy of the various perspectives.

Plan of This Report

It makes the most sense to start at the center of the diagram with the supplier access question, then to develop the answers to the surrounding questions that work best in the light of supplier access policy. This is because the appropriate answers to all other questions follow from knowing what opportunities for competition are possible through supplier access. This report deals with the efficiency and incentive issues. It complements other recent NRRI reports that have analyzed several of the issues shown in the diagram.

NRRI Transmission Reports

In the mid-1980s, the NARUC asked the Electric Power Research Institute (EPRI) and NRRI to study technical and nontechnical impediments, respectively, to increased use of transmission to support a more competitive electric power market. The NRRI report, *Nontechnical Impediments to Power Transfers*,[9] provides a comprehensive compilation of the issues depicted in figure 1-5. Other NRRI transmission reports have focused on particular issues or pairs of issues, with emphasis on the left half of this diagram. The report on *Economic Principles*[10] sets out the concept of transmission pricing as a vehicle for achieving efficiency in the production of electricity, that is, the least production cost for a region. It focuses on the issues of efficiency in using the existing transmission system and incentives for optimally expanding the system. Thus, it considers both short-run and long-run production efficiency.

This report on access and pricing policy is a follow-on study to the *Economic Principles* report. It examines prospectively the expected effects of various proposed access and pricing policies on short-run and long-run production efficiency and on incentives for system expansion. Another NRRI report develops methods for evaluating retrospectively whether transmission has been used effectively to achieve short-run production efficiency.[11]

Engineering and regulatory issues are at the heart of other NRRI transmission reports. The reserve margin issue raises the question whether it is possible to give customers their choice of various levels of service reliability. The technical feasibility and economic benefits of such a practice are examined in a recent NRRI study.[12] The question of federal/state authority and its effects on generation pricing and interutility construction are considered in NRRI's evaluation of the recent (1989) report by the FERC Transmission Task Force.[13] Finally, an NRRI report is forthcoming on new legal issues relating to siting, including both siting of generation under competitive bidding and siting of associated transmission lines.

[9] K. Kelly, ed., *Nontechnical Impediments to Power Transfers*, NRRI-87-8 (Columbus, Ohio: The National Regulatory Research Institute, 1987).
[10] K. Kelly, J. S. Henderson, P. Nagler, and M. Eifert, *Some Economic Principles for Pricing Wheeled Power*, NRRI-87-7 (Columbus, Ohio: The National Regulatory Research Institute, 1987).
[11] N. Rau, *The Evaluation of Transactions in Interconnected Systems*, NRRI-88-9 (Columbus, Ohio: The National Regulatory Research Institute, 1988).
[12] N. Rau and Y. Hegazy, *Reliability Differentiated Pricing of Electric Service*, NRRI-90-5 (Columbus, Ohio: The National Regulatory Research Institute, 1990).
[13] K. Kelly, R. Burns, K. Rose, *An Evaluation for NARUC of the Key Issues Raised by the FERC Transmission Task Force Report*, NRRI-90-7 (Columbus, Ohio: The National Regulatory Research Institute, 1990).

Content of This Report

The remainder of this report, as mentioned, examines the efficiency and incentive issues relating access and pricing policies. We do not consider the other questions and issues further in this report. Our focus on access and pricing as a natural starting point is not meant to downgrade the importance of the other subjects. Indeed, the purpose of this chapter has been to stress their importance. However, the remainder of this report treats only the simpler set of issues shown in figure 1-6. We do not normally distinguish supplier and buyer access, for example. (However, in chapter 6 we separately model the cases where the buyer does and does not have adequate generation of its own.)

Chapter 2 outlines and classifies the principal access and pricing proposals. A method for examining the efficiency aspects of these proposals is introduced in chapter 3; as mentioned, it is an extension of the production efficiency and incentive analysis introduced in the *Economic Principles* report. Chapters 4 and 5 use this method to analyze access and pricing policies for nonfirm and firm transmission services, respectively. In chapter 6, we consider how access and pricing policies may affect incentives for planning new transmission capacity for future economy energy sales. Chapter 7 summarizes the findings and examines their implications for the unfolding policy debate.

While this report stands alone, the reader new to the transmission policy arena may find it helpful to review prior NRRI transmission

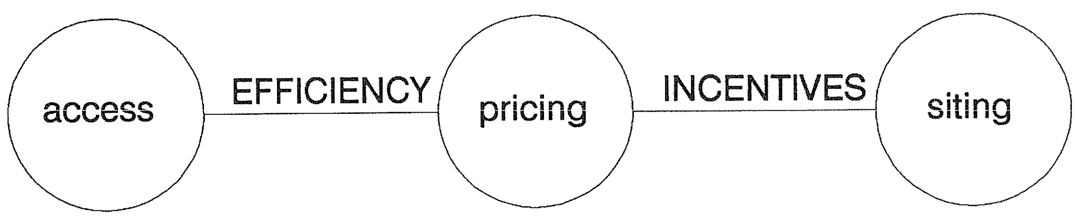

Fig. 1-6. Questions and issues examined in this report.

publications in order to learn how the transmission system works, to obtain detailed explanations of transmission terminology, and to understand the institutional setting within which the debate is taking place.[14] This report is not intended as an introduction to the transmission debate; that is one purpose of the *Economic Principles* report.

This report is intended to examine the efficiency and incentive issues in some depth with an analytical tool not previously used for transmission discussions--and, while we try to keep the use of jargon to a minimum, economy of language requires some use of technical terms for concepts discussed often. Later chapters build on earlier chapters, and the prose becomes increasingly technical, which makes it difficult to browse through this report. Early chapters are easier to read, we hope, and the main findings are summarized in the last chapter. But the reader is encouraged to work through the middle chapters. The results are reported in a way that is intended to be readable, though with some effort, by the nontechnical policy maker. Much of the value of the analysis here is, we believe, a better understanding of strategic behavior by the players in bulk power markets under various government policies--an understanding that is not easily conveyed in a summary but can be developed fully only by following the analysis. If we compare bulk power market strategies to strategies in a game, the summary tells you who wins and the chapters teach you how to play the game.

[14] See Kelly et al., *Economic Principles* and Kelly, ed., *Non-technical Impediments to Power Transfers*.

CHAPTER 2

CLASSIFYING TRANSMISSION ACCESS AND PRICING POLICIES

In the United States today, the electric utility industry is changing from a tightly regulated monopoly business to a mixture of regulation and competition. The Public Utility Regulatory Policies Act of 1978, together with technological maturity and more players in the electricity supply industry and, to some considerable degree, current government policies, have made for greater competition in electric generation. The outcome for industrial organization and regulatory structure is, as yet, unclear. As set out in chapter 1, central to the debate are the questions of who should have access to the electric transmission grid and how much they should have to pay for transmission services.

The electric transmission issue, however important in its own right, is but one example of a new kind of public policy issue regarding how competition and regulation can coexist in an industry. Policy makers now are struggling to cope with this mixture in the electric, natural gas, and telephone utility industries. This report presents one aspect of an ongoing attempt by the NRRI to develop a new framework for analyzing such issues and new tools for analysis.

The Principal Access and Pricing Proposals

Answers to access and pricing questions depend on an understanding of the nature of the market for transmission services. To begin, consider three textbook cases of industrial organization, represented as the three points of a triangle in figure 2-1.

The classic free market is characterized by competition among many sellers to provide goods or services and by competition among many buyers to purchase these goods or services. This direct competition prevents any exercise of market power by either sellers or buyers, drives prices down to the level of marginal costs, and prevents discriminatory pricing. Further, efficient firms make a profit and so are motivated to construct new capacity to provide more goods or services.

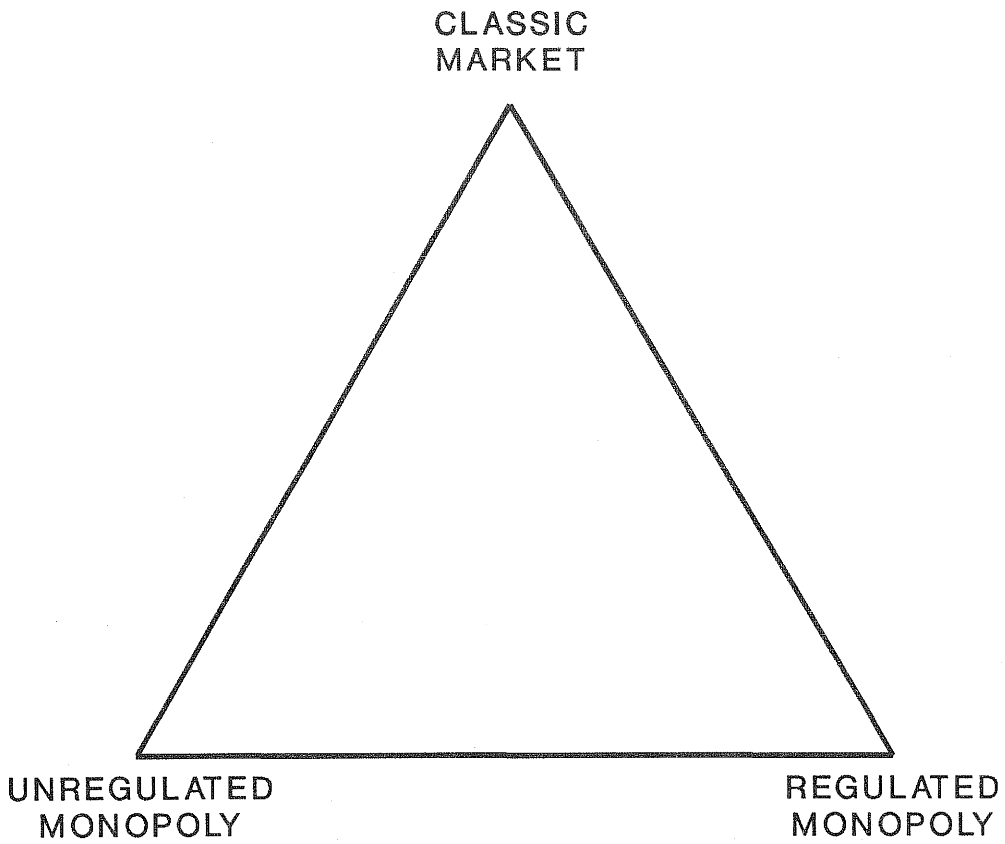

Fig. 2-1. Three textbook industrial organizations.

For the regulated monopoly, on the other hand, government regulation eliminates market power by imposing an obligation to provide service at cost-based rates. The obligation to serve includes the obligation to expand capacity as needed to provide service to all comers. Typically, rates are based on so-called fully allocated embedded costs and must be nondiscriminatory.

The market power of an unregulated monopoly is neither eliminated nor mitigated. Prices for each customer are based on the value of the service to that customer, not the cost of providing it, and so different prices can be charged to different customers. Capacity is restricted and the price is raised.

The Problem

A problem in the United States today is that electric transmission service does not correspond to any one of these three textbook models. The classic market is not possible for two reasons. One, there is usually only one available provider of transmission services, and two, the technical characteristics of alternating current transmission are such that even if several interconnected providers did compete to provide transmission service from a power supplier to a power buyer, the power would flow over the path of least resistance, regardless of which provider won the competitive bid to provide the service.

Transmission service is a form of monopoly service that is neither unregulated nor fully regulated under existing United States law. The Federal Energy Regulatory Commission is authorized and obligated to set transmission service prices. But, some exceptions aside, it is not generally authorized to enforce any obligation to provide service over existing transmission facilities nor to compel the expansion of transmission capacity for the purpose of meeting growing demands for transmission service in the strongly emerging, competitive market for electric generation sales.

Some Proposed Solutions

Several solutions to this problem have been proposed by various stakeholders, including investor-owned electric utilities, publicly owned utilities, consumer groups, federal and state government agencies, independent power producers, and others. One of the first was proposed by the NRRI.[1] Briefly, this NRRI proposal would require utilities to offer transmission service at marginal-cost-based rates. Firm, or reserved, service would be available to all comers at a price equal to long-run marginal cost, and the provider would have an obligation to construct

[1] K. Kelly, J. S. Henderson, P. Nagler, and M. Eifert, *Some Economic Principles for Pricing Wheeled Power,* (Columbus Ohio: The National Regulatory Research Institute, 1987); also K. Kelly and J. S. Henderson, "Pricing Transmission Service in the Electric Power Industry," presented to the TIMS/ORSA Joint National Meeting, Washington, D.C., April 26, 1988.

capacity as needed to provide this service. Non-firm, or as-available, service would be priced at short-run marginal cost. Importantly, the transmission customers, not the provider, would be allowed to choose whether the service would be firm or nonfirm.

In the past two years, almost a dozen other solutions have been proposed. These generally follow either of two approaches. One is to allow utilities to price transmission services "flexibly," that is, as they see fit under prevailing market conditions, so as to increase the incentive for utilities to offer transmission services voluntarily. The other is to impose some type of legal obligation to serve at cost-based rates, moving transmission service toward traditional regulated monopoly status. Some proposals combine features of both approaches, in that utilities would take on this obligation voluntarily in return for flexibility in pricing power sales.

The number of transmission proposals grows with time. Although the proposals vary considerably in design and content, each proposes particular access and pricing policies. These policies may be either explicit or implicit in the proposals. Proposals advocating cost-based transmission rates, especially those using embedded cost, generally advocate mandatory access to the transmission system. Proposals advocating flexible transmission pricing usually call for voluntary service.

Embedded cost rates, supporters argue, are practical and fair. They are practical because they are easily measured. They are fair because they protect utility stockholders and retail ratepayers from letting transmission users be "free riders" on the capital already invested in transmission facilities. Their main drawback is that they do not reflect the degree to which these facilities are oversubscribed or underutilized, would poorly allocate constrained transmission capacity, and do not properly motivate new transmission investments. Marginal-cost rates would reflect such factors, but are said to be difficult to measure and may not thwart user free-riding when transmission capacity exceeds core customer needs.

Flexible pricing proposals vary in design, but all propose a price range with negotiated rates. Most set the floor price equal to embedded cost. Some proposals would set the ceiling price at long-run marginal cost, others use a multiple of embedded cost while still others tie the ceiling price in some way to total generation savings. As expected, advocates of each offer numerous reasons as to why their pricing policy is best. Seldom do these supporting arguments consider how strategic reaction by utilities may affect overall efficiency and equity.

Many of the proposed solutions have appeared as discussion papers, often thirty to forty pages in length. The prominent proposals, some with too many detailed features to be more than briefly summarized here and some with insufficient detail to be reported definitively here, were made by each of the following organizations. They appeared in approximately the order presented here. Some of these proposals are being modified by the sponsoring organizations as the debate continues. The pricing policies are presented here as set out by their sponsors, using terms such as incremental, embedded, or marginal cost; later in this chapter the possible variations in the meanings of these terms are discussed.

NRRI Proposal

The National Regulatory Research Institute (NRRI), the research arm of the NARUC, proposed a transmission model intended to encourage good (that is, economically efficient) decision making by utilities wheeling power and by customers purchasing wheeling services. Good decision making should result in economic dispatch of present generating facilities as well as least-cost generation and transmission capacity expansions.[2] The NRRI cost-based proposal includes an obligation to provide transmission service and gives customers the choice of electing firm or interruptible service, without regard to service term.

The NRRI model proposes short-run marginal-cost pricing for interruptible wheeling service and long-run marginal-cost pricing for firm service. (The model treats incremental costs and long-run marginal costs as practical equivalents.)

Short-run marginal cost is the "running cost" that covers variable expenses for operation and maintenance plus, if appropriate, a congestion charge to reflect opportunity costs. The congestion charge rises as transmission capacity becomes oversubscribed. Its purpose is to allocate capacity to customers that value transmission more. The NRRI model examines several methods to determine congestion charges, such as responsive pricing, auctions, and administrative cost recovery rules, but does not recommend any particular method.

Long-run marginal cost includes both the capital cost of system expansion and appropriate future running costs after expansion. Future

[2] Kelly et al., *Some Economic Principles*.

running costs can be lower than current running costs because capacity additions can decrease line losses.

The NRRI model distinguishes firm from interruptible transmission service. Firm service entails a commitment by the host utility to provide transmission capacity; interruptible service does not. Firm service customers receive a priority similar to that of native load customers, whereas interruptible service customers do not. Long-term firm service would have a two-part (fixed-variable) pricing structure, perhaps with resale rights.

EEI Proposal

The Edison Electric Institute (EEI) represents the collective views of investor-owned utilities (IOUs). EEI has made a number of contributions to the transmission access and pricing debate. It has not, however, offered a specific detailed proposal, in part because its members have a diversity of views. Some own large transmission systems and some do not. The latter are among the smaller IOUs, which depend on other utilities for transmission services. Some of the largest investor-owned utilities intend to become marketers of power and would welcome a transmission policy that facilitates power sales.

The first EEI policy monograph on pricing of transmission services in bulk power markets stresses the importance of keeping wheeling voluntary.[3] The goal is to improve and ensure efficiency in bulk power markets. Appropriate prices would provide clear incentives to wheel and would encourage efficient, reliable transmission service tailored to the needs of all affected parties, including both utility and nonutility power suppliers. Wheeling rates and conditions would be negotiated flexibly on a case-by-case basis to ensure efficiency and equity. The EEI monograph recommends a zone of reasonableness for prices. The zone must be wide enough to include all efficient transactions, and, within the zone, prices must be flexible enough to permit the parties to respond rapidly to changing market conditions. The zone should be administratively simple to implement and be based on the true economic cost of providing various types of service.

[3] Edison Electric Institute, *Pricing of Transmission Services in Bulk Power Markets: Factors for Consideration*, Monograph no. 1 (December 1987).

PG&E Proposal

The Pacific Gas and Electric Company (PG&E), an investor-owned utility operating in northern California, has a voluntary transmission access and pricing proposal that is intended to build on existing industry wheeling practices.[4] The PG&E model grew out of the Company's efforts to satisfy the desire of some of its control-area requirements customers to find their own power suppliers. Hence, it is heavily oriented toward distinguishing requirements and nonrequirements services. However, the wheeler could voluntarily assume an ongoing obligation to provide long-term requirements service in return for generation and pricing flexibility for some nonrequirements services.

Wheeling services would be voluntary (in this sense), point-to-point, and defined by an interconnection agreement. The agreement would, among other things, mitigate uncompensated power flows. The model distinguishes between requirements service, which here means service that is essential to avoid a loss of power to some area, and coordination service, which is not. After offering requirements wheeling services for reliability needs to captive customers at embedded-cost rates, a utility's additional wheeling services would be priced flexibly under a FERC-approved price cap.

The transmitting utility would sign an agreement only with the power buyer, not the seller. The buyer must be a utility. Hence, the PG&E model would somewhat limit access to transmission facilities in that a potential customer must meet certain conditions to become a "Utility Purchaser" and thereby be eligible to receive wheeling services. The purchaser must either be independent of the wheeling utility for its reliability needs or be willing to compensate the wheeling utility for stranded generation investment.

The model defines three types of wheeling services to meet reliability and coordination needs: Reserve Transmission Service, Inter-Control Area Transmission Service, and Coordination Transmission Service. Reserve Transmission Service (RTS) would be long-term firm transmission service for imports of power by a captive customer located within the wheeling

[4] Pacific Gas and Electric Company, "Proposal for Reform of the Bulk Power Market with a Focus on Electric Transmission Pricing Reform and Access," 15 February 1989, Draft. See also R. O. Marritz, "PG&E's Bold Entry in the Transmission Policy Sweepstakes," *The Electricity Journal* 1 no. 5 (December 1988): 26-39.

utility's control area. Long-term here means fifteen years or more. Service would be point-to-point, that is, from a specific power supplier to a specific wholesale load. The amount of RTS made available would be limited to the reliability needs of the captive customer. The wheeling utility would be obligated to add capacity for reliability needs at the customer's expense. The captive customer can use RTS to purchase long-term power from either utility or nonutility sources. Because RTS is for reliability needs, RTS transmission capacity cannot be resold or reassigned, although it can be returned to the wheeling utility.

Inter-Control Area Transmission Service (ICATS) would be long-term (more than fifteen years) firm transmission service for the import of power by Utility Purchasers located in another control area. Service would be point-to-point and limited to the customer's reliability needs. The wheeling utility would be obligated to add capacity for reliability needs at the customer's expense. The Utility Purchaser can use ICATS to purchase long-term firm power from either utility or nonutility sources. ICATS too cannot be resold or assigned but can be returned to the wheeling utility. Unlike RTS, ICATS carries a reciprocal obligation for the Utility Purchaser to provide transmission access through its own control area for the wheeling utility.

Pricing for RTS and ICATS would be cost-based. The Utility Purchaser would pay embedded costs for service on existing facilities and incremental costs for new facilities. The PG&E model would allow some upward and downward price flexibility for RTS and ICATS to reflect scarcity and competition. All revenue from RTS and ICATS would offset retail revenue requirements.

Coordination Transmission Service (CTS) would be all other wheeling transactions. Service would be point-to-point, at the discretion of the wheeling utility, and with no obligation to build. Service could be short-term or long-term, firm or interruptible, within or between control areas, and to a limited extent, brokered. CTS could be used for the purchase of either utility or nonutility power.

Pricing for CTS would be flexible. The PG&E model would have negotiated rates that stay within a FERC-approved price interval. The PG&E model would allow bidding for CTS when transmission demand exceeds capacity along a particular path. Most of the profits from CTS would be passed on to retail ratepayers as a retail revenue requirement offset, but company shareholders would be allowed to keep up to 25 percent as an incentive to upgrade services and expand facilities.

ELCON Proposal

The Electricity Consumers Resource Council (ELCON) is a consumer group composed mostly of large industrials, many of which cogenerate electricity. ELCON's orientation is for nondiscriminatory access at nondiscriminatory prices. ELCON believes that transmission is a natural monopoly and, as such, requires regulatory oversight to prevent monopolistic behavior by its owners.[5] ELCON does not explicitly advocate open transmission access, but recommends a procedure by which any party may seek regulatory approval of its access requests. ELCON endorses state regulatory oversight for intrastate wheeling transactions and federal oversight for interstate wheeling. ELCON recommends that access be provided to both utility and nonutility power suppliers on a nondiscriminatory basis. It supports retail wheeling with state approval but does not advocate mandatory retail wheeling for all.

The ELCON transmission pricing policy position is that wheeling rates should reflect the actual costs incurred to provide the service. Rates would depend on the firmness, length, and timing of service. Embedded cost rates are favored for the use of existing facilities, and incremental cost rates where a utility must construct new transmission capacity. ELCON draws a sharp distinction between incremental and marginal costs (*infra*, pp. 54-59), opposing use of the latter. Embedded cost rates should cover only the embedded costs of transmission facilities actually used. Wheeling rates should provide the owners a fair rate of return on transmission investment, a return that reflects market risk. ELCON, however, recommends against using flexible pricing or other methods based on opportunity costs to set wheeling rates.

According to ELCON, regulatory commissions should have the authority to order transmission system upgrades or expansions to facilitate wheeling. A customer who replaces firm power purchases from a utility with wheeled power obtained from others and later wants to reestablish firm service should not be treated in a discriminatory fashion, but instead, treated as any new customer.

[5] J. Anderson (of the Electricity Consumers Resource Council), "Market Structure and Pricing of Transmission," paper presented to the American Bar Association, San Francisco, California, 26 January 1989.

TAPS Proposal

The Transmission Access Policy Study Group (TAPS) is comprised of members from public and municipal power agencies and electric cooperatives; it represents the viewpoints of noninvestor-owned transmission-dependent utilities (TDUs). The Group's report recommends mandatory nondiscriminatory access, cost-based rates, and single-system integrated planning.[6] The Group views transmission service as a monopoly, as a market distinct from the market for power and energy services, and as a scarce resource. Efficient allocation can be accomplished only by requiring all transmission owners to share all firm and nonfirm capacity in excess of native load needs. The TAPS proposal recommends equal access status for TDUs as both requirements power and economy energy customers. Equal access requires single-system integrated planning that allows all utilities, including TDUs, to enter long-term joint-ownership and cost-sharing agreements. Long-run planning would reduce future bottlenecks and help mitigate undesirable third-party impacts.

Transmission rates should be based on embedded costs, be non-discriminatory, and prevent subsidies or windfalls. The TAPS proposal would allow no opportunity-cost pricing. Rolled-in embedded-cost pricing should be the norm, even for allocating the cost of new transmission facilities. Nonfirm service prices should be lower than firm service prices. Price differences ought to reflect service quality differences. However, nonfirm prices should be high enough to contribute to fixed transmission costs. Transmission rates for coordination services should be set in advance and not be dependent on the value of the particular transaction. Resale of purchased capacity should be permitted, but price mark-ups on resale should not. Restrictions on resale, such as point-to-point, should be prohibited.

Wisconsin PSC Proposal

The Wisconsin Public Service Commission, in its Advance Plan 5, addressed transmission system access and pricing (more precisely, cost

[6] Transmission Access Policy Group, "Proposal of the Transmission Access Policy Study Group for Adoption and Implementation of Fair Access Transmission Policy," unpublished, undated document; distributed at the NARUC Winter Meetings, March 1989 by W. Russel of W. Russel & Associates, Washington, D.C.

sharing) as part of the state's least-cost electric power plan.[7] The Commission requires the state's transmission owners to cooperate in state-wide planning of a transmission system that meets all parties' needs, with no unnecessary duplication of facilities and without unduly benefiting either the owners' retail ratepayers or stockholders at the expense of others. System reliability, compensation for third-party impacts, and optimal system expansion are cited as benefits of a state-wide approach. The Wisconsin Commission lists twenty principles to guide thinking, but these leave considerable room for utilities and cooperatives to craft a final state plan.

The state-wide plan must consider all customer loads, economize on investments, and encourage efficient use of existing transmission capacity. All utilities desiring to help shape transmission policies are entitled to participate. Some wheeling for nonparticipating wholesale customers would be available, but retail customers may not request wheeling services.

The Wisconsin PSC plan gives little detail about pricing policy in deference to FERC pricing jurisdiction. Owners of transmission facilities are to be fairly compensated; however, monopoly profits are not to be earned. Participating utilities would file wheeling tariffs stating prices, terms, and conditions of service.

Alternative Transmission Proposal (ATP)

In mid-1989, several utilities supported an unpublished industry alternative to the PG&E proposal.[8] It too recommends voluntary, point-to-point transmission service. However, it focuses on "supplier wheeling," not "buyer wheeling." It is concerned mainly with setting up a policy for wheeling from a power supplier through a control area utility to another control area utility. Hence, the proposal distinguishes between control-area utilities and noncontrol-area utilities as eligible buyers. It contends that a utility's primary responsibility is to provide reliable power to its own native load customers at the lowest possible cost.

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7 Wisconsin P.S.C., *Wisconsin Public Service Commission Order in Advance Plan 5 On the Subject of Transmission System Use and Cost Sharing*, Docket 05-EP-5 (April 1989): 56-64.

8 "An Alternative Transmission Services Model," unpublished and undated discussion document distributed to the Keystone Transmission Project, Keystone, Colorado (received, June 1989).

Wheeling transactions are to be negotiated so as to protect native load customers, with both reliability transactions and economic transactions for retail customers having a higher priority than any wheeling transactions.

Transmission service to control area utilities is treated differently from service to noncontrol-area utilities, which include full or partial requirements customers that depend on the transmission utility for some or all of their reliability needs. The proposal focuses on transmission service for control area utilities as explained next. (Voluntary wheeling to noncontrol area utilities would entail other costs not summarized here.)

This proposal distinguishes between long-term firm service for reliability transactions and short-term, non-firm service for economy transactions. The long-term firm service price would be cost-based with capital cost and variable cost components. The capital component would be set at incremental cost to protect native load customers when capacity expansion is undertaken, and set at embedded capital cost when capacity is sufficient. When expansion is needed to provide service, the customer has two pricing options available. Under the first option, the wheeling customer would pay just the utility's embedded (plus variable) cost (as well as the cost of minor system upgrades as needed) and then either accept interruptions or pay the wheeling utility for lost economies until the utility's own upgrades are completed. Under the second option, the wheeling utility commits itself to providing firm transmission service. There is greater risk to the wheeler under this option because it is committed to wheel even if the needed new facilities cannot be completed. To compensate for the greater risk the price would be higher, perhaps as high as the replacement cost of the existing facilities. The price would be negotiated and be between the wheeling utility's embedded cost and the replacement cost.

For short-term, nonfirm transmission service, the prices would be negotiated (that is, flexible) and would stay between the utility's "incremental costs" (here, meaning short-run marginal costs) and the total savings provided by the transaction. More specifically, the "cap" on flexible pricing is the difference between the power purchaser's decremental cost and the power seller's incremental cost. The proposal considers several methods to set short-run prices, such as share-the-savings, auctions, and an "up-to" formula linking price to current market conditions.

Utility Working Group Proposal

The Utility Working Group (UWG) is a group of six large investor-owned utilities, several of which have strategically located (or "bottleneck") transmission facilities. The group proposes eliminating certain regulatory barriers to offering transmission services and advocates voluntary "point-to-point" wheeling and flexible pricing for wholesale power transactions.[9]

Access to a utility's transmission system would be extended voluntarily to nonutility sources, such as cogenerators, small power producers, and independent power producers, as well as to other investor-owned utilities and to cooperative and public distribution systems. Transmission service must not harm the reliability of service provided to the retail and requirements customers of the host utility. Parties receiving wheeling service are not to be subsidized, given priority treatment, nor allowed to impose stranded investment costs on native customers.

The UWG proposal mentions two types of wheeling service: long-term firm service and short-term coordination and other nonfirm service. Utilities would voluntarily provide long-term transmission service, subject to capacity availability and would be fully compensated for incremental costs and facility upgrades as well as for related risks. In return for voluntary long-term firm service, the UWG proposal calls for flexible pricing subject to a regulated price ceiling for coordination and other nonfirm transmission services. The price would be negotiated within a price range sanctioned by the FERC. The price ceiling should be high enough to enable the transmission utility to recover all service costs for "shorter-term" transmission service including the costs for additional risks and foregone opportunities.

All negotiated terms and conditions would be put in contract form. The contract could be resold, but the new owner would be subject to all original terms and conditions. For utility purchasers, the UWG proposal would make reciprocal transmission service available to the transmission provider under comparable terms.

[9] Utility Working Group, "Utility Working Group Principles on Wholesale Transmission Services," 12 June 1989, as reported in "Utility Working Group Adopts Transmission Reform Principles," *Electric Utility Week*, 19 June 1989, 1; and "Utility Working Group Transmission Principles Take Debate to New Level," *Electric Utility Week*, 10 July 1989, 14.

APPA Proposal

The American Public Power Association (APPA) represents the interests of utilities owned by local governmental units. The APPA in its white paper, "Transmission Access: Issues and Options," supports mandatory wheeling at cost-based rates.[10] Transmission access should be nondiscriminatory. The rationale behind the APPA position is the monopoly character of transmission: unregulated transmission owners could restrict access to protect bulk power markets as well as charge discriminatory rates. Regional planning that considers all utilities' needs is recommended along with greater emphasis on pooling arrangements and joint-ownership transmission ventures.

APPA recommends cost-based rates but does not give implementation details. The APPA finds fault with flexible pricing approaches, whether capped by opportunity cost, marginal cost, fully distributed embedded cost, or market-based prices. Flexible prices would not resolve access problems, according to APPA, because price incentives require workable competition. Because of the potential for abuse, the APPA urges the Federal Energy Regulatory Commission to ensure nondiscriminatory access.

LPPC Proposal

The Large Public Power Council (LPPC) is an organization comprised of the seventeen largest public power systems across the nation. The goals of the LPPC proposal are to foster competition, promote efficiency, maintain system reliability, mitigate inadvertent flows, and encourage prudent investment. The LPPC proposal recommends voluntary access to excess transmission capacity, cost-based rates for noncompetitive markets, negotiated rates for competitive markets, and binding arbitration to settle disputes over the existence of excess capacity and over wheeling rates.[11]

[10] "APPA Details Transmission Stance, Seeks Exercise of FERC Authority," *Electric Utility Week*, 17 July 1989, 14.
[11] LPPC Transmission Task Force, "Large Public Power Council (LPPC) Transmission Policy Paper," August 1989, distributed at the NARUC Annual Convention, Boston, November 1989. See also "Large MUNIs to Offer Transmission Proposal without Mandatory Access," *Electric Utility Week*, 3 July 1989, 13; "Group Seeks to Bridge Gap between IOUs, MUNIs over Wheeling Access," *Inside F.E.R.C.*, 28 August 1989, 11; and "Open Access: A Midway Stance," *Electrical World*, October 1989, 19.

The proposal does not define "competitive." New transmission would be built for customers willing to finance construction costs.

Wheeling prices would equal embedded costs plus incremental cost in noncompetitive markets with excess transmission capacity. Excess capacity exists whenever firm transmission capacity is above planned needs and reliability requirements. Here, incremental cost is the cost of required minor system upgrades, which would be added to the normal embedded cost rate. When major improvements to the transmission system are required, prices would be based on long-run marginal costs. A major improvement is one for which the long-run marginal cost of providing service exceeds the embedded cost. Wheeling rates based on long-run marginal costs would cover the full cost of all improvements needed to accommodate the wheeling transaction. Wheeling rates for nonfirm service are not explicitly discussed (but might or might not be covered by the rule that rates in competitive markets ought to be negotiable).

The LPPC introduces the idea of binding arbitration to settle disputes over transmission capacity and pricing. Binding arbitration, it is argued, would minimize delay and the expenses associated with disputes.

A New England Proposal

Commissioner Susan Tierney of the Massachusetts Department of Public Utilities has proposed an amendment to the New England Power Pool (NEPOOL) Agreement as it pertains to power sales and wheeling services.[12] The proposal would standardize transmission agreements, which currently vary widely, to take full advantage of low-cost power from both utility and nonutility sources located in and around the NEPOOL service area. Specific goals are to create a formal marketplace for power sales within NEPOOL and between NEPOOL and neighboring regions and also to implement marginal-cost pricing for wheeling services that use Pool Transmission Facilities (PTFs). PTFs are extra-high-voltage lines owned by NEPOOL members and used to move bulk power.

The proposed amendments would affect new power sales and wheeling transactions but leave existing arrangements intact. Under the proposal, greater access would be offered to utility and nonutility power sources that are not members of NEPOOL. The proposal makes it easier for nonmember

[12] Susan F. Tierney (of the Massachusetts Department of Public Utilities), "Transmission Proposal for New England," 28 September 1989, draft.

power sources to become "Pool Planned Units" (PPUs); PPU status means access to the PTFs of NEPOOL. However, before PPU status is assigned to an outside power source, it must supply all its power to a NEPOOL member.

New wheeling rates would be in dollars per kilowatt and reflect the replacement cost of Pool Transmission Facilities. The rate per kilowatt for transmission service would equal the replacement cost of all PTFs divided by total PTF capacity. This would replace the previous practice of using embedded costs of transmission facilities to set wheeling rates. The proposal envisions continued use of "postage stamp" wheeling rates that are insensitive to both the physical length of transmission and the number of utilities traversed.

Wheeling revenues under the new PTF wheeling rate would be deposited into a Pool Transmission Fund. The Fund would be used to compensate owners of PTF facilities, to compensate NEPOOL utilities whose service territories are affected by PPU wheeling, and to finance new PTF construction.

WP&L Proposal

The Wisconsin Power and Light Company, an investor-owned utility, filed a family of transmission tariffs at the Federal Energy Regulatory Commission at the beginning of 1990.[13] The tariffs offer open access transmission service to all nonretail entities. Access is not conditional on generation pricing freedom. Transmission service would be "system-to-system" rather than point-to-point. The service would be available both to captive wholesale customers within WP&L's service area seeking lower-cost outside power supplies and to outside wholesale customers seeking to wheel power across WP&L's control area.

WP&L has filed tariffs for both firm and nonfirm transmission services. The services would be priced at or below full embedded costs; in this sense, pricing is flexible subject to a cap.

For firm service, there would be a fixed charge to reserve capacity and a variable charge for using capacity. The fixed charge would be flexible with a cap expressed in dollars-per-kilowatt-per-month plus a variable charge of two mills per kilowatt-hour. For nonfirm service, WP&L proposes flexible pricing with a cap, based on a slightly complicated formula, that works out to be just below eight mills per kilowatt-hour.

[13] "WP&L Offers Open Transmission Access to All Non-Retail Users," *Electric Utility Week*, 8 January 1990, 1.

NRECA Task Force (CPU) Proposal

The Ad Hoc Transmission Task Force of the National Rural Electric Cooperative Association (NRECA) developed a report on transmission access and pricing, which has not yet (April 1990) been adopted by the NRECA itself.[14] The goals of the report are to devise a way to provide transmission service without undue discrimination or anticompetitive effects and to provide reasonable compensation for utilities involved in power transfers. The report introduces the Coordinated Planning and Utilization (CPU) Model as a way to reach the desired goals.

The CPU Model sets out principles that should govern participation in joint regional planning. Only electric public utilities with an obligation to serve retail load (and some of their affiliates) may become "participants." Easy entry to participant status for eligible utilities is intended. However, participation requires a long-term financial commitment to support the maintenance and growth of the transmission system. Rights to use the regional transmission system would be allocated in proportion to the participant's financial commitment. Nonparticipants are eligible utilities that choose not to join in regional planning. They include transmission dependent utilities that have elected not to be participants and that require transmission service to serve native loads. Access to transmission facilities by nonparticipants would be provided under reasonable terms and conditions after all the needs of participants have been met. Other entities, which are neither participants nor nonparticipants, such as retail customers, would not have access to the transmission system.

The CPU model contains criteria that govern access when the transmission system becomes restricted. Participants would have priority over nonparticipants and, within each of these groups, firm transactions would have priority over nonfirm. The highest priority would go to the requirements retail and wholesale loads of participating electric public utilities.

[14] Ad Hoc Transmission Task Force, "Proposed Approach to Transmission Access and Pricing through a Coordinated Planning and Utilization Model," Report to the National Rural Electric Cooperative Association (NRECA), 12 January 1990.

The CPU model advocates cost-based pricing for regional transmission service. Cost-based prices, by design, provide participants an adequate return on capital investment. This is seen as an important advantage of cost-based prices over those based on market forces, which may result in underrecovery of capital. The price for transmission service would depend on the type of service requested.

For participants, prices would cover all "actual transmission costs," that is, all the normal expenses of network operation and maintenance plus planned capital investments. This obligation could be satisfied by direct payments to other participants, by ownership of transmission facilities, or by some combination of these. Participants marketing excess transmission capacity would be obligated to compensate other participating utilities through a "special transaction cost reimbursement" for any additional costs.

For firm transactions, nonparticipants would pay an allocated share of "actual transmission costs" when capacity is adequate. When it is not, they could either pay for "special transaction facilities costs" covering the costs to upgrade and expand the system, or they could accept a low "firm" service priority. Nonparticipants would also pay for any "special transaction operation costs," such as incremental line losses.

For nonfirm transactions, price for participants would not exceed "actual transmission costs" plus the "special transaction operation costs." In some cases, nonparticipants could pay a "split-the-savings" rate for transmission service.

Other Proposals

Max Wilkinson, a visiting research fellow at Harvard University's Energy and Environmental Policy Center and Natural Resources Editor for *The Financial Times* of London, issued a report in November 1989 recommending marginal-cost pricing of transmission in Great Britain.[15] This Harvard report, "Power Monopolies and the Challenge of the Market: American Theory and British Practice," recommends short-run marginal-cost pricing for all transmission service. Ideally, short-run marginal cost includes the costs of line losses and lost opportunities. Opportunity costs arise as transmission capacity becomes fully utilized.

[15] "Harvard Report: Tie Transmission Costs to Spot Market Power Prices," *Electric Utility Week*, 27 November 1989, 14.

This recommendation echoes the spot market pricing recommendations of Schweppe, Bohn, and Caramanis,[16] which were presented at some length in prior NRRI reports.[17]

Other Solutions

In addition to these proposals, which are advocated in writing by particular organizations and individuals, there are at least four other concepts frequently discussed by various stakeholders, though not necessarily presented yet in written form. These may be identified by the following labels:

STATUS QUO--a defense of past and current transmission access and pricing policy. This policy is favored by, among others, many United States investor-owned utilities. Transmission service is provided only voluntarily. There is no obligation to build transmission lines for wholesale transmission service. Pricing of transmission service is rather loosely regulated, with many different wheeling rate designs in use. The "postage stamp" type of rate is most common--a rate that is independent of the transmission distance. Firm service rates are usually based on embedded capital costs and expressed as monthly, weekly, or daily charges per kilowatt or megawatt transmitted. Nonfirm rates are frequently expressed in mills per kilowatt-hour and are said to have an embedded-cost basis, though occasionally are related to the savings created by power trading.

VOLUNTARY/EFFICIENT--service is voluntary; price is set equal to long-run or short-run marginal cost, as appropriate; the importance of including opportunity costs in transmission prices is often stressed;[18] favored by some industry representatives, consultants, and economists.

VOLUNTARY/FLEXIBLE--service is voluntary; price is always set flexibly by the provider; auctions would be held to set the price when transmission capacity is oversubscribed (as an alternative to

[16] F. C. Schweppe, M. C. Caramanis, R. D. Tabors, and R. E. Bohn, *Spot Pricing of Electricity* (Boston: Kluger Academic Publishers, 1988); 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): 360-76; and F. C. Schweppe, R. E. Bohn, and M. C. Caramanis, *Wheeling Rates: An Economic-Engineering Foundation*, Report TR-85-005 (Cambridge, Massachusetts: Massachusetts Institute of Technology, School of Engineering, Laboratory for Electromagnetic and Electronic Systems, September 1985).
[17] Kelly, *Economic Principles* and *Nontechnical Impediments*, appendices A, B and C.
[18] See, for example, J. H. Landon, J. D. Pace, and P. L. Joskow, "Opportunity Costs as a Legitimate Component of the Cost Of Transmission Service," *Public Utilities Fortnightly*, 7 December 1989, 30-33, 73.

"first come, first served"); favored by some United States investor-owned utilities.

BROKER--allows the purchaser of transmission service to resell reserved capacity to another buyer; favored by some regulators and economists; may be a prominent feature of some more complete proposals rather than a stand-alone policy.

FERC Cases

It is worth mentioning that transmission access and pricing issues arise prominently in many of the cases recently or currently before the FERC. While these do not comprise a distinct access and pricing policy per se, FERC staff is consistently recommending to the Commission that, where a utility applicant seeks Commission approval of a significant change in its status or practice, such approval should be conditional on mitigation of the utility's market power. Market power mitigation is usually considered accomplished when the utility agrees to provide access to its transmission facilities for the firm transmission service of others. This includes the obligation to expand capacity within a reasonable amount of time as needed to provide the service and, where such expansion is unduly delayed, curtail its own nonfirm use of its facilities.

Two former requirements customers of Pacific Gas and Electric, the Turlock and Modesto irrigation districts, acquired transmission access in return for the FERC allowing PG&E to sell some wholesale power and extra transmission at market prices. Public Service Company of Indiana would offer transmission access at cost if the FERC lets it sell some firm power at an unregulated price. Other utilities, utility affiliates, and nonutility generators are before the FERC seeking approval to sell power at market-based rates, but only sometimes in exchange for open access. Current (April 1990) cases involve Portland General Electric, Citizens Energy, and Entergy Corporation (formerly Middle South Utilities), as well as independents such as Commonwealth Atlantic, Doswell, Ocean States, and the small commercial generators within the Orange and Rockland service territory.[19]

[19] This information is from an unpublished summary by FERC staff: Office of Economic Policy, "Handouts for the 1990 FERC Open House for NARUC," Washington, D.C., February 1990.

In related matters recently before the Commission, FERC has extended for a limited time the Western Systems Power Pool experiment, which allows flexible pricing of short-term transmission service subject to a relatively high price ceiling. The Vermont Public Service Board has asked the FERC, under the little-used section 207 of the Federal Power Act, to investigate the adequacy of interstate transmission service under a merger of Northeast Utilities with Public Service of New Hampshire. In a recently completed merger case, that of Pacific Power & Light with Utah Power & Light, FERC approval of the merger was conditional upon open transmission access, including the controversial condition that places the merged company's coordination trading at risk if capacity cannot be provided for any reason. Similar conditions are at issue in the proposed merger of Southern California Edison with San Diego Gas and Electric.[20]

The FERC's ability to impose access conditions on utilities in all these cases depends on the companies requesting something unusual from the Commission. Presumably, the Commission is unable to develop policy for companies not making such requests and so is unable to enforce a uniform national transmission policy.

Market Power and Pricing

Many criteria could be used to evaluate these proposed solutions, including economic efficiency, fairness, compatibility with existing industry institutions and laws, ease of regulatory administration, technical feasibility, effect on transmission system reliability, and the need for new software and data collection either by utility system operators or by government regulators. However, considerable insight into the intrinsic similarities and differences among proposals can be obtained by evaluating them according to just two key criteria: (1) the mitigation of the transmission utility's market power and (2) the profit-constraint imposed by pricing policy.[21] Let us consider such an evaluation after first examining the various ways of mitigating electricity wholesale market power and pricing transmission services.

[20] Ibid.; see also most issues of *Electric Utility Week* and *Public Utilities Fortnightly* for the period September 1989 through April 1990.
[21] This concept emerged in a discussion during a presentation one of the authors (Kelly) made to three regulatory commission staff persons who prefer not to be named. Their contribution, however, is acknowledged.

Market Power Mitigation

Ways to mitigate market power and to price transmission are listed in table 2-1. The ways to mitigate market power are listed with the methods judged more effective near the top of the list, and those less effective at the bottom. In a classic market, as mentioned, market power is eliminated by direct competition among numerous buyers and sellers of the service. But the present alternating current transmission technology does not allow such competition in the provision of transmission service. Regulation, on the other hand, controls market power by imposing an obligation to serve at cost-based rates. Because direct competition in transmission is not possible, traditional utility regulation of transmission might seem to be the logical policy choice.

However, three arguments against rate base regulation of transmission services can be advanced.[22] Those who accept any one of these arguments may look for an alternative to regulation of transmission in the traditional way. Of course, those who reject all three arguments would probably support mandatory transmission at cost-based rates. The first argument is that effective regulation requires new federal legislation and the Congress will not act unless the various industry stakeholders (investor-owned utilities, public power utilities, cooperatives, and other parties) agree upon a preferred policy. Since this will not happen, it is argued, an alternative practical policy that can be implemented under existing law must be found. A second argument is that the division of regulatory authority between the federal government, controlling the *use* of *existing* transmission facilities, and the state governments, controlling the *planning and approval* of new facilities, would hamper effective enforcement of the obligation to serve.[23]

More importantly, and according to a third argument, traditional regulation is based on the implicit assumption that the electric, gas, or telephone utility *wants* to provide service; that growth in service sales is

[22] There is a fourth argument that applies more to transmission service for economy power or for other short-term service. It is that costs change too rapidly and by too large an amount to be expressed in a fixed-rate tariff, which is the usual outcome of a regulatory ratemaking procedure.

[23] For a full discussion of this subject, see K. Kelly, R. Burns, and K. Rose, *An Evaluation for NARUC of the Key Issues Raised by the FERC Transmission Task Force Report*, NRRI-90-7 (Columbus, Ohio) 1990, especially the "twin scepters" discussion on pp. 6-7.

TABLE 2-1

WAYS TO MITIGATE MARKET POWER AND TO PRICE TRANSMISSION

A. Ways to Mitigate Market Power

DIRECT COMPETITION

OBLIGATION TO SERVE

JOINT OWNERSHIP

CUSTOMER CHOICE

RESALE

INDIRECT COMPETITION

B. Ways to Price Transmission

EMBEDDED COST--ROLLED IN

EMBEDDED COST--DIRECT ASSIGNMENT

INCREMENTAL COST--SHORT RUN

MARGINAL COST--SHORT RUN

INCREMENTAL COST--LONG RUN

MARGINAL COST--LONG RUN

FLEXIBLE PRICING--LOW CAP

FLEXIBLE PRICING--HIGH CAP

FLEXIBLE PRICING--NO CAP

Note: The accompanying text explains these terms.

important to the company; and that government needs merely to monitor company constraints on the rate of growth to prevent extraction of monopoly profits. This assumption may well not apply to transmission service because any potential transmission profits are often far outweighed by potential losses in generation sales. Since virtually all major transmission service providers are also generation providers, they may find creative ways to frustrate any transmission service obligation in order to protect their position in the generation market. As a result some policy makers look to alternative ways to mitigate transmission market power.

As shown in table 2-1, such ways include joint ownership of transmission lines either by competing suppliers or by wholesale transmission customers. Joint-owner providers could bid against one another to provide service; a joint-owner customer would have the option to own a fraction of any new line capacity and hence reserve it with assurance for his own use. Customer choice, a feature of the NRRI proposal, mitigates possible abuse of market power in the less regulated nonfirm market by allowing customers always to escape to the more regulated firm market. Allowing customers who have previously purchased space on a transmission corridor to resell their shares to a current buyer who is being charged a very high price by a transmission company is another, though weaker, method of mitigating market power. Ordinarily, the weakest is indirect competition, which imposes a price ceiling on the amount that can be charged for transmission service in some situations. For example, suppose a buyer can purchase 30-mill/kWh power from one source via one transmission provider and 40-mill power from a second source through a second provider. If transmission by the second provider costs 5 mills (for a total cost of 45 mills), the most that the first transmitter can charge is 15 mills.

Pricing Options

Various ways to price transmission services are listed in the lower part of table 2-1. Despite the fact that these terms have been used for many decades in economic regulation and are used in most of the access and pricing proposals, there can be a wide variety of meanings attached to any one term, depending on who is using it. Later in this report, we frequently use a few familiar terms like "embedded cost" or "incremental cost" without precise definition. Here we set out various interpretations of these terms and what they mean when we use them.

Embedded Cost

Price can be based on average embedded transmission costs, calculated either over all the company's transmission costs (rolled-in) or over the costs of just those facilities used in each transaction (direct assignment). Embedded cost is the average depreciated cost of the transmission facilities that are already on the transmission company's books. The average can be per megawatt or megawatt-hour; per year, month, or hour; and sometimes per mile of transmission line. The transmission user is allocated a share of this cost according to the number of megawatts or megawatt-hours transmitted, perhaps according to the duration of service, and (rarely) according to the transmission distance. The purpose of embedded cost pricing is, of course, to guarantee that the service provider recovers no more or no less than its capital investment plus a fair return. Embedded cost pricing does this well, but in the process creates questions about whether various customers contribute equitably to the annual revenue requirement.

The method of allocation affects the unit cost, of course, and hence the cost-based price. The most common method is to divide total embedded transmission costs by the system peak load, giving a dollars-per-megawatt rate, which is applied to the wheeling customer's megawatts. This is the "rolled-in" approach.

By analogy with generation capital costs, one expects embedded historical cost rates for transmission to be lower than prices based on current costs. This expectation for transmission is probably correct in most cases, but is not necessarily always correct. In particular, rolled-in embedded cost rates may exceed nonrolled-in replacement cost rates. Some utilities have a lot of transmission facilities not used for service to wheeling customers (such as radial lines that move power from generators to the grid or from the grid to distribution substations), or they have a large subtransmission system for serving retail loads (but which counts as a transmission facility cost). Such utilities can have high embedded transmission costs per megawatt. Embedded cost transmission prices may be higher than the cost to the customer of constructing a new line for his own use (which he may not be permitted to do).

To give an exaggerated example, suppose the entire state of Texas were a single utility, and a customer wanted to wheel a large amount of power across the narrow northern Texas Panhandle. With rolled-in pricing, his rate would increase in proportion to the cost of transmission facilities throughout Texas, most of which are not in the Panhandle. If his large power transfer were a significant fraction of the state's peak transmission load, he would pay for a significant fraction of the state's transmission facilities, even though he uses a very small portion of these facilities.

Another peculiar effect of this ratemaking approach is that it usually costs more to wheel through several utilities than through one, regardless of their size. This is because each probably has about the same *ratio* of transmission costs to peak load; so each charges about the same embedded cost recovery component in its wheeling rate. If a large utility three hundred miles across were corporately divided into five equal-size utilities each sixty miles across, the embedded-cost wheeling charges for traversing the three hundred miles would increase by a factor of five, with no change in actual "out-of-pocket" engineering costs.

The efficiency of embedded-cost transmission pricing would probably be improved if rates contained a mileage component and if only the facilities actually used to provide service were included in the embedded cost calculation. (We refer to the latter condition as "direct assignment" in table 2-1.) In some circumstances this would be easy to do; in others, quite difficult. It is easiest if power flows only (or predominantly) over one transmission line from a single power source to an isolated load. The distance is known and an appropriate share of the embedded costs of only that transmission line can be directly assigned to the transmission customer.

Frequently, however, power flows from one dispersed utility system through a second to a third. Power comes from all the plants online in the first, enters the second over several tie lines and passes through many and perhaps most of its transmission lines, and enters the third over several tie lines to supply power to the buyer's dispersed transmission grid. In this case, the distance of transmission might be poorly defined. Two or three high-voltage lines might carry, say, 80 percent of the load, with many lower voltage lines each carrying a percent or so. It is these sorts of difficulties that led to use of rolled-in pricing in the first place.

Incremental and Marginal Costs

The shortcomings of embedded-cost pricing have led some to recommend incremental or marginal-cost pricing. If transmission capacity is adequate for the duration of the period for which service is requested (which is what we mean by the phrase "in the short run"), incremental-cost pricing simply reimburses the wheeler for "out-of-pocket" expenses, mostly line losses, which vary with the loading of the line. In this case, short-run incremental costs and short-run marginal costs are about the same. But whenever transmission capacity is inadequate, a properly calculated short-run marginal cost includes the "opportunity cost." Price based on this cost rises just to the right level to ration the capacity optimally. Only those who place a value on the capacity that is above this price level get service.

Short-run incremental cost has no capacity component, and short-run marginal cost has no explicit capacity component. But the opportunity cost component of the latter is an implicit surrogate for capital cost, providing profits during times of tight capacity that can motivate construction of new capacity.[24]

Long-run incremental and marginal-cost pricing each take capital costs into account explicitly. These two cost-based pricing methods have similarities and differences. Each calculates the cost of expanding the transmission system and sets rates so as to recover expansion costs.

Each has difficulty when it comes to deciding the size of the expansion increment upon which the cost calculation should be based. To add just one kilowatt of transmission capacity is very costly on a dollar-per-kilowatt basis because there are no economies of scale. Adding one megawatt is only a little better. There is no natural unit of capacity in the sense of Detroit producing one more car; giving a name to ten megawatts (for example, a "decimegawatt"?) does not make it a natural unit of capacity expansion. The "natural" unit cost of expansion could be considered the cost of building a new transmission line. But at what voltage? Total costs increase with voltage, but unit costs (dollars per megawatt) decline sharply with increasing voltage.

An added complication is that it is often possible to expand transmission capacity on an existing line by adding capacitors or by adding a second circuit to existing transmission towers. These additions have relatively low unit costs (extra costs divided by extra capacity, counting as zero the sunk embedded costs of the existing line). What size increment should then be used to calculate expansion cost where such upgrades are possible?

[24] For an extensive discussion of the virtues and difficulties of recovering capital costs through SRMC pricing, see Kelly et al., *Economic Principles*, 177-87.

One solution is to calculate the cost of expanding capacity by an increment equal to the amount of capacity requested by the transmission customer. But what if there is more than one customer? Suppose there are several wheeling customers. The first wants 100 MW, which can be satisfied by adding capacitors; the second wants 300 MW, which requires a second circuit on existing towers; and the third wants 400 MW, which requires a new 230-kV line. Some incremental-cost advocates would apply a "first-come, first-served" test and calculate a separate incremental cost for each addition and each customer. Others, particularly marginal-cost advocates, would calculate the unit cost of the last addition and charge this to all three customers. Still others would calculate the total cost of the three increments needed, in this case 800 MW, and charge each customer the same "average incremental cost," calculated as the total cost of all three additions divided by 800 MW. It may cost less to meet 800 MW of new load by adding one 500-kV line than by making the three separate upgrades listed above. If so, then this one expansion step makes the marginal cost and "average incremental" cost the same.

Should the size of the capacity increment upon which the unit expansion cost calculation is based depend on whether all three customers' service requests are made at about the same time? Suppose the first customer's request is known to the transmission utility, which expects but does not know that other requests may follow. If the cost calculation is based only on the size of the first customer's need, the unit cost calculated may be much larger (because of loss of scale economies) or much smaller (because only a few capacitors are needed to upgrade an existing line) than the unit incremental cost calculated over the larger capacity increment needed to satisfy expected load.[25]

It may be best always to calculate long-run incremental or marginal cost over a reasonably large increment. This gives the customer better information about the long-run costs of system growth. However, should the company then actually construct the reasonably large increment, recovering only a portion of the capital investment from the first customer, and count on the expected transmission load growth to provide the balance? Or should

[25] Special equity issues arise when the expected future customer is the transmission utility's retail and wholesale requirements load. Should this "customer" always get the rights to the lowest-cost expansion, leaving others always on the margin? For a discussion of these issues, see Kelly et al., *An Evaluation for NARUC of the Key Issues Raised by the FERC Transmission Task Force Report*, 37-47.

the company, while basing its transmission rate on the large increment, install only what is required for the first customer's needs, creating a mismatch between rates and actual costs?

Because the term "incremental cost" can refer to several different concepts depending on how it is calculated, some transmission pricing policies use a term like "actual incremental cost" in the hope of expressing a more precise meaning. They would follow a "first-come, first-served" approach and calculate the actual cost of meeting each customer's needs in turn. If several needs are actually met collectively in one large expansion step, then presumably the "average incremental" cost of the expansion would best represent the actual cost.

Both long-run incremental cost and long-run marginal-cost calculations run into these difficulties in choosing the size of the expansion increment, and to some degree the terms can be used interchangeably because practical calculations of each can yield similar, even identical, numerical results. The two concepts can also be distinguished, however. The long-run marginal-cost concept is well defined, but in practice it must be calculated over a suitably large increment. As we have just seen, "incremental cost" can mean different things, with some meanings closer to the long-run marginal-cost concept than others. Those who de-emphasize the difference between the two concepts do so with the understanding that the method of calculating incremental cost would approximate as closely as is practical the long-run marginal-cost concept. Those who stress the difference choose another method of calculating incremental cost, one designed to reimburse the utility precisely for its extra expense--no more and no less; this version of incremental cost is far closer to the "actual cost" concept just described than to the long-run marginal-cost concept.

Long-run marginal cost would be calculated ideally by finding the cost increase in going from an optimally designed transmission system for meeting present demand to an optimum system for meeting a greater demand. Incremental cost, on the other hand, is simply the cost of adding to today's (presumably not optimal) system. Except for theoretical purists, most regulatory economists would accept this necessary simplification in a marginal-cost calculation, however.

Marginal cost pricing charges all customers the same price; there is no "first-come, first-served" approach, resulting in different prices for different customers, a form of price discrimination. Some incremental cost approaches follow "first come, first serve," while others would avoid such price discrimination by charging everyone the same "average incremental" cost-based price.

More importantly, marginal-cost prices for any one customer ought to change over time, whereas incremental-cost prices are intended to be fixed for the duration of the transaction. One might argue that marginal costs are good for tariffs and incremental costs are good for contracts. Ideally, from the viewpoint of economic efficiency the cost per megawatt of adding transmission capacity would be recalculated periodically and the price of transmission service would be updated to reflect current marginal cost. This approach is suitable for a posted tariff that changes to reflect changes in new transmission line costs. However, as marginal costs rise and fall in the future, the transmission utility would recover more or less than its original transmission investment. This is the well-known dilemma that efficient prices do not satisfy the revenue requirement.

The term "incremental cost" is often used to refer to the dollar value of a utility's extra capital expenditure, for example, to put up a new transmission line for a particular customer's use. The customer could pay the utility a lump sum at the beginning of a, say, thirty-year transmission services contract and pay just an operating-cost-based rate for thirty years. Or he could pay a rate for thirty years that has a capital surcharge, which reimburses the utility exactly (after accounting for the time value of money) for its initial expenditure. The latter is usually what is meant by an incremental-cost-based rate in transmission pricing discussions.

This concept of incremental cost differs from ideal marginal-cost pricing in principle; it also would differ in practice if transmission expansion costs should change significantly over the next thirty years. Fear of electromagnetic-field health effects may make future transmission expansion more costly. Rights of way could become scarce; conductor shielding could be required, or even underground transmission. Then contracts based on today's incremental cost would underprice transmission service in the later years of the contract. On the other hand, such contracts would overprice transmission if economical superconductor technology develops rapidly.

But if real expansion costs (after accounting for inflation) do not change very much during the term of the contract, there is little practical difference between long-run marginal cost and a suitably calculated incremental cost. Indeed, the difference in the costs may be explained mostly by the difference between tariff and contract ratemaking. Given the constraint that a thirty-year contract must be signed today with an optimally chosen fixed capital cost component in the service price, the best practical long-run marginal-cost calculation, in the absence of any knowledge about whether future transmission costs will be higher or lower than today's, may well be today's unit cost of adding a reasonably sized increment of transmission capacity. That is, incremental cost may be the best practical surrogate for long-run marginal cost for use in fixed-price long-term contracts.

For these reasons, although acknowledging that there are theoretical differences between the two concepts, we nevertheless use the two terms interchangeably for the remainder of this report.

Flexible Pricing

Last, the company can be given the freedom to vary prices for transmission services. The price can be set without any constraint other than that imposed by indirect competition. Alternatively, the price may be restricted to some narrow or wide "zone of reasonableness," or simply be constrained to be below some price "cap." Flexible pricing with no cap is equivalent to transmission price deregulation, of course. Some would call for a high cap set equal to a multiple (two-to-four) of cost. Others would set the cap at long-run marginal cost or full embedded cost. The former is often considered a high cap and the latter a low cap, but as our previous discussion indicates, embedded costs can exceed long-run marginal cost, depending on how each is calculated.

Evaluating the Proposals[26]

As mentioned, the access and pricing proposals listed above are best evaluated in terms of the degree of market power allowed and the degree to

[26] This section draws heavily on earlier analyses by one of the authors. See K. Kelly, "Wheeling Prices and Mitigation of Market Power--the Keys to the Policy Puzzle," presented to the Committee on Western Regional Electric Power Cooperation, Las Vegas, Nevada, April 7, 1989; and K. Kelly, "Feasibility of Electric Transmission Pricing Policies," presented to the CORS/TIMS/ORSA Joint National Meeting, Vancouver, B.C., Canada, May 9, 1989. For similar analyses, see Federal Energy Regulatory Commission, *The Transmission Task Force's Report to the Commission*, Washington, D.C., October 1989, chapter 4; see also four transmission policy articles in *The Electricity Journal*, April 1990.

which prices are held down to traditional embedded cost levels. Such a categorization for a representative sample of the proposals is shown in table 2-2.

To categorize these transmission access and pricing proposals, one must recognize that most proposals treat two types of transmission service differently, as in the case of the NRRI proposal. One service usually is for essential transmission of power supplies needed to maintain service, often bought through long-term contracts. The service of transmitting such power may be called firm, reserved, requirements, or intercontrol-area transmission service. The other is for less essential power supplies that are imported temporarily to substitute low-cost purchased power for the buyer's own higher-cost generation. Transmission service for such power may be called nonfirm, as-available, economy, coordination, or interruptible service. This categorization is a helpful oversimplification that treats pairs of services in each proposal as essentially the same, although these actually may differ considerably from one proposal to another. For example, the NRRI proposal treats any transaction as firm if it is not subject to interruption (barring a technical failure) even if it is one-month replacement power for a nuclear plant being refueled. The PG&E proposal, on the other hand, treats any transaction of less than fifteen years as nonfirm. Further, the use of the terms "firm" and "nonfirm" here does not correspond to standard industry use; indeed, there is no single meaning for these terms as used throughout the United States and Canada.

The upper part of table 2-2 treats market power and pricing for firm services; the lower part, for nonfirm. The abbreviations used in the table should be easily understandable in terms of the discussion of table 2-1. However, the appearance of the PG&E proposal twice in the table needs clarification. The actual PG&E proposal, here called PG&E(A), makes participation voluntary on the part of the transmitting utility. Because many, perhaps most, utilities might choose not to participate, PG&E(A) is considered equivalent to the Status Quo proposal. However, if it is assumed that utilities must play by the PG&E proposal rules, then this alternate proposal is evaluated under the label, PG&E(B).

The results of the evaluation of the two PG&E versions are quite different. The Alternative Transmission Proposal (and others) is also evaluated quite differently depending on whether its proponents are merely paying lip service to the voluntary nature of each transaction or whether they would actually use the voluntary condition to restrain trade. The

TABLE 2-2

TEN ACCESS AND PRICING PROPOSALS, CATEGORIZED BY METHOD OF MARKET POWER MITIGATION AND PRICING METHOD, FOR FIRM AND NONFIRM TRANSMISSION SERVICES

	(1) STATUS QUO & PG&E(A)	(2) PG&E(B)	(3) NRRI	(4) ELCON	(5) TAPS	(6) ATP	(7) WP&L	(8) CPU (NRECA)	(9) VOLUNTARY/ EFFICIENT	(10) VOLUNTARY /FLEXIBLE
Firm Service: Market Power Mitigation	Indirect	Oblig to Serve	Oblig to Serve	Contingt Oblig to Serve	Oblig to Serve & Multi-Owner	Indirect	Voluntary Oblig to Serve	Oblig to Serve & Multi-Owner	Indirect	Indirect
Firm Service: Pricing	Embedded (rolled-in)	Embedded & Increm	Increm (LRMC)	Embedded & Increm	Embedded (rolled-in)	Embedded & Increm	Flexible with Embedded Cap	Embedded & Increm	Increm (LRMC)	Flexible
Nonfirm: Market Power Mitigation	Indirect	Weak Resale Provision	Limited Oblig to Serve & Customer Choice	Contingt Oblig to Serve	Oblig to Serve	Indirect	Voluntary Oblig to Serve	Oblig to Serve	Indirect	Indirect
Nonfirm: Pricing	Embedded (rolled-in)	Flexible	SRMC	Embedded	Embedded (rolled-in)	Flexible	Flexible with a Cap	Embedded & Increm (& Flexible)	SRMC	Flexible

SOURCE: Authors' analysis

PG&E proposal is evaluated both ways here to make this point; others, like ATP, are not.

One way to analyze and contrast these proposals systematically is to display them in a two-dimensional space, with axes that measure the degree of mitigation of market power and the degree of departure from embedded cost pricing. The results are shown in figure 2-2(a) for firm service and figure 2-2(b) for nonfirm service. Each policy is designated by a code number in a circle, as indicated by the legend below the figures. For simplicity (and because some of the policies are not adequately articulated), the many gradations of table 2-2 are reduced to a few simple categories on these axes. The combination of an obligation to serve together with any one other mitigation approach (resale, joint ownership, or customer choice--but not indirect competition) is assumed to have the same degree of market power mitigation for each of these approaches.

The lower left cell on the figures, close to the origin, corresponds to the status quo: embedded cost prices with no service obligation and with only occasional indirect competition available to introduce market discipline. Moving to the right along the horizontal axis is moving toward traditional regulation of transmission service. The TAPS proposal is one that comes close to traditional regulation for both firm and nonfirm services.

Moving up the vertical axis removes traditional pricing constraints without mitigating market power, creating in effect an unregulated monopoly service. On this axis, flexible prices are value-based with no regulatory cost-based cap. The voluntary/flexible model is the best example of this.

Policies that lie off the axes involve trade-offs: some relaxation of traditional embedded-cost price controls is allowed in exchange for some measures to mitigate market power. Trade-offs occur for policies that are positioned near the southwest-to-northeast diagonal in either part (a) or (b) of figure 2-2. Policies near a diagonal, such as PG&E (B), NRRI, and ELCON for firm service, represent a significant convergence of views among three seemingly quite distinct policy proposals. This convergence is not at all apparent from the proposal documents and certainly not from the sometimes contentious debates among proponents of the policies. This analysis therefore may reveal opportunities for compromise in policy formulation. For nonfirm service, the positions of these three policies are more scattered, although they still tend to be off the two main axes.

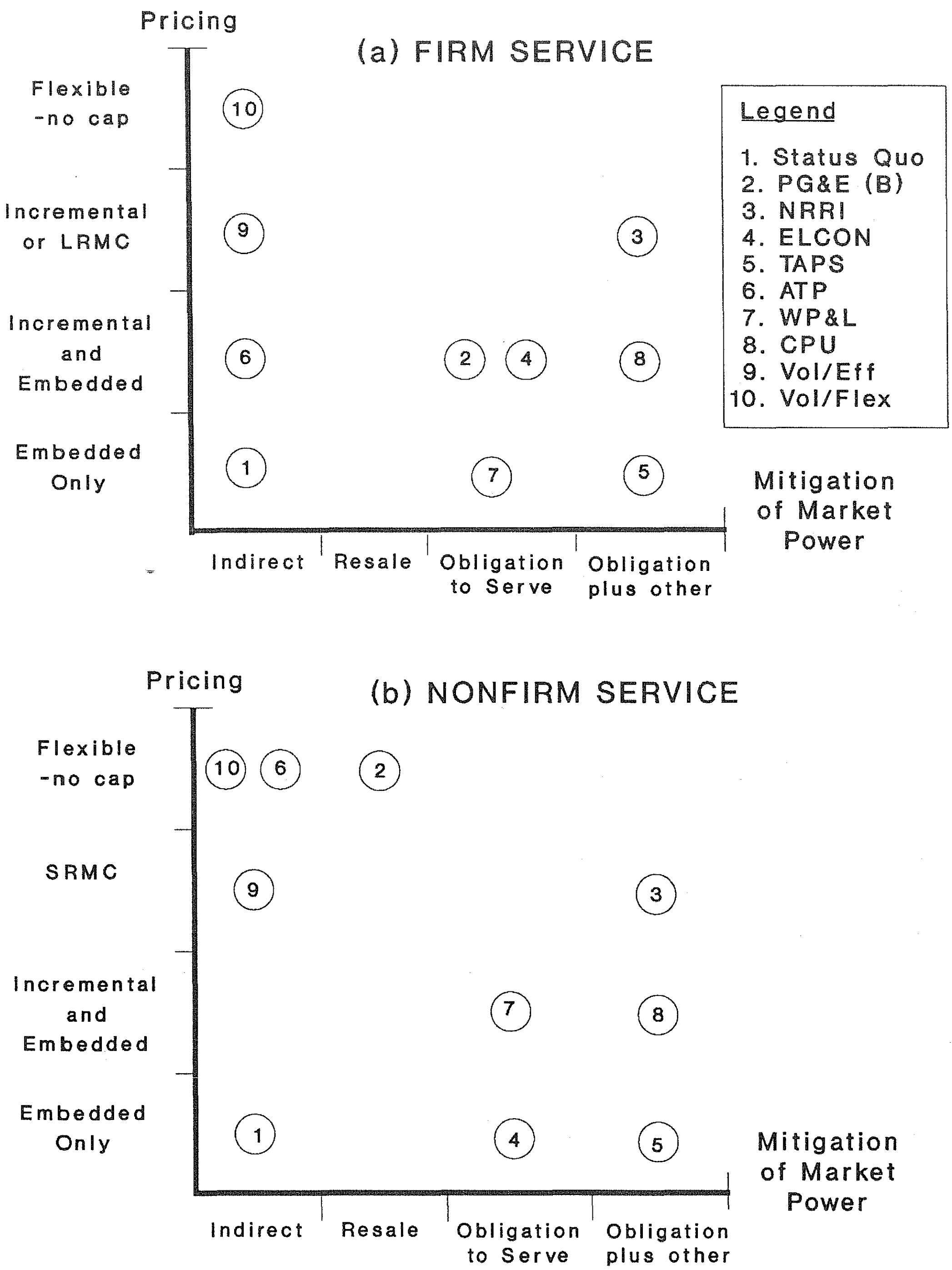

Fig. 2-2. Transmission policies categorized by degree of departure from embedded cost pricing and degree of mitigation of market power, for (a) firm transmission service and (b) nonfirm transmission service.

Notice that, especially for the nonfirm service, the policies form two clusters and have two policies "left over" that do not quite fit in either cluster. There is the "northwest" cluster with policies 6, 9, and 10, and the "southeast" cluster with policies 4, 5, 7, and 8. Policy 2, PG&E(B), is toward the southeast for firm service and toward the northwest for nonfirm; remember, however, that this "B" version of the PG&E model is located in the southeast cluster precisely because we assumed a mandatory obligation to serve that is not part of the actual PG&E proposal. Policy 1 (Status Quo) is alone in the southwest, and policy 3 (NRRI) lies to the northeast, close to but not quite in the southeast cluster. One can also plot the average of the two positions for each policy on the two parts of figure 2-2. This yields two fairly distinct clusters (2, 6, 9, 10 and 4, 5, 7, 8) with 1 and 3 as outliers.

This clustering suggests that there is a tendency of policies to cluster into two broad groups: (1) a limited-regulation-of-monopoly group composed of policies 2, 6, 9, and 10, and (2) a somewhat traditional regulation-of-monopolies group containing policies 4, 5, 7, and 8. In our discussions of clusters prior to this report, we called these the trade-off approach and the regulatory approach, respectively.

In a very similar analysis, the FERC Transmission Task Force named the clusters akin to these two approaches the Contract Model and the Planning Model, respectively.[27] Since these latter names have become well known in the current debate, we adopt them here.

It seems likely that as new policy proposals emerge (as they continue to do) they will fit in one of the two cluster groups. The framework for analysis presented here can help identify the appropriate cluster group of new policies. Further, policy makers can concentrate on developing the best policy of each type instead of considering each new policy proposal individually as it comes forward. Apparently quite different policies that actually lie close together on the axes can be identified as candidates for compromise and consolidation to reduce the number of options for policy makers to consider.

[27] Federal Energy Regulatory Commission, *The Transmission Task Force's Report to the Commission--Electricity Transmission: Realities, Theory and Policy Alternatives*, October 1989. A third alternative in the Task Force Report, the British Model, is different from our third alternative, the Status Quo. This presents no serious problem. We simply did not evaluate the British approach.

An interesting exercise is to try to place the ten proposals in the triangle presented in figure 2-1. This may involve as much art as science, but consider the following scheme. Policy 5 (TAPS) must be placed close to the regulated monopoly corner of the triangle, and policy 10 clearly belongs in the unregulated monopoly corner, as shown in figure 2-3. Moving away from the unregulated monopoly corner toward the opposite side of the triangle (which connects the classic market and the regulated monopoly) is to move from value-based pricing to cost-based pricing, with embedded costs placed lower (closer to the traditionally regulated monopoly corner) and marginal costs placed higher (toward the classic market). Moving away from the regulated monopoly corner is to move away from a strong obligation to serve toward a weaker (or no) obligation.

The positioning of policies in figure 2-3 follows this general scheme (relying on some features of the proposals not reported here) and makes use of the average positions of the policies in the two parts of figure 2-2. Admittedly, some judgement is required for the placement of policies, and not a lot can be claimed for the precision of this placement.

The result, however imprecise, illustrates the important fact that most of the policies do not lie at a corner of the triangle. Economic theory provides us with a good understanding of the behavior of firms in classic markets and the behavior of regulated and unregulated monopolies, that is, firms at corners. But we have a very limited ability to predict the behavior of firms in conditions that place them well inside the triangle.

The behavior of utility firms in such circumstances is the subject of the remainder of this report. In the next chapter, we examine a tool for use in developing an understanding of the likely strategic behavior of firms under various new ground rules for electric transmission access and pricing policy.

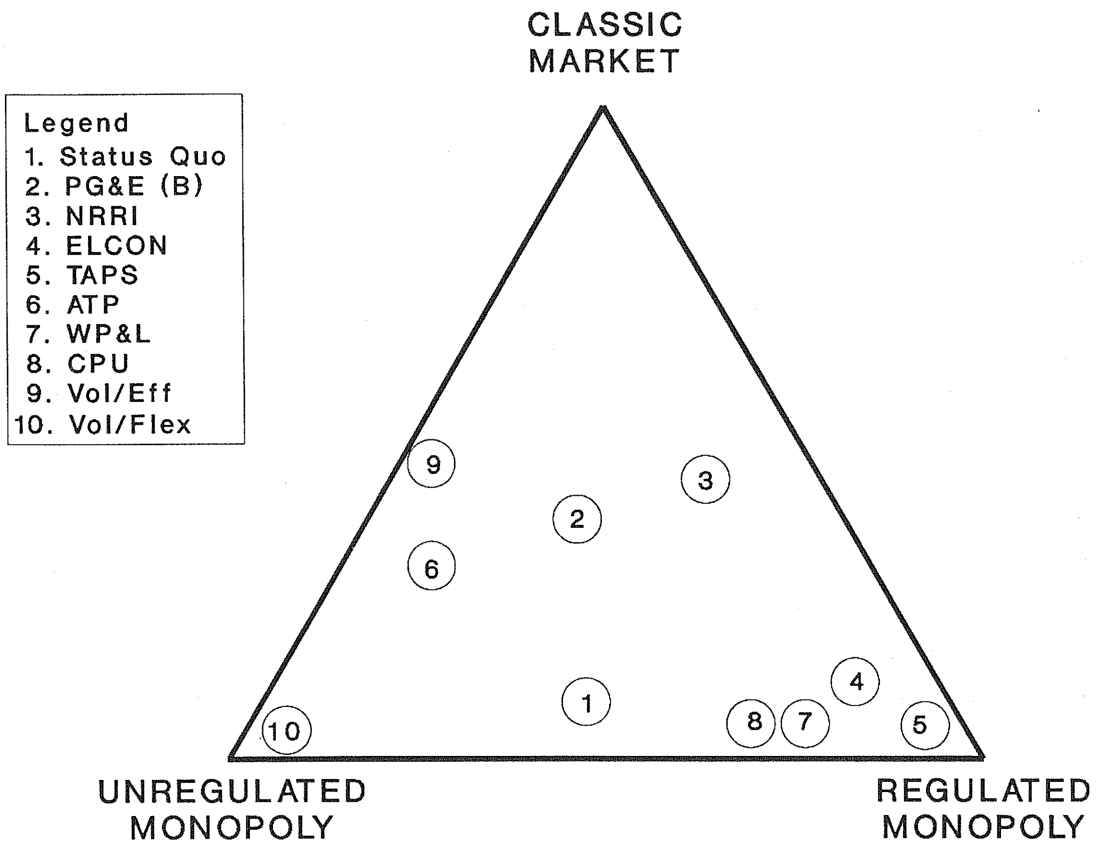

Fig. 2-3. Transmission policies categorized by degree of departure from the three textbook industrial organizations.

CHAPTER 3

TRANSMISSION POLICIES AS THE RULES OF A GAME

The results of a public policy debate over electric transmission pricing and access will have an important effect on the evolution of the electric power business and in government regulation of this business. The debate on access asks whether transmission service should be voluntary or mandatory. The debate on pricing asks whether marginal, incremental, or embedded cost pricing--or flexible pricing--best fosters generation and transmission efficiencies while being fair to all parties.

Most public policy discussions and analyses of the proposed policy choices use intuition and industry experience to examine the problems and to predict the outcome. However, intuition and experience developed in the past in a regulated monopoly world may not be the best guide to understanding future outcomes in a more competitive world. Some mention is sometimes made of how strategic interplay and coalition forming among utilities could influence efficiency. But, no quantitative analysis of these influences has been attempted.

This chapter introduces a simple quantitative method of analysis that is based on applying game theory to the questions of efficiency and fairness posed by the access and pricing rules. Despite its seemingly frivolous name, game theory is widely used for the study of serious matters. Extensive use of game theory in strategic arms studies, one of many so-called "war games," is perhaps the best example. It has also been used in a diverse variety of studies, ranging from operations research and business strategies to election campaigning and population biology.

Game theory is also an important tool in economics,[1] especially for market studies.[2] It is particularly useful for considering the strategic

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[1] See A. Schotter and G. Schodiauer, "Economics and the Theory of Games: A Survey," *Journal of Economic Literature* (June 1980): 479-527; and M. Shubik, "Game Theory Models and Methods in Political Economy," in K. J. Arrow et al. (eds.), *Handbook of Mathematical Economics, Vol. 1* (New York: North-Holland, 1981); and N. N. Vorob'ev, *Game Theory: Lectures for Economists and Systems Scientists* (New York: Springer-Verlag, 1977).
[2] See, for example, M. Shubik and L. Shapley, "On Market Games," *Journal of Economic Theory* 1 (1969): 9-25.

behavior of small groups of buyers and sellers.[3] It is also useful for considering how the gains achieved by cooperating parties will be divided among the parties.[4] It is useful not only for studying profit allocation but also cost allocation, and for this reason several applications of game theory to public utility pricing have been studied.[5] Game theory has been also used in recent studies simulating the operation of a hypothetical deregulated U.S. electric power market[6] and in analyses of transportation systems composed of either cooperating or noncooperating parties.[7]

Modeling the Transmission Market

Here we apply game theory concepts to transmission access and pricing policy evaluation. In the first section of this chapter, we set out the more important assumptions and limitations of the simple transmission market model used for our game theory analysis of these policies. In the course of this, we consider some interesting aspects of the electricity bulk power market, only some of which are captured by our simple transmission market model. In the next section of this chapter, we introduce a few game theory concepts and our pictorial method of presenting analytical results, which is intended to allow the reader to follow discussions of these results in later chapters with relative ease and better insight.

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[3] J. W. Friedman, *Oligopoly and the Theory of Games* (New York: North-Holland, 1977); L. G. Telser, *Competition, Collusion, and Game Theory* (Chicago: Aldine Atherton, 1972); and R. Luce and H. Raiffa, *Games and Decisions* (New York: Wiley, 1957).

[4] Among the best of the quantitative articles is M. Shubik, "Incentives, Decentralized Control, the Assignment of Joint Costs and Internal Pricing," *Management Science* 8 (1962): 325-43. Several good articles also have appeared in accounting journals, for example, S. S. Hamlen, W. A. Hamlen, and J. T. Tschirhart, "The Use of Core Theory in Evaluating Joint Cost Allocation Schemes," *The Accounting Review* 52 (July 1977): 616-27.

[5] See, for example, S. C. Littlechild, "A Game-Theoretic Approach to Public Utility Pricing," *Western Economic Journal* 8 (June 1970): 162-66; and W. W. Sharkey, "Suggestions for a Game-Theoretic Approach to Public Utility Pricing," *Bell Journal of Economics* 13 (1982): 57-68.

[6] R. Schmalensee and B. W. Golub, "Estimating Effective Concentration in Deregulated Wholesale Electricity Markets," *Rand Journal of Economics* 15 (1984): 12-26; and B. F. Hobbs, "Network Models of Spatial Oligopoly with An Application to Deregulation of Electricity Generation," *Operations Research* 34 no. 3 (1986): 410-25.

[7] C. S. Fisk, "Game Theory and Transportation Systems Modelling," *Transportation Research* 18B (1984): 301-14; and P. T. Harker, "The Core of a Spatial Price Equilibrium Game," *Journal of Regional Science* 27 no. 3 (1987): 369-89.

Chapter 4 treats nonfirm transmission and chapter 5 treats firm transmission. The first of these is concerned with the economic efficiency of transmission access and pricing policies in the short run. The second considers long-run efficiency. Chapter 6 examines certain long-run effects of the nonfirm policies. Here in chapter 3, our concern is, for the most part, introducing the features that are common to all these treatments. Also, as discussed in more detail later in this section, the economic efficiency analysis in this study focuses more on the efficiency of electricity production than the efficiency of resource allocation.

A Three-Player Game

The games are kept manageable by focusing mostly on the interplay among three entities: a seller of power S, a transmitter of power W, and a power buyer B. S can be a utility with excess generating capacity, for example, or a nonutility generator. W is typically a control-area utility that moves power from S to B. B can be another control-area utility or a utility within W's control area that depends on W or others to supply power for its customers' needs.

Selecting just three entities out of many in a region may seem to restrict the analysis unduly, but most of the key effects of transmission access and pricing policies actually can be discovered through a carefully analyzed three-player game. Consider a bulk power market with any number of buyers and sellers; figure 3-1 illustrates the case where there are six entities labeled A through F. In figure 3-1(a) these have an arbitrary spatial arrangement, but we can always mentally arrange them into a circle, as in part b, for simplicity of illustration. We can assume any configuration of transmission lines. Part (c) shows the most complete configuration, in which every entity is directly connected to every other; here no wheeling is needed because (loop flows aside) any entity can sell power to any other entity without having to wheel the power through a third party.

If we know the production costs (system lambdas in the short run) of the entities A through F, it is not always possible to determine the outcome of a "game" played among the parties. For each player the object of the game is to maximize his own profit or, equivalently, to minimize his own cost. Each low-cost producer tries to maximize his profit by selling power at the highest price he can get, and each high-cost producer tries to maximize his cost savings by displacing his own generation with purchases

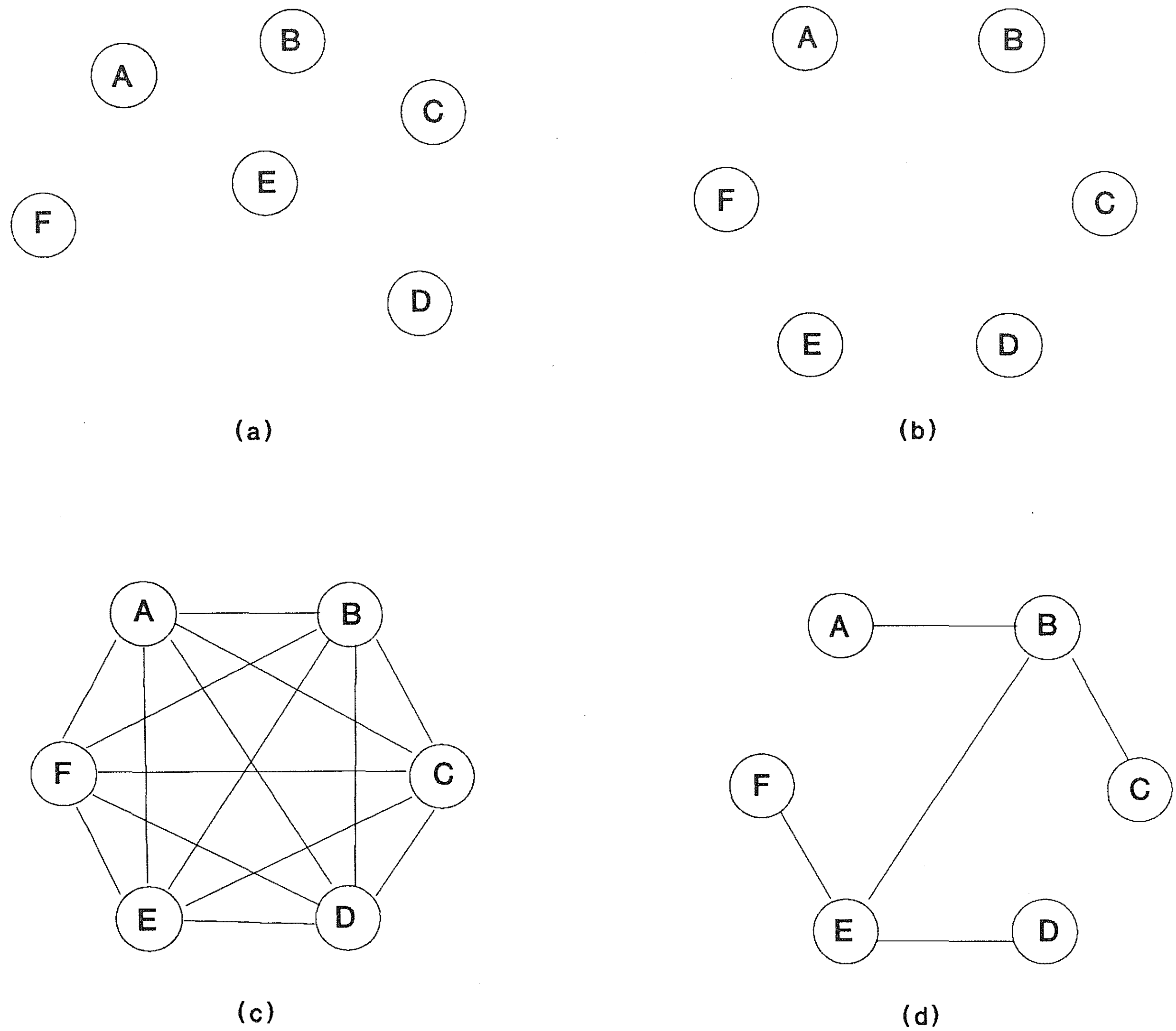


Fig. 3-1. Various arrangements of utilities (circles) and transmission lines.

from others at the lowest price possible. Although each player acts in his own self-interest, the result of the game in the absence of regulatory constraints is that the players cooperate to minimize the total production cost of all the entities in the region.

We cannot predict which pairs of buyers and sellers will trade power or at what price, but we can predict the production cost savings. If transmission costs are negligible, the savings will be the same *as if* the lowest production cost entity sells to the one with the highest production cost, then to the one with second highest cost, and so on, until it uses up its lowest cost capacity. The second-lowest-cost producer then satisfies the remaining highest avoided cost, and so on until all cost savings opportunities are exhausted.

The point here is that one important part of the outcome of the six-player game can be discovered by playing a series of basic two-player games.

In figure 3-1(c), transmission is available for all possible transactions. The result would be the same as if a common carrier transmission network were available to bring together any seller-buyer pair. In the United States today, of course, there is no such common carrier network, nor is every pair of entities directly interconnected. The situation is better illustrated by the transmission configuration of figure 3-1(d). Here, if A and E strike a deal, B would have to wheel power to complete the deal. Now the minimum number of players needed for a basic game is three. (If A wants to sell to F, both B and E would have to wheel. In many cases, B and E can be treated together as a wheeling coalition, the equivalent of one "wheeling" player.)

Part of the outcome of a many-player game can be found by a series of basic three-player games, where we begin by choosing the lowest cost producer as the potential seller, the highest cost producer as the potential buyer, and the intervening utility (or utilities) as the wheeler. The three-player game is our "unit of analysis." In figure 3-1(d), if A is the lowest cost producer, it becomes the seller S. If E is the highest cost producer, it is designated the buyer B. If S and B are not directly interconnected, the utility (or utilities) that would have to wheel the power is designated W. Other parties, such as C, D, and F in figure 3-1(d), can affect the outcome of this three-player game even though they are not counted as direct players. As explained more fully later, they cannot necessarily stop the trade between S and B, which is the most profitable trade to be made, but as alternative power buyers and sellers they can influence the price at which the S-B trade occurs.

Game theory can be applied easily to a market with many players, but we restrict our analysis to three-party transactions for two reasons. First, most of what we need to know about the effects of access and pricing rules on bulk power markets can be discovered through the three-player unit of analysis. Second, it is possible to give simple pictorial displays of the outcomes in three-party markets, whereas outcomes in markets with more parties must be presented as large arrays of numbers. With three players, results can be displayed in figures instead of tables.

Seller, Wheeler, and Buyer

To keep our analysis general, we assume in chapters 4, 5, and 6 that the seller, wheeler, and buyer are independent utilities. That is, in general S can have both generation and retail load. So can W and B. For simplicity, it is assumed that W owns the transmission tie lines between S and W and between W and B.

The fact that S has generation and load is expressed algebraically by denoting S's generating capacity by Q_S and its load (or demand) by D_S.[8] These are fixed quantities. If S were in fact not a utility, but an independent power producer (IPP) that has no retail load of its own or a PURPA qualifying facility, the results would be found by setting D_S equal to zero in the analysis here. Since S is by definition the seller, Q_S cannot be zero; and if S is a utility it must have extra generating capacity after meeting its retail load; that is, $Q_S > D_S$.

Similarly, the buyer can have generating capacity Q_B and retail load D_B, also fixed quantities. Since B is by definition the buyer, D_B must not be zero. However, the buyer can be an independent utility with $Q_B \geq D_B$, a partial requirements customer with $D_B > Q_B > 0$, or a full requirements customer with $Q_B = 0$.

W's generation and load, Q_W and D_W, are constant too. W also can be a company that offers only transmission service (Q_W and D_W are zero) or one that offers only generation and transmission with $Q_W > 0$ and $D_W = 0$.

[8] We use the word "demand" to refer either to the quantity of energy (kilowatt-hours) or the amount of power (kilowatts) required by customers. Because time is not a variable in our model, these are proportional quantities. In the electric industry, demand always means power.

Conceivably, W also can be a T&D with $Q_W = 0$ and $D_W > 0$, if the T&D is in a position to wheel.

We refer to S, W, and B as independent utilities to signify the general case where all these constants are not zero. By this, we do not mean to imply that transmission access should not be offered to other entities or that our analysis is not valid for other entities. One can apply our results to other entities by setting the appropriate constants equal to zero.

Further, we ignore the internal transmission costs of S and B. The costs of either S or B transmitting power from its own generating units to its own loads does not enter into our analysis. The costs of transmission from S to W and from W to B are assumed to be borne entirely by W and recouped by W either explicitly in a transmission fee or indirectly from trading profits. (Real profit is gross receipts less all costs including transmission costs.) Cases where S or B own the tie lines complicate the analysis by multiplying the number of situations to be examined, without giving any policy insights.

Known, Constant Production Costs

We assume that the production costs of seller, wheeler, and buyer are known and constant. These are marginal (or incremental) costs denoted C_S, C_W, and C_B, respectively. In the short-run nonfirm market, we take these costs to be the system lambdas of the utilities. In the long-term firm market, these are the costs for each utility to construct and operate a new generating unit. In a competitive bidding context, these production costs would be the bids submitted by each company if it were to submit a zero-profit, cost-based bid to supply long-term firm power.

In a real market, of course, bidders do not submit cost-based bids. They bid to supply power at the highest price that they think will win the bid. Especially for IPPs and QFs, the seller's true production cost may well not be known.

System lambdas might also not be known for IPPs or QFs or not known precisely for utilities. A company's system lambdas may be displayed on a computer screen with great precision (for example, 19.294 mills per kilowatt-hour), and yet the actual system lambda may be a few mills more or less than this. This is because the calculation of the lambda depends on such factors as which units are on line at what power levels, the accuracy of their heat-rate curves as a function of power level, the accuracy and currency of the fuel's BTU-content measurement, and their fuel inventory cost-accounting policies (FIFO v. LIFO). Thus, while we assume that utilities trade power until ideally all differences in system lambdas are eliminated, in practice utilities may not bother to eliminate a nominal difference of a few mills because this may be more an apparent than a real cost difference.

Further, we make the simplifying assumption that production costs are constant and supply quantities are limited. We assume, in the case of the seller S for example, that the utility can produce amount Q_S at cost C_S. In the case of a firm power bid, Q_S is the maximum amount of power capacity (in megawatts) that S's new units can supply at incremental cost C_S. Either S cannot supply more than Q_S, perhaps because of a limit on its cooling water supply or because of an emissions limit, or any supply in excess of Q_S would cost so much more than C_S that it would not be competitive in the market.

In the case of nonfirm power, a utility's production cost curve is properly modeled as a continuously increasing function of the amount supplied. However, the curves have a step-like character to them. As coal burning units are powering up, system lambda increases over the range of (say) 17 mills to 21 mills. But when coal-fired capacity is used up and oil-burning peakers are turned on, lambda jumps to over 30 mills. To simplify our calculations, we assume that S has a certain amount of coal power at a constant cost of (say) 20 mills, after which it has no more capacity available, that is, none in which the nonfirm market has any interest.

Uniform Policy

We assume that in any one "game" the access and pricing policy is known to all, applies equally to all parties, and does not change over time.

With this assumption, a merchant IPP can in fact be treated as an independent utility with no retail demand of its own ($D_S = 0$) because the same access and pricing rules would apply to an IOU and an IPP. Also, the results for a control-area utility buyer, if its Q_B goes to zero, apply to a full-requirements customer. In any one analysis, the rules for the S-W transaction are the same as for the W-B transaction.

Public policy might appropriately charge an IPP an access fee to join a transmission grid or charge a requirements customer an exit fee to compensate for stranded investment. If these fees are converted into transmission rate surcharges, then rates would not be uniform for all parties, as we assume they are here. We make this assumption, not as a policy recommendation but merely as a way to keep our calculations simple.

We assume further that rules do not change over time. This is especially important for the analysis in chapter 6, where a utility W today plans new transmission for future gain. It does so with complete assurance that today's access and pricing rules will still apply after the new facilities are constructed.

Goal: Minimize Retail Rates

We assume that each utility's management, stockholders, and retail customers all share a common goal: namely, to provide that utility's retail service at the lowest possible cost.[9] This assumption is often justified, and it simplifies our analysis considerably. In some cases, however, the goals of these parties are at odds and the market model should properly represent each party as a separate player. Figure 3-2 shows in part (a) the nine-player game that would result if we did not make this assumption, while in part (b) it shows the much simpler game we actually analyze. (The game would be even more complicated if federal and state regulators were not simply rulemakers but also players.)

It is usually understood that the seller offers its more expensive generation for wholesale sale, after less expensive generation has satisfied retail demand. When all generating capacity is in retail rate base, any revenue from bulk power sales merely offsets the retail revenue requirement. There is no profit for stockholders from bulk power sales. By maximizing the selling price, the seller minimizes its retail rates.

The buyer's retail rates go down, often through the fuel adjustment clause, if its power purchase decreases its costs. We assume the buyer wants to purchase power at the lowest possible cost and hence wants to minimize its retail rates. The wheeler's wheeling revenues at least cover out-of-pocket wheeling costs; any extra revenues collected for the use of its transmission facilities, which are in the retail rate base, are used to lower retail revenue requirements and so lower retail rates. The wheeler

[9] If S or W has no retail load, its goal is simply to maximize its profit (revenue minus cost) or minimize its losses (for service provided below cost).

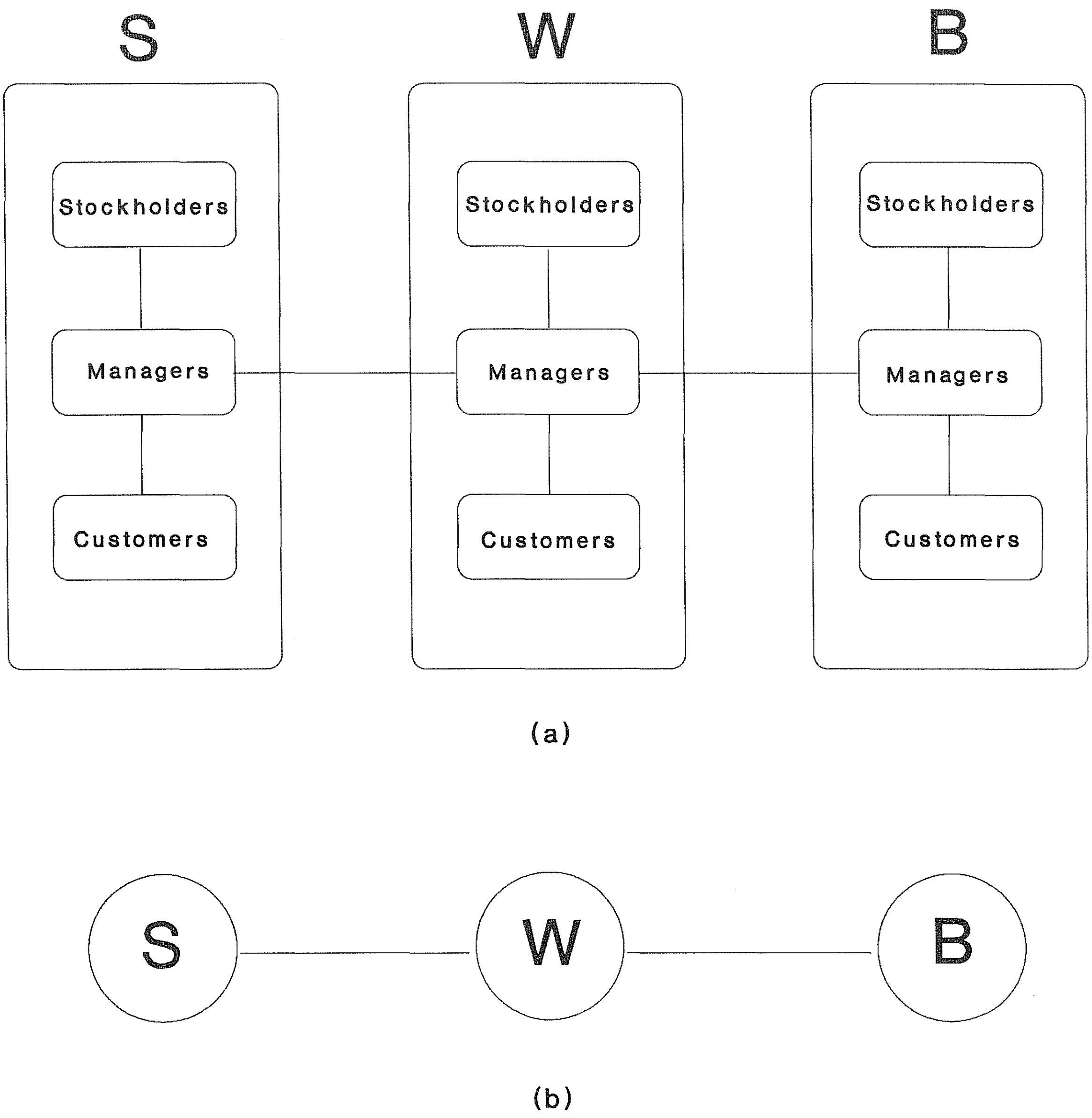


Fig 3-2. Three utilities as (a) a nine-player game and (b) a three-player game.

wants to get as much wheeling revenue as possible in order to keep its own retail rates as low as possible.

Why really do utility managers and stockholders want retail rates to be low? Apart from legitimate "noneconomic" reasons, such as the personal pride of managers in doing a good job, lower rates help to increase the company's market share and hence profit. Retail service is the heart of the electric company's business, and the company competes with natural gas suppliers and sometimes with suppliers of oil, coal, or other fuels. Low retail electric rates are important for retaining or increasing the share of the energy market served by electricity. Also, despite the electric company's seeming monopoly position, there is at least some competition among electricity suppliers. Sometimes large retail customers can successfully switch electric companies to receive service from a lower-cost neighboring company. If retail rates are too high, some large commercial or industrial customers may generate their own electricity and perhaps even sell their excess output to the electric company under PURPA rules. Market share in a growing community, especially increasing market share, means growth in company earnings, which benefits both stockholders and company officers. Hence, the assumption that a utility acts to lower retail rates is generally reasonable.

There are exceptions however. For example, the buyer's retail rates may include the costs of power purchased during a historical test year. Unless adjustments are made, there is an economic incentive for having a high level of costs during the test year and lower costs when the rates based on that test year are in effect. Stockholders can profit from the difference. Depending on fuel-adjustment-clause design, there may be a disincentive for the buyer to increase purchased power costs over the test-year level if these extra costs cannot be recovered in the fuel clause and extra fuel expenses of own-generation can be recovered. In this case, managers acting on behalf of stockholders have an incentive to use their own generating units even when purchased power costs less. In situations like this, the "rules of the game" are such that actions to minimize retail rates are no longer the same as actions to maximize stockholder profit.

As the electric utility business changes in the 1990s, the number of such situations faced by utility managers may well grow. To the extent that bulk power generation and transmission services become profitable businesses in their own right, companies may rethink the notion that retail service is at the heart of the electric business. A crucial step to begin this process is that stockholders be allowed to earn at least some profit on wholesale generation and transmission services, profit that really goes into dividends, not just into retail rate reductions. Such profits are being seriously considered as incentives to help open up competition in regional electric markets. Already, some generating units are not in rate base, and there are proposals to sell the output of some generating units in rate base at market rates with a sharing of the profits between retail customers and shareholders. This can create situations where the interests of the seller's shareholders and ratepayers are not the same. For example, suppose a company has two choices. Choice A would lower production costs and retail rates by 4 mills and yield nothing for shareholders, but choice B would lower costs by 5 mills with 3 mills going to rate reduction and 2 mills going to stockholder profit. Ratepayers would prefer A, getting 4 mills instead of 3, and stockholders would prefer B, getting something instead of nothing. Choice B can be justified on the basis of greater cost reduction.

The interests of the wheeler's ratepayers and stockholders may be divided too. Consider, for example, the question of whether to construct new transmission capacity to facilitate power exchanges among others. If shareholders can earn profits on transmission service, they have an incentive to invest in such new capacity. Managers may want to protect themselves (and stockholders) from the risk that this investment will be unprofitable by seeking to include the investment in the retail rate base.

One can imagine an amoral market game in which the "correct" strategy is, first, to construct generation or transmission capacity and include it in retail rates. This protects stockholders from loss. (In a slightly more complicated game, one could assign a probability to having the facility included in retail rate base. In a still more elaborate game one could make the state regulatory commission a player.) Second, the strategy is to try to sell generation or transmission in the wholesale market under a shared-savings rule, with part of the profit used to reduce the retail revenue requirement and the rest going to stockholders. In this second step, the interests of ratepayers and stockholders are the same; they share the profit. However, in viewing the whole game, one can see that their interests are at odds. This is because ratepayers get only a portion of the profits if the investment venture is a success but, in the simplest version of the game, pay for the entire investment if it is unsuccessful.

Setting out the strategy of this game does not imply that utilities have tried or will try to follow it. Note, however, that thwarting such a strategy requires a public utility commission's vigilance and correct forecasts of retail generation and transmission capacity requirements. One lesson of the last seventeen years is that neither commissions nor utilities forecast well. It is perhaps ironic that we are entering a more competitive era that requires utilities and commissions to forecast well to prevent suspicions that such strategic games are being played.

The role of utility company mangers will become more ambivalent as the interests of customers and equity owners diverge. It is generally assumed that the company officers' responsibility is to represent the shareholder. However, even in unregulated firms, this representation is known to be less than fully satisfactory. In utilities where many small investors as well as somewhat aloof institutional investors are owners, their ability to oversee management performance is relatively weak. Managerial interests are distinct from either ratepayer or owner interests, tending more toward assuring adequate earnings than risking a lot on extraordinary earnings and toward assuring that earnings are good over the next few years rather than over the next few decades. A fuller discussion of this matter is available elsewhere[10] and not needed here. The only point to be made here is that management's decision on such matters as transmission capacity expansion may be decided on some basis other than strict pursuit of either long-run shareholder profit or minimization of long-run retail service costs.

Despite these complications, we use the model depicted in figure 3-2(b) and assume, for simplicity, that each "player" (S,W, or B) is a single entity with the simple goal of maximizing its own profit or, equivalently, minimizing its own retail service cost.

Constant Retail Loads

We assume that the retail loads of the wheeler and the buyer, denoted D_W and D_B, are fixed. We do not treat daily or seasonal load variations. More important, we assume for simplicity that these loads are constant; they do not vary with the price that W and B pay for purchased power. Whether or not power is purchased to meet a portion of these loads is, of course, affected by the wholesale power price. In reality, purchase power prices affect the buyer's retail rates either immediately or eventually, so that the purchased power price must affect the retail load, at least eventually. This raises an issue of pricing efficiency. The economic

[10] See D. Czamanski et al., *Regulation as a System of Incentives*, NRRI-81-17 (Columbus, Ohio: The National Regulatory Research Institute, 1981).

efficiency of any pricing policy has two aspects, productive efficiency and allocative efficiency. In our analysis, we consider only the efficiency of production. That is, we examine whether a transmission pricing policy would result in the least-cost generation of electricity, assuming retail loads are constant.

Achieving production efficiency does not assure allocative efficiency, as the following discussion shows. Least-cost generation is promoted by transmission pricing rules that encourage good decisions about power purchases and consequently good decisions about which set of generating units to bring on line to meet a region's total load. Good decisions are those that result in incremental benefits to all parties greater than incremental costs to all parties. There is no single best pricing rule for production efficiency. All the good rules equalize marginal costs across the grid and result in use of the same generating units and in the same flows on power lines as results from economic dispatch of all the sources in the region.[11]

Various good rules differ according to how the gains from trade are shared among the parties. Suppose, for example, that the buyer's avoided cost is 72 mills per kilowatt-hour, the seller's production cost is 30 mills per kilowatt-hour, and the wheeler's transmission cost is 2 mills. The gain from trade between S and B is 40 mills per kilowatt-hour. If S and W provide their services at their marginal costs, the buyer B enjoys all the gain. But the seller could charge more, for example, 50 mills for power while the wheeler could charge (say) 12 mills for transmission, resulting in a delivered price to the buyer of 62 mills. It would still be in B's best interest to buy all the power it can from the low-cost producer S at 62 mills rather than generate its own power at 72 mills. Now, however, the seller gains 20 mills (which is its revenue of 50 mills less its cost of 30 mills) out of the 40-mill total gain available. The wheeler and the buyer each get 10 mills of gain. This pricing policy satisfies the production efficiency goal because the lowest-cost producer generates the power.

Nevertheless, overall economic efficiency could be lower under this pricing policy if the buyer's retail consumers purchase less electricity

[11] For a detailed discussion of the concept of the equalization of marginal costs across the grid, see chapter 6 of K. Kelly et al., *Some Economic Principles for Pricing Wheeled Power*, NRRI-87-7 (Columbus, Ohio: The National Regulatory Research Institute, 1987).

when the purchased power cost (one component of their retail rate) is 62 mills per kilowatt-hour than they would when it is 32 mills per kilowatt-hour. The total regional load can then be below the optimal level if the rate paid by the buyer's retail customers exceeds the true regional marginal cost. In the language of economics, too few of society's resources are allocated to electricity production because of high prices, and the "allocative efficiency" of these prices is less than optimal even though productive efficiency is optimal. In short, the load is too low but the right generating units are serving it. Marginal-cost pricing promotes both kinds of efficiency and hence overall economic efficiency.

In practical terms, high retail prices can affect the buyer B in several ways. Not only can individual retail customers purchase less electricity, but some customers may seek to become retail customers of other nearby utilities, perhaps of the wheeler W. Also, if B is a smaller company in or near W's service territory there may be pressure for B to merge with W to eliminate the retail rate differences.

The Concept of the Core

While is not our purpose to try to teach game theory here, in this chapter we introduce a few game theory concepts that are necessary for following the analysis in later chapters. To begin, consider just two neighboring utilities, S and B, that can trade power bilaterally without wheeling. Suppose S has a power production cost of 3 cents per kilowatt-hour. This can be either S's system lambda in the short-run, or, in the long-run, the total incremental cost (capital plus operating) of a new unit on the drawing board. S's low production cost makes it a potential power seller. B has a production cost of 7 cents per kilowatt-hour and is a potential buyer. Assume line losses and other transaction costs are negligible. At what price is the power sold?

There is no way to answer this question unless more information is provided. Most industry analysts know that the practice in the United States is to sell short-term economy energy on a split-savings basis and long-term firm power on some sort of cost basis. But suppose one has no knowledge of these practices. What then can be said about the price at which the power would be sold? S should be willing to sell power at any price above 3 cents. B should be willing to buy power at any price below 7 cents. The range of economically feasible prices in this case is from 3 to

7 cents. This range of prices represents what is called the "core" of this "game."

In this section we develop the concept of the core in a nonalgebraic way, using diagrams rather than equations to set out useful features of the concept. The simple seller/buyer situation just introduced is examined first and used to develop ideas about bargaining, market power, ways of sharing the gains from trade, and constraints on the core. Then these ideas are reexamined for the situation in which the services of a third party, the wheeling utility, are needed for the seller and buyer to consummate a wholesale power transaction.

A Bargaining Game

Imagine that S and B engage in a bargaining game to determine the price at which power is traded between them. S may argue that the price should be 7 cents--or something very close to 7, such as 6.9 cents to provide B with a small savings per kilowatt-hour, which can amount to a significant dollar savings if the trading volume is large enough. S may bluff, saying it has another buyer available willing to pay 6.8 cents--so it must get something very close to 7 cents from B. If B accepts the bluff, it may agree to pay this high price, and B enjoys virtually none of the gains from trade. Instead, S makes a profit of nearly 4 cents (7¢-3¢) on each kilowatt-hour exchanged. Its gain in dollars is the unit profit times the trading volume.

On the other hand, B may convince S to sell its power for 3 cents. B may bluff that it knows of an alternate seller, or it may convince S that an appeal to regulators would in the end force S to sell his power at cost anyway. Then B "wins the game" and enjoys all the gains from trade.

We cannot know before the game is played how the total gain from trade of 4 cents will be shared between S and B. We know only that S will not sell for less than its 3 cents out-of-pocket cost, and B will not pay more than its avoided cost of 7 cents. We define the core of the game as the range of possible outcomes.[12] In this case the core is any price between 3

[12] This definition is adequate for our purpose. Any elementary game theory text will provide a more precise--and mathematical--definition of the core. For a thorough discussion, see Lester G. Telser, *Economic Theory and the Core* (Chicago: University of Chicago Press, 1978).

cents and 7 cents, as shown in figure 3-3(a). As mentioned, the total gain depends on the sales volume; if 100 million kilowatt-hours are traded, for example, the gain is $4 million. There are infinitely many ways of dividing this between S and B, such as 50-50, 60-40, 70-30, and so on.

This leads to an alternate way of expressing the core, as shown in figure 3-3(b). A line runs from point S to point B; its length indicates the amount of the gain from trade, and the position of any point on this line indicates how the gain is shared. The midpoint M represents an even splitting of the gains. The left endpoint S represents the seller getting all the gains, and the right-hand endpoint B represents the buyer getting all the gains. Points to the left of S or the right of B are said to be "not in the core" or "outside the core;" either B or S refuses to trade at such a price.

Because we use the concept of the core throughout much of this report, it is appropriate to explore the concept further here. In a truly competitive market with many sellers and many buyers, various seller or buyers obtain large shares of the gains from trade while others obtain little or none. Competition drives the price down to the marginal cost of the most costly producer from which buyers are willing to buy, and at the same time competition drives the price up to the marginal value of the customer who values the power the least. These twin drives set the market price. Sellers that can produce at lower marginal cost (because they are more efficient or have access to low cost production resources) earn a profit by getting their costs below the market price. Any such producer obtains a positive share of the gain. Similarly, to the extent the buyer values power more than the market price it enjoys a greater share of the gain.

The distribution of gains between buyers and sellers depends on the supply and demand characteristics of the market. For example, if all sellers have about the same marginal production cost, close to the market price, while various buyers place a wide distribution of values on the purchase, the buyers as a group obtain most of the gain. This many-player situation is analogous to a point close to B in the two-player diagram of figure 3-3(b). On the other hand, where sellers have a wide distribution of production costs, the selling sector obtains a larger share of the gain. It would obtain almost all the gain if the various buyers all valued the purchase to the same extent. In the case of wholesale electric power, there are situations where most buyers want to displace generation by one fuel type (such as oil) and so have a similar avoided cost, and sellers

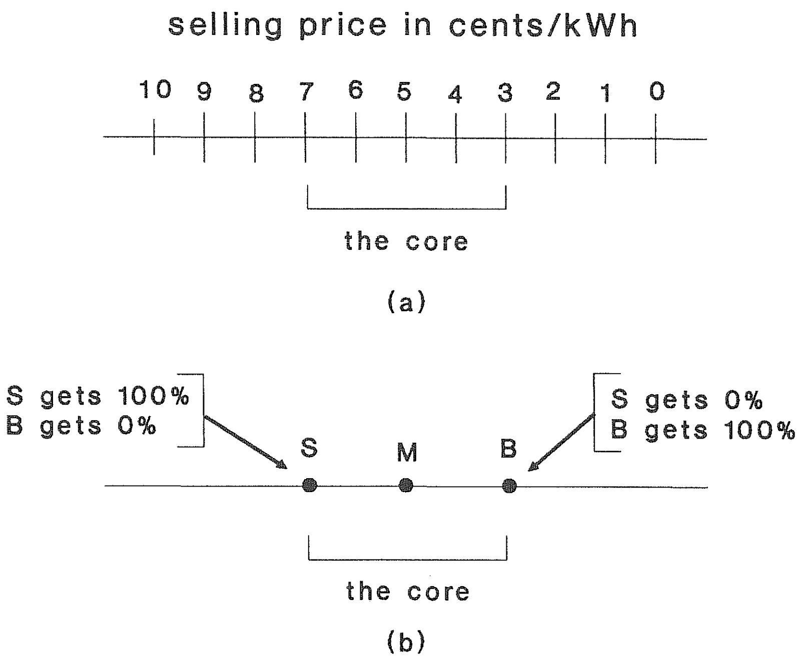


Fig. 3-3. The core of a two-utility game expressed in terms of (a) selling price and (b) percentage of the gain to either party.

have a variety of production technologies and costs (hydro, nuclear, coal, sometimes with tax-advantaged capital costs). In such a case, competition is capable of producing a situation analogous to a point close to S in figure 3-3(b).

In a monopoly situation, however, with one seller and many buyers, the seller may be able to "charge what the market will bear," capture virtually all the gains from trade, and operate at or near the point S in figure 3-3(b). Most markets are neither perfectly competitive nor perfectly monopolistic, but somewhere in-between.

The relative numbers of buyers and sellers also affects which gets the greater share of the gain in a competitive market. Anyone who has negotiated a price for the purchase or sale of a home understands the idea of a seller's market and a buyer's market. In a "seller's market" with relatively few sellers and many buyers, the market may be characterized by a point on the left side of the core, closer to S than to B. A point in the core nearer to B than to S characterizes a buyer's market--typically one with many sellers and few buyers.

Market Power

Economists and attorneys in antitrust cases frequently use the concept of market power. An excellent review of the market power concept, its measurement, and its antitrust applications has been written by an economist, William Landes, and a legal scholar, Richard Posner.[13] A few of the key ideas in this review article are summarized here. Market share is sometimes used as a measure of market power, with large market share indicative of great market power. Market share can be a poor measure of market power, however. For example, large market share may reflect a company's efficiency, low cost, and hence low price, which is not an antitrust violation per se. Particularly for regulated industries with a monopoly franchise, market share is a very poor measure of market power. Indeed, an unprofitable market in a regulated company's service area might be served at a loss as part of the franchise obligation to serve. Here, counterintuitively, a 100-percent share of the market reflects a lack of market power.

The most common definition of market power is the ability to set price profitably above the competitive level. A common mathematical measure of market power is the Lerner index:[14]

$$MP = \frac{P - MC}{P},$$

where MP is the Lerner index of the market power of the seller of a commodity, P is the actual selling price, and MC is the marginal cost of producing the commodity.

In our example, if S is forced to sell at the marginal cost of 3 cents ($P = MC$), its market power measure is zero. If it must sell power at the price that would result under competition, it has no market power. If it can raise the price to an arbitrarily high level without losing such a large volume of sales that the price increase is not profitable and must be rolled back, its market power measure gets close to one. The highest price it can hope to sell at in our example is 7 cents, at which point the Lerner

[13] W. M. Landis and R. A. Posner, "Market Power in Antitrust Cases," *Harvard Law Review* 94 no. 5, March 1981, 937-96.
[14] A. P. Lerner, "The Concept of Monopoly and the Measurement of Market Power," *Review of Economic Studies* 157 (1934).

index is 0.57. A positive number indicates positive market power. In contrast, if S could somehow be forced to sell below marginal cost, it would have a negative Lerner index, which we could call "negative market power." It would not sell below marginal cost voluntarily (unless its strategy is to bankrupt competitors in a price war). In the short-run power market, regulation is unlikely to require a power seller to sell below his system lambda.[15] In the long-run power market, however, regulation may require a potential wholesale power seller to sell firm power at the average embedded production cost of all its generating plants at the time of the wholesale sale; this cost can be less than the incremental expansion cost of any new generation capacity required for this bulk power sale. The result of such regulation can be to inhibit expansions and sales that might otherwise occur in the absence of regulation--a situation that can be described as having a negative Lerner index. Here, regulation constrains the game to a point (see figure 3-3) that is to the left of S, and hence outside the core. The only allowed transaction, in this case expansion followed by a firm power sale, does not occur because it is not in the core.

In figure 3-3, if S has market power this is reflected by an actual sales price close to 7 cents in (a) and a trading gain located in the core near point S in (b). S having little market power, which we refer to as B *having* market power in this two-party market, is reflected by an actual sales price close to 3 cents in (a) and a trading gain located in the core near point B in (b). We can also think of B as having a kind of "market power" to the extent that it can obtain a price below its avoided cost, here 7¢/kWh.[16] If it must pay 7 cents, it has no market power. It will not voluntarily pay more than 7 cents, which would correspond to B having "negative market power" and would be represented by a point outside the core, to the right of point B. Some utilities argue that this situation actually occurs when the administratively set avoided-cost price for purchase of power from PURPA qualifying facilities (QFs) is higher than their actual avoided cost.

[15] However, regulation does require a form of average-cost pricing in order to avoid undue discrimination among customers, and the residential price may, for example, be above marginal cost in urban areas and below marginal cost in rural areas.
[16] One is tempted to define a buyer's market power index in terms of the buyer's marginal benefit MB: MP = (MB-P)/MB.

The usefulness of the concept of the core is that it expresses the well-known fact that while the outcome of a business negotiation cannot always be predicted, the range of possible outcomes (that is, the core) can be calculated in advance. If no gains from trade are possible, we may say there is no core or the core does not exist. For example, if the seller's cost is 3 cents and the buyers's cost if 3.5 cents but there are line losses over the tie lines connecting them equal to 0.6 cents, then no trading gains are possible and there is no core. As a result, no transaction occurs.

Fair Allocation of Gains

Because the core in this two-player game is a range and not a single point on the line, people who study games have devised certain standard ways of dividing the gain, usually using some sort of fairness criterion. Each way results in the selection of a single "fair" point on the line. Each point is normative, not a prediction of an actual outcome, and applies to those situations where the parties cooperate to achieve the greatest possible total gain.

We mention the two best known ways here because these are used later in this report, particularly in appendix B.[17] One method, devised by Lloyd Shapley and named after him, is based on the average increase in gain observed by letting players join the game in various combinations and sequences. Another method calculates a unique point in the core (called the "nucleolus"), which minimizes the amount of "unfairness" to any one player considering the contribution each makes to generating the gain. Both methods implicitly acknowledge the market power of the various players, so that players with more market power get a larger share of the gain. In appendix B, we use the Shapley value and nucleolus as measures of market power, as explained in later chapters.

In our simple game with S and B, both methods yield the same simple result: split the gain 50-50 between S and B. This in fact is what

[17] These methods are not explained here, merely mentioned. Mathematical formulas for calculating these standard ways of dividing the gain are given in most game theory texts. See also L. Shapley, "A Value for n-Person Games," *Annals of Mathematics Studies*, no. 28 *Contributions to the Theory of Games, Vol. II*, ed. by H. W. Kuhn and A. W. Tucker (Princeton, New Jersey: Princeton University Press) 1953, 307-17; and D. Schmeidler, "The Nucleolus of a Characteristic Function Form Game," *SIAM Journal of Applied Mathematics* 17 no. 6, November 1969, 1163-70.

utilities do, with FERC approval, for economy transactions. (Some analysts have suggested that real business negotiations may often--but certainly not always--have results close to one of the standard "fair" ways of sharing the gains. At least one empirical study tends to support this view.)

Constraints on the Core

In an unregulated game, something other than a 50-50 split is certainly possible, especially if other sellers or buyers are involved. Suppose B has a second potential supplier whose production cost is 6¢/kWh. This constrains the core of the S-B negotiations to the price range 3 cents to 6 cents since S cannot persuade B to pay more than 6 cents in this case. Here S can obtain at most three-quarters of the gains from an S-B trade (3¢ gain out of a 4¢ difference in production costs). The constrained core is illustrated in figure 3-4. Current industry practice is to have the trade still take place at a price of 5 cents on a split-the-difference-in-lambdas basis despite the threat of a second supplier. But in this case both the "nucleolus method" and the Shapley method would yield a different result from this, and from one another. Each gives a somewhat smaller share of the gain to S, reflecting its decreased market power with the presence of a second seller. The Shapley approach even gives a share of the gain to the second seller (a solution not in the core of S-B game) even if this "seller" sells no electric power in the final outcome.

The core can also be constrained by regulation. For example, suppose S has some excess generating capacity for the next ten years, and B wants to buy firm generation from S for thirty years. S would sign a thirty-year sales contract if it could set a thirty-year price with a capital component at or above the long-run marginal capital cost of generation. The revenues would allow S to construct new capacity to meet its own needs ten years from now, thus holding its own customers harmless and perhaps providing a profit too. This price may be good for B if its own expansion costs for self-generation are higher. But if regulation were to require S to sell for thirty years at a lower embedded-cost-based price, S would decide not to sell. The regulatory "solution" to this game kills the deal.

This is depicted in figure 3-5, which shows the only solution permitted by regulation to be outside the original core. If intercompany sales are voluntary, no power agreement is reached. The constrained core is defined as the area of overlap between what is economically feasible (the unconstrained core) and administratively possible. In many cases the

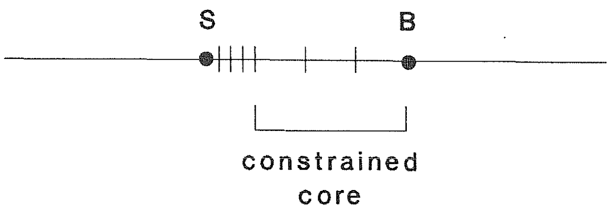


Fig. 3-4. The core of the two-utility game constrained by another seller.

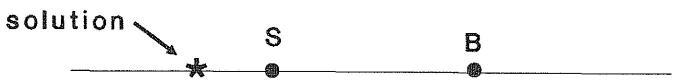


Fig. 3-5. A two-utility game with no core.

constrained core is smaller than the unconstrained core. In the example just given, the constrained core does not exist.

<u>The Core with Three Players</u>

Consider next the case where the two utilities, S and B, require the transmission services of an intervening utility W, a potential wheeler. S is the lower-cost producer and B is the higher-cost producer, as before. S can sell to B if W wheels. If W wheels at cost (we mean marginal cost unless otherwise specified), the situation is the same as before: there is a bargaining "game" between S and B to divide the trading gains, defined as the difference in their production costs less the transmission cost.

This simple situation becomes more interesting--and complicated--if W does not have to wheel at cost. Then W can use its strategic position to argue for a share of the trading gains in addition to having its marginal costs reimbursed. Moreover, W may have generation and load of its own and may want to sell to B or buy from S.

What happens depends partly on whether S has enough low-cost generation to supply both W and B and whether there is enough transmission capacity to accommodate all desirable trades. Each variation in assumed production costs for the three parties and in their generating capacities, loads, and transmission capabilities creates a new situation, or bargaining game. Each game has a maximum generation cost savings, net of transmission costs, that can be realized if the parties cooperate. This is the trading gain, which now has to be split three ways.

What happens also depends on the laws and regulation governing access and pricing rules. These "rules of the game" constrain the game and affect who "wins," that is, who captures the largest share of the gain.

There is no way to know ahead of time how the three parties will share the gain unless further information is provided about the "rules of the game." Any one of the three parties may get 100 percent of the gain, and there is an infinite number of ways of splitting the revenues among the three parties. Suppose S's production cost is 3¢/kWh, B's avoided cost is 7.2¢/kWh, and W's wheeling cost is 0.2¢/kWh wheeled. Setting aside bilateral trades between S and W and between W and B for the moment, the gains from trade between S and B are 4¢/kWh (7.2¢ - 3.0¢ - 0.2¢). S will sell power for any price at or above 3 cents, and B will buy power for any price at or below 7.2 cents. If it is the buyer who must pay the wheeling price to W and if this price equals cost (0.2¢), B will pay S any price at or below 7.0 cents so that its total expense (payment to S plus payment to W) is no more than its avoided cost, 7.2 cents. As in the previous example, the price B pays to S is in the range of 3 cents to 7 cents, but now the upper number depends on the wheeling price.

Absent a legal obligation or regulatory requirement, W will not wheel for a price less than 0.2 cents, its cost. But it may negotiate for a higher price. W might, for example, hold out for a 1.2¢/kWh wheeling price, guessing that S and B are willing to give up 1 cent of the 4-cent gain in order to get the remaining 3-cent gain that cannot be realized without W's cooperation. Pushing this argument to its limit, it is conceivable that W could raise the wheeling rate almost all the way to 4.2¢/kWh, getting 0.2 cents of cost reimbursement and almost 4 cents of profit on each kilowatt-hour wheeled. This is the most W can charge without driving S or B out of the deal. At any wheeling rate below 4.2

cents, some gain remains for S and B, and they must decide how to split the gain between themselves as before.

The Core Triangle

A simple way of illustrating how the total gain is shared among three parties is shown in figure 3-6. The figure is a triangle with all three sides of equal length; the length of each side equals the total gain.

If one of the "rules of the game" is that W must wheel and do so at cost (marginal cost), then W has neither profit nor loss and gets none of the gain. All the gain is then split between S and B, and the core is represented by the S-B line in figure 3-6, just as it is by the S-B line of figure 3-3(b).

But suppose W is not constrained in this way, while S is constrained either by regulation or by competition to sell its power at marginal production cost. Now S gets none of the gain, and W and B can bargain to share the whole gain. The W-B side of the triangle represents this new core. The B corner of the triangle is the point at which the buyer gets all the gain; at the W corner the wheeler gets it all; each point on the W-B side corresponds to a unique way of splitting the gain between them. The point labeled "1" in figure 3-6, for example, is three-quarters of the way from the W corner to the B corner and so represents a bargaining outcome in which B gets 75 percent of the gain, W gets 25 percent, and S gets none.

The meaning of the third side of the triangle should now be obvious. Points on this side represent bargaining outcomes under which the buyer gets none of the gain; that is, it pays a delivered price for power that equals its true avoided production cost. The seller and wheeler divide the whole gain. Points on the S-W side of the triangle closer to W represent W getting a larger share of the gain. Point 2 in figure 3-6 represents 50 percent to S, 50 percent to W, and 0 percent to B.

At points inside the triangle, each of the three parties gets a positive share of the gain. At the center of the triangle, point 3, each gets an equal share, one-third of the total gain. (Point 3 is one-third of the way from the S-B baseline to the W corner, one-third of the way from the W-B side of the triangle to the S corner, and one-third of the way from the S-W side to B.) Other points inside the triangle represent other ways of sharing the gain. The closer a point is to any corner, such as S, the greater the share of the gain to that party, in this case S. Consider point 4. It is inside the triangle so all parties get a positive share of

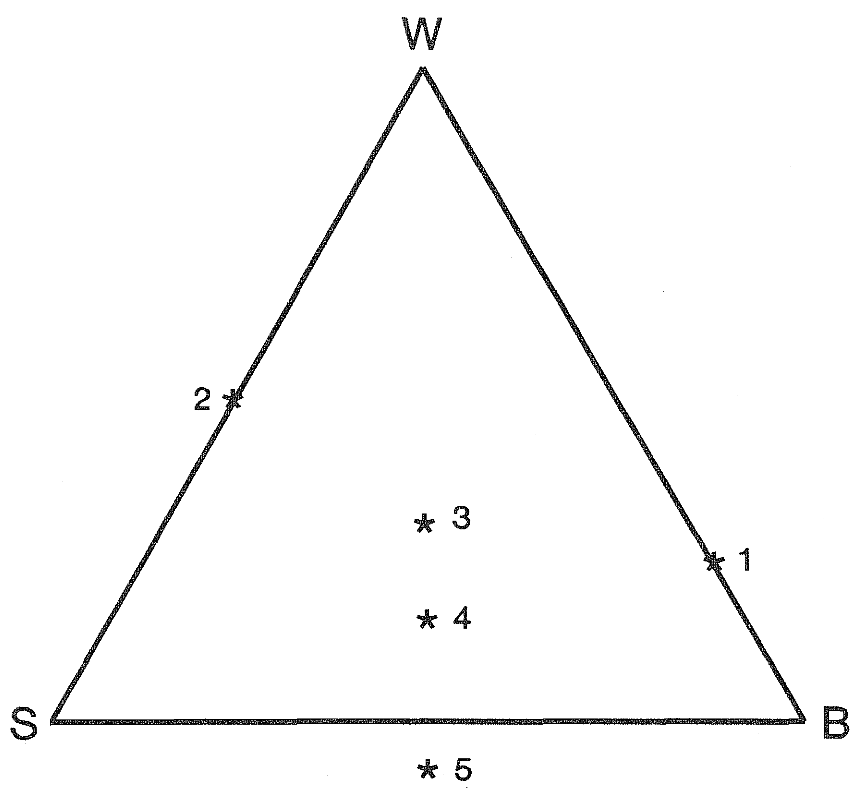


Fig. 3-6. The core triangle.

the gain. But it is far from the W corner so W's share is small. Like point 3, point 4 is also on a "midline" of the triangle, the line from W to the midpoint of the S-B side. At any point on this midline S and B get equal shares. Point 4 is placed 15 percent of the way up this midline from the S-B side toward the W corner, indicating that W gets 15 percent of the gain. S and B split the remainder, each getting 42.5 percent of the gain.[18] All points that are as far from the S-B baseline as point 4 get 15 percent of the gain. Imagine a dotted line drawn through point 4 parallel to the S-B side of the triangle. At all points on this line, W gets 15 percent of the gain, but the shares of S and B are different at different points. Where this dotted line meets the S-W side of the triangle, W gets 15 percent and S gets all of the remainder, 85 percent of the gain.

Each point in the triangle represents a unique way of sharing the gain, and every possible way of sharing the gain can be represented by a point in the triangle. Why this is so is explained in appendix A, which provides more information to the mathematically inclined on how to understand the triangle. It also gives methods for converting from gain shares to triangle positions and vice versa.

Points outside the triangle have a meaning also. There, at least one of the parties gets a negative share of the gain. To see this, consider that moving from inside the triangle to a point on the S-B side means moving from a situation where W gets a positive share of the gain (its revenue is above its marginal wheeling cost) to one where it gets a "zero share" (revenue equals cost). A point such as point 5, below the S-B line, represents W recovering less than its marginal cost for its wheeling service. Since the wheeling price is too low, the apparent gain to S and B is larger than the true gain. W subsidizes the S-B transaction. This is more likely to occur in the long run than in the short run; it can happen in the long run if W is required to construct new transmission capacity from S to B but must charge a price less than the long-run marginal transmission cost. Point 5 can be said to represent the case where the gain shares are: S gets 55 percent, B gets 55 percent, and W gets -10 percent. The total still adds to 100 percent, but W's losses contribute to

[18] In determining the gain-sharing represented by point 4 it is convenient, but not necessary, to start with the W share. To determine the S share first, draw a dotted line through point 4 parallel to the side opposite S (the W-B side). This dotted line is 42.5 percent of the way from the W-B side to the S corner (measured along the perpendicular). See appendix A for a fuller explanation.

S and B's gains. Point 5 represents a situation that W will not enter into voluntarily. It is not an economically feasible solution to the bargaining game among S, W, and B. In other words, point 5 is not in the core of the game.

Points on or inside the triangle are in the core. Points outside the triangle are outside the core; that is, they represent ways of sharing the gain that would be vetoed by at least one of the three parties, who would refuse to cooperate in a power trade. Points outside the W-B side of the triangle (northeast of the triangle) represent S selling power at a price below its marginal production cost. As mentioned, this is unlikely in the short-run but might be required by traditional cost-of-service regulation in the long-run. Points outside the S-W side of the triangle reflect buyer losses: power purchases at a price above avoided cost. This is quite unlikely unless required for some QF firm purchases.

The Core Triangle and Market Power

The core triangle is a useful way to depict the market power of transmission utilities. If transmission utilities must provide transmission service and must set price equal to cost (short-run or long-run marginal cost as appropriate), they have no market power. The Lerner index for their transmission service then is zero. The core of the game is constrained to be just the S-B baseline of the core triangle, as in figure 3-3(b).

The higher above the baseline of the core triangle that an outcome is located, the more market power the wheeler has. Since marginal transmission costs are typically a few mills per kilowatt-hour and power prices are typically a few cents, the maximum laissez-faire wheeling price is an order of magnitude larger than the wheeling cost. This gives a maximum Lerner index for wheeling service very close to one.

In the absence of any regulatory rules or other constraints, the core is the entire triangle. If there is money to be made in moving power from S through W to B, in the absence of rules we cannot predict at which point on or in the triangle a trade will be consummated. We can only say that, absent rules, the point will not be outside the triangle. As mentioned, there are various "fair" ways of dividing the trading gain; both the Shapley and nucleolus methods would give each party a one-third share (point 3 in figure 3-6) in the absence of regulation.

Access and pricing regulations can constrain the core without confining it to the S-B baseline. The size and shape of the constrained core are pictorial indications of the wheeler's market power, as well as of the market power of the seller and buyer. Because real business deals often occur with gain sharing close to one of the "fair" points, the positions of these "fair" points within a constrained core is another indication of a transmission entity's market power. The higher that the point lies above the S-B baseline, the greater the wheeler's market power for the situation analyzed.

It is important to emphasize that any point on the S-B baseline represents wheeling at marginal cost, not embedded cost. In the nonfirm market analysis using a short-run marginal-cost baseline, an embedded-cost-based wheeling rate allows the wheeler to collect not only operating costs but also a contribution to the capital cost of its existing transmission facilities. This probably corresponds to a point above the baseline and inside the triangle. If rolled-in embedded cost (as explained in chapter 2) is used for pricing, this may be represented by a point well above the baseline. While embedded cost pricing is considered cost reimbursement in the regulatory arena, the extra recovery of sunk capital costs here is considered a "profit" for the utility/ratepayer coalition in that it reduces retail rates. The ability to command this profit (or induce regulators to require it) is a measure of utility/ratepayer market power. However, if wheeling must be provided where opportunity costs--a component of short-run marginal cost--are not recovered, then service is provided below actual marginal cost: this is represented by a point outside the triangle and below the baseline. Inability to collect (or persuade regulators to allow recovery of) full short-run marginal cost is a measure of lack of market power.

Also, as discussed previously, an embedded cost rate for long-term firm service may be above, equal to, or below long-run marginal cost, depending on the circumstances. Hence, embedded-cost firm service may be above, on, or below the baseline of the long-run core triangle.

Coalitions

A coalition is a group of utilities that cooperate to get a greater share of the gains from power trading for themselves at the expense of others. In the parlance of game theory, the largest group in which all the players in the game cooperate is called the grand coalition, and any smaller coalition is called a subcoalition. These terms are not needed for our simple three-player game, in which the grand coalition is the seller, wheeler, and buyer and a subcoalition is any pair of these; but they are useful for discussing an eight-player game reported in appendix B. We denote coalitions with braces, so that {SWB} refers to the grand coalition and {SW} refers to the seller-wheeler coalition.

The value of a coalition is the power cost savings realized by cooperating instead of generating in isolation, net of the costs imposed by cooperating. It is the gains from trade. The value of a coalition is denoted by V. V(SWB) is the value of the grand coalition, for example; its value per kilowatt-hour is the buyer's avoided production cost less the seller's marginal production cost less the wheeler's marginal transmission cost. Notice that V(SWB) equals the length of any side of the core triangle. The value of a subcoalition, such as the subcoalition {SW}, is the gain from bilateral trading between S and W, denoted V(SW). V(WB) and V(SB) are defined similarly. V(SB) is the gain that S and B can obtain acting together without W. If S and B are not directly interconnected (and wheeling by W is not mandatory), V(SB) = 0.

Coalitions with Outsiders

In most cases, the value of a "coalition" containing just one player is zero. V(S) is zero, for example, if S neither profits nor bears any extra costs if it does not cooperate with W or B. In some cases where a player interacts with a party outside the game, however, it is convenient to assign a value to the player acting alone, and this imposes a constraint on the core.

Consider the case in which S can sell his power to another party X instead of B, with transmission interconnections as shown in figure 3-7(a). Suppose S's production cost is 3 cents per kilowatt-hour and B's is 7.2 cents. W's transmission cost is 0.2 cents. To keep the example simple, assume for the moment that W is only a transmission provider and has no production cost of its own and that the transmission cost from S to X is negligible.

There are two ways to handle the presence of X. One, and the better way, is to play a four-player game in which X can be either a seller or buyer depending on how its costs relate to other players' costs. If X's production cost is 4 cents, for example, it can either buy from S or sell

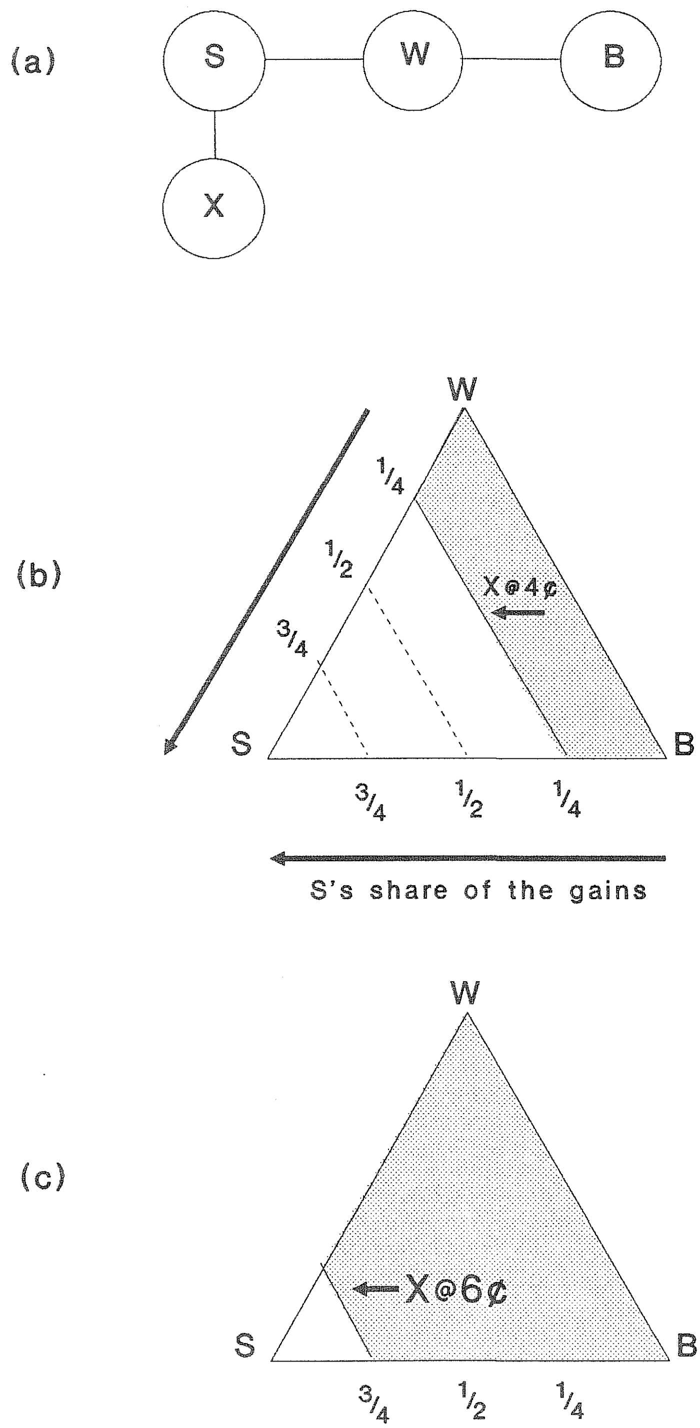


Fig. 3-7. Core constrained by a second buyer.

to B or W. We cannot predict what power prices would result from bargaining, but we can find the core of this game, which in this case is not a simple two-dimensional triangle but a three-dimension figure.[19]

A second and simpler way to treat X is possible if X can deal only with S and if the price of a sale from S to X is assumed to be known. Suppose that X has access only to S and that X has a standing offer to buy power from S at a definite price, say 4 cents. Then S knows it can make a 1-cent profit on each kilowatt-hour sold to X. If S has limited capacity and must choose between selling to B and selling to X, it will sell to B only if it can make a profit of 1 cent or more.

The fact that S can form a coalition with a party outside the three-player game is modeled by assigning a nonzero value to S "going it alone" in the three-player game. This situation is illustrated in figure 3-7(b). The full triangle represents the full gain from trade between S and B, which is 4 cents. For S to sell to B is the correct economic decision, assuming X's avoided cost is less than B's. But the presence of X constrains the core: S would not agree to any trade with B in which S gets less than one-fourth of the 4-cent gain, and so the shaded area in the figure is no longer part of the core. The range of economically feasible outcomes is more limited than before, and so the core is smaller. The new constrained core is the unshaded area in the figure. The presence of a second potential buyer makes it more a seller's market than a neutral market. B's bargaining power is reduced. The constrained core is not only smaller, but is shifted toward the S corner of the triangle.

Also, the market power of the wheeler is reduced. The wheeler can now bargain for at most three-quarters of the gains from trade; that is, the wheeling rate is now capped by indirect competition (as explained in chapter 2) at 3 cents per kilowatt-hour instead of 4 cents per kilowatt-hour.

The degree to which the core is constrained is determined by X's standard buying price. Figure 3-7(c) shows the core when X offers to buy at 6 cents. If X's avoided cost is 6 cents, the economically optimum decision is still for S to sell to B, even though S now gets three-fourths or more of the gains. If generation price regulation limits the price on

[19] By extension of the discussion in appendix A, one can see that the core of a four-player game is a tetrahedron, a four-sided solid pyramid with each side an equilateral triangle. As more players join the game, it is better not to try to draw the core but to define it with algebraic equations or numerical tables defining its boundaries.

an S-B sale (but somehow does not similarly limit the S-X price), the additional constraint imposed by regulation may prevent the parties from reaching the efficient result.

Figure 3-8(a) illustrates a very similar situation in which the buyer has an alternate power supplier, Z. The possibility of an "outside coalition" constrains the three-player core here also. Suppose Z has a standing offer to sell power at 6.2 cents, including a negligible transmission cost. Then B will not pay any more than 6.2 cents for the sum of S's selling price plus W's transmission price. B can get 1-cent profit, or 25 percent of the gain on its own. As a result, the core is constrained as in figure 3-8(b). Figure 3-8(c) illustrates the constrained core if Z's price drops to 4.2 cents. This is clearly a buyer's market, caused by seller competition. Again, the wheeler's market power is also limited.

The core is doubly constrained if there is both an alternate buyer and an alternate seller, as shown in figure 3-9(a). Depending on their buying and selling prices, the constrained core may exist, as in figure 3-9(b), or not, as in figure 3-9(c). In the first case, X's price is close enough to S's cost and Z's price is close enough to B's cost that the S-W-B transaction is still the best deal. In (b), the core exists for this grand coalition; the range of possible bargaining prices between S and B is smaller, however. The wheeler's maximum possible wheeling price is about half what it was before because of indirect competition. In the second case, shown in (c), S would not sell for less than 6 cents and B would not buy for more than 4.2 cents. Thus, there is no core. That is, there is no possibility of a voluntary {SWB} transaction at any price. (In this case, the result is not inefficient. The total gains from S-X trading and B-Z trading exceed the S-B trading gains. Because of the cost relationships, the result of approximating this five-player game as a three-player game with constraints illustrates only this one feature of the full result.)

Because of loop flow, assuming there is an alternate wheeler does not yield a similar result. Unlike perhaps any other market, who provides the service is unaffected by who wins the bid to provide the service. Consider an alternating current transmission system with four utilities interconnected as shown in figure 3-10. Y, like W for the present, is a company that provides only transmission service. For S to sell to B, either W or Y must agree to wheel. Regardless of which one agrees, the power divides up and flows through both W and Y in some proportion. A typical United States convention is that the wheeler carrying the greater

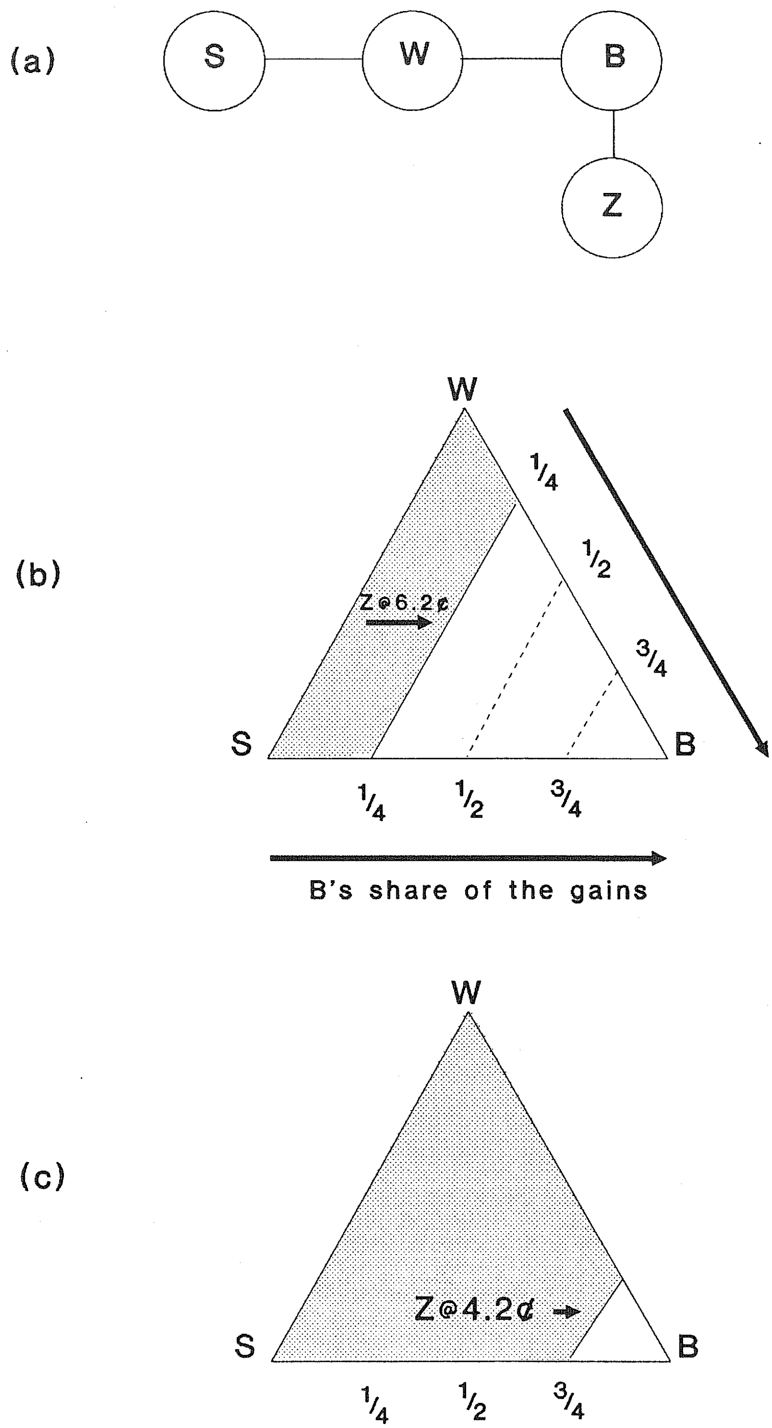


Fig. 3-8. Core constrained by a second seller.

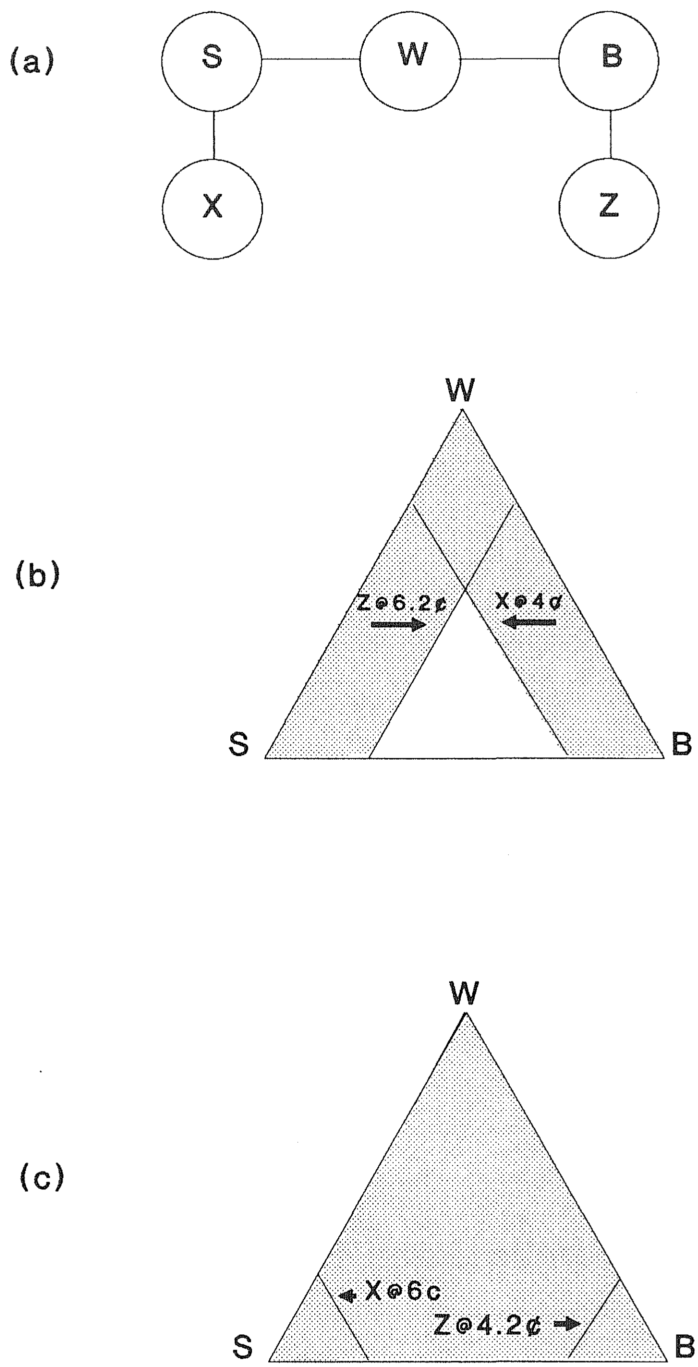


Fig. 3-9. Core constrained by a second buyer and a second seller.

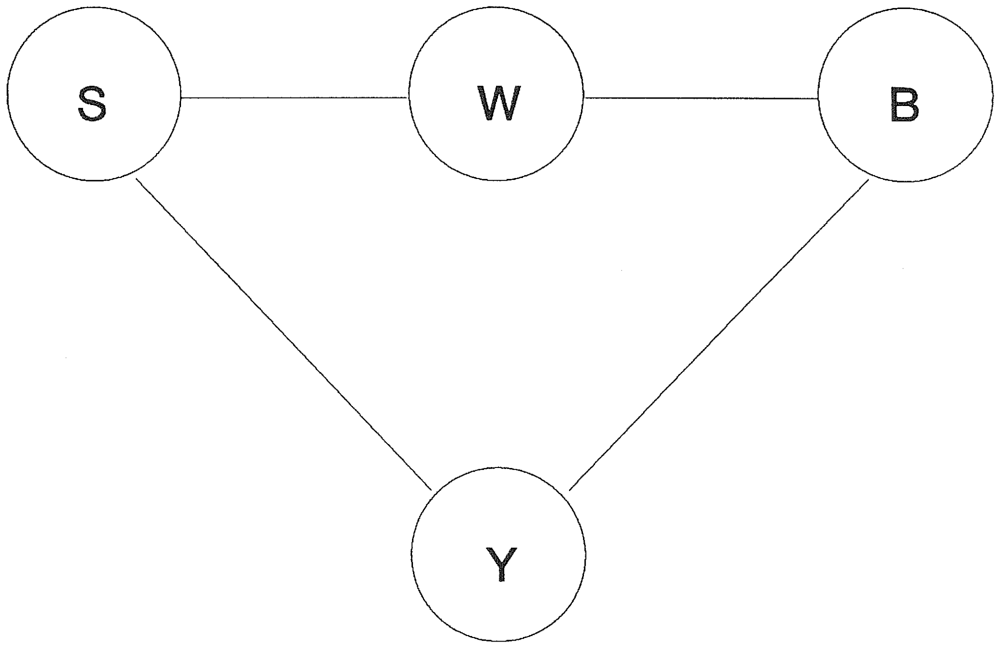


Fig. 3-10. Competition between two wheelers.

share should be the one to agree. But assume we ignore this convention and try to promote competition between W and Y to provide transmission service. As they bid against each other, the wheeling price is driven down to zero. This is because each bears a constant transmission loop flow cost regardless of which one wins the service bid and collects all the revenue. Since the cost is inescapable and any revenue is better than no revenue, each undercuts the other's previously bid price in turn until the bid price goes to nothing. Competition does not work efficiently.

This creates an incentive, of course, for W and Y to form a coalition, bargain together for a profitable wheeling rate, and devise a formula for sharing the gain. Then the coalition could be represented as a single wheeling player W in further analysis. The wheelers could accomplish much the same thing by appealing to regulators to arrange for technical reviews of wheeling requests, institute profitable wheeling rates, and provide compensation for loop flow.

Coalitions of Players

Apart from coalitions with outsiders, a player's alternatives in the three-player game are to go it alone, join the grand coalition {SWB}, or form a coalition with another player. Let us now recognize that W is itself a utility, which may affect the game as either a seller or buyer itself. If W were to have the lowest production cost ($C_W < C_S$ and $C_W < C_B$), the outcome is simple: if W cannot meet the demands of both S and B, it sells to the higher bidder, which is the one with the higher production cost to be avoided, C_S or C_B. If B's cost is higher, S is out of the game because it cannot block the bilateral W-B transaction, and the core is confined to the W-B side of the core triangle. This core is nevertheless constrained by S's production cost as S is a potential second buyer. This really is a two-player game with a constraint: the gain achievable by all three parties is no greater than that achievable by the pair W-B. Similarly, if W is the highest-cost producer and S and B each have enough extra generating capacity to displace W's high cost generation, W plays a two-player game to purchase power from S or B, whichever is the lower-cost producer.

The more interesting situation is one in which W's production cost is between S's and B's, with S's lower by definition. Here the gain achievable by a pair can be greater than zero but less than value of the grand coalition, V(SWB). Now, the three-party trade is the best outcome in that it satisfies all electric loads with the largest savings, but the values of various subcoalitions constrain the core. To keep it interesting, we must assume that production quantities are limited, otherwise we get the obvious result that S should satisfy all of W's and B's demands as well as its own.

Any pair of companies can form a coalition to bargain with the third company for a large share of the total gain. To be effective though, the coalition must have a value: it must be able to threaten to get some gain without the cooperation of the third company and leave the third company with nothing. The {SB} coalition has no bargaining power and is not effective. This coalition may attempt to insist on, say, 80 percent of the gain for itself, leaving W just 20 percent. But {SB} can do nothing without W's help, and W can easily ignore the threat.[20] The coalition {SB} cannot hold up because S and B have no more market power together than they have individually. In fact, it is easy for W to break up this coalition, for which V(SB) = 0, by offering to form the coalition {SW} with S or by suggesting the coalition {WB} to B, either of which may have real value.

The value of {SW} depends on W's production cost. Consider the costs as shown in figure 3-11(a). The production cost C is still 3 cents for S and 7.2 cents for B. Let us begin by assuming W's production cost is 6.1 cents. The transmission cost T is 0.1 cent from S to W, 0.1 cent from W to B, and 0.2 cent from S to B. S can sell to either W or B but does not have enough power for both. S selling to B produces the biggest savings (avoided cost less new expenses) per kilowatt-hour sold:

$$V(SWB) = 7.2¢ - 3¢ - 0.2¢ = 4¢,$$

whereas S selling to W results in smaller savings because B continues to self-generate at high cost:

$$V(SW) = 6.1¢ - 3¢ - 0.1¢ = 3¢.$$

Still, the savings are substantial for {SW}. S and W still want to form the grand coalition and save 4 cents, but they can insist that they get at

[20] However, S and B can threaten to seek to change the rules of the game, for example, by lobbying for mandatory wheeling; or they can threaten an antitrust action. These factors, which may make V(SB) > 0, are not included in this analysis.

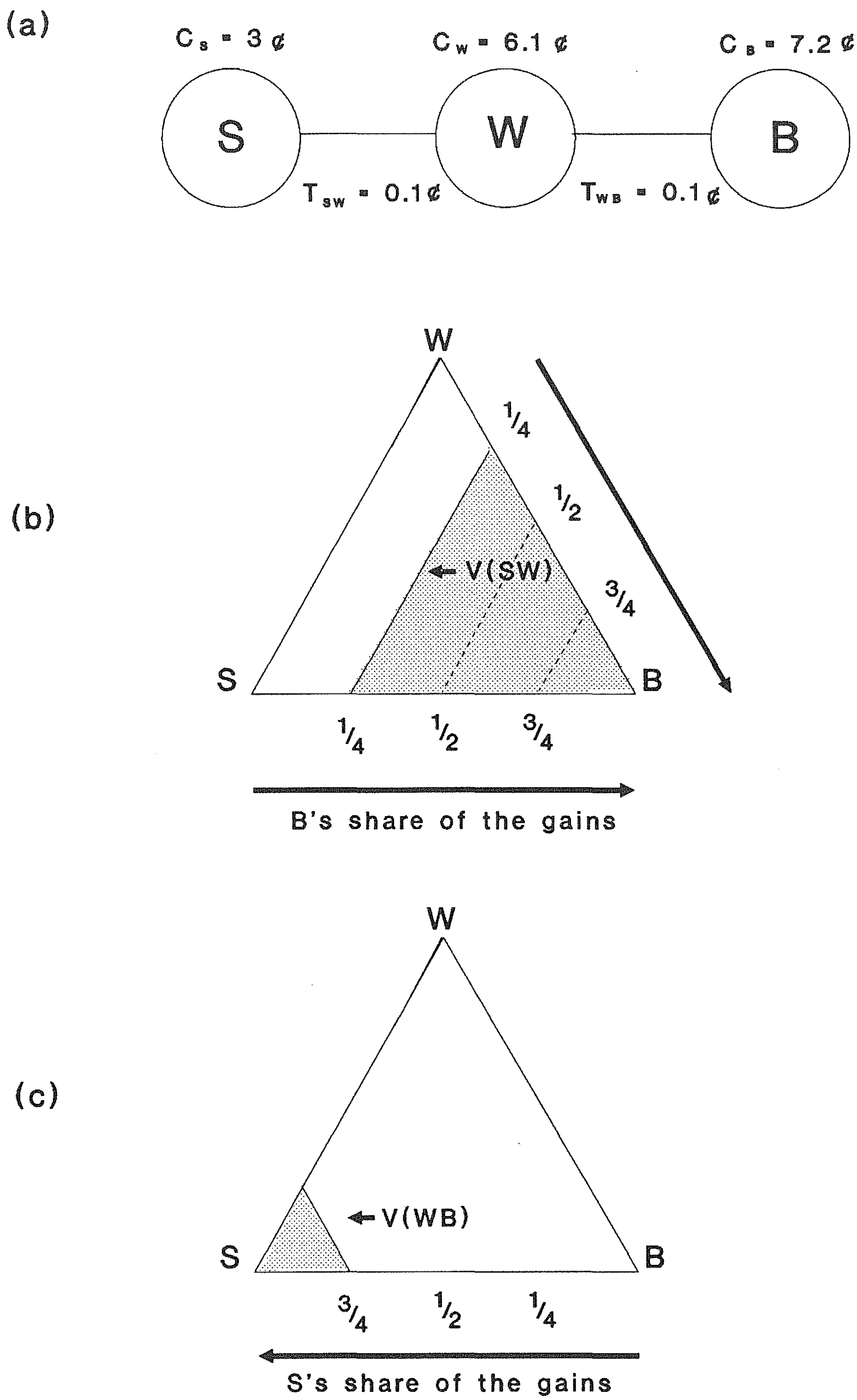


Fig. 3-11. Core constraints imposed by individual wheeler coalitions.

least 3 cents of this savings and can bargain for more. If B does not agree, S and W would trade bilaterally, share the 3 cents, and B gets nothing. B can bargain for anything up to a 1-cent share, which is one-fourth of the total gain, but no more. This is illustrated by the constrained core of figure 3-11(b). The only economically feasible divisions of the grand coalition's gain are those that lie in the unshaded region of the triangle, where B gets no more than a quarter of the gain. The {SW} coalition effectively limits B's bargaining power.

S's bargaining power is only slightly constrained by the {WB} coalition in this case. S's power price is limited because W can offer to displace B's expensive power. The value of the coalition per kilowatt-hour sold from W to B is

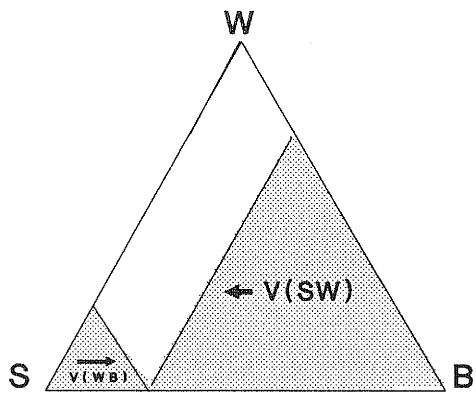
$$V(WB) = 7.2¢ - 6.1¢ - 0.1¢ = 1¢.$$

Since W and B acting alone can save 1 cent, they require at least a 1-cent share of the 4-cent {SWB} gain; that is, S can get at most 3 cents or three-quarters of the gain. Figure 3-11(c) shows this relatively small constraint on the core.

Both {SW} and {WB} constrain the core. The {SWB} transaction is the best and does occur. But absent price regulation, we cannot predict the selling price of the power or the transmission rate. However, we know not only that the transaction must be represented by a point inside the triangle, but also that B cannot get more than 1 cent and S cannot get more than 3 cents per kilowatt-hour. Hence the correct constrained core for the situation in figure 3-11(a) is that shown in figure 3-12(a). This is the area of the triangle that remains unshaded after the constraints of figures 3-11(b) and (c) are added. These two constraints always intersect at the S-B baseline, unless generation or transmission capacity limitations prevent one of the constraints from being effective. This core represents a situation in which the seller's market power is greater than the buyer's because the unshaded area lies more to the seller's side of the triangle. However, the wheeler's bargaining power is unaffected: it is still possible for the wheeler to get any share of the gain from 0 to 100 percent.

In this example, W's relatively high production cost gives it stronger buyer than seller characteristics. This results in a seller's market. A buyer's market results if W is a more competitive seller. The case where the wheeler's production cost is 4.1 cents per kilowatt-hour is illustrated in figure 3-12(b). That the unshaded region is predominantly on the right

(a)



(b)

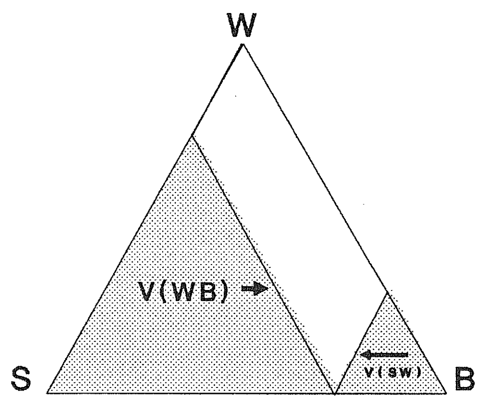


Fig. 3-12. Constrained core by (a) high and (b) low wheeler production costs.

characterizes a buyer's market. The wheeler in this case is more a seller than a buyer.

Notice that if W's production cost falls to 3.1 cents the core disappears. S loses all bargaining power, and a simple bilateral trade between W and B should occur. Similarly, B loses all bargaining power if the wheeler's cost rises to 7.1 cents, at which point W wants to buy all of S's available generation.

Core Constraints: A Summary

The core of a transmission market game reflects the character of the market and signifies who has market power. The size and shape of the core are affected by three factors that constrain the core:

(i) the capacities, demands, production costs, and transmission costs of the three players S, W, and B: these set economic constraints on generation and transmission prices;

(ii) wholesale generation pricing laws and regulations: these may specify or constrain the generation price; we assume that no obligation to provide wholesale generation service exists;

(iii) transmission access and pricing laws and regulations: these too may specify or constrain the transmission price; they may also mandate transmission service.

In the next two chapters, the effects of various transmission regulations on the size and shape of the core are examined to see how these regulations would affect bulk power markets. Because the core is affected by all three factors above, it is necessary to examine the effects of transmission policies under a variety of economic conditions and with several forms of generation price regulation.

CHAPTER 4

ACCESS AND PRICING POLICIES FOR NONFIRM TRANSMISSION SERVICE

In this chapter we examine the near-term effects of several models of access and price regulation for nonfirm transmission service. Some longer-term effects of nonfirm policies are considered in chapter 6. Equations representing the nonfirm models are introduced and are presented to specify the models precisely and also to permit construction of core triangles that clearly display the results. They are relatively easy to follow, and many policy analysts would want to do so. However, the reader can also read the chapter, skipping over the equations, without great loss or can go directly to the findings. But a large part of the value of the analysis lies in the understanding of market strategies one gets by going through the scenarios in detail--something no summary can capture.

The analysis considers the effects of various nonfirm access and pricing policies on electric production efficiency and on the allocation of the gains from trade. Sensitivity analyses are undertaken and discussed.

Nonfirm and Firm Services

In this chapter we examine access and pricing policies for nonfirm transmission; in the next chapter, for firm transmission. As discussed in chapter 2, there is no universally accepted meaning of these terms. "Firm" usually means that service needed to avoid customer outages is provided at a high level of priority and is not to be interrupted for an economic reason. Firm service interruption must be due to an unavoidable engineering constraint. "Nonfirm" means lower priority, usually because higher-cost local generation is available if needed to replace lower-cost purchased power. Nonfirm power is often called economy power, coordination service, interruptible service, or as-available service.

Firm power and firm transmission service are frequently provided for a long time, years and in many cases decades. Thus, firm power choices often involve long-run power supply decisions. Such decisions include questions of new generating unit and new transmission facility construction. There are, however, some short-term firm power supply contracts involving, for example, replacement power for a nuclear unit being refueled. Nevertheless, we assume in chapter 5 that "firm" means "long-run," and we examine the effects of firm policies on production efficiency in the long-run. Hence, chapter 5 deals with optimal expansion of the generation and transmission system.

Here in chapter 4 all analyses are short-run. It is assumed that all transactions occur in a timeframe too short to influence generation capacity expansion decisions or transmission facility construction decisions. While nonfirm is usually short-term, the service we labeled nonfirm for the PG&E model in chapter 2 can be up to fifteen years duration.

This division of transactions into short-run nonfirm and long-run firm omits one potentially important class of transaction, which might be labeled long-run nonfirm. Conventional wisdom holds that utilities do not construct transmission for nonfirm service: it is built either for firm service or for reliability. Extra transmission capacity constructed for reliability can be used for nonfirm service because such service can be interrupted if the capacity is needed for a reliability reason.

Nonfirm transmission service has been unprofitable for utilities, however, because of regulation. It is important to consider how a company's business strategy would change if nonfirm service were loosely regulated or deregulated. The construction of transmission facilities for profit in the nonfirm transmission service market is the subject of chapter 6.

In today's policy debate, long-term firm transmission service is the focus of attention, and short-term nonfirm service receives little consideration. This is because competitive bidding for new firm power supplies is currently of great concern and hence the availability and cost of long-term firm transmission service is being examined by power suppliers and buyers as well as policy makers. Most of these suppliers and buyers are not the larger investor-owned utilities, who frequently engage in short-term nonfirm trading. The view seems to be that firm transmission policy reform is needed to protect "the little guy," and that nonfirm policy need not be of great concern because "the big guys" can take care of themselves.

Despite this view, both types of services are important. Since 1945, firm sales for resale have been a relatively constant percentage of the amount of power generated in the United States: each year about 15 to 20 percent of generation has been sold as firm wholesale power. Economy interchanges have grown steadily, from 5 to 7 percent of United States generation in the 1945-1950 period to 22 to 24 percent in the mid-1980s.[1]

Whether it will continue to grow further is uncertain, but even at present levels the practice of nonfirm economy interchanges yields great savings in national electricity production costs, suggesting that nonfirm transmission access and pricing policy reform deserves serious attention in its own right, not just as the residual of the firm policy. Several large utilities are proposing a trade-off, greater freedom from regulation in the nonfirm generation and transmission market in return for assuming an obligation to provide transmission service in the firm market. It is thus important to examine the possible effects of relaxed regulation--or even deregulation--of nonfirm service.

Besides being important in its own right, the nonfirm analysis serves as a good introduction to the firm analysis. It is easy to envision a short-run spot market in nonfirm power, and we introduce next concepts, symbols, and equations for examining such a market. This introduces the analysis in chapter 5, in which the long-run market is modeled in a very similar way.

Specification of the Model

Figure 4-1 displays the configuration of utilities that is modeled. The solid lines show the configuration considered in all analyses. The dashed lines indicate possible alternative configurations, which are considered later in the sensitivity analyses. Firms X, Y, and Z are not explicitly modeled as players in the game; rather, they represent any potential external market that the S, W, or B can participate in. X is a potential buyer of S's power (at a fixed, assumed price P_x), Y is a potential buyer of W's power or a potential seller to W (at price P_y), and Z is a potential seller to B (at price P_z). To simplify the analysis, it is assumed that if S, W, or B forms a coalition with an external market,

[1] Authors' calculations based on data from U.S. Department of Energy, Energy Information Adminstration, *Interutility Bulk Power Transactions: Description, Economics, and Data*, DOE/EIA-0418 (Washington, D.C.: U.S. Government Printing Office, 1983), 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), 34.

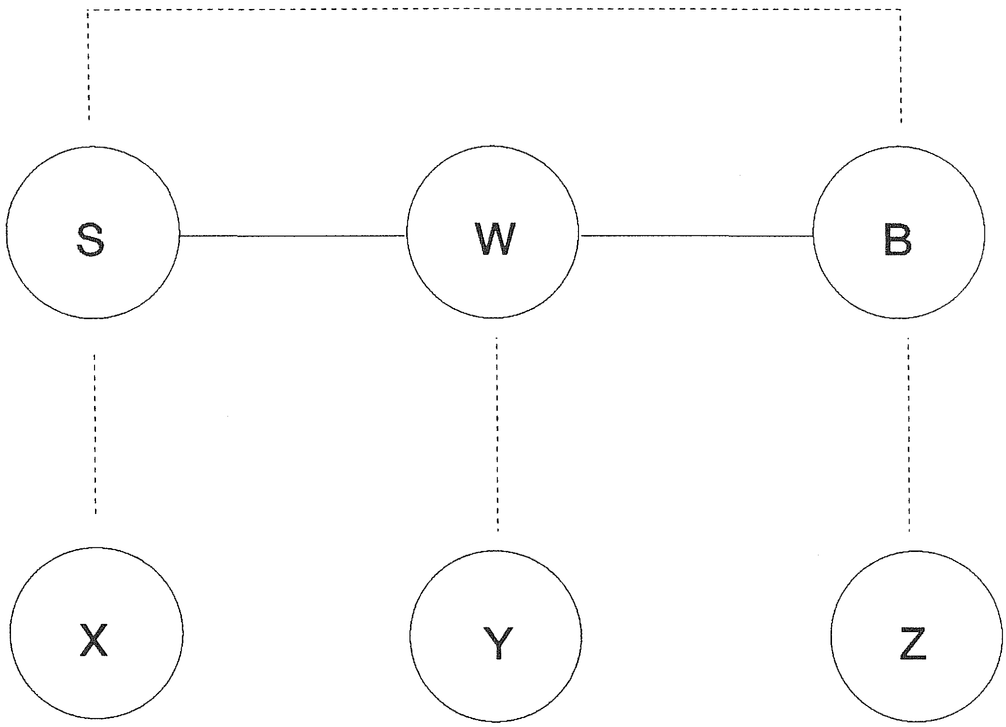


Fig. 4-1. Configuration of utilities in this analysis.

then that coalition excludes the other two players. For example, {WY} excludes S and B.

The remainder of this chapter is organized as follows. First, we examine how the simple seller-wheeler-buyer (S-W-B) system works under historical/current regulation, the Status Quo, and compare the results with what would happen under complete deregulation. As part of this, we consider systems having more complex configurations, including the existence of other markets, that is, other places for S to sell, W to buy or sell, or B to buy; the existence of multiple sellers and/or buyers; and the existence of an alternative, but more expensive S-to-B transmission route. Then, we summarize the assumptions and look at the short-run results for four other access and pricing models. Finally, an application of the methods to an actual system of eight utilities is discussed.

Access and Pricing Policies

Counting the Status Quo as a model, five transmission pricing models are considered:

1. Status Quo--voluntary access with cost-based pricing for both firm and nonfirm transactions
2. Planning Model--mandatory access with cost-based pricing (not necessarily embedded costs) for both firm and nonfirm transactions
3. Contract Model 1--the wheeler takes on an obligation to provide firm service at cost-based rates in return for nonfirm transmission pricing flexibility and perhaps also nonfirm generation pricing flexibility; flexible pricing for nonfirm transactions; incremental cost pricing for firm transactions
4. Contract Model 2--voluntary access with flexible pricing for both firm and nonfirm transactions; firm transmission is provided with a cost-based cap to other control-area utilities, in return for flexible (market-based) nonfirm--and perhaps firm--generation pricing; there are firm pricing options (discussed in chapter 5)
5. NRRI Model--mandatory access; the customer can choose either firm or nonfirm service for any transmission need; long-run marginal cost-based pricing for firm transactions; short-run marginal cost pricing for nonfirm transactions.

The effects of the transmission policies can depend on the prevailing policy for pricing generation sales. In all our analyses of nonfirm power purchases, we often consider the case where the generation price is set at marginal cost (system lambda). However, two other pricing mechanisms are considered for generation where they result in different patterns of production:

1. Split savings: the price is half-way between the seller's and buyer's marginal costs, and
2. Flexible pricing: in order to outbid a rival, a provider of power agrees to sell power at less than the split-savings price, or a buyer, for like reasons, agrees to pay more than the split-savings price.

These two pricing approaches potentially yield different production patterns only when mandatory access promotes bad wheeling (wheeling that increases total production costs). What can occur then is that W outbids a rival in order to prevent bad wheeling. Even if production patterns are unaffected by flexible pricing, the distribution of gains would, in most cases, be altered.

For each transmission pricing model, the strategies available to each player are summarized in the analysis that follows, and the probable solution (or solutions) to the "game" is set out. Then, the following questions are asked:

- Is all good wheeling likely to occur? "Good wheeling" is defined as that which lowers production costs for the entire system.
- Can bad wheeling occur? "Bad wheeling" is defined as that which raises production costs compared to the least-cost generation and transmission solution.
- What is the distribution of the gains among the seller, wheeler, and buyer? The gains are measured relative to a "no trading" base. The distribution of gains is also compared to the distribution that would occur under marginal-cost pricing of both generation and transmission (a benchmark for allocative efficiency).

The terms "good wheeling" and "bad wheeling" are defined more specifically below, as needed.

Simple Short-Run S-W-B System

The model parameters (upper case) and decision variables (lower case) are defined as follows:

A = Fraction of split savings between S and B that is paid to W as a wheeling fee

i = S, W, or B

C_i = Short-run production cost (\$/MWh) of power for player i (that is, C_S is the system lambda for the seller S; C_W is the lambda of the potential wheeler W; and C_B is B's lambda)

D_i = Quantity of electricity demanded (MWh/unit time) for player i (load)

F_{ij} = Regulated wheeling fee (\$/MWh), based on embedded or incremental cost (depending on the model), for transmission from player i to j. It is collected by W if i=W or j=W.

Q_i = Generation capacity (MW) of the marginal power plant for player i

q_i = Actual production by player i

T_{ij} = Actual cost of transmission from player i to j (assumed to be borne by W if i=W or j=W)

Y_{ij} = Transmission capacity (MW) of the tie line between players i and j

y_{ij} = Actual transfer of power from i to j

A basic assumption is that:

$$C_S + T_{SW} + T_{WB} < C_W + T_{WB} < C_B; \quad Q_S > D_S.$$

Otherwise, wheeling from S to B may not be economic. Some situations involving uneconomic wheeling are considered in later analyses. It may happen that B wants to buy power from S where W's production cost is greater than B's (or lower than S's due to capacity constraints). Such situations arise in appendix B. (Depending on capacity constraints, wheeling can take place with $C_S + T_{SW} + T_{WB} < C_B < C_W$ if $Q_S - D_S > D_W + D_B$. It is assumed that wheeling cannot take place from S to W via B.)

Another basic assumption is that $Q_S > D_S$; that is, S has extra generating capacity. We assume also that the buyer has enough capacity to meet its own needs if it must ($Q_B \geq D_B$). As a base case, we also assume that, in the short run, transmission capacity is sufficient to transmit any power that B would want to buy from S. That is, Y_{SW} and Y_{WB} do not constrain wheeling in this first analysis.

The maximum possible "good wheeling" occurs if the least expensive pattern of production $\{q_i^*, y_{ij}^*\}$ results. That is, each party produces and transfers the "right amount" of power to minimize aggregate production costs. The asterisks denote optimality. This is the "least cost dispatch" solution for the group of utility players considered. The actual amount of wheeling is defined as $\mathrm{MIN}(y_{SW}^*, y_{WB}^*)$, which might be zero. (The notation MIN(A,B) means the lesser of A and B.) Here, "wheeling" is used in a general sense to include any arrangement for transmitting power; hence if the "wheeler" W buys power from S and resells it to B, this is a form of "wheeling" that may yield W a high "wheeling fee." We call this simultaneous buy/sell and sometimes refer to it by the acronym SBS. The SBS transaction is not called "wheeling" in the industry because W owns the power at one point. For example, if 200 MW flows from S to W and 100 MW flows from W to B, we conclude that 100 MW is "wheeled" from S to B by W, regardless of whether this is legally a wheeling transaction, an SBS transaction, or some combination of the two.

Good wheeling occurs if

$$\mathrm{MIN}(y_{SW}, y_{WB}) > 0$$

and $C_S + T_{SW} + T_{WB} < C_W + T_{WB} < C_B$.

Good wheeling can also occur if $C_W + T_{WB}$ is larger than C_B, as long as W's potential demand for S's power is filled first. Similarly, good wheeling can occur if $C_W + T_{WB}$ violates the left inequality, as long as W already has sold all it can to B.

Bad wheeling, on the other hand, occurs if

$$\mathrm{MIN}(y_{SW}, y_{WB}) > 0$$

and either:

$C_S + T_{SW} + T_{WB} > C_B$, or

$C_W + T_{WB} > C_B$ and W's potential demand for S's power is not filled, or

$C_S + T_{SW} + T_{WB} > C_W + T_{WB}$ and W's potential for selling power to B is not filled.

Other types of bad wheeling may be possible, but are not considered here.

Status Quo versus Deregulation

We begin by examining the effects of existing access and pricing rules for nonfirm transmissions on bulk power market efficiency. Then we compare the results with the results if nonfirm transmission service were to be completely deregulated.

Status Quo

The Status Quo model for wheeling nonfirm power in the short run is reduced to these essentials:

- access is strictly voluntary
- pricing of generation sales between adjacent parties follows the 50:50 split-savings rule. For example, consider a sale from i to j. The expense per MWh to the receiving party j, including the cost of transmission, is $(C_i + C_j + T_{ij})/2$. (If transmission rates are regulated, the regulated price F_{ij} may be substituted for T_{ij}.) The price received by the seller, net of transmission costs (but <u>not</u> of generation costs), is $(C_i + C_j - T_{ij})/2$; that is, the cost of transmission has been deducted from the expense to the buyer.
- sales from S to B via W can occur in one of three ways:

  <u>Wheeling Price Structure 1</u>: simultaneous buy/sell ("SBS"), in which W buys from S quantity y_{SW} at a price based on the 50:50 split-savings rule (between the costs of S and W of generation, net of transmission costs), and at the same time W sells to B the amount y_{WB} at a price based on split-savings (between W's and B's generation costs, net of transmission costs). If y_{SW} equals y_{WB}, the entire transaction is a simultaneous buy/sell. If one is greater than the other, the lesser quantity is a simultaneous buy/sell, and the difference (the absolute value of $y_{SW} - y_{WB}$) is a simple bilateral trade between neighbors.

  <u>Wheeling Price Structure 2</u>: wheeling by W at a fixed rate or fee ("WhF"), in which W charges a wheeling fee F_{SB} (which we may sometimes express as the sum of two components, $F_{SW} + F_{WB}$) for wheeling of amount $\text{MIN}(y_{SW}, y_{WB})$ from S to B. The remaining bilateral sales (either $y_{SW}\text{-MIN}(y_{SW},y_{WB})$ or $y_{WB}\text{-MIN}(y_{SW},y_{WB})$) are priced using the 50:50 split-savings rule (net of the

transmission fee F_{ij}). W pays the actual cost of transmission T_{ij} in all cases.

Wheeling Price Structure 3: wheeling by W, in which W earns a fraction A (typically 10-15 percent) of the savings split between S and B ("WhS") for wheeling amount MIN(y_{SW}, y_{WB}). Any remaining bilateral sales are priced using the split-savings rule (using T_{ij} as the transmission cost charged).

In any particular scenario, it may be assumed that one, two, or all three of those cases are feasible, unless subject to a regulatory constraint. (For example, FERC may mandate wheeling price structure type 2 in a particular model.)

What strategies are open to each player in the "Status Quo" game? Each player can choose to form a coalition with any other willing player. The possible coalitions then are {S}, {W}, {B}, {SW}, {SB}, {WB}, {SWB} (and, in some scenarios, {SX}, {WY}, and {BZ}). Consistent with the concept of the core, it is assumed that any player or subgroup of players leaves the grand coalition if it would earn a higher profit by doing so.

The Status Quo model can now be summarized as follows. In it, access is voluntary and "wheeling" from S to B can occur in one of three ways:

1. Simultaneous Buy/Sell (SBS) by the wheeler (though this is not normally called "wheeling"),
2. Wheeling at a fixed fee F_{SWB}, not necessarily equal to the cost of wheeling, ("WhF"), and
3. Wheeling in which W earns a fixed fraction A of the savings split between S and B ("WhS").

Most of the analyses below do not differentiate between the WhF and WhS options. This is because the results are fundamentally the same if the price charged for wheeling bears no necessary relationship to the marginal wheeling cost. Hence, only the WhF results are discussed, unless a true difference between WhF and WhS does arise.

Strategies Available

The options available to each player in the nonfirm market are outlined below. The "go it alone" strategy, in which a player refuses to cooperate with the other players, is designated as the "null" strategy ϕ.

S: - Sell nonfirm power to accessible buyer who offers the highest price
- ϕ (do not sell nonfirm power to anyone)

B: - Buy nonfirm power from accessible seller who offers the lowest price
   - ϕ (self-generate and/or rely on firm power purchases; do not buy nonfirm power)

W: - SBS (unless prohibited by regulation)
   - WhF (WhS is not considered separately because the differences between it and WhF are not significant here.)
   - Buy from S and do not sell or wheel to B (that is, form the subcoalition {SW}).
   - Sell to B and do not cooperate with S (that is, form the subcoalition {WB}).
   - ϕ (do not buy from S, sell to B, or wheel from S to B)

We consider only the split-savings method of generation pricing here because flexible generation pricing does not alter the pattern of production (though the distribution of gains does change).

The questions addressed for each circumstance described next are:

(1) Does the core exist--that is, is the grand coalition {SWB} stable and does all economic wheeling take place?

(2) What fraction of the gains from trade accrue to W (which is a measure of W's market power)?

The effect of external markets (X, Y, or Z) is not yet considered. Neither is a direct link from S to B. It is assumed that $Q_S \geq D_S$ and $Q_B \geq D_B$.

It is also assumed that $Q_W > D_W$; that is, the wheeler has extra capacity it would like to sell to B. If that is not true, then simultaneous buy/sell would seem unlikely or may be prohibited, and the only options available to W are either to wheel or not using structure 2 or 3. In that case, the solution is simple: if the wheeling fees collected are greater than $T_{SW} + T_{WB}$, then W will agree. Otherwise, no core exists and "good wheeling" will not occur.

For all Status Quo cases, "bad" wheeling never takes place (that is, wheeling taking place when $C_S + T_{SW} + T_{WB} > C_B$). This is because W would never find such wheeling profitable (and thus would not voluntarily agree to it) under wheeling price structures 1 and 3 (split savings), while either S and B or W would veto wheeling under price structure 2 (depending on the relative size of T_{ij} and F_{ij}, the true cost and price of wheeling).

Regulation of Simultaneous Buy/Sell

Two regulatory situations regarding simultaneous buy/sell are examined. Under the Status Quo, a wheeler can refuse a request for voluntary wheeling at a low regulated rate and offer instead to accomplish the same physical transaction by buying low and selling high. The wheeler may do this if simultaneous buy/sell is permitted by regulation as an alternative to complying with a wheeling request. We also examine a single modification to the Status Quo in which SBS is not permitted after a wheeling request is made, even though the wheeler is not obligated to honor the wheeling request.

Simultaneous Buy/Sell Permitted. In this case, the core exists for the Status Quo game if $C_S + T_{SW} + T_{WB} < C_W + T_{WB} < C_B$. It is better for W to simultaneously buy/sell than to participate in one of the subcoalitions. Given this choice by W, it is better for S and B to participate in the simultaneous buy/sell than to go it alone.

If W can also choose to wheel at a fixed price F_{ij} (pricing structure 2), it always prefers to simultaneously buy/sell unless the wheeling fee is so much higher than the cost of wheeling that the wheeler gets more than half the total gain. Where $C_S < C_W < C_B$, this can be expressed as:

$$C_B - (C_S + F_{SW} + F_{WB}) \quad < \quad (F_{SW} + F_{WB}) - (T_{SW} + T_{WB})$$

[Gain to B and S from trade under structure 2] < [Gain to W = wheeling fee - wheeling cost]

A similar result obtains in comparing structure 3 to simultaneous buy/sell.

In this circumstance, the wheeler always gets at least half of the value of the grand coalition (strictly half, if simultaneous buy/sell is the pricing structure adopted).

Simultaneous Buy/Sell Not Permitted. In this case, the core exists only if W's profit is greater under pricing structure 2 (or 3, whichever is adopted) than under the subcoalition {SW} or {WB} where the profits are based on split savings. In the case of structure 2 (fixed fees F_{ij}), the core exists only if both of the following conditions hold:

$$(F_{SW} + F_{WB}) - (T_{SW} + T_{WB}) \quad > \quad [C_W - (C_S + T_{SW})]/2$$

[Profit to W from wheeling per MWh] [Gain per MWh to W in coalition {SW}]

$$(F_{SW} + F_{WB}) - (T_{SW} + T_{WB}) \quad > \quad [C_B - (C_W + T_{WB})]/2$$

[Profit to W from wheeling per MWh] [Gain per MWh to W in coalition {WB}]

Thus, W voluntarily wheels only if wheeling fees are substantially above the marginal cost of wheeling. This assumes that $y_{SW} = y_{WB}$ = the amount of power that would be wheeled in the grand coalition, and this is the same as the volume of sales in subcoalitions {SW} or {WB}. Somewhat more complex relationships hold if these conditions are relaxed, but the basic result is the same.

Summary of Status Quo Results

Does All Good Nonfirm Wheeling Take Place under the Status Quo? The answer depends on whether simultaneous buy/sell is permitted. It is assumed that cost conditions are such that good wheeling is possible.

If SBS is allowed, then economic wheeling always takes place. SBS is the solution, unless the difference between the wheeling revenue and the wheeling cost, $F_{SWB} - (T_{SW} + T_{WB})$, is greater than one-half the gain from trade (based upon the wheeling fee, $C_B - C_S - F_{SWB}$). In the latter case, W prefers WhF, wheeling at a fixed price.

If, however, *SBS is not allowed*, then the core exists only if W's profit under WhF is greater than that under either of the subcoalitions {SW} and {WB}. These conditions are discussed earlier above: if there are gains achievable by W in bilateral trading with S or W, W's wheeling profit would have to be substantially above the marginal cost of transmitting power to induce wheeling. Thus, it seems unlikely that all good wheeling would take place in that case. (This assumes, of course, that S's low-cost generating capacity is limited.)

Does Bad Nonfirm Wheeling Take Place under the Status Quo? The answer is no, basically because all deals are voluntary. This conclusion presumes that bad wheeling is uneconomic (would increase production costs) and consent is impossible to obtain under the Status Quo if a deal would lower total benefits (losers would not be compensated by winners).

What Is the Distribution of Nonfirm Market Gains under the Status Quo? If SBS is the solution, then, for the simplest cases (no binding transmission constraints and S having just enough capacity to meet all of B's need), W gets half of the gains from trade. The closer W's production cost is to B's (than to S's), the more of the remaining gains accrue to S.

If W voluntarily chooses WhF instead, then this is because W earns more than half the gains in that solution.

Under the simple capacity conditions just described, a prohibition of SBS, causing either {SW} or {WB} to form, causes W to get 0.25 to 0.5 of the total potential (but partially unrealized) gain, with the other party in the subcoalition getting an equal amount. W gets almost half the gain if its own production cost is very close to that of S or B; it gets about a quarter if its cost is about midway between S's and B's costs. The excluded party gets nothing. (This assumes that the actual or implicit transmission fee compensates each party for the actual transmission cost. We normally do not think of bilateral trades as having a transmission cost, but of course there are at least some line losses.)

Deregulation

Before examining specific new models for the regulation of transmission access and pricing, let us see what happens if we assume there are no regulatory restrictions on what prices wheelers or sellers of bulk power can charge. The game can then be analyzed using the unconstrained core. We can compare the result with the results under the current system of regulation, the Status Quo.

A very general result is that, for the game involving S, W, and B (but not yet X, Y, and Z in figure 4-1), the core always exists if there are gains from trade. This is true even if S is directly connected to B. It is true for any values of transmission costs and capacity, generation costs and capacity, and demand. The result follows from the linearity of the cost structure and the assumption that subcoalitions are not affected by the actions of parties outside the subcoalition (that is, there exist no "externalities"). Indeed, this result applies to games involving any number of parties, as long as the grand coalition is defined as including all parties.

However, for nonlinear conditions (for example, quadratic line losses) or where externalities exist (for example, loop flows), this result may or may not hold. But transmission losses are usually small relative to the potential gains from trade, so that if loop flows are not a major factor, we can be confident that a core exists. Thus, at least some acceptable way of sharing the gain should be available that leaves no subcoalition "significantly" worse off than acting alone.

Results for Changing Parameters

Next we present some examples of numerical results and conclusions derived from sensitivity analyses, in which we consider how the results change as the values of the important parameters change. These results are for both the Status Quo model and the complete deregulation model with the core unrestricted by any access or price regulation.

Unless otherwise stated, the results of all sensitivity analyses are compared to the "Base Case" results of Case 1, below.

Case 1: Base Case

Figure 4-2 shows the core of the complete deregulation game and points corresponding to various solutions of the Status Quo game for a base set of assumptions. This figure uses the notation for pricing constraints developed at the end of chapter 3. The core has this symmetrical shape under the following highly restrictive assumptions:[2]

$$C_S + T_{SW} - C_W = C_W + T_{WB} - C_B \ ,$$

$$Q_W - D_W \geq Q_S - D_S = D_W = D_B \leq Y_{SW},\ Y_{WB} \ , \text{ and}$$

$$Y_{SB} = 0 \ .$$

S has just enough extra capacity to serve W or B with none remaining. W also has enough extra capacity to serve B. Transmission capacities do not constrain anyone. In later cases, we consider more general conditions.

The Shapley value ("SV") equals the nucleolus (not shown). (These terms are introduced in chapter 3.) Both are coincident with the simultaneous buy/sell solution ("SBS") in the Base Case. W gets half of the gains from the grand coalition.

Comparing point K (for equally shared returns to W and B under coalition {WB}) to point SBS, we see that W's welfare improves by wheeling, while B's is left unchanged. (Note that SBS and K are on a line parallel to the SW side of the triangle.) A similar conclusion results from comparing point L (S and W's equal returns under {SW}) with SBS; S is no better off under wheeling, but W's position is much improved. Therefore, if S (or B, as the case may be) is already trading with W, S (or B) reaps no additional gain from wheeling. S (or B) has no incentive in that case to force W to wheel. (Of course, a very different conclusion results if

[2] It can also be symmetrical under less restrictive assumptions.

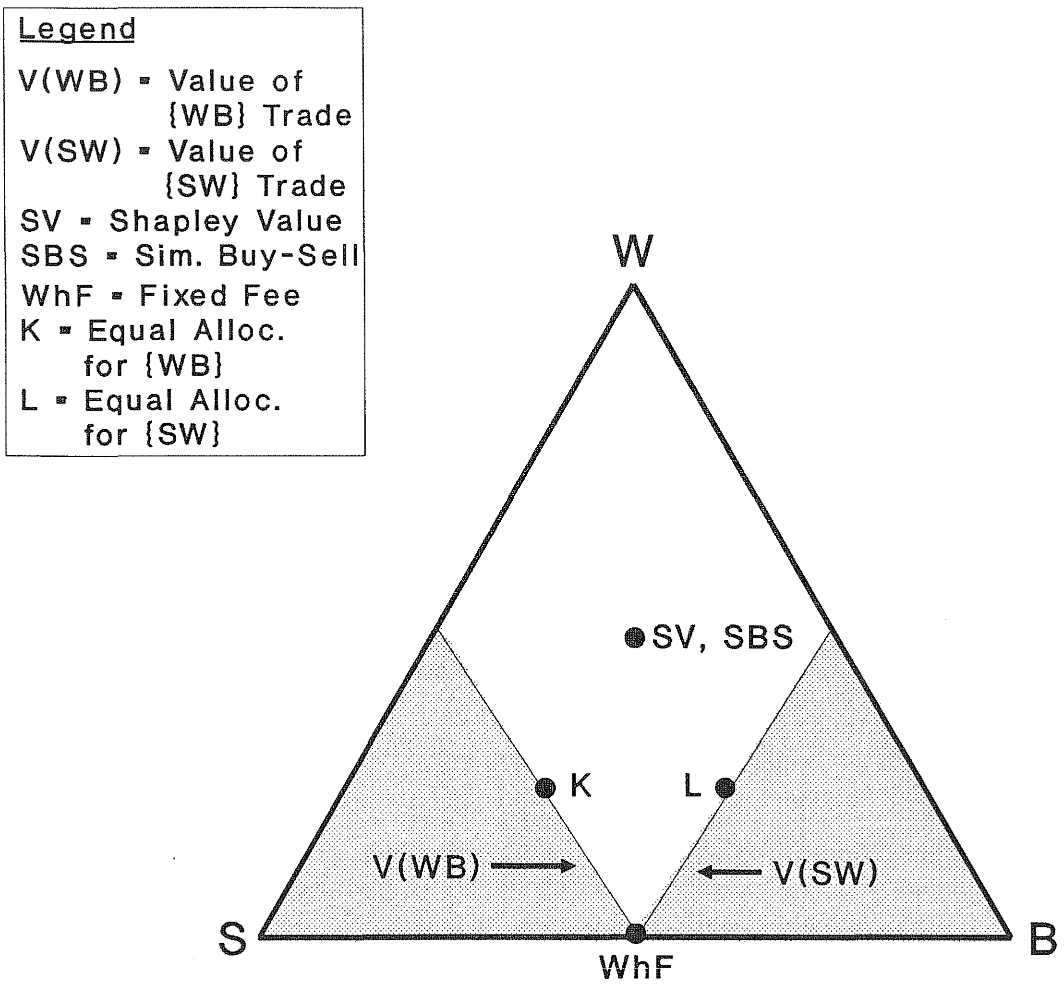


Fig. 4-2. Base case core under deregulation of nonfirm generation and transmission prices.

SBS is not an option to W and wheeling takes place at a fixed fee. In figure 4-2, the WhF point is located for marginal-cost pricing of wheeling in this Base Case. Unless F_{ij} is much greater than T_{ij}, both B and S are made better off by wheeling under pricing structure 2. A similar conclusion applies under price structure 3.)

If $F_{ij} = T_{ij}$, then the wheeling solution (structure 2, point "WhF") is coincident with the baseline of the core, and W earns none of the gains from trade and thus has no market power. Note that W's profit at this point is lower than at the points labeled K and L, which show W's and B's equal sharing of returns under coalition {WB} and S's and W's similar returns under coalition {SW}, respectively. Thus, under the Status Quo model, W would choose not to wheel if price structure 2 is the only option. As F_{ij} increases from T_{ij}, point WhF moves up toward the center of the core. If simultaneous buy/sell is not allowed, the grand coalition does not become attractive for W until the point WhF moves higher in the triangle than both points K and L, W's gains under the subcoalitions; then W obtains at least half the gain it would have gotten under SBS.

Similar results hold for the case in which wheeling solution 3 is the only one permitted.

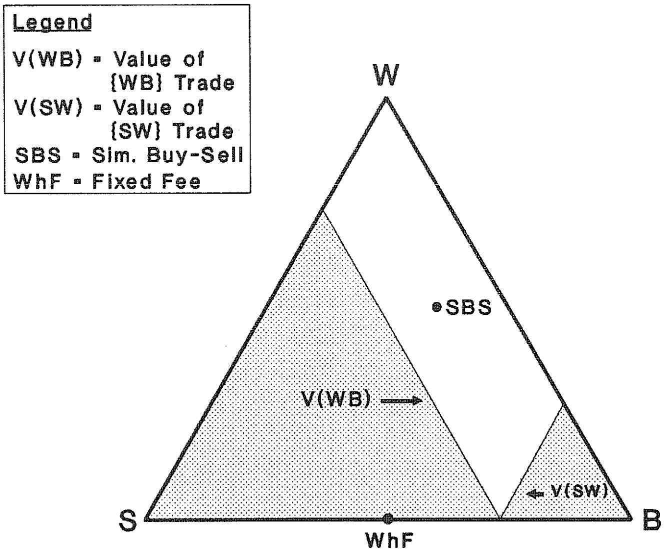
Case 2: Variations in Generation or Transmission Costs

Changes in generation costs C_i or transmission costs T_{ij} affect the shape of the core by shifting it either (1) towards B, increasing B's market power if C_S, C_B, or T_{SW} increases, as shown in figure 4-3(a), or (2) towards S, increasing S's market power if C_W or T_{WB} increases, as shown in figure 4-3(b). The relative market power of W does not change under the unregulated system (in terms of the proportion of the gains from trade it can obtain under SBS). However, its gain in dollars may be more or less. The core's shape shows only the relative gains.

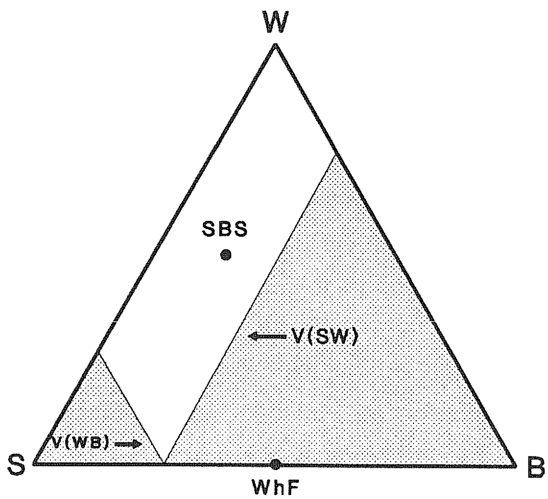
In all these solutions, the nucleolus, Shapley Value, and SBS points remain coincident (at the center of the constrained core) unless costs change so much as to violate the constraint that

$$C_S + T_{SW} + T_{WB} < C_W + T_{WB} < C_B \ .$$

However, WhF stays fixed in the center of the S-B baseline if $T_{ij} = F_{ij}$; that is, the wheeler never gets any of the gains from trade, which are instead split between S and B. If C_W falls so far that it becomes economic



(a)



(b)

Fig. 4-3. Nonfirm deregulation core with market conditions favoring (a) the buyer and (b) the seller.

to ship from W to S, the Shapley value may not be in the core and is not coincident with SBS and the nucleolus.

Case 3: Variations in the Wheeling Fee or the Profit Share

If the wheeling fee F_{ij} is more than the cost T_{ij}, the WhF point shifts. For any value of transmission and generation capacities, an increase in F_{ij} moves the WhF point up toward the W corner of the triangle. That is, the wheeler gets some of the gains.

Similarly, as the portion A of the split savings that the wheeler gains under price structure 3 increases, point WhS becomes more attractive to W as it moves toward the W corner. At A = 0.5, points SBS and WhS become coincident (if either T_{ij} is negligibly small or A is the share of the gain after accounting for transmission costs.)

However, if $F_{ij} < T_{ij}$, then WhF actually falls outside the core triangle: W is worse off than being by itself. (This assumes that $Q_S - D_S = Q_W - D_W = D_W = D_B$ and that there are no transmission capacity constraints. In more general circumstances, WhF may even be inside the triangle and perhaps the constrained core as the gains to W from bilateral trading with S or B add to any wheeling gains or losses.)

Case 4: Changes in Generation or Transmission Capacity

Lowering the seller's generation capacity Q_S or its tie-line capacity Y_{SW} is equivalent to lowering C_S or increasing C_W or T_{WB}, in terms of its effect on the shape of the core and the location of the SBS solution, the Shapley value, and the nucleolus. The Shapley value, nucleolus, and SBS solutions remain coincident in the center of the constrained core. However, the WhF and WhS solutions are shifted into the interior of the triangle, since in the grand coalition W now has a residual split-savings relationship with either S or B. If $T_{ij} = F_{ij}$, WhF lies on the boundary of the constrained core on the constraint resulting from the value of the coalition {WB}, denoted V(WB). If the profit share A just covers the cost of transmission, WhS also lies on that constraint.

Lowering transmission capacity Y_{WB} is equivalent to increasing C_S, C_B, or T_{SW} in terms of its impact on the location of the constrained core, the SBS solution, the Shapley value, and the nucleolus. The WhF and WhS solutions, however, are now in the interior of the triangle, on the constraint resulting from V(SW) because of the value to W of the bilateral

S-W trades that occur as a result of insufficient transmission capacity from W to B. WhF lies on this constraint line if $T_{ij} = F_{ij}$, and WhS lies on it if A just covers the cost of transmission.

Lowering both Y_{SW} and Y_{WB} simultaneously leaves the relative location of the constrained core and the various points unaffected. However, the total gain available to the parties is smaller.

Odder things happen as the wheeler's generating capacity Q_W changes. If Q_W is lowered, the size of the constrained core expands, as shown in figure 4-4, compared to its size in the Base Case of figure 4-2. S gains (relative) market power at the expense of W and B. This happens because the value of the coalition {WB} falls, due to W's reduced capacity to serve as an alternate seller. Now the nucleolus, Shapley value, and SBS points are distinct.

If there is an alternate direct route from S to B (Y_{SB} becomes positive) and if direct sales from S to B are economic, then an additional constraint is added to the core, denoted V(SB) in figure 4-5. The Shapley value is no longer coincident with SBS; the former is worse for W. The larger the value of Y_{SB}, the smaller the constrained core becomes and the less is W's market power. Increases in the direct route's cost T_{SB} have the opposite effect.

Case 5: External Market Opportunities

External markets, represented by X, Y, and Z in figure 4-1, increase the market power of the player involved by putting a tighter lower bound on the absolute gains.

Figure 4-6 shows the effect of setting P_X (the price X would pay for S's power) at $0.25(C_B - C_S - T_{SW} - T_{WB}) + C_S$. S would have to earn a gain of at least $0.25(C_B - C_S - T_{SW} - T_{WB})$ in order to make it worthwhile to participate in the grand coalition, instead of selling to X, an action that has a value to S that we denote as V(S). This is chosen to be identical to S's gain from SBS (that is, SBS is on the V(S) constraint) or from participating in {SW} under the Base Case assumptions, denoted by point L in figure 4-6. If P_X is higher than $0.25(C_B - C_S - T_{SW} - T_{WB}) + C_S$, S rejects the SBS solution. W's market power is mitigated somewhat. Therefore, if W wants to preserve the grand coalition, it has to accept a lower share of the gains (perhaps by shifting to pricing structure 3 with a value of A less than 0.5). If this is not possible, then "good wheeling"

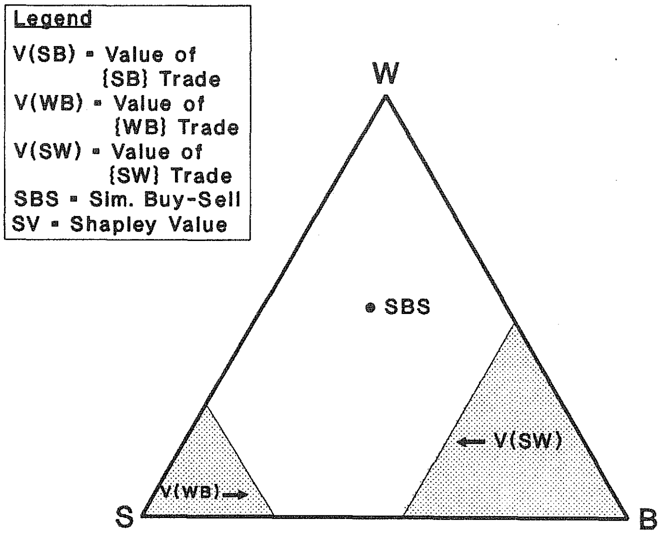


Fig. 4-4. Nonfirm deregulation core with the wheeler having little capacity for sale.

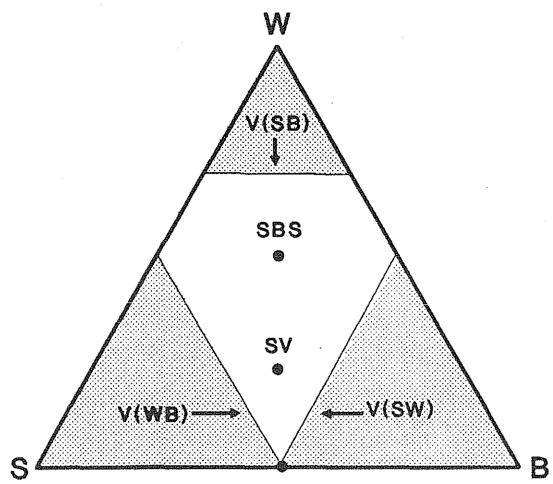


Fig. 4-5. Nonfirm deregulation core where there is an alternate wheeling path.

may not occur. Here, the Shapley value is no longer coincident with either the nucleolus or point SBS.

Of course, if P_X is the result of a split-savings policy, then overall social welfare may be maximized by forming two distinct coalitions: {SX} and {WB}. However, if P_X just equals the marginal benefit to X of buying power from S, then formation of these two coalitions would prevent "good wheeling" and social welfare would be lower.

If B has market Z available where it can buy power at price P_Z, an analogous result occurs, as shown in figure 4-7. Having Z gives B the value V(B) for "going it alone" with respect to players S and W. Again, W's market power is mitigated, and it is possible for a player (in this case, B) to reject the SBS solution if P_Z is low enough. This vetoing of the grand coalition {SWB} may be good or bad, depending on the relationship of P_Z to the actual marginal cost of Z providing power.

On the other hand, if W has an external market Y available to it (either for buying power at $P_Y < C_W$ or selling power at $P_Y > C_W$), then W's market power increases (in terms of the minimum value of the gain it receives).

Other Access and Pricing Models

We now consider new ways of regulating transmission access and pricing. For brevity, we select for analysis one generic Planning-type model, two Contract-type models, and the NRRI proposal. (These terms are explained in chapter 2.) As in the analysis above, i stands for S, W, or B; C_i is the incremental (or decremental) short-run production cost (system λ) for player i; the Q_i are their generation capacities; and the D_i are their demands (system loads). T_{SW} is the short-run marginal transmission cost from S to W, and T_{WB} is that from W to B. Y_{SW} and Y_{WB} are the capacities of those two lines. Let F_{SWB} be the wheeling fee charged for wheeling from S to B via W; this can be divided (as before) into two portions, F_{SW} and F_{WB}. These are all "given" factors not under the players' control.

Factors that the players can decide are "decision variables." The decision variable q_i represents the actual generation of party i, and y_{ij} represents the amount of power transmitted from i to j.

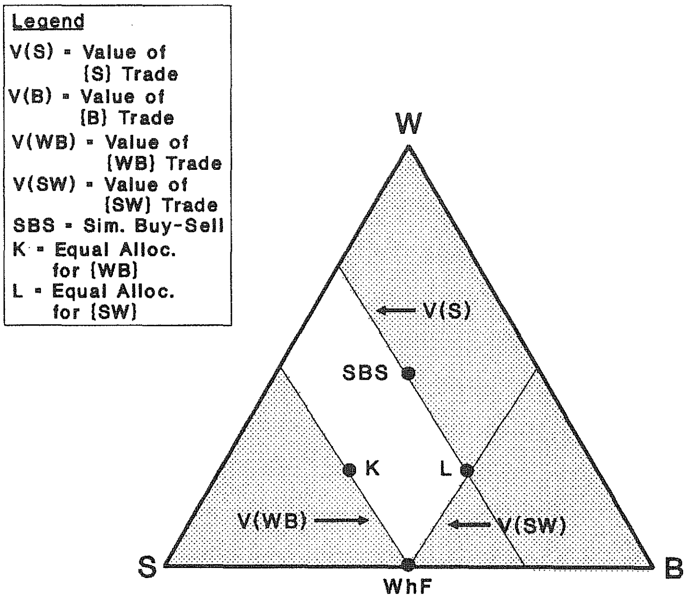


Fig. 4-6. Nonfirm deregulation core with seller having alternative buyer.

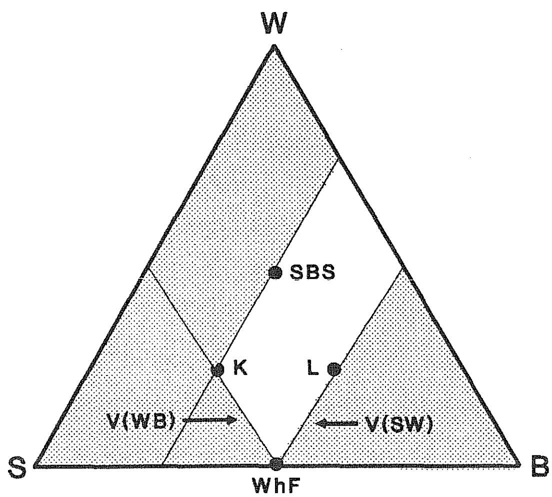


Fig. 4-7. Nonfirm deregulation core with buyer having alternative seller.

Planning Model

The Planning model is a general name covering several distinct transmission reform proposals, as set out in chapter 2. What they have in common is the viewpoint of potential transmission users; in contrast, the Contract model expresses the general view of today's transmission owners. Users want access, either automatic mandatory access or a procedure under which they can petition for access with the assurance that the petition will be considered by an impartial regional planning body, a government regulatory agency, or a court--not just by the transmission owner, who would be able to assign the highest priority to its own use.

There is, of course, no specific model called the Planning model. For the purpose of evaluating Planning-type models here, we must assume specific access and pricing features for a typical Planning model. Mandatory access is assumed.

Most transmission proposals that fit under the Planning umbrella advocate embedded cost pricing for the use of existing transmission facilities. Some but not all call for incremental cost pricing of new facilities where the need for a new facility can be identified with a specific new user. This amounts to embedded cost pricing for nonfirm service and either embedded cost pricing or incremental/long-run marginal-cost pricing for long-term firm service, where our concern is optimal system expansion. As set out fully in chapter 3, embedded cost prices are higher than marginal-cost prices for nonfirm service, unless the transmission system is congested; for long-run firm service with a large enough expansion increment, one expects embedded cost to be below marginal, though this would not be so in every case.

To complicate the Planning model pricing philosophy a little more, consider that the FERC Transmission Task Force, which coined the term "Planning model," envisions "spot prices for short-term, nonfirm transmission services that are monitored by a central regulator" under the Planning model.[3] Monitoring does not cap prices; its purpose is to

[3] Federal Energy Regulatory Commission, *The Transmission Task Force's Report to the Commission--Electricity Transmission: Realities, Theory and Policy Alternatives* (Washington, D.C.: Federal Energy Regulatory Commission, October 1989), 160 and table 5-2.

prevent monopoly-induced capacity constraints that would artificially drive up spot prices. Spot prices in a competitive transmission market precisely equal short-run marginal costs--including opportunity costs, a cost component that almost all advocates of the Planning-type models oppose.

Hence, in our Planning analysis, both nonfirm and firm wheeling prices are nonflexible, cost-based fixed-rate prices (denoted WhF), which may or may not equal marginal cost. This rate does not apply to simultaneous buy/sell (SBS) "wheeling"; we consider cases where SBS is both allowed and prohibited.

Nonfirm power prices today are often set on the basis of split savings. In the absence of a specific contrary provision, it is safe to assume that proponents of various Planning-type models take for granted the continuation of this practice. In defining a generic Planning model, however, the FERC Task Force sees nonfirm power prices being set by competition,[4] which we refer to here as flexible pricing with no regulatory cap.

Strategies Available. Having mandatory access with wheeling prices being set equal to "cost" (not necessarily marginal cost) gives B another option: it can require W to wheel power. Here, flexible generation pricing might yield different patterns of production from split-savings pricing; hence we show this as a strategy also available to the players.

S:
- Sell to accessible buyer who offers the highest price. (If flexible pricing of generation is allowed and W is competing to sell to B, then match any price discount by W, as long as it is profitable to do so.)
- ϕ

B:
- Buy from accessible seller who offers the lowest price. (If flexible generation pricing is permitted and W is competing to buy from S, then match any bid-up in price by W, as long as it is profitable to do so.)
- Require W to provide access to S under the wheeling pricing policy WhF. (If flexible generation pricing is permitted and W is competing to buy from S, then still match any bid-up price by W, as long as it is profitable to do so.)

[4] Ibid., table 5-2, 160.

- ϕ (self-generate and/or rely on firm power purchases)

W:
- SBS (unless prohibited by regulation)
- WhF (WhS is not considered separately because differences between it and WhF are not significant here.)
- Buy from S. (Raise the power price above the split-savings level, if necessary, to outbid B if flexible generation pricing is permitted.)
- Sell to B. (If flexible pricing is permitted, lower the price from the split-savings level, if necessary, to outbid S.)
- ϕ

<u>Does All Good Nonfirm Wheeling Take Place under the Planning Model?</u> The answer is yes, as long as wheeling fees are not so far above the actual marginal cost of wheeling as to make good wheeling transactions (those for which $C_B > C_S + T_{SW} + T_{WB}$) look bad (because $C_B < C_S + F_{SWB}$).

Some good wheeling could be blocked if wheeling rates are based on embedded cost and there is adequate transmission capacity (that is, marginal cost is below embedded cost). Embedded costs are "sunk" and from a strictly economic perspective should not affect coordination trading decisions. Recovering them in coordination wheeling fees may prevent the realization of all possible gains from trade.

<u>Does Bad Nonfirm Wheeling Take Place under the Planning Model?</u> B can require bad wheeling under the Planning model if the costs of generation and transmission are more than the buyer's production cost ($C_B < C_S + T_{SW} + T_{WB}$) and if wheeling fees are held far enough below marginal cost so that the buyer's production cost exceeds the generation plus transmission prices ($C_B > C_S + F_{SWB}$). This can occur especially when transmission capacity is fully loaded, driving up the short-run marginal cost of transmission, which includes opportunity costs. If flexible generation pricing is not allowed, bad wheeling can take place in this circumstance.

If flexible generation pricing is permitted, however, then the answer to this question is "no"--at least for the simple case in which S and W both have just enough excess capacity to meet B's needs, and W could also buy from S. Then W finds it in its self-interest to try to counter the wheeling requirement by forming a subcoalition--either by bidding more than B for S's limited extra capacity or by bidding a lower price than S to sell power to B (whichever results in the smaller loss). W does this, even if it results in a loss, if this loss is less than that incurred under mandatory wheeling.[5] (This presumes that the utility feels both losses equally--that is, that ratepayer and stockholder losses are no different.)

However, even though bad wheeling is blocked a bad result can still occur. This happens, for example, if the optimal solution is for S, W, and B each to self-generate and not interact with the other players (that is, ϕ for each), but the solution that in fact occurs is one of the subcoalitions involving W, which in this case is suboptimal. If, in self-interest, W is driven to form an uneconomic subcoalition with one of the other two players in order to avoid wheeling below cost (for nonfirm service, this would mean below opportunity cost), the result is a solution more costly than the optimal solution (self-generation by all), but less costly than the forced wheeling option.

The latter conclusion means that, under our version of the Planning model, even if no wheeling occurs suboptimal coordination transactions could still occur.

<u>What Is the Distribution of Nonfirm Market Gains under the Planning Model?</u> Assuming that good wheeling is taking place and that wheeling rates are not greater than actual wheeling costs, then S and B split all of the gains. Indeed, if F is held below cost, then S and B can split more than the total gain; this excess is extracted from W, which can be rendered worse off than if it could go it alone (choosing ϕ).

The effect of mandatory access on the distribution of gains is most dramatic in the case where W's marginal production cost (system lambda) is closer to B's than to S's, and the wheeling rate just equals transmission cost. Then, the SBS solution favors S and W, while WhF of figure 4-8 favors S and B. These solutions are shown in the core diagram of figure 4-8, along with the core of the unregulated game. (It is assumed in this figure that there are no transmission constraints and that S's and W's

[5] This result is obtained by assuming that W adjusts its bid just enough to drive S (or B, as the case may be) out of the market. The result is the same as Bertrand spatial competition [--see B. F. Hobbs, "Network Model of Bertrand and Limit Pricing Equilibria in Spatial Markets," *Operations Research* 34 no. 3, May/June 1986, 410-25; and B. F. Hobbs and R. E. Schuler, "Assessment of the Deregulation of Electric Power Generation Using Network Models of Imperfect Spatial Competition," *Papers of the Regional Science Association* 57, 1985, 75-89--] or a Vickrey auction where the price is equal to the second lowest marginal cost (in the case of W competing with S to sell to B) or the second highest marginal benefit (in the case of W competing with B to buy from S). (Here, marginal cost or benefit is calculated using the wheeling fees rather than the actual cost of transmission.)

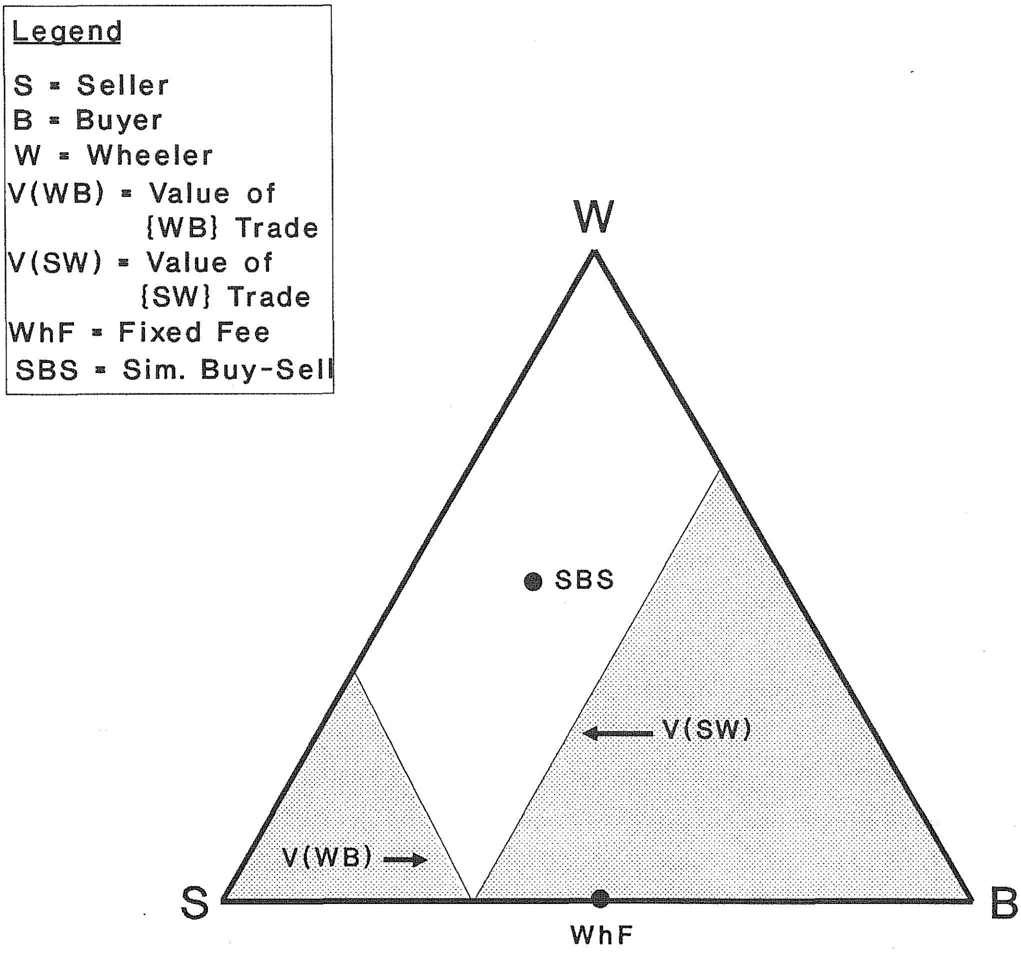


Fig. 4-8. Nonfirm core for the planning model.

available extra generating capacities are each equal to B's demand, which also equals W's potential demand for S's power.) The effect of the Planning model is to allocate W's potential gains to B. Thus, Planning, or tight regulation, can be viewed as a means of eliminating W's market power, transferring it to B. Alternatively, avoiding tight regulation can be regarded as allowing W to continue to retain some market power.

On the other hand, if the wheeling rate F is significantly above marginal transmission cost, W does share some of the gains even if B requires W to wheel.

The point labeled WhF in figure 4-8 represents wheeling at marginal cost and split-savings pricing of generation; this point is not in the constrained core. If split-savings pricing is a regulatory requirement, this generation pricing requirement, together with transmission price regulation, stands in the way of the most efficient power trade. S must sell to W instead of to B. The S-B sale can be accomplished either with split-savings pricing at a higher transmission price or at a marginal-cost-based transmission price with S allowed to charge a generation price above split savings. The latter solution is represented in figure 4-8 by the point where the constraint lines, V(WB) and V(SW), intersect the baseline of the triangle.

Contract Model

As with the Planning model there is no single version of the Contract model. We consider two distinct versions of the Contract model, which we called Contract Model 1 and Contract Model 2.

In Contract Model 1, wheeling is voluntary, although the wheeler may choose to take on a long-term contractual obligation to provide firm transmission service to all eligible parties in return for which regulators agree to permit a great deal of flexibility in nonfirm transmission pricing, and perhaps in nonfirm generation pricing. Firm transmission has cost-based pricing. Firm prices are based on embedded cost if the transmission system need not be expanded to provide the service and otherwise on incremental/long-run marginal cost. In our firm service analysis in the next chapter, we assume long-run conditions; that is, the planning horizon is distant enough that transmission capacity must always be expanded. Thus, firm pricing simply becomes incremental cost pricing.

In Contract Model 2, access is strictly voluntary and pricing is flexible for both nonfirm and firm service. However, the wheeler could voluntarily agree to a long-term contractual obligation to provide firm transmission service to other control-area utilities at flexible prices with a cost-based cap (other firm service pricing options are explained in chapter 5) in return for flexible (market-based) nonfirm--and perhaps firm--generation pricing.

Contract Models 1 and 2 are essentially the same for nonfirm service. The difference appears in the case of firm service.

Contract Model 1

Strategies Available. If W does not assume an obligation to serve, then the situation is the same as the Status Quo. If it does, then the nonfirm market is very much like the deregulated case studied earlier. For S and B, the strategies are the same as before. For W, however, the options are:

W:
- SBS
- Wheel at flexible rate negotiated among the parties
- Buy from S
- Sell to B
- ϕ

The nonfirm wheeling rates that W can charge are either not regulated or assumed to be subject to very loose bounds that are unlikely ever to become binding (that is, unlikely ever to restrict the core).

Does All Good Nonfirm Wheeling Take Place under Contract Model 1? The answer is "yes." This is because the solution "S sells, W wheels at a flexible rate negotiated among the parties, and B buys" is the core of this game, and the core must exist, as discussed previously. The SBS solution lies within the core, and so it is one possible solution. Any of the possible solutions results in the maximum possible "good wheeling."

Does Bad Nonfirm Wheeling Take Place under Contract Model 1? No, since each party's participation is strictly voluntary, unlike the Planning model in which mandatory access can compel W's participation even if wheeling would be "bad."

What Is the Distribution of Nonfirm Market Gains under Contract Model 1? The core of this game has the general shape shown in figure 4-9. It is impossible for either S or B to get all of the gain under the "good wheeling" assumptions; however, W could conceivably get it all. In the simple situation in which $D_W = D_B$, S's excess capacity equals W's, and there are no binding transmission constraints, then the centroid of the

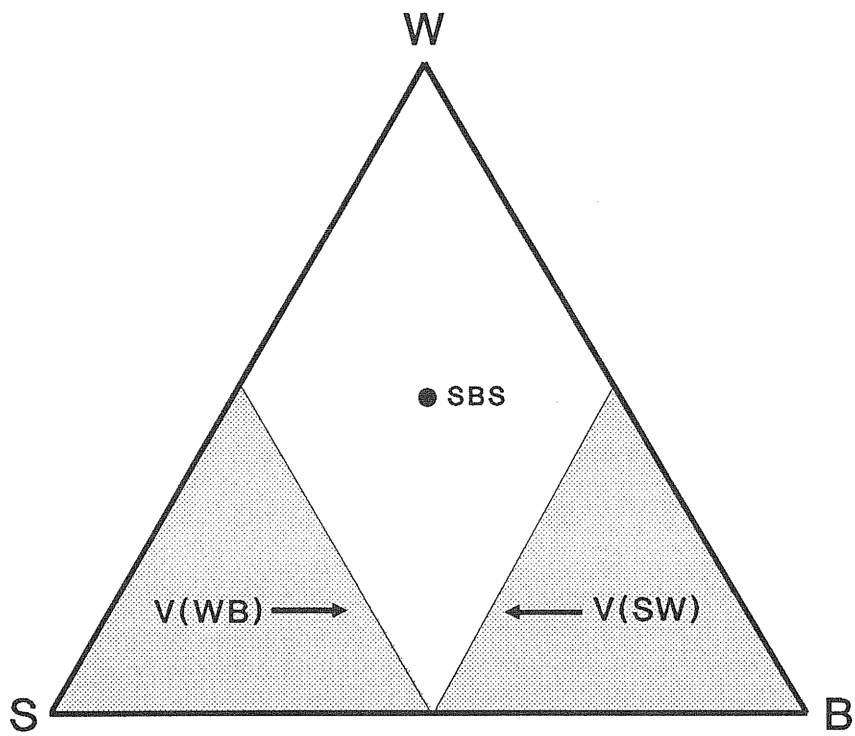


Fig. 4-9. Nonfirm core for the contract model.

constrained core is the same as the SBS solution, which also equals the Shapley value and the nucleolus. W always obtains half the gain at that point, with B's and S's relative shares depending on how large their system lambdas are relative to W's.

Contract Model 2

Strategies Available. For nonfirm transmission, the strategies are the same as for Contract Model 1 (assuming B is not a full or partial requirements customer: Contract Model 2 does not permit sales to such buyers). Any bounds on the wheeling price that W can charge are such that it is unlikely that completely unrestricted transmission prices would ever fall outside the bounds. W would not consent to a price below the lower bound, equal to the short-run marginal cost of transmission, because W would then definitely be worse off. Likewise, S and B would not consent to a wheeling tariff that exceeds $C_B - C_S$ because that would result in W getting all the gains from trade and then some, leaving S and B worse off than without the trade.

Because this model is essentially the same as Contract Model 1 in the case of nonfirm transmission, the productive efficiency and distributional effects are the same as for that model.

NRRI Model

In the NRRI model, there is an obligation to provide transmission service, either firm or nonfirm, at the customer's choice. Nonfirm service is priced at short-run marginal cost, including full opportunity cost. Firm service is priced at long-run marginal cost, including the full long-term capital cost of system expansion.

Strategies Available. The nonfirm strategies and results for this model are the same as for the Planning model where wheeling rates are always set equal to short-run marginal costs, assuming the buyer chooses this option for coordination transactions.

Does All Good Nonfirm Wheeling Take Place under the NRRI Model? Yes. No party wants to entice W to form a subcoalition. If split-savings pricing of generation is strictly adhered to, S and B cannot be made better off by forming a subcoalition compared to the WhF solution with F equal to marginal cost. WhF is then at the midpoint of the baseline of the triangle, as shown in figure 4-10 for split-savings pricing of power.

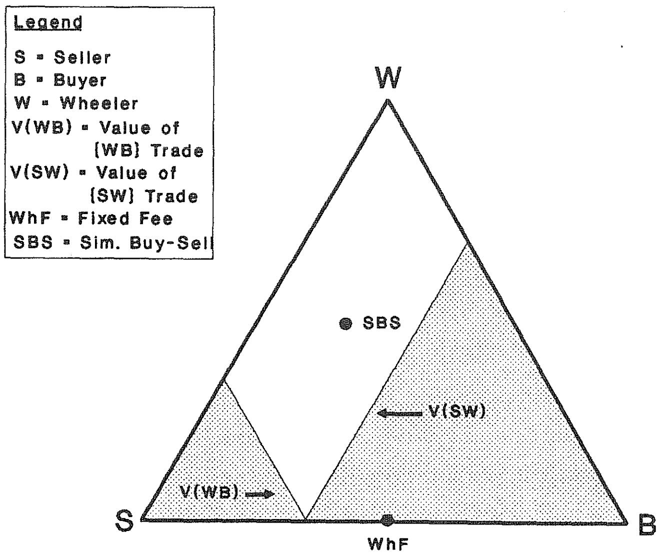


Fig. 4-10. Nonfirm core for the NRRI model under split-savings generation pricing.

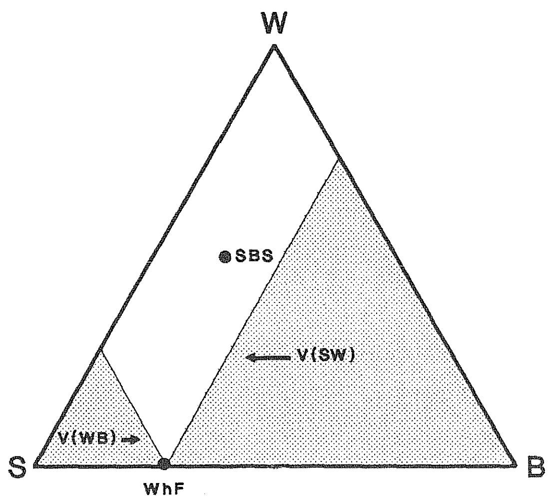


Fig. 4-11. Nonfirm core for the NRRI model under flexible generation pricing.

If flexible generation pricing is allowed, the equilibrium WhF point moves toward the S corner of the core, as shown in figure 4-11. Again, neither S or B is able to improve its position by forming a subcoalition.

Does Bad Nonfirm Wheeling Take Place under the NRRI Model? No. Because F equals marginal cost, the correct incentives are given.

What Is the Distribution of Nonfirm Market Gains under the NRRI Model? When transmission capacity is not congested W gets none of the gains, and the only question is how they are split between S and B. Under split-savings pricing of generation they are split evenly, but under flexible generation pricing, W's relative cost position influences the final equilibrium (assuming Bertrand or Vickrey auction-type competition where the selling price is based on the second-lowest bid). If W's costs are closer to B's than to S's, then S gains a greater fraction of the gains, all else being equal, as in figure 4-11.

However, as transmission capacity becomes congested, there is an opportunity cost component to the price, and the wheeling rate can increase from several mills to several cents. W then gets much of the gains from trade. If there were several competing seller-buyer pairs competing for transmission service, W could auction the transmission capacity available for nonfirm service. If several bidders get service, W's share of the total gain depends on the value of the service to the winning bidders relative to the service price set according to value placed on the service by those bidders on the margin between winning and losing the bid.

It is intended that W's gain would motivate investment in new transmission capacity to alleviate the bottleneck. Hence, the gain would be converted into capital expenditure. Regulation would be needed, however, to ensure that the optimal level of investment in new capacity is made. (See chapter 6.)

An Example with Actual Utility Data

The usefulness of the concepts presented in this chapter was tested in a case study of eight utilities, using actual data for utility generating capacities, system loads, transmission tie-line locations and capacities, and system lambdas. The case study is described in some detail in appendix B along with core triangles for certain special three-player situations. Two of our findings are summarized here.

If all eight utilities cooperate by trading nonfirm power in the grand coalition, the result is the same as if there were economic dispatch among all the utilities, taking into account transmission constraints and costs. The savings are $710 million a year, compared to the case where each of four utilities generates to meet its own load and four other closely interconnected companies cooperate as they have historically. These savings are 15 percent of the annual cost without cooperation and are achieved if the wheeling prices equal short-run marginal transmission costs.

We also examined the effect of embedded cost-based transmission rates. Embedded cost pricing makes unprofitable some trades that would have been profitable under marginal-cost pricing so that, as expected, the savings are reduced. However, the reduction in savings is relatively small, only $50 million out of $710 million. This is because an embedded-capital-cost surcharge of a few mills per kilowatt-hour is small compared to the few-cents differences in system lambdas. The surcharge thus has a small effect on power purchase decisions. This suggests that, if wheelers resist nonfirm wheeling at marginal-cost-based rates and reasonable embedded cost rates are needed as a policy compromise to obtain the wheeler's cooperation, the efficiency losses may be small compared to the potential losses that would occur if the utilities did not cooperate at all.

Further, the allocation of the gain among the eight utilities can change dramatically over time. We forecast load growth over a thirteen-year period for these eight companies and considered their generating reserves, generation expansion costs, and generation capacity expansion constraints. The savings grows slightly to $814 million over thirteen years. However, even with no change in transmission line configuration and no new transmission capacity constraints, the identity of the companies that are the principal beneficiaries of trading is very different as the marginal generating costs of the companies change over time. This supports the argument for conservatism in transmission investment for coordination sales: lines built to capture trading gains available today could be a liability if those gains are not available tomorrow.

CHAPTER 5

ACCESS AND PRICING POLICIES FOR FIRM TRANSMISSION SERVICE

Introduction

Here we take up the effects of transmission access and pricing policies on firm transmission service. A principal theme of this chapter is the analogy between the short-run nonfirm market and the long-run firm market. In the nonfirm market, we used system lambdas, transmission costs, system loads, and generation and transmission capacities to determine whether economic dispatch would be encouraged or discouraged by transmission policies. There is an analog to each of these concepts in the long run, and we stress the analogy by using the same notation for a long-run concept here as we use for its short-run counterpart in chapter 4.

System lambda, the short-run marginal generation cost, becomes the cost of constructing and operating a new generating unit, which is the long-run marginal cost of generation. Similarly, short-run transmission cost (line losses for the line not fully loaded) becomes the incremental cost of capacity expansion and operation. Present utility loads are replaced by forecasts of loads at the end of a certain planning horizon.

We do not here prescribe a particular planning horizon; it may be, for example, one fifteen-year step into the future. If so, one would forecast the loads at that time and consider various ways to meet the loads of all the utilities in the region, such as (i) having each utility construct generating capacity to meet its own needs, (ii) having each utility either build its own capacity or have a contiguous neighbor do so, whichever costs less, or (iii) having each utility let all other utilities/power suppliers bid to supply it with power and select the lowest generation-plus-transmission cost option. Of course, the price of firm transmission service is a relevant factor in the last case.

This last case is the long-run analog of economic dispatch. It is a procedure for obtaining the optimal configuration of new generating units and transmission lines so as to minimize the regional electricity production cost at the end of the planning horizon. The ability of "economic dispatch" or "least-cost planning" actually to minimize costs depends on transmission access policy and on the relationship between transmission prices and transmission costs. It also depends importantly on generation pricing policy, as we shall see. From the mathematical perspective, the analyses in chapters 4 and 5 are virtually identical. Indeed, that is the point we stress.

Firm transmission access and pricing policy is the focus of concern in today's transmission reform debate. Despite its importance, our treatment of it can be brief. Much of the analysis of chapter 4 applies here: we use the same analytical framework, the same notation and equations, the same group of transmission policies, and the same way of examining and displaying the effects of policies. The main differences, of course, are that we examine here that part of each policy that concerns firm transmission and we consider firm generation pricing policies, which differ from their nonfirm counterparts.

As a result of the similarities, chapter 5 is much like chapter 4. Our intent is to develop a way of thinking about capacity expansion decisions that draws on the analogy with economic dispatch. The reader familiar with a prior NRRI report[1] should recognize this analogy as another expression of the analogy between the equalization of short-run marginal costs across the grid and the equalization of long-run marginal costs across the grid.

This chapter is organized as follows. First, the simple seller-wheeler-buyer system is introduced for the long-run case, and its assumptions are set out. Then we evaluate the long-run results for the five pricing models. We conclude by examining briefly alternative configurations, including the existence of other markets (other places for S to sell, W to buy or sell, or B to buy) and the existence of an alternative but more expensive S-to-B transmission route.

Transmission Models

The long-run aspects of five transmission access and pricing models are considered:

1. Status Quo--voluntary access with cost-based pricing for both firm and nonfirm transactions

[1] K. Kelly et al., *Some Economic Principles for Pricing Wheeled Power*, NRRI-87-7 (Columbus, Ohio: The National Regulatory Research Institute, 1987), chapters 6 and 7.

2. Planning Model--mandatory access with cost-based pricing (not necessarily embedded costs) for both firm and nonfirm transactions
3. Contract Model 1--the wheeler may take on an obligation to provide firm service at cost-based rates in return for nonfirm transmission pricing flexibility and perhaps also nonfirm generation pricing flexibility; flexible pricing for nonfirm transactions; incremental cost pricing for firm transactions
4. Contract Model 2--voluntary access with flexible pricing for both firm and nonfirm transactions; firm transmission is provided with a cost-based cap to other control-area utilities in return for flexible (market-based) nonfirm--and perhaps firm--generation pricing (other firm pricing options are set out later in this chapter)
5. NRRI Model--mandatory access; the customer can choose either firm or nonfirm service for any transmission need; long-run marginal cost-based pricing for firm transactions; short-run marginal cost pricing for nonfirm.

The emphasis in this chapter is on models 1, 2, and 4 for the following reasons. First, the firm transaction part of Contract Model 1 looks just like the firm part of the Planning model with wheeling rates equal to long-run marginal cost (which we consider here as equivalent to incremental cost), except for the provision that if a wheeler agrees to provide long-run service at marginal cost, it can flexibly price short-term coordination transactions. We discuss briefly how a wheeler might evaluate the decision to wheel in that circumstance. Otherwise, Contract Model 1 is not examined separately from the Planning model here.

Second, the NRRI long-run pricing model is, in our analytical framework, indistinguishable from the Planning model with long-run marginal cost-based rates. We do not treat here that aspect of the NRRI model in which a buyer can choose a portfolio of firm and short-run wheeling arrangements. With this considered, the NRRI model does differ from the Planning model.

For firm power purchases, two generation pricing rules are considered. The first is the Status Quo, in which firm generation sales are assumed to be priced at full incremental cost (assumed here to equal long-run marginal cost). The second is a deregulated scenario where firm power is sold at market prices; that is, the seller receives whatever price he can negotiate or the price at which he wins a competitive bid.

For each transmission pricing model, the strategies available to each player are summarized and the probable solution (or solutions) to the game is found. Then, as in the previous chapter, the following questions are asked:

- Is all good wheeling likely to occur? "Good wheeling" is defined as that which lowers production costs for the entire system.
- Can bad wheeling occur? "Bad wheeling" is defined as that which raises production costs compared to the least-cost generation and transmission solution.
- What is the distribution of the gains among the S, W, and B?

The terms "good" and "bad wheeling" are interpreted more specifically below, as needed.

The Simple S-W-B System

By analogy with the previous chapter, let C_i be the long-run incremental generation production cost for player i (i=S,W,B), Q_i be the players' long-run generation capacities, and D_i be their long-run demands (loads). The generating capacity is the amount that each supplier is *able* to construct and operate at cost C_i. In the long run, it might be argued that there should be no capacity limit, and this case is considered. However, there are certain resources that are limited, such as low-cost hydroelectric sites and cooling water for thermal plants. Also, fossil plant emission limits may constrain a supplier's ability to expand generating capacity at a low incremental cost. For these reasons, we consider the case in which Q_i is finite.

Let the long-run transmission cost from S to W be T_{SW}, and T_{WB} be that from W to B. No capacity limits are considered on these lines; it is assumed that any transmission capacity *which W wishes to build* can be built. Let F_{SWB} be the wheeling fee charged for wheeling from S to B via W; this can be divided into two portions, F_{SW} and F_{WB}.

The decision variable q_i represents the actual construction/production of any party i, and y_{ij} represents the amount of firm power transmitted from i to j.

We assume that $C_S < C_B$ and $Q_S > D_S$; that is, S can build extra generating capacity at a long-run marginal cost (excluding transmission costs) that is less than B's. $Q_S - D_S$ might be greater than or less than D_W or D_B. Assume also that the buyer can build enough capacity to meet his own needs if need be: $Q_B \geq D_B$ is possible.

Two alternative generation cost assumptions for W are considered. The first is that $C_W + T_{WB} \geq C_B$; this is the case, for instance, if B and W have identical long-run marginal generation costs. The second is that $C_W + T_{WB} < C_B$. In that case, W has a significant long-run cost advantage because, for example, it might be located closer to fuel or cooling water sources.

We use the same definitions of good and bad wheeling as in the previous chapter but repeat them here for convenience and to stress the analogy with the short-run analysis. The maximum possible "good wheeling" occurs if the least expensive pattern of production $\{q_i^*, y_{ij}^*\}$ results in the long run. This requires construction of the most economical new generating units at the best locations, taking into account the need for (and cost of) new transmission capacity. This is analogous to the short-run "least-cost dispatch" solution and may require wheeling. As before, the actual amount of wheeling is $\text{MIN}(y_{SW}^*, y_{WB}^*)$, which might be zero.

Good "wheeling" occurs if at least some firm power flows from S to W and from W to B, whether or not there is a formal S to B sale with W agreeing to wheel:

$$\text{MIN}(y_{SW} , y_{WB}) > 0$$

and if S's delivered cost is less than W's delivered cost, which is less than B's self-generation cost:

$$C_S + T_{SW} + T_{WB} < C_W + T_{WB} < C_B .$$

Note that by "delivered cost" we mean the actual resource cost, or marginal cost, of generating power and transmitting it from seller to buyer. This may differ from the "cost" the buyer sees, which is the sum of generation and transmission *prices*. Good wheeling can also occur if $C_W + T_{WB}$ is higher than C_B, as long as W's demand for S's power is met first. Similarly, good wheeling can occur if $C_W + T_{WB}$ violates the left inequality, as long as W has already sold all it can to B.

Bad wheeling occurs if power flows from S to W to B; that is,

$$\text{MIN}(y_{SW}, y_{WB}) > 0$$

and any one of the following is true:

(i) S's delivered cost to B is more than B's own cost ($C_S + T_{SW} + T_{WB} > C_B$),

(ii) W's delivered cost to B is more than B's own cost ($C_W + T_{WB} > C_B$) and W's potential demand for S's power is not filled, or

(iii) S's delivered cost to W is more than W's own cost ($C_S + T_{SW} + T_{WB} > C_W + T_{WB}$) and W's potential for selling power to B is not filled.

Other types of bad wheeling might be defined, but are not considered here.

Each of the models is discussed in turn below. For each, we consider both $C_W = C_B$ and $C_W < C_B$, cost-based generation prices and unregulated generation prices, and other sensitivity analyses.

Status Quo

In the Status Quo model, we assume that access for firm power transmission is voluntary (notwithstanding possible antitrust law applicability in some cases) and that wheeling charges F are "cost based," either long-run marginal cost (=T) or embedded cost (≠T). As discussed in chapter 2, embedded cost might be higher or lower than LRMC, depending on the transmission system improvements that are necessary to accommodate the transaction.

Strategies Available. The options available to each player are outlined below. The "go it alone" strategy, in which a player refuses to cooperate with the other players, is again designated as the "null" strategy ϕ.

S: - Expand generating capacity and sell to accessible buyer who offers the highest price
- ϕ (do not expand and sell)

B: - Buy from accessible seller who offers the lowest price
- ϕ (construct own generating capacity and self-generate)

W: - Wheel, building sufficient transmission capacity to meet B's demand for S's power
- Wheel, but build only enough transmission capacity to convey power from S that is in excess of W's own needs
- Buy from S; do not cooperate with B (subcoalition {SW})

- Expand generating capacity and sell to B; do not cooperate with S (subcoalition {WB})
- ϕ

Does All Good Firm Wheeling Take Place under the Status Quo Model?

The following discussion is, of course, for the case in which good wheeling is economically possible; that is, marginal transmission costs are not so high as to make wheeling uneconomic. In the next few figures the conditions under which our associated discussions apply are given in the figures. In all cases, the cost of S's generation plus transmission to both W and B is less than W's and B's own generation cost. Note that W's gain in these figures includes not only wheeling profits, but also profits on generation sales and savings on power purchases. Hence, W may be forced to wheel at cost and may still be able to adopt a strategy that yields a real gain.

If generation sales are cost-based (that is, S can charge no more than C_S for its power) and *wheeling rates equal long-run marginal transmission costs* (F=T in all cases), the answer to the question is sometimes "yes" and sometimes "no." The reason can be seen from the cores presented in figure 5-1. In some cases, the best of the "Status Quo" solutions (each such solution being represented by the letter Q) is outside the core of the game. If two points are shown on a diagram, point "a" is the solution for which W first uses S's excess power to fully satisfy B's demand before meeting its own needs, building y_{WB} = MIN (D_B, Q_S-D_S) (we call this W's first strategy); point "b" is the solution for which W builds only y_{WB} = MAX(0, Q_S-D_S-D_W), taking care of its own demand first (W's second strategy).

In figure 5-1(a), the case where W's power costs more than B's is considered. S has enough extra capacity to supply either W or B and still have some left over. Here, all good wheeling takes place, provided W is willing to build the necessary transmission y_{WB} at the price F_{WB}. W first buys all the firm power it can from S, and any excess firm power that S has left is wheeled to B. Because wheeling revenues recover incremental costs and the price S receives is the same as its generation cost, the Status Quo (Q) solution lies on the intersection of the {SW} constraint and the line segment connecting W and B; that is, S gains nothing and W gains exactly what it would under the {SW} coalition. This point is in the core (at the edge of the area that is unshaded) and is the point in the core that is both least favorable to S and most favorable to B.

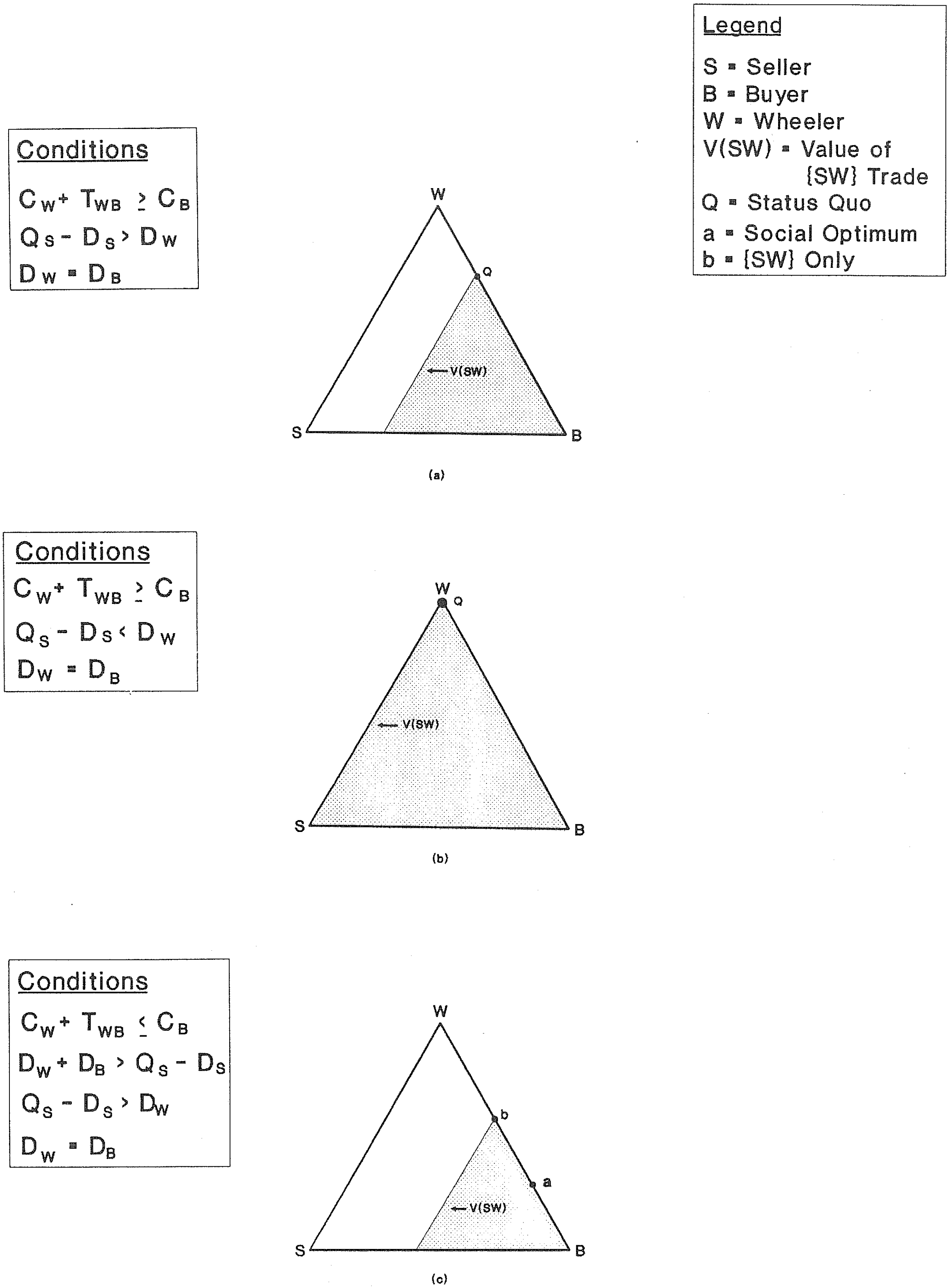


Fig. 5-1. Firm cores for the status quo with generation priced at long-run marginal cost.

In the case shown in figure 5-1(b), W's power again costs more than B's, but here S's extra capacity is less than either W's or B's need. Now S sells only to W with none left over, and no wheeling occurs. But there is no good wheeling that could take place, since the most economic solution is for S to sell all its excess capacity to W. There is no three-player core. This is a two-player game in which, under cost-based generation price regulation, W gets all the gains.

In the figure 5-1(c), W's delivered cost of serving B is less than B's avoided cost, and S has enough extra capacity to serve either W or B with some left over. W does not agree to the socially optimal solution, which is to build enough transmission capacity from S to W to transmit all S's extra power and enough from W to B to satisfy B's demand [point a, with $y_{SW}=Q_S-D_S$, $y_{WB}=D_B$]. The optimal solution is outside the constrained core. W does get some gains if $Q_S-D_S>D_W$, since it is able to purchase some of S's power. Nevertheless, W would choose option "b" instead, which represents the solution where W builds enough S-to-W transmission but builds only enough W-to-B transmission to wheel the power left over after its own demand is satisfied [$y_{SW}=Q_S-D_S$ and $y_{WB}=\mathrm{MAX}(0,Q_S-D_S-D_W)$]. Hence, S receives no gain; W receives a gain equal to its gain with the subcoalition {SW}, but B receives a smaller gain than it would in the grand coalition {SWB}. Some but not all good wheeling takes place. (Note that "b" represents a total level of gain less than that of the grand coalition because "b" is an inefficient solution. As such, "b" does not represent the normal three-way sharing of the grand allocation gain. Its location cannot be interpreted in the usual way; here the location of "b" is simply at one end of the V(SW) line, with its location on the W-B side of the triangle having no meaning.) Thus, some good wheeling does not take place.

If the transmission rate (F) deviates from long-run marginal transmission cost (T), then the points in the figure shift. If embedded cost pricing is required for firm transmission so that F<T, then point Q in figure 5-1(a) moves outside the core. In this case, W does not agree to wheel at a loss; instead it forms subcoalition {SW}. The same thing happens to "b" in figure 5-1(c), a worse solution because instead of some good wheeling taking place, none does.

If F>T, which can occur under the Status Quo if the rolled-in area-wide embedded cost exceeds the incremental transmission cost for a given transaction, then no changes occur unless F is so much higher than T that point "a" in figure 5-1(c) moves into the core, which seems unlikely under typical cost conditions.

If firm generation prices are market-based or unregulated, but the firm transmission rate is set at incremental cost, then the situation is as illustrated in figure 5-2. The capacity, demand, and cost conditions in parts (a), (b), and (c) of this figure are the same as those in the corresponding parts of figure 5-1. In figure 5-2(a) the Status Quo solution (Q) lies somewhere in the area enclosed by the dashed line, which itself is within the core. The dashed line encloses all the points within the core that can result from S increasing the price it charges for its power. (Actually, three sides of this dashed parallelogram are coincident with existing core constraints but are shown slightly separated for clarity.) W cannot get all the gains because it cannot raise its wheeling rate. Neither W nor B can be made better off by such a price change. Good wheeling takes place, but S is likely to get more of the gains than before. In figure 5-2(b), the Status Quo solution (Q) becomes the entire side of the triangle connecting S and W because there is no limit to the generation price that S can bargain for other than B's avoided cost.

Unregulated generation prices in the case of figure 5-2(c) result in all good wheeling occurring. This is because S can raise its price so that W is now unable to get all the gains from an {SW} subcoalition (which was point "b" in figure 5-1). The result is that the Status Quo solution lies in the overlap of the core and the region below the dashed line. Points to the right of this overlap are accepted by S and W because they can form subcoalition {SW}. Points above the overlap are not feasible if it is presumed that S would not charge less than C_S for its power sales to W and W can only charge a transmission fee that covers its cost. (However, if S could make side-payments to W, then points toward the W-corner would be feasible.)

If W has a cost advantage relative to B ($C_W+T_{WB}<C_B$), but not as large as S has ($C_S+T_{SW}<C_W$), the Status Quo outcomes do not change as long as S is compelled to sell its power at a price equal to C_S. Basically, a new constraint is added to each triangle in figures 5-1 and 5-2: a line parallel to the W-B side of the triangle, which represents the profit that W and B could earn from subcoalition {WB}. Figure 5-1(a) is reproduced with this new constraint in figure 5-3.[2]

[2] Under the assumptions made here, it is impossible for the {SW} and {WB} constraints to intersect within the triangle, which implies that at least one point on the S-B side of the core triangle is in the constrained core.

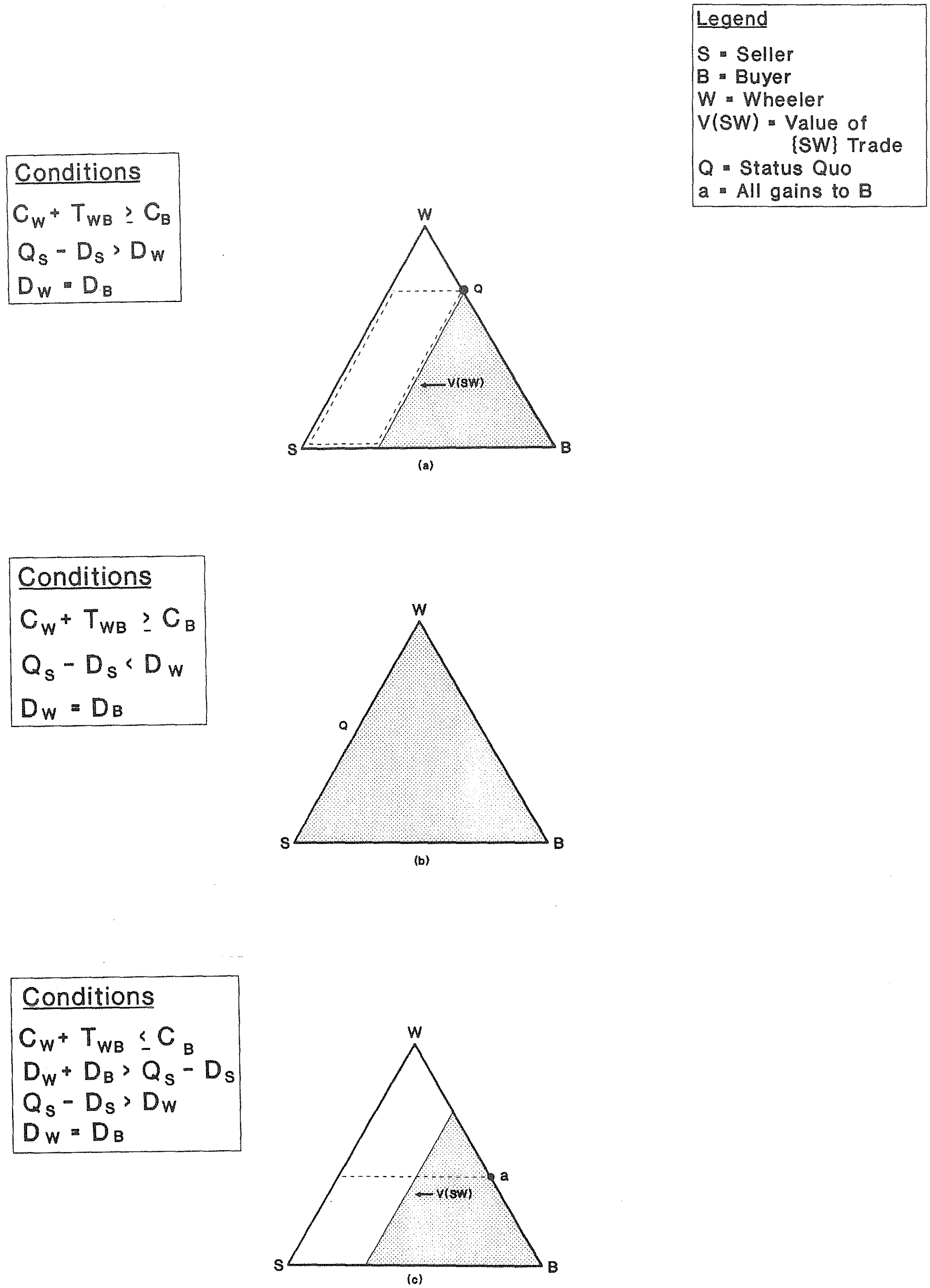


Fig. 5-2. Firm core for the status quo with generation at market-based prices.

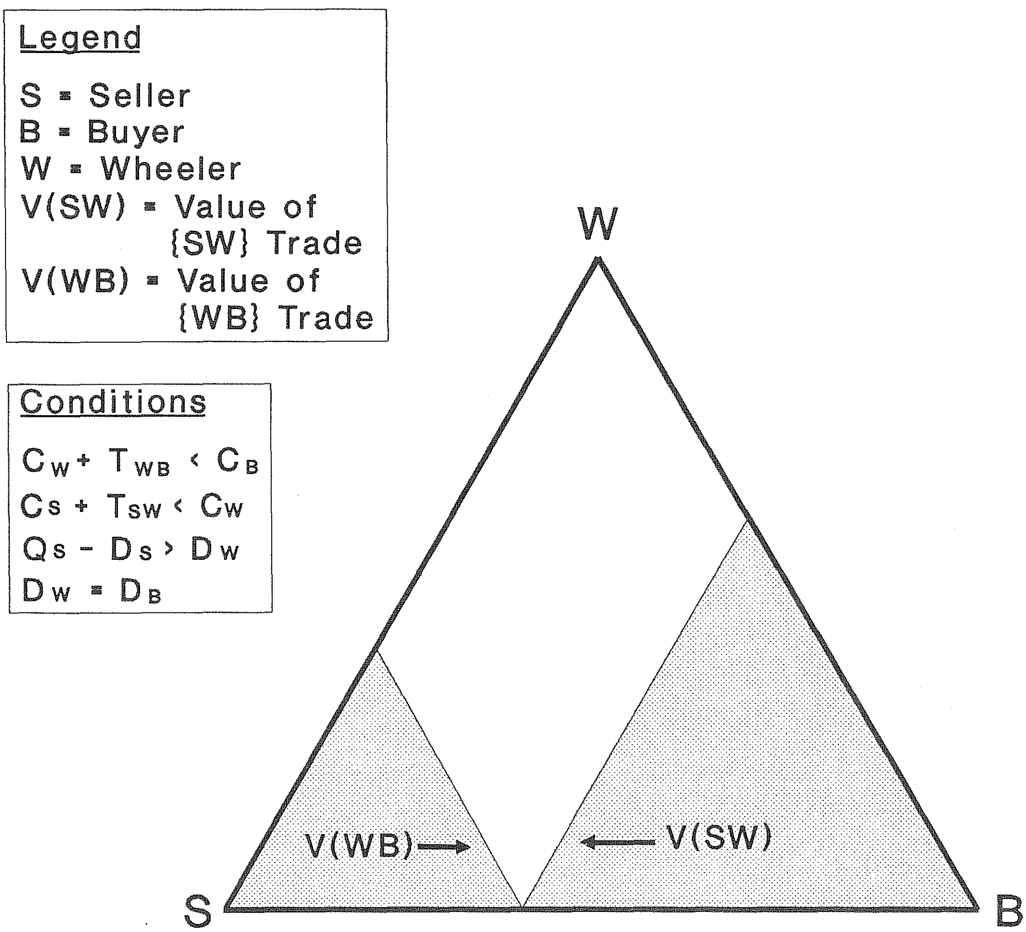


Fig. 5-3. Firm core for the status quo with the wheeler as a potential power seller.

The new {WB} constraint does not alter the conclusions made earlier. However, if S can increase the price of generation above C_S, the new constraint can further restrict the size of the dashed areas shown in figure 5-2.

Whether the potential generating capacity of S or W is limited or not does not affect the general nature of these results (although the exact shape of the core may change, in a manner analogous to the shape changes discussed in the short-run analysis).

Does Bad Firm Wheeling Take Place under the Status Quo Model? The answer is *no*. For wheeling to be uneconomic it would have to increase production costs. Because all trades are voluntary under the Status Quo, consent is not possible for a trade that would lower total benefits (where losers would not be compensated by winners).

What Is the Distribution of Firm Market Gains under the Status Quo Model? If generation prices are regulated, S gets no real gain and W always gets a significant proportion of the gains. However, if generation prices are unregulated, S would likely get some of the gains, mostly or all at W's expense, especially if W's production cost is high enough so the {SW} constraint is close to the S-W side of the core triangle.

Planning Model

The generic Planning model evaluated here is the one introduced in chapter 4. In brief, it calls for mandatory access at cost-based rates.

Strategies Available. Mandatory access with wheeling prices set equal to "cost" (not necessarily marginal cost) again increases the options available to B by one: it can require W to wheel power.

S: - Expand generating capacity and sell to accessible buyer who offers the highest price. (If unregulated pricing of generation is allowed and W competes to sell to B, then match any price cuts of W's as long as it is profitable to do so.)
   - ϕ

B: - Buy from accessible seller who offers the lowest price. (If unregulated generation pricing is permitted, and W is competing to buy from S, then match any price offer of W as long as it is economic to do so.)
   - Force W to provide access to S. (If unregulated generation pricing is permitted and W is competing to buy from S, then match any price offers of W's as long as it is economic to do so.)

- ϕ (self-generate or rely on alternative resources such as cogeneration, demand-side management, or firm power purchased outside the S-W-B system.)

W:
- Construct new transmission capacity for wheeling and wheel power at a fixed rate only if compelled (assuming the rate is less than or equal to long-run marginal transmission cost; otherwise, W might do so voluntarily)
- Buy from S
- Expand generating capacity and sell to B
- ϕ (do nothing if not compelled)

Does All Good Firm Wheeling Take Place under the Planning Model? The answer is *yes*, provided wheeling fees are not so far above the actual marginal cost of wheeling as to make good wheeling transactions ($C_B>C_S+T_{SW}+T_{WB}$) appear bad ($C_B<C_S+F_{SWB}$). (In a more detailed model that treats production cost as a continuously changing function of production level, there is always some loss of good wheeling if rates are too high, as shown in appendix B for the short-run case.) However, it appears unlikely under current cost conditions that embedded transmission cost would be much above long-run marginal cost.

Good wheeling takes place even if the solutions are not in the core of the game. The reason that these solutions would still be implemented is that W's consent is not required; access is mandatory. Example solutions under the Planning model are shown in figure 5-4 as an open circle. (The cost, capacity, and load conditions in parts (a), (b), and (c) of this figure are the same as in the corresponding parts of figures 5-1 and 5-2.)

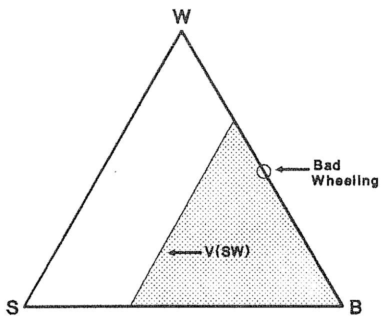
Does Bad Firm Wheeling Take Place under the Planning Model? B may require bad wheeling if the actual (long-run marginal) cost of B constructing its own generation is less than the costs to others of constructing generating and transmission capacity to serve B ($C_B<C_S+T_{SW}+T_{WB}$), but firm wheeling rates are held far enough below long-run marginal cost so that $C_B>C_S+F_{SWB}$. If S sells its power at cost, bad wheeling can take place in this circumstance. For example, in figure 5-4(a) and (b), B is able to compel W to wheel at cost, even though power is more valuable to W under these cost conditions. The point "O" represents a possible outcome that results from the solution $y_{SW}=Q_S-D_S$, $y_{WB}=D_B$ (rather than $Q_S-D_S-D_W$), with B getting all of its demand met first and W getting the remainder. W's share of the grand coalition gain is less than this point indicates because regulation has created two two-player games (first, S sells to B with W having no voice in the decision, and then

Legend

S = Seller
B = Buyer
W = Wheeler
V(SW) = Value of {SW} Trade

Conditions

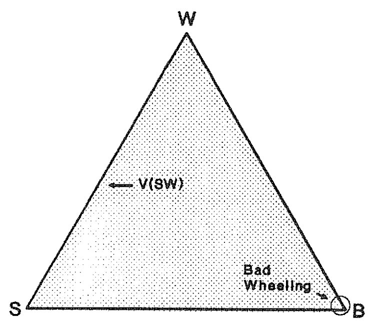
$C_W + T_{WB} \geq C_B$
$Q_S - D_S > D_W$
$D_W = D_B$



(a)

Conditions

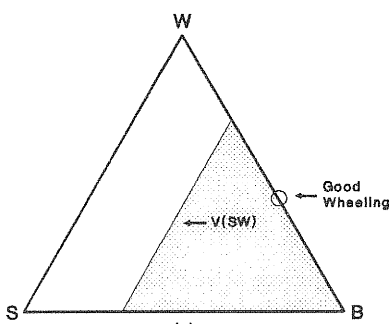
$C_W + T_{WB} \geq C_B$
$Q_S - D_S < D_W$
$D_W = D_B$



(b)

Conditions

$C_W + T_{WB} \leq C_B$
$D_W + D_B > Q_S - D_S$
$Q_S - D_S > D_W$
$D_W = D_B$



(c)

Fig. 5-4. Firm core for the planning model.

S sells to W) in place of the three-player game. The result is that the total gain shared here is less than under an optimal solution. The loss of production efficiency is

$$[2D_W-(Q_S-D_S)](C_W+T_{WB}-C_B).$$

Note that this can be prevented by proper pricing of transmission.

However, just as in the short-run case described in the previous chapter, if generation pricing is deregulated, then the answer to the question "can bad wheeling occur?" is "no"--at least for the simple case in which S and W both have just enough extra capacity to meet B's needs, and W could also buy from S. Then, W finds it in its self-interest to block the wheeling requirement by forming a subcoalition--either by outbidding B for S's extra capacity or by underbidding S to sell to B, whichever results in the smaller loss. W does this, even though it takes a loss in doing so, when this loss is less than the loss that would be incurred by having to construct wheeling capacity for which it would be reimbursed on the basis of historical costs. Note that here the assumption that W's components (retail ratepayers, stockholders, and managers) share a common interest is crucial; otherwise the decision-making component of W may accept a loss if another component of W would bear it.

As in the nonfirm power analysis, this result is obtained by assuming that W adjusts its bid just enough to drive either S (or B, as the case may be) out of the market. Again, even though bad wheeling does not occur, a bad result can occur if the optimal solution is for S, W, and B each to self-generate and not interact with the other players, but in self interest W is driven to form an uneconomic subcoalition with one of the other two players. As in the nonfirm analysis, this conclusion means that, even though we may observe no wheeling under a Planning model, bad bulk power decisions still can be made as a result of the model.

<u>What Is the Distribution of Firm Market Gains under the Planning Model?</u> Assuming that good wheeling is taking place and that wheeling fees equal actual wheeling costs, S obtains none of the gains, and B obtains at least as much as it would have under the Status Quo model; in most cases, B would gain much more than this. For example, consider figure 5-4(a) when $T_{WB}=F_{WB}$. The Planning solution places the point O toward B's corner--that is, mandatory access allows B to receive all the gains that W would otherwise enjoy. Point O may be located so that W gets some gain; this is due entirely to W's purchase of S's remaining power after W has fully

satisfied B's wheeling demand at no gain to W. Efficiency is not improved; instead, the gain is drastically redistributed (perhaps fairly, perhaps not) compared to the comparable Status Quo cases in figures 5-1(b) and 5-2(b). Indeed, if F is set below incremental cost, B can earn more than the total gain; this excess is extracted from W, which can be rendered worse off than if it chooses to be uninvolved.

The closer that C_W and C_B are to each other relative to C_S, making for a seller's market in the absence of regulation, the more dramatic is the gain shift to B resulting from a mandatory access policy. Also, the closer that Q_S-D_S is to D_W, and D_W and D_B are to each other, the greater the shift in the gain, as residual bilateral trading opportunities are eliminated.

On the other hand, if F is significantly above marginal transmission cost, W shares some of the gain even if B requires W to wheel. Figure 5-4(c) illustrates the type of situation in which the Planning model works best: B's production cost is greater than W's. Here good wheeling takes place under the Planning model.

Contract Models

Contract Models 1 and 2 are described in chapter 4. Here we examine their effects on long-run production efficiency and gain sharing.

Contract Model 1

In Contract Model 1, W can decide whether to grant firm access at cost-based rates in exchange for being allowed to price nonfirm transmission and perhaps nonfirm generation flexibly. If W decides not to grant firm access, the results of the Status Quo analysis apply here. If W does provide access at cost-based rates, the results of the Planning model analysis apply. The firm market portions of the Planning model and this Contract model are remarkably alike in their essential features, differing mostly in the nonessential features that their proponents choose to emphasize. One essential feature of the Contract model not captured by this statement, however, is the linking of firm and nonfirm policies.

Ideally, this model would be evaluated by analyzing in detail the long-run profits to be gained from flexibly priced nonfirm transactions and comparing these to the gains given up (if any) by giving access. This detailed analysis is not done in this chapter, but methods for doing so are developed in chapter 6. There, a framework is developed that can be used to estimate such profits. A model is introduced in which there is a long-term coordination market such as one due to the long-term availability of hydropower. W decides to provide wheeling to B depending on the profits it can make. The amount of capacity W provides depends on what it can charge for wheeling and what its own uses of the power might be. In some cases, it chooses to isolate B, analogous to the "b" solution in figure 5-1(c).

The gains that would be given up by wheeling firm power at cost could be estimated by the type of analysis presented earlier in this chapter. Then it would be a matter of W deciding whether these losses are compensated for by the coordination profits. Under Contract Model 1, some good long-run firm wheeling may be prevented if the short-run gains are not high enough to induce W to provide firm access voluntarily. This in turn depends on how tight a price cap is imposed on nonfirm wheeling rates.

Because this system requires the voluntary cooperation of W, there must be an improvement in social welfare if there is wheeling, as opposed to the no-wheeling situation. However, it is conceivable that some bad firm wheeling would take place but be tolerated by W because it wants the profits from flexible pricing of nonfirm generation and transmission. If the "carrot" of flexible pricing is attractive enough, W might inadvertently encourage uneconomic firm wheeling transactions, perhaps by voluntarily agreeing to wheeling rates that are too low.

Contract Model 2

This model is a voluntary access proposal and applies only to inter-control area sales.

Strategies Available. The strategies available are basically similar to those under the Status Quo model, except that wheeling rates are not necessarily equal to costs. There are two transmission pricing options:

1. Embedded cost plus incremental cost, which is defined here as either (i) short-run variable costs alone if there is excess capacity, or (ii) if capacity is constrained, the sum of short-run variable costs, the cost of any required transmission upgrades, and opportunity cost.
2. A negotiated fee that must be between (i) embedded cost plus short-run variable cost and (ii) replacement cost.

Let us examine where the solutions to this model might lie in the long-run core triangle. Figure 5-5 illustrates the results. Normally, one expects wheeling to occur from S to B through W when C_B is greater than

Legend

a = Low Embedded Cost
b = High Embedded Cost
L = Lower Cost Bound
U = Upper Cost Bound

Conditions

$C_W + T_{SW} \geq C_B$
$Q_S - D_S > D_W$
$D_W = D_B$

Conditions

$C_W + T_{SW} \geq C_B$
$Q_S - D_S > D_W$
$D_W = D_B$

Conditions

$C_W + T_{WB} \leq C_B$
$D_W + D_B > Q_S - D_S$
$Q_S - D_S > D_W$
$D_W = D_B$

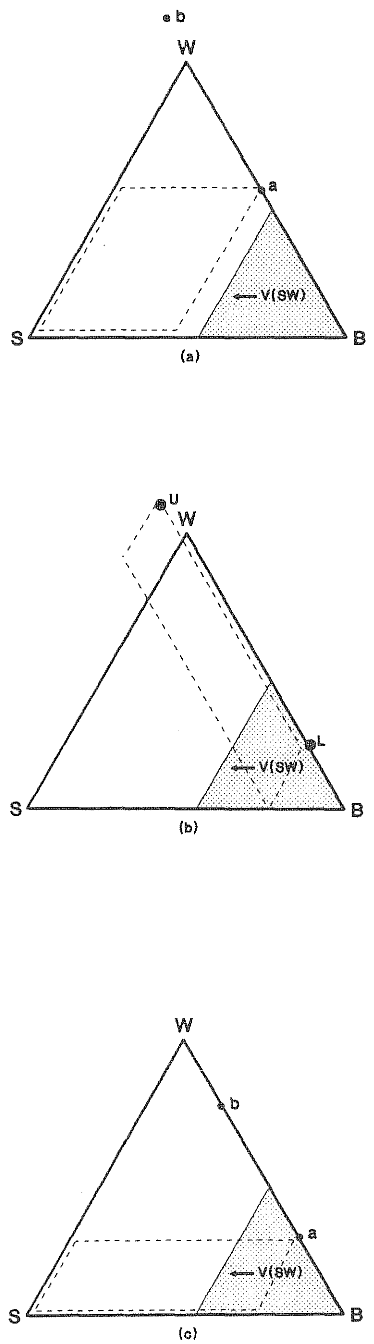


Fig. 5-5. Firm cores for contract model 2.

$C_W + T_{WB}$. We examine this simple case shortly and get the expected results; it is illustrated in figure 5-5(c). First, however, we take up the more complicated case where $C_W + T_{WB}$ is greater than C_B; W should satisfy its own need for S's power before wheeling to B, unless wheeling gains exceed cost savings from its own purchase from S. (We set aside for the moment the case where W wheels only because of the obligation it voluntarily assumes because the foregone savings of purchasing from S are outweighed by gains in the nonfirm market.) This situation is illustrated in figure 5-5(a) and (b). (As in some previous figures in this chapter, for which a two-player coalition's gain can exceed that from wheeling, placement of points in the three-player core may not have the usual interpretation.)

Does All Good Firm Wheeling Take Place under Contract Model 2? Consider pricing option 1 in figure 5-5(a), first for the case in which S must sell its firm power at cost and then for the case of deregulated generation pricing. Suppose W should be the one to buy S's power on the basis of production efficiency. Figure 5-5(a) shows this situation, where the value of the subcoalition {WB} is zero, S's power is more valuable to W, and S has enough generating capacity so that it can sell to either W or B, if allowed, and have power left over. The solution under pricing option 1 is shown for two different levels of embedded transmission costs: low ("a") and high ("b").

Consider what happens as the embedded cost component of the transmission price increases from a starting value of zero. When the embedded cost component of the price is zero, the solution would lie on the intersection of the {SW} constraint line and the W-B side of the triangle, since the wheeling fee equals incremental cost and W gets none of the gain resulting from S selling to B. Also, S obtains none of the gain from its sales to either W or B. A positive embedded-cost term shifts the solution toward the W corner because W now gathers some of the gain from S's sales to B in the form of embedded cost rents. As long as embedded costs are not too high, the solution remains in the core ("a"). But if embedded costs become high enough, or the gain from S's sale to B is small enough, the solution moves out of the core ("b"). In this case, B would have an incentive to leave the coalition by self-generating.

Thus, there are circumstances under which good wheeling might not occur with this pricing model. However, such prevention of good wheeling either may be unlikely or unimportant. As long as W has its own needs satisfied first, if the gains from S's sale to B are large enough W has some incentive to calculate its embedded-cost price at a reasonable level so that the sale can occur and W can enjoy some of the gain resulting from S's extra power availability. Where these gains are too small to induce wheeling, any productive efficiency loss from not consummating the trade would be small also.

Continuing with figure 5-5(a), consider now the situation in which the price of generation is deregulated. Suppose S raises the generation contract price it charges to W but not the price to B. The solution shifts parallel to the S-W side of the triangle, toward S and away from W. It would shift in this direction until S's generation price equals W's long-run marginal production cost; this would fall short of the S-B side by an amount equal to the portion of the gain that W obtains (via the wheeling charge) from the S-B trade. If, on the other hand, S raises the power price to B only, the solution shifts toward, and perhaps as far as, the S-W side of the triangle. (In the latter case, B earns none of the gain, of course.) If S can price-discriminate, charging W more than B, then the solution would be on the S-W line, short of point S by the gain that W is able to get from S's sale to W. As a result, any point within the dashed area of figure 5-5(a) is a feasible solution. This assumes that embedded costs are low; if embedded costs are high--as at point "b"--then no solution is feasible because no matter how S might vary its power price, it cannot entice B to join the grand coalition {SWB}.

The conclusion under deregulated generation prices therefore is the same as under regulated generation prices: too high an embedded cost component in the wheeling charge under pricing option 1 could prevent good wheeling.

Now consider pricing option 2, again with $C_W + T_{WB} > C_B$, first for regulated generation prices and then for deregulated generation prices. The results are illustrated in figure 5-5(b). The possible firm wheeling rates can be anywhere between short-run variable cost plus embedded cost (point L) and replacement cost (point U), which is outside the core. As a result, the range of feasible outcomes is the overlap (if any) of the core with the line segment connecting these two points. In figure 5-5(b), overlap occurs because the replacement cost is assumed to be greater than the incremental cost and the sum of short-run variable cost and embedded cost is assumed to be relatively small. A case in which good wheeling might not occur is if the embedded cost is so high as to render wheeling--even under the lowest possible fee--unattractive to B (that is, point L falls outside the triangle). However, this possibility seems even more unlikely and unimportant than under pricing option 1, since point L by definition always lies on or to the S-W side of the solution resulting from pricing option 1. (An even more unlikely case in which good wheeling does not occur is if the replacement cost should be less than the incremental cost, in which case W would block the deal, preferring to deal with S alone--but this situation is not credible.)

If generation prices are deregulated, solution points that could result are shown as the overlap of the core with the area surrounded by a dashed line in figure 5-5(b). This region is developed using the same logic as for the analogous region in figure 5-5(a) and illustrates the same result. (The only situation in which power price deregulation might result in good wheeling where regulated generation prices would not is when the replacement cost point U is southeast of the V(SW) constraint, which is not a realistic situation.)

Figure 5-5(c) shows the "normal" case in which S's power is more valuable to B than to W. S would make sales to both in the optimal solution, satisfying all B's needs first. Assuming that W's demand is not completely met by S's sales to W and that S prefers to sell to B first, W might block good wheeling because it would prefer to have all of S's power for itself. This would happen only if solutions resulting from this pricing model fall outside the constrained core.

One way this could happen is under the following circumstances. Generation prices are regulated, and pricing option 1 is adopted. Under pricing option 1, if embedded costs are low enough, W would not obtain enough of the gain from S's sales to B to make up for the gain W loses by not forming a subcoalition with S. This is shown as point "a" in figure 5-5(c); it is not in the constrained core. (Higher embedded costs in the wheeling rate could shift this to point "b," in which case W would be better off wheeling. B, knowing that otherwise there would be no deal, might accept an embedded-cost transmission rate. This same deal could also be made under pricing option 2 if the replacement cost point U is above the {SW} subcoalition line.)

Deregulation of generation prices could correct this potential blockage of good wheeling. If S charges a higher price for its power sales to B, the solution would move toward the constrained core. With a large enough price increase, the core would be reached. Such a price movement does not make W better off, but does prevent the subcoalition {SW} from forming.

Other possibilities of good wheeling being prevented are possible, but have unimportant consequences or occur under unlikely circumstances.

In general, pricing option 2 is more likely to overlap with the core of the game since it encompasses a wider range of outcomes, including pricing option 1 if replacement costs are higher than incremental cost plus embedded cost.

Will Bad Firm Wheeling Occur under Contract Model 2? Since this system is voluntary, the answer is generally no--all parties must concur before wheeling occurs, and this does not happen if at least one party is worse off, as is the case with bad wheeling. The exception, as discussed earlier, is if C_W is greater than C_B but W wheels to B anyway to gain freedom from regulation of its nonfirm generation and transmission prices.

What Is the Distribution of Firm Market Gains under Contract Model 2? With generation regulation, W and B get all the gains. Deregulation shifts the solution in S's direction, and W is better off than under the Planning model because it sometimes can earn a profit on its power sales. In figure 5-5(c), if a solution is in the core, then W obtains more of the gain than under the Planning model, primarily because B must persuade W to consent to wheel.

Outside Markets

Two cases are considered here: the existence of other markets for S, W, or B, and an alternative transmission route from S to B. As set out in chapter 3, their effects are to put additional constraints on the core. Other markets would place floors under the gain that each party would obtain, as shown in figure 5-6. The results are entirely analogous to the results in the nonfirm market, as discussed in chapter 4.

These markets are not likely to be a threat to good wheeling for the following reasons. If we have regulation of generation prices, S cannot get any gain from an external market for its power in any event, so only solutions lying on the W-B edge of the triangle are feasible. If B's external market is profitable enough to make it refuse to enter into an agreement with S and W, the gain that W can lose is just the difference between its incremental wheeling cost and its wheeling fee. (This difference may equal the embedded cost of transmission, which is not likely to be large.) An external market for W seems least likely to preclude the solution points discussed here under a regulated generation market since

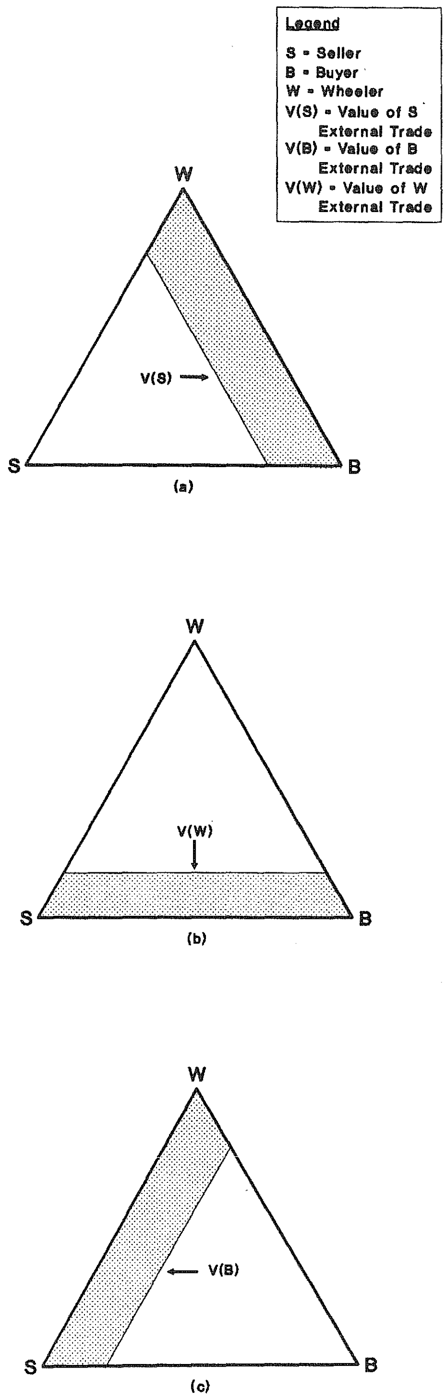


Fig. 5-6. Firm cores constrained by outside markets.

the points it renders infeasible are precluded anyway by the {SW} coalition.

In a deregulated generation market, the constraints imposed by external markets shrink the core. If they eliminate all feasible solutions, the gains from an S-W-B deal are probably not that much larger than the gains the players would earn in the external market. Hence, the net social loss, if any, is unlikely to be large.

An alternative route for moving power from S to B puts a constraint on the core as illustrated in figure 5-7. This type of constraint might preclude some good wheeling with generation prices regulated because it would eliminate solutions that lie above (on the W-side of) the constraint line. If embedded costs are high, including them in the wheeling rate might motivate B to buy power from S via the alternative route, even though the route through W is of lower cost.

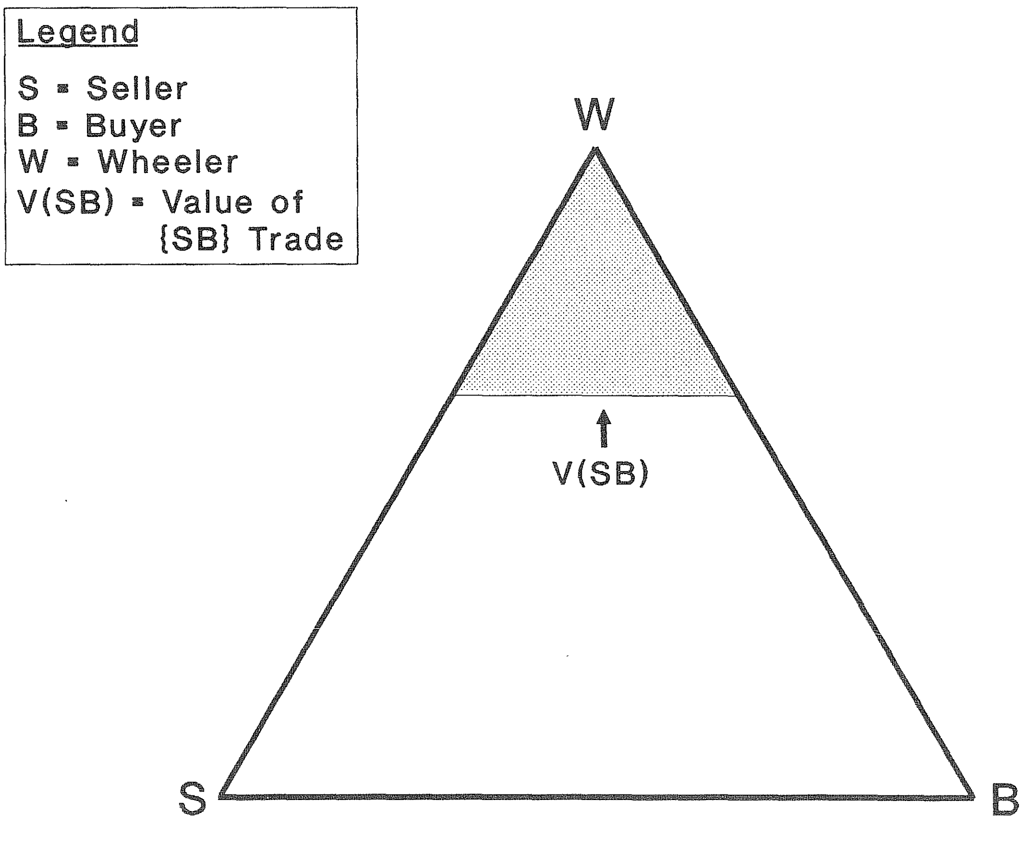


Fig. 5-7. Firm core constrained by alternate route.

CHAPTER 6

PLANNING TRANSMISSION CAPACITY FOR NONFIRM SERVICE

In this chapter, we examine a wheeler's strategy of building transmission capacity to earn a profit on nonfirm wheeling services, including simultaneous buy/sell. Conventional wisdom holds that utilities do not build transmission for coordination services, but the Pacific Northwest-Southwest Intertie is an example to the contrary. It was built, and is now being expanded, to displace thermal generation with low-cost hydropower as available.

Transmission has usually been constructed only for firm service with regulatory or contractual guarantees of cost recovery, or for reliability, with reliability capacity available for interruptible coordination service most of the time. Constructing transmission capacity for nonfirm service has been a poor investment: it risks a loss of capital if service does not materialize, and price regulation prevents the investor from earning a profit. In a more loosely regulated nonfirm power market, it may be a good investment if profits on wheeling services are permitted.

Because of policy makers' current focus on firm access and pricing policy--and their apparent willingness to trade firm access for nonfirm pricing flexibility--it is important to examine the strategic behavior of wheeling utilities in this new environment. As discussed early in chapter 4, the volume of nonfirm trading in the United States has been growing steadily since the mid-1940s and now exceeds the firm power sales volume. In this chapter we develop some insights into the construction incentives that would exist in a freer nonfirm market.

The approach is to extend the analyses of the previous two chapters. Here, the wheeler decides how much new transmission capacity to construct (a long-run decision) based on its knowledge of the nonfirm generation and transmission prices that will be in effect after construction (short-run prices).

The wheeler does not know how much use will be made of its new facility. However, it can estimate the probability of various usage levels. This situation may represent, for example, the case where a transmission investment is made to carry coal-fired power from Appalachia to New England but New England's future demand for this power is uncertain, depending on such factors as weather, effectiveness of conservation measures, and Canadian power availability and cost. Alternatively, the supply may be uncertain. This may be, for example, because annual variations in precipitation affect the supply of hydroelectric power. In this chapter to keep the number of cases examined reasonable we introduce the method of analysis using supply uncertainty only, and take hydro uncertainty as the usual example.

The analysis covers two stages. In the first stage, the wheeler W decides how much capacity to build for nonfirm transmission service. In the second stage, S, W, and B play a nonfirm three-player game, which is identical to the games in chapter 4. However, W's decision in stage one is based on a complete understanding of the strategic consequences of the stage-two game. All players know with certainty what access and pricing rules will be in effect in stage two.

We assume that regulation does not require the wheeler to provide firm transmission service for nonfirm power. This is a crucial, although reasonable assumption. It may or may not represent actual future transmission access policy. Suppose the seller and the buyer could compel W to construct new transmission facilities for their nonfirm trades, which they would pay for regardless of use. They would then be both the risk-takers and the profit-seekers. They should know as much as the wheeler about the probable variation in future hydro supply and, being just as smart, would maximize their own gain by compelling the wheeler to build the "right amount" of firm transmission capacity to handle their future economy power trades. The wheeler's market power, incentive to construct voluntarily, and strategic behavior can be studied only if transmission users cannot get firm transmission capacity for nonfirm power. Hence, we assume they cannot throughout this chapter.

This assumption is reasonable because, especially under the Contract model, the transmission provider may require evidence of a firm power purchase, such as a contract between S and B for firm generation service, before it undertakes investment in new transmission construction. The signed contract may represent its assurance that its investment can be recovered.

While the assumption is reasonable, it is not necessarily good policy. In fact, the essence of the NRRI model is that the transmission user has the choice of firm or nonfirm transmission for *any* transaction, whether it be for long-term or short-term power, or for firm or nonfirm power. Much of the efficiency claimed for the NRRI approach relies on this principle of customer choice, which takes away much of the wheeler's market power. It seems likely that, under some versions of the Planning model, users may be able to require construction of any new transmission capacity that they agree to pay for, regardless of its use. The analysis in this chapter does not apply to the situation where the users have this choice.

Once new transmission construction for nonfirm power transport is strictly voluntary on the part of the wheeler, then pricing policies that encourage such construction have an efficiency advantage. This chapter examines that advantage. It examines in particular the ramifications of the Contract model for nonfirm market efficiency. It should be remembered though, that any efficiency advantage may also be achieved by the principle of customer choice, as under the NRRI model and perhaps the Planning model.

The Approach

The system configuration under consideration is the same as in earlier chapters:

S ---- W ---- B,

where S now is a potential provider of economy/coordination power that varies annually in quantity of supply, W is a wheeler who owns both transmission lines (S-W and W-B) and is a potential purchaser of S's power, and B is a potential purchaser of S's power.

This chapter contains two distinct analyses, one in which B is another control-area utility and one in which B is a requirements customer of W. They are distinguished in two ways. One is by the equation assumed for B's demand. Where we assume that B has a linear, downward-sloping demand curve (additional quantities demanded have lower value to B because its own marginal production cost decreases as it purchases more from others), we say B is a control-area utility. Where we assume that B's marginal energy cost equals W's marginal energy cost (because W supplies B), we say B is a requirements customer of W.

Second, when B is a control-area utility we assume W must decide how much transmission capacity to build from S to W and from W to B. But when B is a requirements customer we assume adequate capacity already exists from W to B, so that only the capacity from S to W needs to be decided by W.

Assumptions

In all cases, S's economy power is hydropower that it has in excess of its own needs. The amount of hydropower it has available to sell at any particular time is Q_s. (In the equations, the marginal cost of S's power is set equal to zero. This is for algebraic convenience; it merely sets a reference point for cost, as in setting zero on the Celsius temperature scale to be the temperature at which water freezes. In this linear analysis, only cost *differences* matter. A positive cost for S makes the algebra more cumbersome but would not change the nature of the results.)

W's potential demand for economy purchases is D_w, while B's potential demand is D_b. Unlike the constant D_B in the previous chapters, D_b here is a function of price. If a tie line is not operating at capacity, the short-run marginal cost of transmission over either the S-W or W-B tie line is assumed to be negligible compared to other costs involved and so for convenience is set equal to zero.

As mentioned, W's decision can be viewed as a two-stage problem. In the first stage (the long-run decision), W decides how much transmission capacity y_{sw} from S and y_{wb} to B it should construct. In the second stage (the short-run decision), S, W, and B make short-run power supply and wheeling decisions based on the actual amount of hydropower that becomes available and on the access and pricing model that is in effect at that time. The amount of hydropower available in the second stage is random. W's objective in the first stage is to maximize its expected profit earned (or, equivalently, minimize its expected cost) in the second stage, deducting the cost of building the transmission line in the first stage.

This problem can be pictured using the decision tree in figure 6-1. The squares represent decisions by the players, and the circles represent uncertain future events ("nature's decisions") outside the players' control. The square on the left represents W's decision about how much transmission capacity to construct for carrying S's nonfirm hydropower. The diagram shows three choices in this first stage (high, medium, and low amounts of capacity), but in our equations the amount of capacity W can build is modeled as a continuous variable ranging from zero on up. This is stage one.

In stage two, after the capacity is built we learn the actual hydro availability. This stage is repeated annually. In the figure, this is represented as lines emerging from the circles labeled high, medium, and

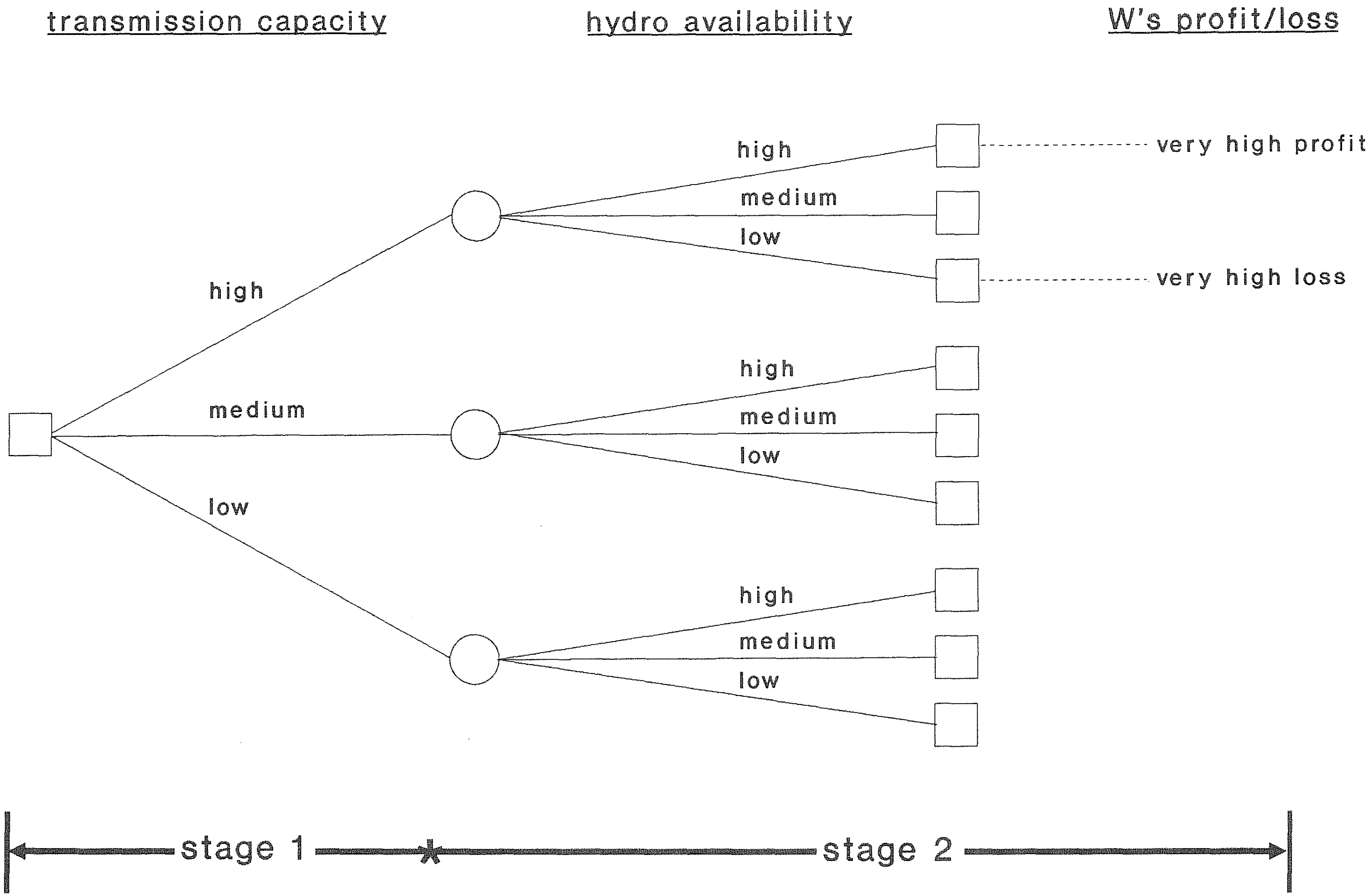


Fig. 6-1. Decision tree for planning transmission capacity for nonfirm power.

low availability, and there is a probability (not shown) associated with each level, such as 10 percent, 70 percent, and 20 percent, respectively. (These three probabilities are, of course, the same for each of the three circles because nature does not decide precipitation on the basis of W's prior construction decision, Murphy's Law notwithstanding.) In the model, however, hydro availability is a continuous variable with an associated continuous probability distribution. When the actual hydro availability is known, this determines the quantity that we called Q_S in chapter 4; then S, W, and B play a nonfirm game, as in chapter 4, to divide the gain. This game is represented by the squares on the right.

The game determines W's profit. If W builds a high level of transmission capacity, then in years when there is high hydro availability its profits should be very high, but in low hydro years it has the greatest loss on unrecovered transmission investment. These two outcomes (and only these) are shown in the figure. For other levels of transmission capacity and hydro availability its profit or loss (not shown) is between these extremes.

W's problem then is as follows: given (i) a continuous probability distribution for hydro availability, and (ii) a known access and pricing rule for nonfirm transmission, what level of transmission capacity would maximize its expected profit? For us the questions are: how closely do various access and price rules come to motivating W to build the socially optimum level of transmission capacity? And what are the income distribution consequences?

Nonfirm Wheeling to a Control-Area Utility

Here the situation is that both B and W would like to compete on equal terms to purchase surplus coordination power, such as hydropower from S, but W has a geographic advantage, since power must flow through W to get to B. First, we summarize the assumptions made, then present two methods for addressing the problem, and finally explain and present some numerical examples of the results.

B is in a different control area from W, and its avoided costs are a downward-sloping function of the amount of power it purchases. W can wheel S's excess hydropower to B, and the amount of hydropower S has available is a random variable. W's marginal generation and transmission costs are assumed to be constant.

To distinguish this analysis of transmission capacity built to accommodate coordination trading from the analysis of chapters 4 and 5, we use lower-case subscripts for the variables. The amount that S sells to W is x_{sw}, and x_{sb} is what it transmits or sells to B. W can generate power at cost C_w in order to meet its demand D_w if insufficient hydropower is available. W's decision concerns how much transmission capacity y_{sw} to build between S and W and how much capacity y_{wb} to build between W and B at capacity costs CC_{sw} and CC_{wb}, respectively. These variables, y_{sw} and y_{wb}, may represent new or additional tie lines or simply the expanded internal transmission capacity that W needs to buy power from S or sell power to B.

The notation listed next follows that presented in chapters 4 and 5 except that, as mentioned, lower-case subscripts are used. All quantities are in kilowatts, unless otherwise noted. As before, decision variables are denoted by lower-case letters and fixed parameters by upper case letters.

y_{sw} = amount of transmission capacity built by W between S and W
y_{wb} = amount of transmission capacity built by W between W and B
CC_{sw} = annualized cost of transmission line y_{sw} [$/kW/yr]
CC_{wb} = annualized cost of transmission line y_{wb} [$/kW/yr]
P_{bo} = price intercept for B's linear demand curve

Other variables not listed are the same as in prior chapters.

Only one possible outcome of the short-run flexible pricing games is examined, and it is defined as follows. During times when any transmission constraint is binding, W charges a wheeling fee equal to the minimum of the following quantities:

- the difference between S's marginal cost (=0, as explained earlier) and B's marginal benefit (MB_b), evaluated at the marginal (last) kWh bought by B; and
- a preset ceiling F_u on wheeling rates.

When neither tie line is congested, the wheeling fee falls to a flat rate, $F_{sb}=F_{sw}+F_{wb}$, which might, for example, be based on embedded cost. It is assumed that as much of S's power as possible is first allocated to B since this transaction has the higher gain, and any remaining power is then sold to W. Sales between S and W are consummated on a split-savings (net of the transmission fee F_{sw}) basis. W's gain per kilowatt-hour purchased from S on this basis is $0.5(C_w+F_{sw})$. (We assume here that no transmission congestion charges are applied to S's sales to W, even if the transmission line is used to capacity.) B's purchases from S are also priced on a split-savings basis, net of W's wheeling fee.

Analytical Method

W's problem is to choose nonnegative values of y_{sw} and y_{wb} in order to maximize its profit. Its profit equals the transmission fees it collects minus (1) the cost of meeting its demand via its own generation and purchase from S and (2) the cost of building transmission capacity. Most of the equations expressing various versions of this profit maximization problem are given in appendix C. However, one equation (the most general form from which the others are derived) is presented here to illustrate the technique. The problem is summarized in the following general expression for W's expected profit, with the meaning of each term expressed in brackets below:

$$\underset{\{y_{sw}\geq 0,\,0\leq y_{wb}\leq D_{bo}\}}{\text{MAXIMIZE}} \quad \text{Profit}_w = \frac{8760P_f}{Q_{sm}} \Big[\int_0^{y_{wb}} (F_{sw}+F_{wb})y\,dy$$

[Fees earned when y is not used to capacity]

$$+ \int_{y_{wb}}^{Q_{sm}} \text{MIN}(P_{bo}-My_{wb}, F_u)y_{wb}\,dy + \int_{y_{wb}}^{\text{MIN}(y_{sw},y_{wb}+D_w)} 0.5(C_w+F_{sw})(y-y_{wb})\,dy$$

[Fees earned when y_{wb} used to capacity]

[Cost saved by purchases from S, when y_{sw} not used to capacity]

$$+ \int_{\text{MIN}(y_{sw},y_{wb}+D_w)}^{Q_{sm}} 0.5(C_w+F_{sw})\{\text{MIN}(y_{sw},y_{wb}+D_w)-y_{wb}\}\,dy\Big] - [CC_{sw}y_{sw}+CC_{wb}y_{wb}]$$

[Cost saved by purchases from S when y_{sw} used to capacity]

[Transmission line construction cost (annualized)]

$$- C_wD_w ,$$

[Cost of generation with no purchases from S]

where Q_{sm} is the maximum amount of hydropower that could become available, and M is the negative of the slope of B's marginal benefit (demand) curve.

In the second term, the "MIN" operator ensures that the fee charged is the minimum of the marginal benefit to B ($=P_{bo}-My_{wb}$) and the fee ceiling F_u. The "MIN" integral limits ensure that most power that is sold to W is the minimum of $y_{sw}-y_{wb}$ and D_w. D_{bo} is the most that B would want to buy. The upper bound on y_{wb} ($y_{wb} \leq D_{bo}$) results from B's declining demand curve, as set out in more detail later.

Solving the Integral Analytically

The integral above cannot be directly integrated and then differentiated to solve for the optimal y_{sw} and y_{wb} because of possible discontinuities caused by the "MIN" terms and the bounds on y_{sw} and y_{wb}. Instead, seven possible versions of this integral are analyzed, and the best of the feasible solutions is taken as optimal. Each version represents a different resolution of the "MIN" terms and/or a different combination of binding bounds upon y_{sw} and y_{wb}. These seven versions are:

Version Ia: The ceiling on wheeling rates is not binding (a wheeling fee equal to B's marginal benefit would be charged when either transmission line is used to capacity) and $y_{wb} < y_{sw} < y_{wb}+D_w$ in the optimal solution. That is, W on occasion buys power from S, but W's demands do not constrain the amount of power that S can sell.

Version Ib: Same as Ia, except that the ceiling on wheeling rates does bind (that is, a wheeling fee equal to the ceiling is charged when a transmission line is used to capacity).

Version IIa: Same as Ia, except that $y_{wb} < y_{sw} = y_{wb}+D_w$ (W's demand constrains the amount of power that S can sell. Note that the optimal y_{sw} can never exceed $y_{wb}+D_w$ because S would never use the portion of y_{sw} that is in excess of W's demand, D_w, and B's potential purchases, which are limited by y_{wb}.)

Version IIb: Same as IIa, except that the ceiling on wheeling rates does bind.

Version IIIa: Same as Ia, except that the optimal y_{sw} and y_{wb} are equal. That is, B's potential demand and willingness to pay for power are so large that W cannot justify building any additional y_{sw} to allow sales by S to W; all the capacity is used to wheel power to B.

Version IIIb: Same as Ib, except that the optimal y_{sw} and y_{wb} are equal.

Version IV: W "chokes off" B, setting $y_{wb} = 0$ and building y_{sw} to optimize its purchases from S. (If transmission costs are high enough, this may include the solution $y_{wb}=y_{sw}=0$.)

In order to determine which version is applicable under a given set of parameter assumptions, all seven versions are first solved. Then, versions that are infeasible are eliminated because they violate either the definition of the pricing policy (the wheeling fee when transmission is congested must be the minimum of the marginal benefit and the ceiling), the optimality condition that y_{sw} cannot exceed D_w+y_{sw}, or the bounds y_{sw} and y_{wb}. Next, the best of the feasible solutions is picked as the optimal solution to the original problem. By construction, at least one of the versions yields a feasible solution. In appendix C, an equation for W's profit is defined for each version, and expressions for the optimal line capacities y_{sw} and y_{wb} in each case are derived. The analytical results presented in appendix C have been verified by numerical integration for a variety of parameters.

More complex situations, as reported later on, are handled only through numerical integration of the integral.

Numerical Results of the Analytical Approach

Using the analytical approach to solving the integral, we consider only flexible pricing of nonfirm transmission and make one simplifying assumption, namely, that W has no excess capacity ($Q_w=D_w$). Later, other pricing policies are treated numerically, without this restrictive assumption.

Here we calculate a quantity that we call "social welfare." Ordinarily, this term does not apply to firm-to-firm transactions; it applies only to sales to ultimate consumers. It is the sum of producer's surplus, or--where producers sell at cost--it is the total area under the utility's retail demand curve less the cost of power to retail customers. But, under the highly restrictive assumptions here, particularly the assumption that retail consumer demand is insensitive to the purchased power price, true social welfare is greatest when the benefits to the purchasing utility are greatest. Thus, we calculate as a proxy for social welfare the area under the buying utility's demand curve less its total costs.

Introduction

The questions of interest to policy makers are:

1. Are ceilings to wheeling fees desirable?
2. If so, what are the optimal ceiling levels, and how do they depend on cost and demand conditions?
3. How "flat" is the optimum of the curve showing social welfare as a function of the ceiling F_u? With a flat curve, it is not necessary to know the exact optimum, since any value near it yields almost the same production efficiency. A peaked curve means that it is important to choose a value carefully, which probably is difficult for a regulatory agency to do, given uncertainties in data.
4. At what ceiling values does W choose not to build any transmission capacity to B at all (y_{wb}=0)?
5. What ceiling levels result in the greatest return to S and B?

The answer to the first question is definitely *yes*. The reason is that a ceiling that binds takes away an important source of market power for W--the ability to restrict y_{wb} and cause the congestion fee to rise (due to the negative slope of B's demand curve). This result is demonstrated later in this chapter.

Because of the number of different versions that must be checked, it is difficult to derive analytical answers to the other four questions. Instead, we answer those questions for a wide range of parameter values. Figures 6-2(a) through 6-2(m) show thirteen plots of social welfare (= the integral of B's demand curve minus total costs), W's profit (revenue - expenditures), y_{sw}, and y_{wb} for thirteen different sets of parameters values.

The base case, shown in figure 6-2(a), assumes the following values:

- W's demand D_w = 500 MW
- W's marginal cost C_w = 0.03 $/kWh
- A uniform probability distribution of hydropower availability Q_s, with an upper limit of Q_{sm} = 1,000 MW and a lower limit of 0 MW
- B's demand curve having a price intercept of $0.10 per kWh and a quantity demanded of 500 MW at a price equal to C_w
- Transmission line costs CC_{sw} and CC_{wb} each equal to $17.52/kW/yr
- Transmission fees F_{sw} and F_{wb} each equaling $0.004/kWh

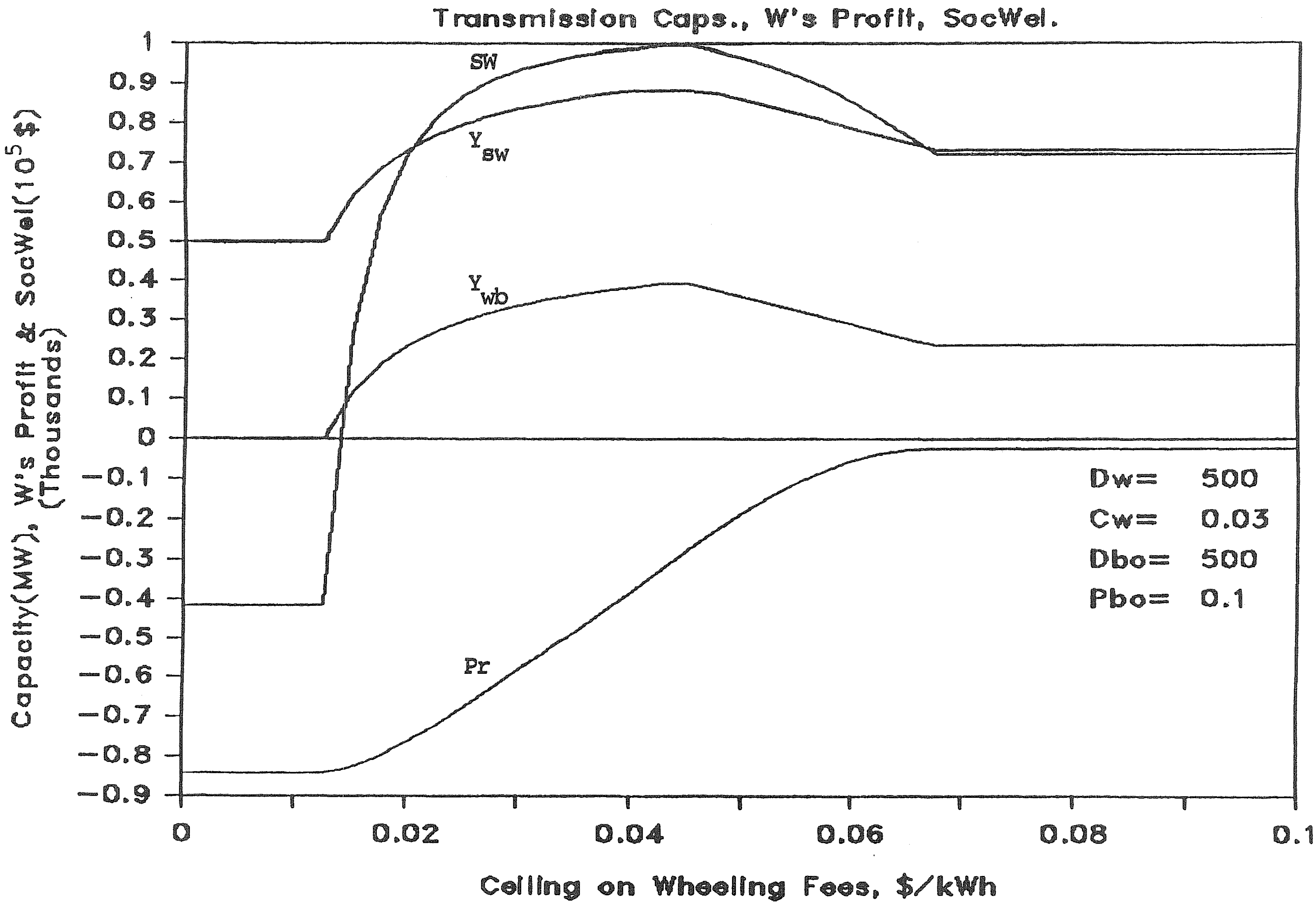


Fig. 6-2. Transmission capacity, y_{sw} and y_{wb}, for nonfirm power under flexible pricing: variation of social welfare (SW) and profit (Pr) under (a) base case conditions (above) and other conditions in parts (b) through (m).

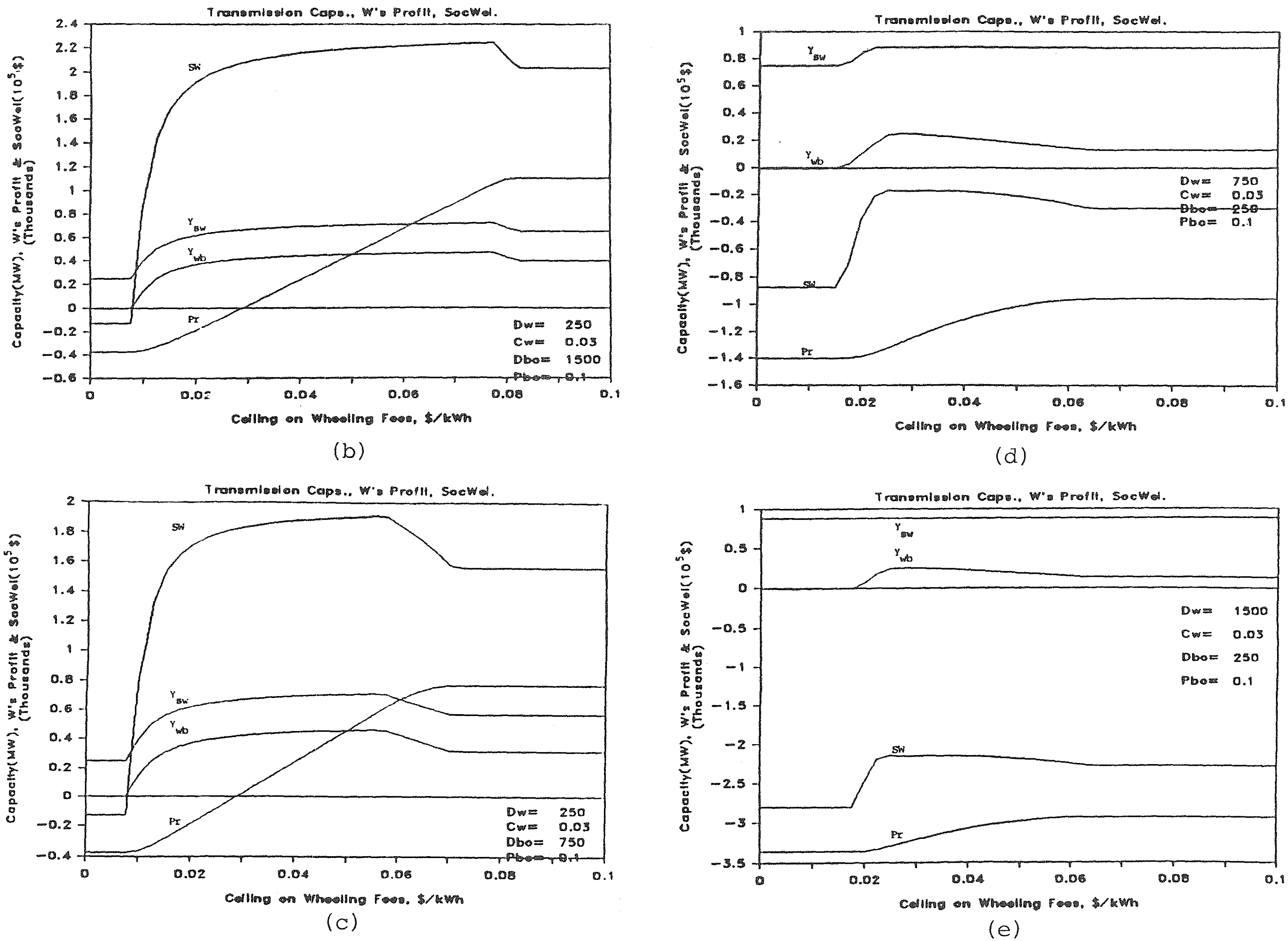


Fig. 6-2(b), (c), (d), and (e). Effects of different relative sizes of W and B.

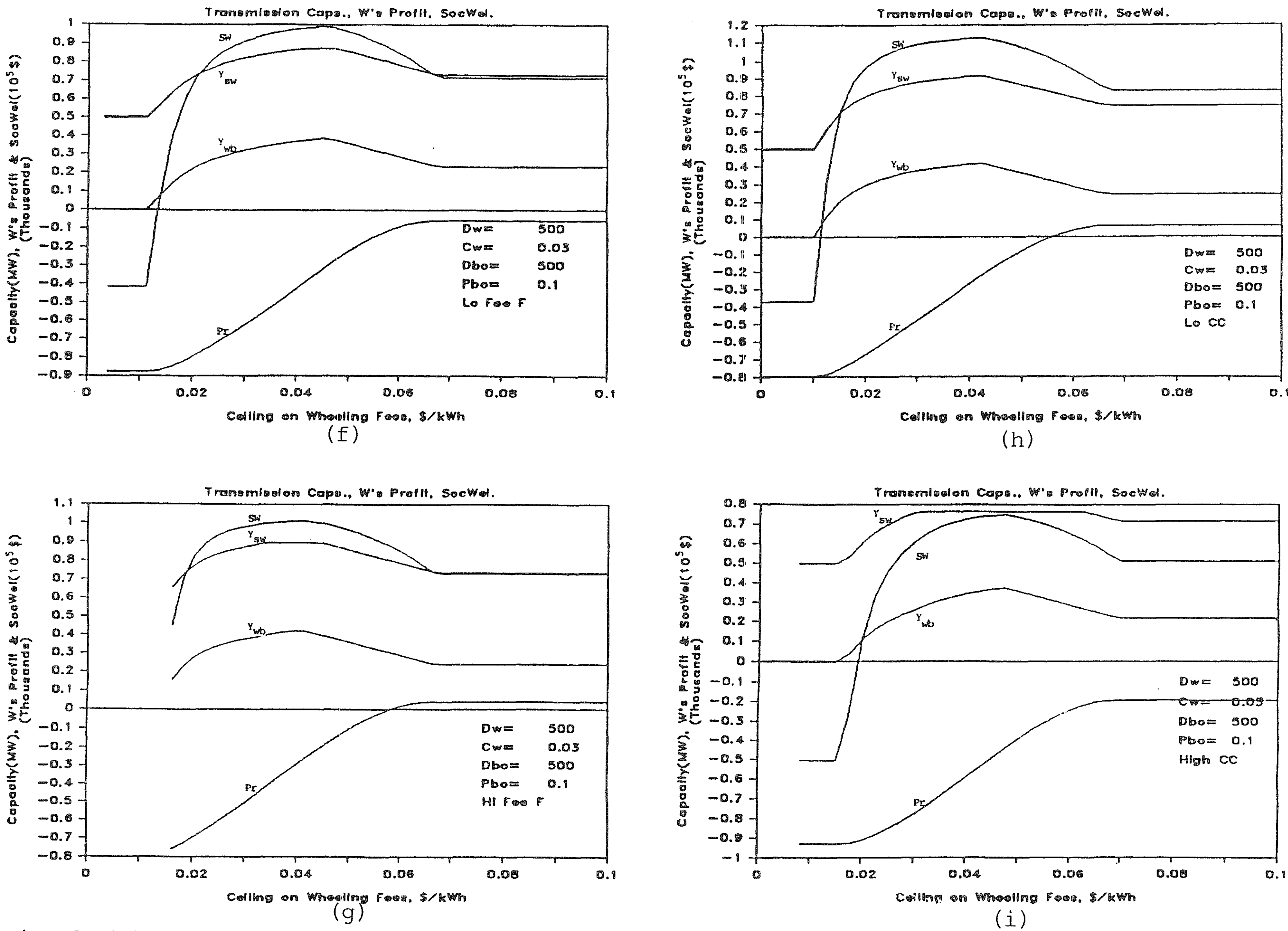


Fig. 6-2(f), (g), (h), and (i). Effect of various wheeling fees (F) and transmission construction costs (CC), where "Lo" and "Hi" values of F and CC are half and double, respectively, their base case values.

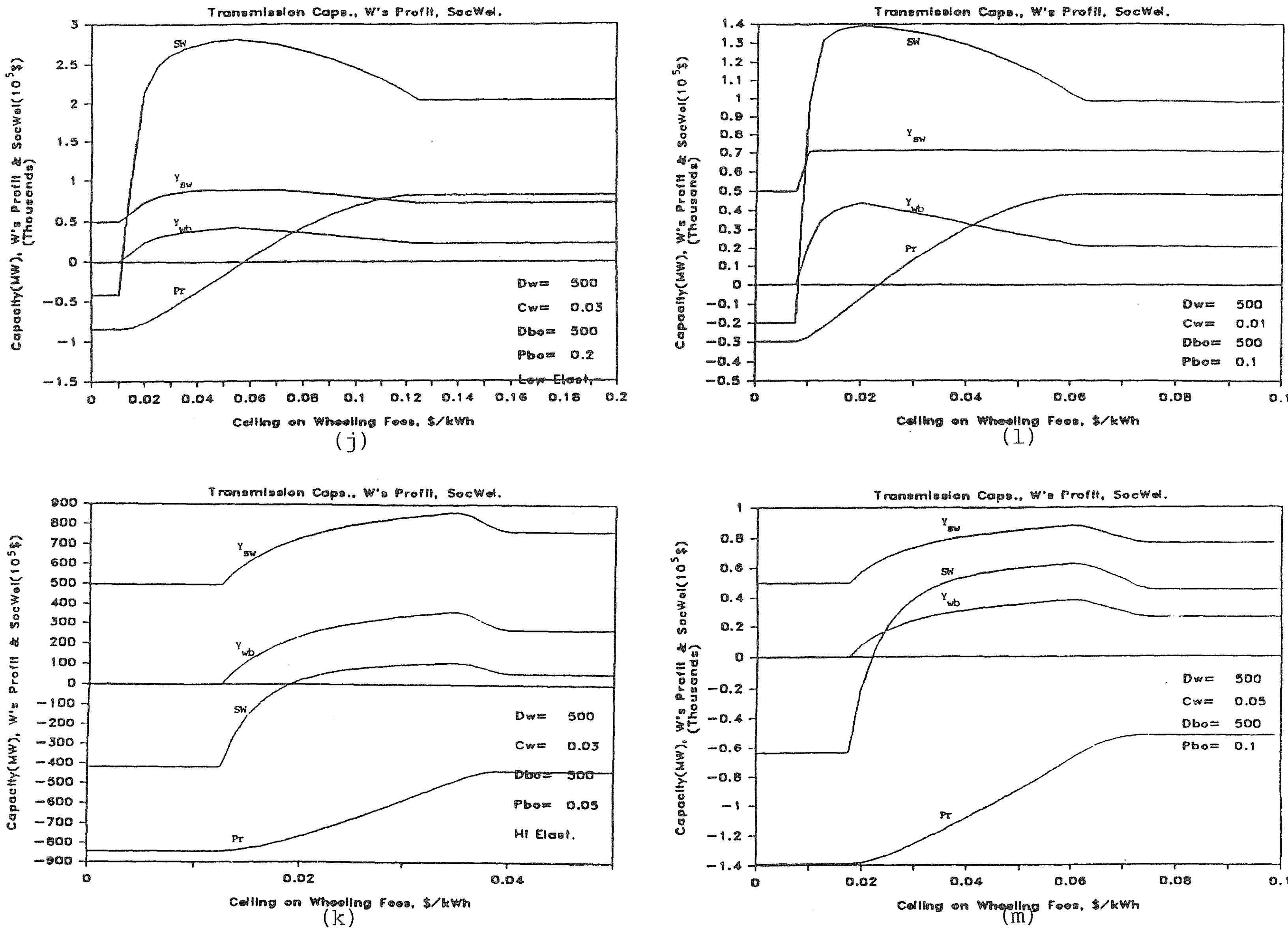


Fig. 6-2(j), (k), (l), and (m). Effects of various elasticities for B and marginal costs for W.

Figures 6-2(b) through (e) look at different combinations of D_w and D_{bo}, ranging from small D_w/large D_{bo} in figure 6-2(b), to the opposite in figure 6-2(e). These figures show the effects of different sizes of wheelers and buyers, ranging from a small wheeler and huge buyer (such as a small utility owning the bottleneck between S and a power pool) to a very large wheeler and a small buyer (such as a large control-area utility and a small independent system). Figures 6-2(f) and (g) show the effect of increasing the wheeling fees, F_{sw} and F_{wb}, from low to high (the low fee might be based on embedded cost, while the higher one might be based on opportunity cost). Figures 6-2(h) and (i) compare the results under small and large transmission construction costs. These costs might be a proxy for distance, the larger costs being applicable, perhaps, for interregional transfers while the smaller costs might be within a region. Figures 6-2(j) and (k) show the effect of different price elasticities (modeled by varying the price intercept P_{bo}). A low price elasticity means that B's marginal costs are fairly constant over a wide range, while a high elasticity means that marginal costs quickly increase if little hydropower is available (perhaps because B has little spare generation capacity and a variety of fuel sources). Finally, figures 6-2(l) and (m) show the effect of changing W's marginal cost; a higher marginal cost means that the hydropower is more valuable, and transmission capacity additions should be easier to justify. Because of the way that B's demand curve is defined, a higher C_w also increases the marginal benefit that B receives.

Let us consider the answers that emerge from these analyses.

Questions 1 and 2: What Is the Best Ceiling?

Moderate ceilings on wheeling rates are desirable because they strip W of some of its market power and remove one incentive to restrict y_{wb}--that of congestion fees that are higher for smaller amounts of capacity. (However, another incentive remains: the smaller y_{wb} is, the more frequently W can charge the congestion fee.)

This is shown in all the curves, which nearly always have the shapes shown in figure 6-3. The maximum social welfare corresponds to the level of the ceiling F_u that yields the highest values of y_{wb} and y_{sw}. Too high a ceiling allows W to exploit its position and (as shown also in the numerical simulations in appendix D) results in a significant loss of production efficiency. Too low a ceiling removes W's incentive to wheel; in most cases, W builds no lines to B, preferring to keep S's hydropower

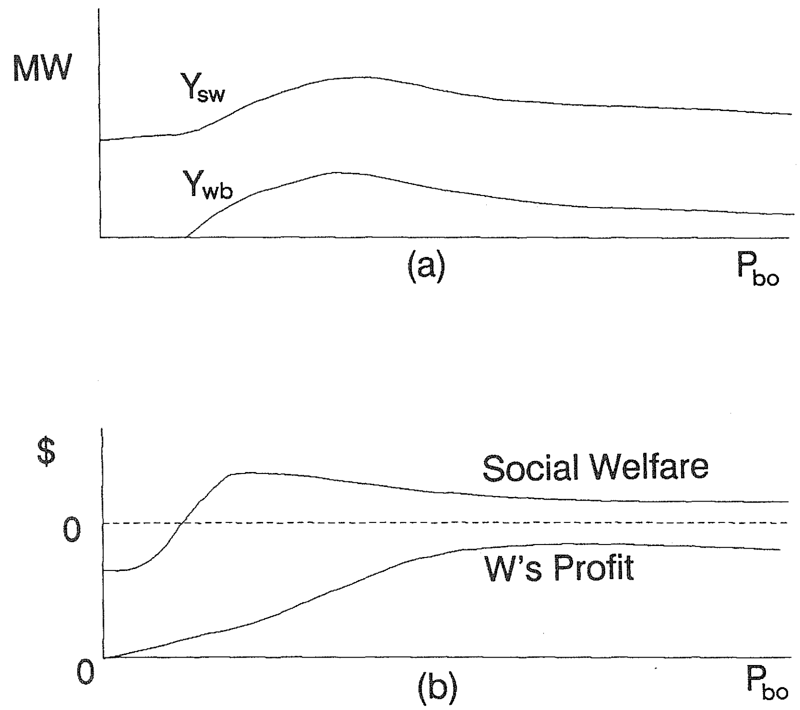


Fig 6-3. Generic curves for optimal nonfirm rate ceilings.

for itself. Too low a ceiling is considerably worse than too high a ceiling: for example, in the base case shown in figure 6-2(a), too high a ceiling results in a social welfare loss of about $30,000,000 per year (= 1.0-0.7 x 1000 x $100,000/yr), while too low a ceiling yields a loss of $160,000,000 per year (=1.0-0.4 x 1000 x $100,000/yr).

In figures 6-2(a) through (m) the social welfare optimizing point is quite high, usually in the range of $0.04/kWh to $0.06/kWh, with extremes of $0.021 and $0.075/kWh. The lower optimal ceilings occur under the following assumptions:

- a large W and small B [high D_w and low D_{bo}, figures 6-2(d) and (e)], because the value of the power to B is relatively low
- a high price elasticity [low P_{bo}, figure 6-2(k)], because the value of the power to B is relatively low
- a low cost of generation for W [low C_w, figure 6-2(l)], because the value of power to both W and B is low

The higher optimal ceilings occur under the opposite assumptions, for the opposite reasons, as shown in figures 6-2(b), (c), (j), and (m).

These effects follow only if W uses the pricing policy assumed here--a low rate when transmission capacity is available and a high rate when it is completely used. In other circumstances, the effects of a rate ceiling may be quite different and probably would not be as dramatic as in these results.

Question 3. How Flat Is the Optimum?

Most of the curves show a flat optimal region. For example, consider figure 6-2(a), where the aggregate social welfare varies from $-42,000,000 per year to $+100,000,000 per year. Any ceiling between $0.025/kWh and $0.06/kWh would yield at least $90,000,000 per year in welfare. Only for figures 6-2(k) and (l) where the value of the hydropower is relatively low are the social welfare functions relatively "peaky."

Even more reassuring is that the optimal regions under different parameter values overlap to a great extent. This seems to imply that a wheeling rate ceiling in the range of $0.02 to $0.04/kWh captures most of the production efficiency benefits in nearly all cases. It does not appear that regulatory agencies would have to choose the ceilings very accurately, which is a desirable characteristic of this pricing model since agencies possess limited ability to accurately forecast costs, demands, and how wheelers will make transmission capacity decisions.

Question 4. What Ceilings Cause W Not to Build Any Capacity to B?

If the rate ceiling is low enough, W decides that it is more profitable to buy S's power for its own use (on a split-savings basis) than to build a line to wheel it to B--even if the power would be much more valuable to B than to W. This occurs in all the parts of figure 6-2 when the ceiling falls to a value between \$0.008/kWh and \$0.018/kWh. The lower value occurs for those situations in which W has few valuable uses for the power: either D_w is small, as in figures 6-2(b) and (c), or C_w is small, as in figure 6-2(l). Low values also occur if transmission costs are low, as in figure 6-2(h).

Question 5. What Ceilings Yield the Greatest Return to S and B?

Of course, W's profits are highest under the highest ceilings. (This is because, in general, relaxing a constraint cannot worsen the optimal value of the objective, W's profit.) However, it does not follow that S and B's returns are greatest when W's profits are smallest. Indeed, S and B's return, which in figure 6-3 is the difference between the social welfare curve (SW) and W's profit curve (Pr), is smallest when W's profit is also lowest. This occurs when the price ceiling is small, below \$0.02/kWh or so. This is because W chooses the very inefficient solution, building no transmission link to B. Everyone is worse off in that case. Thus, moving to a higher ceiling, such as \$0.04/kWh, results in a Pareto improvement--everyone is better off.

Hence, a low ceiling policy that might initially appear to be in B's interest actually could be a worse policy for B, as B would gain nothing if W were to set y_{wb} to zero.

The figures show that the ceiling that results in the most total return to S and B is somewhat lower than the socially optimal level. Their return is optimized when the difference between the SW and Pr curves in figure 6-3 is greatest, which occurs when the slopes of the curves are identical. For example, in the base case this occurs at a price ceiling of \$0.028/kWh, a value just over half the optimum ceiling. Note, however, that the social welfare at this point is still quite high compared to the worst possible solution, and it is also higher than the high ceiling solutions. This implies that it is likely to be possible to "buy" S and B's approval for a flexible pricing system by setting a relatively low ceiling without too much loss of production efficiency. (If the ceiling is set too low, there is the risk that W will choke off B.)

Nearly all the figures show that S and B maximize their joint return when the ceiling is in the range of \$0.021 to \$0.028/kWh. Three figures fall outside this range. If transmission line construction costs are high [high CC_{sw} and CC_{wb}, figure 6-2(i)], S and B are best off under a ceiling of \$0.035/kWh. However, if the value of power to W and B is low [represented by a high elasticity for B in figure 6-2(j) and a small marginal production cost C_w for W in figure 6-2(k)], the optimal ceiling for S and B is \$0.02/kWh or lower.

As for B's return and S's returns calculated separately, if B and S split any savings resulting from wheeling, an increase in the return for one generally is correlated with an increase for the other.

Solving the Integral Numerically

By solving the integral presented earlier numerically we can treat more general conditions, and in particular we can look at pricing policies other than flexible pricing for nonfirm transmission. (The disadvantage is that computational effort limits the range of the parameters that can be examined.) To begin, we review and extend the assumptions of the analysis.

Assumptions

B is still a distinct control area whose avoided costs are a downward-sloping function of the amount of power it purchases. This downward slope can result from B using power from S or W to offset B's most expensive generation sources first. W can either wheel S's excess hydropower or sell its own surplus thermal power, if any, to B. W's marginal costs are assumed to be constant. Figure 6-4 shows S and W's supply costs, C_s and C_w respectively, and B's avoided costs (marginal benefits, MB_b, of its purchases D_b). The amount that S sells to W is x_{sw}, and x_{sb} is what it sells to B. W can either generate for its own consumption (x_{ww}) or for sale to B (x_{wb}). Q_w, W's capacity, may be equal to or greater than W's requirements for power, D_w, depending on the assumption made. Again, W's decision is how much transmission capacity y_{sw} to build between S and W, and how much y_{wb} to build between W and B.

In the next section, we consider the case where B is a requirements customer of W. The results of that analysis may differ from those of the

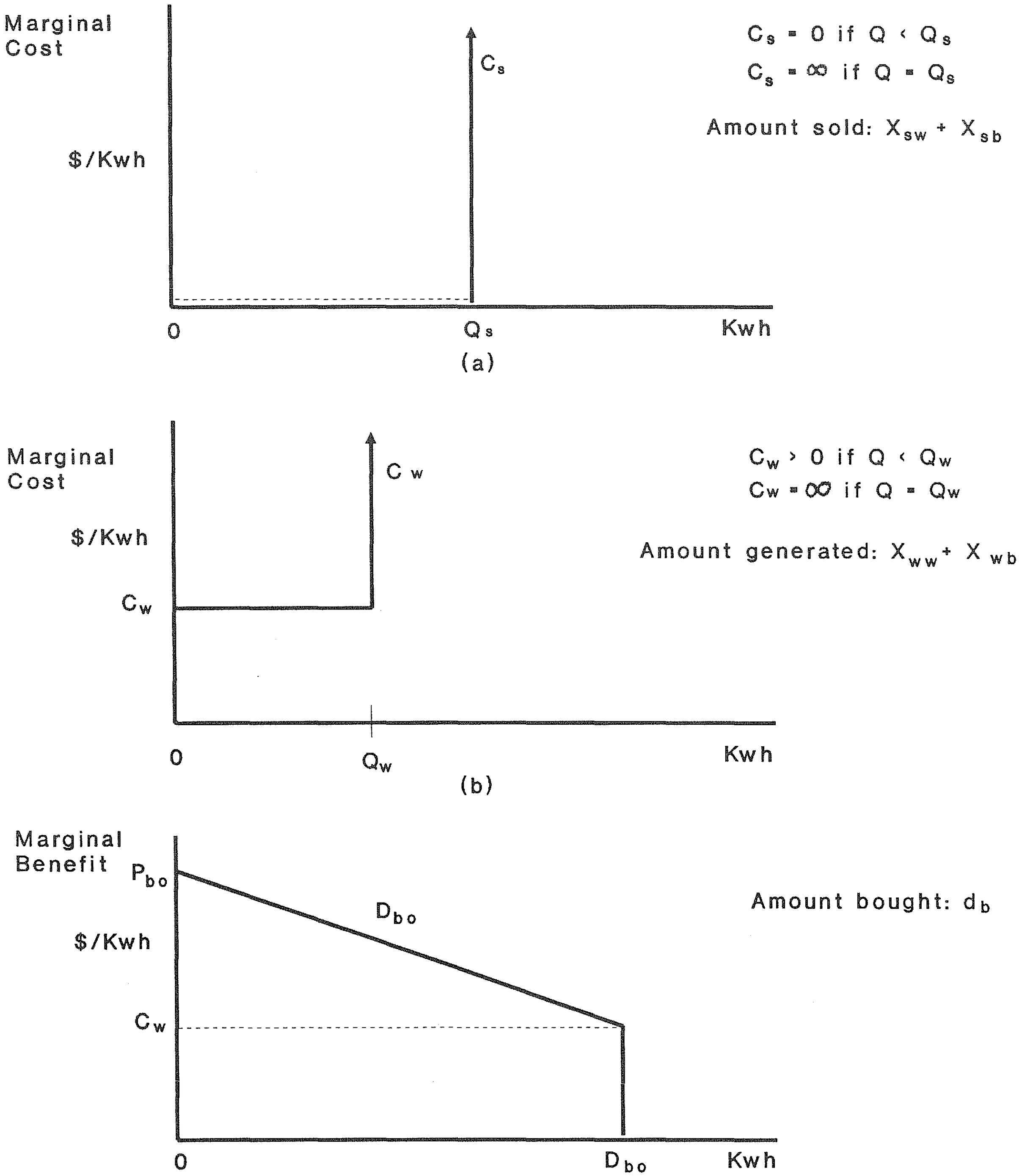


Fig. 6-4. Supply costs for S and W and avoided cost for B, in the study of capacity for wheeling nonfirm power to a control-area utility.

analysis here, where B is an independent control-area utility, for several reasons:

1. B's avoided cost curve MB_b is downward sloping here, which may give W more opportunity for exploitation.
2. Both y_{sw} and y_{wb} are decision variables, since B is not a requirements customer of W. W may, as a result, build ample y_{sw} for its own needs, but constrain B's access to economy energy from S by building only a small amount of y_{wb}. When B is a full requirements customer, however, y_{wb} must be adequate to meet all B's needs.
3. W may have power supplies that it wishes to sell to B, which may additionally motivate W to restrict the amount of transmission capacity y_{sw} from S in order to prevent wheeling.

Access and Pricing Models Considered

The following pricing models are considered.

1. Ideal. W builds exactly the amount of y_{sw} and y_{wb} that minimizes long-run total power supply costs for S, W, and B together.

2. Simultaneous Buy/Sell. W buys from S using a split-savings rule and, at the same time, sells to B also on the basis of split savings. The "savings" to be split in each case are net of the wheeling fees F_{sw} and F_{wb}, as appropriate, charged by W. Savings to B are calculated using the integral of its avoided cost curve from 0 to D_b, the amount of power that B buys. B buys power until its avoided cost MB_b falls below the delivered price (which, at its lowest, equals C_w+F_{wb}) or until it is impossible to purchase additional supplies.

3. Wheeling at a Fixed Fee. Subject to transmission capacity constraints, any available hydropower is first wheeled to the highest value customer, which is B. (The case in which W buys its needs first is not considered here.) W charges $F_{sw}+F_{wb}$ for such wheeling transactions. Then, once B's needs are satisfied as much as possible from S, W may buy any remaining hydropower. After that point, W may sell any excess power it can generate to B, if such a transaction is possible and attractive from B's point of view. Transactions between S and W, W and B, and S and B are priced using the split-savings rule, where the savings are calculated net of any wheeling fees.

This can be viewed as a Planning model approach in that access to *existing* transmission facilities is mandatory at a price $F_{sw}+F_{wb}$ set by regulation. However, the amount of new transmission facilities that W builds for coordination service is solely W's decision. As discussed earlier, it is assumed here that "mandatory access" does not mean that B or S can force W to build transmission capacity for nonfirm transmission service.

4. <u>Congestion-Charge-Based Flexible Pricing</u>. This approach uses one possible way of implementing the short-run portion of a Contract model with flexible pricing. During times when any transmission constraint is binding, W can charge a wheeling fee equal to the minimum of the following quantities:

- the difference between S's marginal cost (=0 here for convenience) and B's marginal benefit (MB_b), evaluated at the marginal (last) kilowatt-hour bought by B; and
- a preset ceiling on wheeling fees.

When no link is congested, the wheeling fee falls to $F_{sw}+F_{wb}$. Just as in the Planning model, it is assumed that as much of S's power as possible is first allocated to B, and any remaining power is then sold to W. At that point, W can sell to B if any economic opportunities remain. Any bilateral sales are consummated on the basis of split-savings (net of transmission fees). In bilateral S-W and W-B transactions, however, we assume that the (implicit) wheeling fee is always F_{sw} and F_{wb}, respectively, even if the transmission lines are used to capacity.

5. <u>Gain-sharing Flexible Pricing</u>. In this flexible pricing model, it is assumed that in the short-run game the transmission capacity is allocated efficiently and the gains from trade are distributed according to the Shapley value of the short-run game. The reason for considering this game is to analyze a flexible pricing model that does not result in the wide price swings and large amount of market power yielded by the congestion-fee-based model.[1]

[1] In certain simple games, the Shapley value is the same as the simultaneous buy/sell solution (see the short-run analysis of chapter 4), but not always. The net profit that each player receives in the short-run

(Footnote continues on next page)

6. <u>NRRI Model</u>. This is like the congestion-fee-based flexible pricing model, except that if transmission is at capacity there is no wheeling fee price cap. This model is included for completeness using the short-run marginal-cost pricing features of the model. It is this pricing practice that is actually being evaluated because the NRRI model, which emphasizes the principle of customer choice, does not apply to the basic situation examined in this chapter, namely, that wholesale customers cannot choose firm wheeling for nonfirm power.

For each particular value of the available hydropower, Q_s, all these prices and quantities are calculated for the various configurations of the transmission system, y_{sw} and y_{wb}. W's problem is then to choose y_{sw} and y_{wb} to maximize its expected return from future short-run power sales, minus the cost of building the transmission lines. The gains to S and B and the total social welfare are also calculated as an expectation over possible values of Q_s.

Numerical Results

No analytical solutions are derived because these models are significantly more complex than those earlier in this chapter and in

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(Footnote continued from previous page)
Shapley solution is given by the following equations, derived from the definition of the Shapley value:

S's profit = V(SW)/6 + V(SWB)/3 - V(WB)/3
W's profit = V(BW)/6 + V(SWB)/3 + V(WB)/6
B's profit = V(BW)/6 + V(SWB)/3 - V(SW)/3

where: V(WB) = C(W) - C(WB)
= W's cost of meeting its own demand, minus the cost of the WB coalition (This difference equals the value of the integral of B's demand curve minus W's generation and transmission costs under {WB}.) (No C(B) term appears because B's net benefits are assumed to be zero if it does not join a coalition.)

V(SW) = C(W) - C(SW)
= W's cost of meeting its own demand, minus the cost of the SW coalition (This difference equals W's generation and transmission cost savings when it can buy from S.) (No C(S) term appears because S's net benefits are also assumed to be zero if it does not join a coalition.)

V(SWB) = C(W) - C(SWB)
= W's cost of meeting its own demand, minus the cost of the {SWB} coalition (This difference equals the value of the integral of B's demand curve minus W's generation and transmission costs under the grand coalition {SWB}.)

appendix C. In particular, there are two more decision variables: y_{wb} and x_{wb}, and an additional constraint (Q_w). These complications mean there are, in general, many more combinations of cases to consider. Instead, simulations on a computer spreadsheet were developed, which numerically integrate over the probability distribution of Q_s to determine the expected costs/profits for each participant under each pricing model. A sample set of runs is presented here.

The "base case" numerical values assumed for the parameters are as follows:

Distribution of Q_w:	Uniform between 0 and 1,000 MW (a ten-point approximation is used in the integration).
Assumptions for W :	C_w = \$0.03/kWh Q_w = 500 MW D_w = 500 MW
Assumptions for B :	Linear marginal benefit/avoided cost curve, with price intercept P_{bo}= \$0.10/kWh and MB_b = C_w = \$0.03/kWh at d_b = D_{bo} = 500 MW
Transmission :	Construction costs for transmission lines CC_{sw} = CC_{wb} = \$0.002/kW/hr (or \$17.52/kW/yr). F_{sw} = F_{wb} = \$0.004/kWh No price ceiling for flexible wheeling fees, which results in a maximum fee equal to MB_b

<u>General Conclusions: Efficiency</u>. The results for the base case and nineteen other cases are presented in tables in appendix D. Here, we briefly interpret these results. For every set of parameter values examined, the productive efficiency of the models is ranked as follows:

1. Ideal
2. Simultaneous buy/sell (nearly identical to the ideal)
3. Gain-sharing flexible pricing
4. Congestion fee-based flexible pricing
5. Wheeling at a fixed fee

Under the ideal model, a gain of about 3 to 7 cents per kilowatt-hour of hydropower produced is realized, depending on the scenario. These figures are calculated by dividing the gains (shown in the table in appendix D) by the product of 500,000 kW (the expected hydropower production) and 8,760 hours/year. For example, in the base case the gain is 5.335 cents/kWh produced. This number is high because of the high marginal benefits B gains for the first few megawatts it buys.

The simultaneous buy/sell model results in nearly the same outcome as the ideal model; W decreases the optimal y_{sw} by about 5 percent and the optimal y_{wb} by 0 to 5 percent, compared to the ideal. This is because the wheeler's profit is roughly proportional to the gains from trade; as a result, W has an incentive to consummate every profitable transaction. Productive efficiency is only slightly less than the ideal (see "loss of welfare" in appendix D). The loss of welfare is 0.05 to 0.1 mills per kilowatt-hour of hydropower produced, about 0.1 to 0.3 percent of the total gain under the ideal solution.

For similar reasons, the Gain-sharing Flexible Pricing model also results in relatively little loss in productive efficiency, although more than the simultaneous buy/sell. The losses are on the order of 0.5 percent to 3 percent of the potential gains from trade (about 0.2 to 0.9 mills per kilowatt-hour of hydropower). The values of y_{sw} and y_{sb} that W chooses are 10 to 15 percent smaller than the ideal solution.

If no ceiling is imposed on wheeling fees, then the productive efficiency loss under congestion-fee-based flexible pricing is much worse; one to two orders of magnitude higher than the Gain-sharing case. This is because setting the wheeling fee equal to the marginal gain from trade during times of transmission capacity shortage provides W with a strong motivation to restrict transmission capacity. The motivation has two origins. First, the less the capacity, the more frequently it is congested. Second, the smaller the capacity, the higher the congestion-based wheeling fee, since B's demand D_b is smaller and therefore its marginal benefit MB_b is higher. The amount of capacity that W provides is about half that of the ideal case. This should not surprise us, since this is what a monopolist does when given a linear demand curve and constant supply costs.

The productive efficiency loss when there is no ceiling amounts to 5 to 20 percent of the gain realized under the ideal solution, around 0.2 to 1.2 cents per kilowatt-hour of hydropower. Under the base case assumptions, for example, flexible pricing (with a congestion-fee and no ceiling) yields only 88 percent of the potential gains.

However, if a ceiling is imposed then the productive efficiency of the congestion-fee-based flexible pricing model can improve substantially. Further discussion of this effect is provided later.

The conclusions of the last three paragraphs also apply to the NRRI model (scenario 11a in appendix D, table D-4 is the no-ceiling case, while cases 11b and 11c impose increasingly strict ceilings).

The production efficiency loss is greatest under the fixed-fee model (in most cases, several times greater than under congestion-fee based flexible pricing.) The loss is between 40 percent and 65 percent of the total gain under the ideal model under most of the assumptions tested. W nearly always chooses to choke off B so that W can buy the hydropower instead of B. The only exceptions occur when W has significant extra generating capacity of its own that it would like to sell, or if the wheeling fee is very high. In the extra capacity case, if W's benefit selling to B on a split-savings basis is greater than that buying from S on the same basis, then W decides to choke off S and build ample transmission capacity only from itself to B (see scenario 2 in appendix D). The welfare loss is about one-third lower than in the base case, but still large. If wheeling fees are set very high (1.6 cents per kilowatt-hour, scenario 10), W is motivated to undertake some wheeling, which lessens the welfare loss even more.

This has an important implication for long-run firm sales. If they are always priced on the basis of cost (giving all gains to the buyer) rather than on split savings as assumed here, then W has even a stronger motivation under a voluntary access system to deny access to B.

General Conclusions: Distribution of the Gains among S, W, and B. In appendix D, the total gains to S, W, and B are shown in the simultaneous buy/sell case, but for the other three wheeling models the *changes* relative to the simultaneous buy/sell case are shown.

The effect of the choice of pricing model on the *distribution* of the gains is, of course, significant. A switch from simultaneous buy/sell (the status quo) to wheeling at a fixed fee does not improve the welfare of B. Instead, B is usually much worse off under such a policy change because W provides no capacity for nonfirm service to B.

Switching from a simultaneous buy/sell to a congestion-fee-based flexible pricing model (with no ceiling) generally makes W better off at the expense of B and, usually, S. The exception occurs if moderate ceilings are imposed on the maximum wheeling charge that W can levy; in that case, S and B are the better-off parties instead. However, a ceiling that is too low (as in scenario 2g) can make all parties worse off, because W chooses to choke off B. The effects of the fee ceiling are discussed further later on.

Let us compare the pricing models from W's point of view. If we rate the most profitable model (congestion-fee-based flexible pricing with no ceiling) a "10" and the least profitable model (wheeling at a fixed fee) a "0", then the split-savings model would be rated about "8" and the gain-sharing flexible pricing model would be rated a "5" or so. If a low to moderate fee ceiling were imposed on the congestion fee-based model, however, W would be almost as bad off as under wheeling at a fixed fee.

From B's perspective, it always fares best under either the gain-sharing flexible pricing or simultaneous buy/sell models (which is better depends on the particular circumstance); both are always better for B than congestion-fee-based flexible pricing with no ceiling or fixed-fee-based wheeling, which is usually the worst case for B.

S always finds the gain-sharing flexible solution to be the best. This confirms what we expect from some of the simpler models presented earlier: gain-sharing (using the Shapley value) favors S more than the simultaneous buy/sell solution if the value of the {WB} coalition is zero.

Effects of Fee Ceilings on the Congestion-Fee-Based Flexible Pricing Model. Two types of effects are discussed here: efficiency effects and income distribution. (Many of these results confirm the results explained earlier in this chapter in the discussion of the effects of ceilings under this model.)

A change in the price ceiling under the flexible pricing model significantly changes the amount of transmission capacity that W is willing to provide (scenarios 2b through 2g, 4, 5, 9b, 11b, and 11c in appendix D). As soon as the ceiling is low enough so that it is binding (that is, the congestion fee no longer is set equal to B's marginal benefit), W loses one of its two incentives to restrict capacity--restricting transmission capacity further does not result in an increase in the congestion fee. However, restricting capacity still increases the time during which the congestion fee can be charged. But if the ceiling is set too low, W eventually decides to choke off B and form a coalition with S alone because a very low ceiling looks just like a fixed-wheeling-fee scheme to W. Hence, the amount of capacity y_{wb} that W builds is related to the fee ceiling in the general manner depicted in figure 6-5.

Since social welfare is generally larger for larger values of y_{wb}, welfare also follows the same general curve, implying that there is an optimal ceiling to wheeling fees that is neither too large nor too small. (Recall that the analytical solution for a congestion-fee-based flexible pricing model presented earlier in the chapter reaches a similar

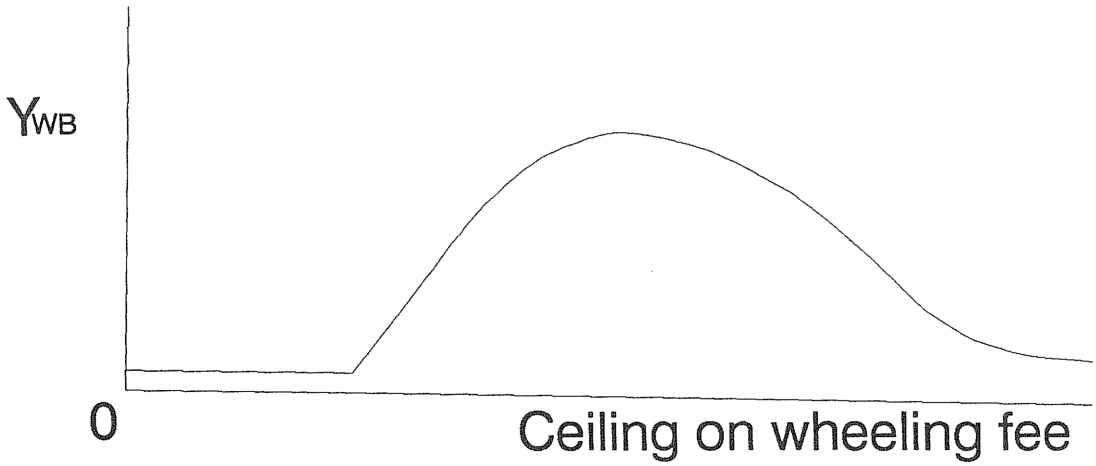

Fig 6-5. Relation of transmission capacity to wheeling price ceiling.

conclusion.) For example, comparing scenarios 2c and 2d to 2a in appendix D, we see that a ceiling in the range of 2-to-3 cents per kilowatt-hour results in significantly more transmission capacity being built between W and B (about 90 MW more) than does the higher ceiling. As a result, nearly all the potential gains are now realized, and over 90 percent of the production efficiency loss is regained. Scenarios 2c and 2d are actually better than the gain-sharing solution for scenario 2a (reversing their ranks in the list given earlier). The production efficiency losses in 2c and 2d are only 0.2 mills per kilowatt-hour of hydropower, less than 12 percent of the gain in the ideal solution. As another example, imposition of a ceiling of 5 cents per kWh on the NRRI short-run model lowers the production efficiency loss suffered by 75 percent (scenario 11b vs. scenario 11a).

If the ceiling is too low, on the other hand, W loses all incentive to build any y_{wb}; as a result, W chokes off B (y_{wb}=0) and keeps all of S's hydropower for itself (scenario 2g). The result is a dramatic welfare loss, several times greater than that which occurs if no ceiling at all is imposed. All parties are worse off than in the no-ceiling situation.

As discussed earlier, the social welfare curve (as a function of the ceiling) is often quite "flat" around the optimal ceiling. This means that it is not necessary to get the ceiling exactly right in order to reap most of the potential gains. Scenarios 2b through 2f, representing a range of ceilings from 1.5 to 5 cents per kilowatt-hour, illustrate this result: they have nearly the same social welfare.

Of course, W would much prefer the higher ceiling as its gain is then greater. Moderate fee ceilings redistribute the gains in S's and B's favor. W is much worse off under the very low ceilings, almost as bad off as under the fixed-fee models. W's profit is relatively high under a higher ceiling (here, 5 cents per kilowatt-hour). These results imply that a moderate ceiling on short-term wheeling rates might enhance W's incentive to expand capacity (thereby increasing productive efficiency), while making the flexible pricing model more palatable to other parties. However, too low a ceiling makes everyone worse off (scenario 2g).

Consider the case in which W has extra generating capacity it would like to sell. In scenarios 2a through 2g, W's demand is 500 MW, but its capacity is 1,000 MW. The interesting result is that the efficiency loss relative to the ideal in this case is less than for the situation in which W has no excess capacity. For example, compare scenario 2b with scenario 4, or scenarios 2d and 2e with scenario 5. Because W can sell some of its output to B, it has an incentive to push y_{wb} higher than it would otherwise be (from 33 percent to 50 percent higher), which results in a greater level of welfare.

To sum up this point, these results reinforce the conclusion reached earlier that a moderate ceiling on rates (within some broad range) can greatly enhance production efficiency compared to the no-ceiling situation. However, too low a ceiling can destroy W's incentive to add capacity (as in scenario 2g).

Other Sensitivity Analyses. This discussion summarizes other important implications of the various scenarios set out in appendix D.

First, a change in the price elasticity of B's demand for economy power does not qualitatively change the results (scenarios 6,7). The lower the elasticity, the smaller the optimal y_{wb} and the larger the welfare loss compared to the ideal under the simultaneous buy/sell and both flexible pricing models. The reason is the familiar one that a monopolist can restrict output if demand is inelastic. The exception is the fixed-fee model, where W can do nothing to affect the price it charges for transmission.

Second, an increase in the fixed wheeling fee (in appendix D, a doubling to almost one cent per tie line) greatly increases W's motivation to build capacity to B in the fixed-fee wheeling model (scenario 11). W no longer chokes off B, the loss of welfare is cut by two-thirds (relative to the base case), and B obtains a positive share of the gains (as opposed to the zero share it gets otherwise).

Nonfirm Wheeling to a Requirements Customer

Next we examine the case in which B is a requirements customer of W, and both B and W would like to purchase surplus hydropower from S. B is assumed to be able to buy power at the same cost as W because B's avoided cost is the energy charge for the firm power it buys from W. The amount of hydropower S has available is still a random variable. W's decision concerns how much transmission capacity y_{sw} to provide from S to W, given the pricing structure W expects will prevail in the short-run wheeling game at the time the new capacity comes into use.

First, we describe the topology of the system and (briefly) the pricing models. We then summarize the general nature of the results obtained. In appendix E, some extremely general results are presented for the Status Quo, Planning, and Contract models, which were derived using a mathematical program. To obtain results for other flexible pricing models and the NRRI model, however, some specific assumptions have to be made for probability distributions that describe the availability of economy energy from S and the amount of demand by each party. These also are set out in appendix E.

Assumptions

Because B is a requirements customer of W, transmission line W-B is assumed to be in place with enough capacity to meet B's full load. B has contracted for firm supplies of power from W whose energy cost is denoted by C_f; this energy charge is assumed just to equal W's marginal cost of production. (We assume that the cost of transmission from W to B is negligible. However, a nonzero cost would not affect the results.) Any purchases of economy power by B from S would displace the firm supplies B would otherwise buy from W, saving C_f (\$/kWh). However, it is assumed here that the capacity costs of firm power must still be paid by B to W; therefore, such costs are treated as fixed in this analysis and do not affect B's decision about whether to purchase from W directly or have S's economy power wheeled through W. It is further assumed that, if W buys power from S, this lowers its marginal production cost saving C_f (\$/kWh). Therefore, B and W's marginal energy costs are always the same.

As before, W's problem can be viewed as a two-stage problem. In the first stage (the long-run decision), W now decides only how much transmission capacity y_{sw} from S it should construct. (Recall we assume that y_{wb} is adequate.) In the second stage (the short-run decision), S, W, and B make short-run power supply and wheeling decisions based on the actual amount of hydropower that becomes available and on the access and pricing model that is in effect at that time. Again, the amount of hydropower available is random in the second stage.

W's objective in the first stage is to maximize its expected profit (or, equivalently, to minimize its expected cost) in the second stage, net of the cost borne in the second stage for having built the transmission line.

Pricing Models

Five basic pricing models are considered for the short-run (second-stage) game:

1. Status Quo, in which short-term generation sales are priced on a split-the-difference basis and where W can choose to use simultaneous buy/sell or to wheel. As shown in chapter 4, in most circumstances W chooses buy/sell over wheeling at a fixed fee. (If simultaneous buy/sell is not allowed and if W when it wheels voluntarily must do so only at a fixed fee F ($/kWh), then W wheels only after its own need for economy power is fully satisfied and there is spare transmission capacity. In this case, the game is the same as the "Planning Model I" game, described next.)

2. Planning Model I, in which W wheels power from S to B at a fixed fee F ($/kWh) and B is not a preference customer of S. In this case, W chooses to meet its own needs first (paying a price based on split savings). Then, if there is transmission capacity and economy power to spare, W wheels power to B (which would pay S according to the split-savings rule). (It is assumed that F is not set so high as to motivate W to wheel rather than use the power itself; F would have to equal $C_f/2$ for that to happen here.)

3. Planning Model II, in which B is a preference power customer of S. W must wheel all the power B wants before S would sell any to W for its needs. Again, wheeling takes place at fixed cost F $/kWh.

4. Contract Model with Flexible Pricing, in which W is free to charge any price for wheeling that the market allows, subject to upper and lower bounds set by regulation. The outcome of the short-run pricing game can be described using the core, as in prior chapters. The only constraint on the core is the gain that the subcoalition {SW} could obtain on its own. We examine several pricing outcomes that might result.

5. NRRI, in which B is charged short-run marginal cost for wheeling--including a congestion charge if tie line S-W is at capacity. (The full NRRI model is not simulated here. We assume that B cannot choose to request firm transmission service for uncertain future coordination power. Yet, B is most likely to make this choice in just those situations that W is most likely to find profitable under other pricing models.) The congestion charge is C_f because, if B increases its purchases by 1 kWh, W's generation cost goes up by C_f (because it would have to decrease its purchase of S's power by 1 kWh). We assume that the congestion charge is related to W's actual marginal cost of generation, C_f. (This may differ from marginal cost as W views it, since W would have to pay a nonzero price for any power it purchases from S, even though S's power is produced at zero marginal cost.)

Summary of Results

The methods, analysis, and detailed results are in appendix E. It is shown under a wide range of conditions that, if W charges a wheeling fee at or below C_f, flexible pricing under the Contract model results in the most nearly optimal amount of transmission capacity y_{sw} and the smallest loss in productive efficiency relative to the ideal solution. The ideal solution is constructed by minimizing the overall expected cost for S, W, and B together. The Planning model results in significantly less transmission capacity and much greater productive efficiency losses. The Status Quo results are between the Contract model (flexible pricing) and Planning model outcomes (and, in most cases, are closer to the former).

However, if under flexible pricing W charges only C_f when transmission capacity is constraining and a lower fee F ($/kWh) when it is not, then W builds less capacity (in many cases, far less) than under the Status Quo (just as in the previous discussion). The NRRI results are similar; charging short-run marginal cost motivates W to restrict capacity y_{sw} so that the congestion charge is collected more often.

This seemingly contradicts the logic of spot-market transmission pricing, which says that charging short-run marginal cost, including a congestion charge, results in the optimal expansion of the transmission grid; this is because W is not a price taker and knows that the price it can charge at certain times depends on how much capacity it has built earlier. Advocates of spot-market pricing acknowledge, however, the potential for such abuse of W's market power. For this reason, the NRRI model advocates the principle of customer choice, not included in this simple analysis, which allows B also to forecast the future availability of hydropower from S and to obtain firm transmission service at long-run marginal cost, thus avoiding the congestion charge entirely.

Numerical Results

Here, we give just one example of the numerical results derived from simulations based on the models in appendix E. The assumed values of the parameters are:

Q_{sm} = 10 [MW] $\qquad$ C_f = 0.03 [$/kWh]

$F = 0.001$ [\$/kWh] $CC = 4380$ [\$/MW/yr]

$D_w = 5$ [MW]

The value of Q_s is always between zero and Q_{sm}, its maximum value.

The results for a few sample cases are given in table 6-1, in which all data are in thousands of dollars per year, except for y_{sw}, which is in megawatts. Note that if there is a change in policy from the Status Quo (which is nearly as good, in efficiency terms, as the ideal) to Planning Model I (with no preference power), B is not any better off, but S and W become much worse off. Notice also that W's gains are large compared to its investment in most cases--especially under the the NRRI and Contract models. (The NRRI model yields slightly less profit for W because it charges a low wheeling rate if transmission is not at capacity.)

The potential for large gain may make the subject of this chapter--construction of transmission capacity for coordination power sales--an important future issue in the industry, especially if the national pricing policy eventually adopted is one that permits a large fraction of these gains to be captured by potential wheelers.

TABLE 6-1

SAMPLE RESULTS OF NONFIRM CAPACITY ANALYSES

Model	Optimal y_{sw} [MW]	Total Gain [in thousands of dollars]	Share of the Gain S	W	B	W's Line Cost
Ideal	9.8	1271	N/A	N/A	N/A	43
Status Quo	9.7	1270	634	636	0	42
Planning I	5	964	476	487	0	22
*Planning II	9.7	1270	634	159	476	42
*Contract Model	5	964	159	646	159	22
*NRRI	5	964	164	635	164	22

Source: Author's calculations based on methods set out in appendix E.

* Preference Power example: B's needs met first, subject to transmission constraints.
Note: N/A signifies that the ideal model does not indicate a unique way of sharing the gains. Totals may not add due to rounding.

CHAPTER 7

A MID-1990 STATUS REPORT

As of mid-year 1990, the debate in the United States over transmission policy seems to be moving in what may be its eventual direction of resolution. What follows is one view of this motion.

Firm Service

Several large investor-owned utilities are agreeing to provide firm service. While most insist that service is voluntary, it is being offered to all qualified transmission users. The debate therefore seems to be moving forward, for some companies, from one over whether to provide service to one over the conditions under which service is to be provided.

There are several reasons for this forward motion, including wariness about the antitrust implications of refusing firm service and the pressure exerted indirectly by the interests of the FERC, state commissions, and even the Congress in competitive bidding and least-cost regional planning for firm power supplies. The consequent need for at least some loosening up of transmission access is causing motion. There has also been forward motion because of initiatives from within the power industry; many utilities would prefer to work out for themselves acceptable rules that are compatible with transmission system operating practices and reliability constraints than to have rules imposed by others that may present technical difficulties in compliance. The open access tariff filed voluntarily by the Wisconsin Power and Light Company is the best example of an action that creates pressure for others in the industry to move away from a simple "no wheeling" position.

The firm transmission access issue divides the industry along nontraditional lines. It is not a utility-versus-ratepayer issue, nor an issue of investor-owned utilities (IOUs) versus public power. The dividing line that comes closest to describing the issue is the transmission "haves" versus the "have-nots." Those that have transmission facilities have been cautious about providing access; these "haves" include the large IOUs, the large federally owned hydroelectric authorities, and the large public power agencies. The "have-nots," who depend on the "haves" for much of their transmission needs, favor more open access, of course. They include the smaller IOUs, and most municipal and cooperative utilities. It has been difficult, therefore, to formulate an "industry" position on transmission or even an IOU or public power position.

Even the distinction between the "haves" and the "have-nots" does not provide a fully accurate description: some of the largest IOUs who are "haves" want to become competitive suppliers of power and cautiously favor more open access. (Reportedly, some companies have difficulty forming even a company position on transmission, with the retail rates division at odds with the power marketing division.)

One result of these various positions and pressures has been a gradual, though not unanimous, industry acceptance of somewhat more open access to firm transmission service. Access for control-area utilities as buyers is perhaps the most readily accepted, and resistance to access for requirements customers is weakening provided there is some transition period during which requirements customers become independent utilities and the stranded investment difficulty is phased out. Retail customer access faces stiff opposition though, and the link between requirements and retail access (see chapter 1) is recognized by only a few policy makers. Supplier access now faces relatively little opposition for the case of long-term firm power sales, but the short-term spot market supplier would have great difficulty in obtaining transmission access today.

Whether a positive attitude toward transmission access on the part of strategically located wheelers can substitute for mandatory access remains to be seen. As we found in our chapter 5 analysis of firm access, current access and pricing rules block some good firm transactions but do not force any bad ones. Contract-type models have the same shortcoming. In particular, under a typical Contract model a wheeler can buy from a low-cost seller for his own use and so prevent a buyer who values the power more from having the power wheeled. Planning models, however, facilitate almost all good firm transactions by mandating access to the best buyer. However, they also encourage some uneconomic transactions.

For those segments of the industry that are making the transition to a more positive attitude toward access, the question moves from one of access to questions of pricing, priority, and trade-offs.

Pricing

In pricing firm transmission, one can move to either of two extremes. At one extreme, new transmission users can pay the full cost of expanding transmission capacity along all parts of the grid over which their power flows. In a competitive bidding situation, this has the virtue of allowing the evaluator of bids to compare fairly the full long-run incremental costs of bids from generating units at separate sites, taking into account the costs of both the new generating facilities and the new transmission facilities required over a long (say, thirty-year) planning horizon.

However, this does not result in a fair comparison of bids if some bidders must pay the full incremental cost of transmission while others, such as the transmission owner if it bids, face a lower price based on embedded cost. The other extreme is for every transmission user to pay the same embedded cost rate to create a "level playing field."

Considerable support seems to be emerging in favor of a compromise pricing policy that balances these pricing efficiency and equity concerns. This is a policy that starts with embedded-cost pricing for all transmission users, but has new suppliers or buyers also pay the full cost of joining the transmission system. This additional cost is the incremental cost of any new transmission facilities that are needed specifically because of the geographic location of the new user.

This concept is analogous to traditional retail ratemaking practice. The price of retail service for a particular customer or group is the embedded cost of generation and transmission plus the costs "directly assignable" to that customer or group. For example, distribution costs are not assigned to large customers that take power directly from transmission lines, but are assigned to residential customers and others that require a distribution system; the cost of a subtransmission line constructed solely to link a large factory to the grid is not included in everyone else's rate base but is paid for entirely by that factory, either in a lump sum or as a surcharge on its retail service rate.

This firm pricing approach, embedded cost plus directly assignable incremental cost, has been proposed both in some Contract-type models and in some Planning-type models and may well represent a compromise solution to the firm pricing problem. The incremental cost feature is helpful for signaling the long-run marginal cost of transmission due to a candidate power supplier's location. The embedded cost basis alleviates the problem of transmission price discrimination due only to the user's identity or history--discrimination that can affect the identification of the lowest-generation-cost bidder. As reported in chapter 4 for nonfirm service pricing, our analysis shows that economic efficiency losses with embedded cost pricing are small compared to the huge losses that can occur if no power trading takes place. If some embedded cost pricing is needed as part of a policy compromise to obtain a more open power market, it is a compromise well worth making.

Priority

For transmission "haves" who do not oppose firm power access in principle and who can agree on firm pricing, the access question in essence is a priority question: how are transmission uses prioritized when transmission capacity is insufficient to satisfy all requests for its use? Here a clear difference of views emerges between the "haves" and the "have nots." The "haves" are transmission owners who support the Contract model, and the "have-nots" are transmission users who support the Planning model.

The Contract model reserves capacity for the owner's firm and nonfirm uses first, and then the firm needs of others are met with excess capacity or new construction. Firm service to others cannot begin until a contract is signed to construct enough capacity to meet the new obligation without curtailing the owner's historical firm and nonfirm use of its own transmission facilities. Before the contract for firm service is signed, the outside user is viewed as the newcomer; this means his costs are those on the margin and, if transmission cannot be sited, his needs are not met. During the term of the firm service contract, the outsider's firm service is truly firm and has the same priority (unless the contract says something else) as the owner's firm service to retail load. During the term of the contract, the outsider's firm transmission has higher priority than the owner's nonfirm; during a system emergency the owner's nonfirm power gives way to all firm commitments. After the contract expires, according to some versions of the Contract model, the transmission facilities revert to the owner for its customers' firm and nonfirm needs, and the outside user is on the margin again. He has again a lower priority than the owner's nonfirm use and must pay a transmission rate that compensates for any needed system expansion if service is to continue. One motivation of the owners in taking this position is to shield their retail customers from any incremental costs imposed by offering wholesale transmission service to other utilities.

These other utilities want to protect their own retail customers from forever having to face transmission prices for importing power that are higher than the prices faced by the retail customers of the owner. The transmission "have-nots" favor some approach that plans for the firm transmission needs of all parties equally. Under such a Planning model, everyone's firm needs would always have higher priority than anyone's nonfirm usage.

A possible compromise policy that has been gaining some favor is for new users to be "on the margin" before the first contract for firm service, at which time they might have to "buy in" to the transmission system if directly assignable costs are identified. Afterwards, however, they would pay only the average embedded cost in any follow-on contract for providing the same transmission service.

These priority issues pertain mostly to the allocation of transmission capacity in a normal situation. There are additional concerns about priority in an emergency, when transmission lines must shed load. Also, a question closely related to the priority questions is: who makes the technical determination that existing capacity is inadequate for a new transaction and must be expanded? These concerns clearly relate to the question of who has responsibility for assuring the reliability of the transmission system, as discussed in chapter 1.

Trade-offs

While Planning model proponents want simply to create an obligation to provide firm (and nonfirm) transmission service, Contract model advocates usually want to bargain. They want to accept voluntarily an obligation to provide firm service in return for greater pricing freedom in the nonfirm sector.

At present, the Federal Energy Regulatory Commission (FERC) is inclined to encourage such trade-offs because the Commission is interested in competitive bidding for long-term firm power and is willing to bargain for open access, not having the authority to require it. As discussed in chapter 1, coordination of federal and state actions and goals is needed to avoid jurisdictional conflicts regarding trade-off policies. Such trade-offs call for careful examination of the resulting nonfirm market characteristics.

Firm v. Nonfirm

As discussed in chapter 2, the terms "firm" and "nonfirm" have a variety of meanings in the United States electric power business, and many pricing proposals use substitute terms with their own nuances, such as requirements service and coordination service, to categorize types of service to which different access and pricing policies would apply. An important aspect of transmission policy discussions in 1990 is the effort to define a commonly understood vocabulary for these concepts.

After chapter 2, we use the terms "firm" and "nonfirm" as if everyone understood these in the same way, but in fact this is not the case. Is firm service defined by its priority level, its duration, or a combination of these? As the term is used in the industry today, there are many kinds of firm transactions. They differ with respect to purpose, duration, and the level of reliability required. Power for which no back-up is available needs to be the "most firm" because if transmission fails the lights go out. Such firm transactions can last anywhere from a few hours for emergency power to thirty years or more. The highest level of reliability a utility can provide is the same as that provided to its retail customers. Not every firm transaction requires this level of reliability, however. A power seller may accept a lower level of reliability for its firm sale, for example, than a power buyer would accept for its firm purchase. The seller may want only one transmission line to connect it to the grid to hold down its cost, whereas the buyer may be willing to pay for two or more lines to be sure of "keeping the lights on" in its service territory.

Nonfirm is associated with low priority. Back-up generation, though more expensive, is usually available should nonfirm transmission be interrupted. Nonfirm power transactions, whatever they are called, can last from one hour to several years.

If policy makers choose close regulation of firm transmission in exchange for deregulation of nonfirm transmission, we need a better definition of these terms so that we know for a particular transaction which access and pricing rules apply.

Nonfirm

Relatively little attention is paid to nonfirm transmission policy despite the enormous value of the trades occurring in the nonfirm market.

Our analysis of the nonfirm market in chapter 4 indicates that the nonfirm market should operate efficiently under existing access and pricing rules through the use of a series of bilateral trades (simultaneous buy/sell), with much of the market power residing with the wheeler. Under the Status Quo, the wheeler can buy low from the seller and sell high to the buyer, making a profit on the mark-up. Deregulation would change this very little. Tighter regulation of nonfirm transmission, even aside from the technical difficulties for regulators in keeping track of cost changes, is undesirable (chapter 4) in that uneconomic transactions may be encouraged.

Further, tight regulation of nonfirm transmission can affect production efficiency quite adversely (as discussed in chapter 6) in that it discourages construction of transmission facilities even though the facilities' costs are justified by the coordination market sales they make possible. There is an optimal amount of such construction that is encouraged neither by cost-based price regulation nor complete deregulation, but by flexible pricing subject to a moderately high ceiling price.

A view with a growing constituency is that nonfirm generation and transmission prices can be deregulated, particularly if firm access is available as an alternative and if firm transmission users can resell their contract rights to firm capacity. Resale would limit the wheeler's market power in the nonfirm market. The FERC is not at all ready to deregulate the nonfirm market, however, unless this freedom is tied to mitigation of the wheeler's firm market power. The Commission's limited extension of the Western States Power Pool experiment, mentioned in chapter 2, is evidence of this.

Market Power

Deregulation of firm generation prices and nonfirm generation and transmission prices may be accepted by policy makers if the wheeler's market power is eliminated or substantially mitigated. It is important therefore to understand the factors and circumstances that create and destroy market power in bulk power markets. Our studies show that market power depends on several factors. Unless one prescribes mandatory access at marginal-cost-based rates and prohibits simultaneous buy/sell trading, it is not easy to derive a simple rule for eliminating market power under all circumstances in markets with a few participants.

Market power depends on the relative production costs of the various parties and the relations of utilities' extra generation capacities and loads, as well as on the access and pricing rules in effect. The case study in appendix D with real utility data shows how sensitive market power is to cost, supply, and demand conditions, as illustrated by the great variation in core shapes under reasonable changes in market conditions. Further, market power changes with the availability of external suppliers or buyers of power and the characteristics of any loop flows. And market power can change dramatically over time (chapter 4 and appendix B) as cost and load conditions change.

Simple rules about market power are often inadequate. For example, consider a utility receiving bids from several alternative suppliers, one of whom must have his power wheeled to reach the buyer. One might suggest a rule that if there are more than, say, five bidders, the wheeler's power to extract wheeling profits is adequately controlled by indirect competition. However, if the bidder who requires wheeling has a much lower cost than the others--such as a hydroelectric facility competing with thermal generating units, the wheeler's market power may be constrained very little.

The discussions in chapters 4 and 5 reveal the important relationship between generation pricing policy and transmission policies as they affect market power. It is not always possible to assess the effect of transmission policy on market power without knowing which generation pricing policy is in effect. For example, we found that uneconomic wheeling transactions can occur under the Planning model in both the firm and nonfirm markets if generation prices are regulated, which cannot occur if these prices are deregulated.

New Tools

The strategic behavior of a small number of utilities and other parties in power markets is difficult to predict using conventional methods of market power analysis. A principal purpose of this study has been to add a new tool to the regulator's tool kit, game theory.

It permits a more systematic examination of the range of possible outcomes in bulk power markets. It is easy to assume, for example, that access and pricing rules would always be applied to the simple case where the buyer's avoided cost is above the wheeler's, which is in turn above the seller's. Somewhat complicated situations arise when this is not so, however, as we see in chapter 5. Yet such situations appear to be common, as we see in appendix B.

The new tool helps to sort out the effects of policies in such unanticipated circumstances and suggests helpful ways of evaluating markets. In evaluating the efficiency of bulk power market over the long run and assessing where market power resides in such markets, our analysis suggests that it is helpful to think in terms of a short-run analogy, as explained in chapters 4 and 5. Bidding for firm supplies is analogous to an hourly spot market for nonfirm power, long-run incremental generation costs are the counterpart to system lambdas, and transmission facility expansion and operating costs are analogous to line losses. Just as efficient short-run access and pricing rules minimize short-run costs throughout a region, efficient long-run rules lead to the lowest regional production costs over a longer-term horizon.

APPENDIX A

THE CORE TRIANGLE: A GEOMETRIC VIEW

In chapter 3, the core triangle is introduced without any mathematical justification. This appendix provides a better understanding of how a three-way sharing of the gain can be mapped onto a two-dimensional surface. It also helps one to interpret what a position in the core triangle means in terms of who gets what.

This type of triangle is used in many fields to display proportions among three categories. In soil science, for example, such a diagram shows how the weight of a particular soil type is divided into three sizes of soil particles: sand (coarse), silt (medium), and clay (fine). In chemistry, the triangle is used to display how the character of a particular chemical bond is made up of covalent, ionic, and metallic components.

As introduced in chapter 3, consider three parties to a power transfer transaction: a seller S, a potential wheeler W, and a buyer B. When all three cooperate, power flows from S through W to B and substitutes S's lower-cost generation for B's higher-cost generation. Also, S may sell to W and W to B. (We do not consider reverse sales from B to S explicitly; if "B" has the lowest cost power it is called the seller and is labeled S.) The gains from trade are the generation cost savings less the true costs of transmission.

Consider how the total gain from trade is divided among the three parties. If s is the fraction of the gain that goes to S, w is the fraction that goes to W, and b is the fraction that goes to B, then

$$s + w + b = 1,$$

because the gain is fully divided among the three parties with none left over.

We can plot how the gain is shared in a three-dimensional diagram, with one axis for each of the fractional shares of the gain that goes to S, B, and W respectively. This is shown in figure A-1(a). The point A is one that results from a unique way of dividing the gain: s, w, b. The point A lies in the plane defined by the equation $s + w + b = 1$. This plane intersects the s-b plane at an angle, passing through the three points $(s,b,w) = (1,0,0)$, $(0,1,0)$, and $(0,0,1)$ as shown in figure A-1(a).

Let us restrict values of s, w, and b to the range zero to one, inclusive, on the assumption that no party can obtain more than 100 percent of the gain and no party engages in trading at a loss. (This assumption would be violated if, for example, mandatory wheeling took place at a price below cost. Then W would suffer a loss, and S and B would share a gain that exceeds the "true gain" of generation cost savings less true transmission costs.) With this restriction, the possible locations of the point A are bounded by the triangle shown in figure A-1(a). Its base in the s-b plane is the line $s + b = 1$; one side of the triangle lies in the vertical s-w plane and is defined by the equation $s + w = 1$; $b + w = 1$ defines the third side of the triangle. Any gain-sharing arrangement in which any party suffers a loss, compared to having no transaction, lies outside the triangle and hence outside the core.

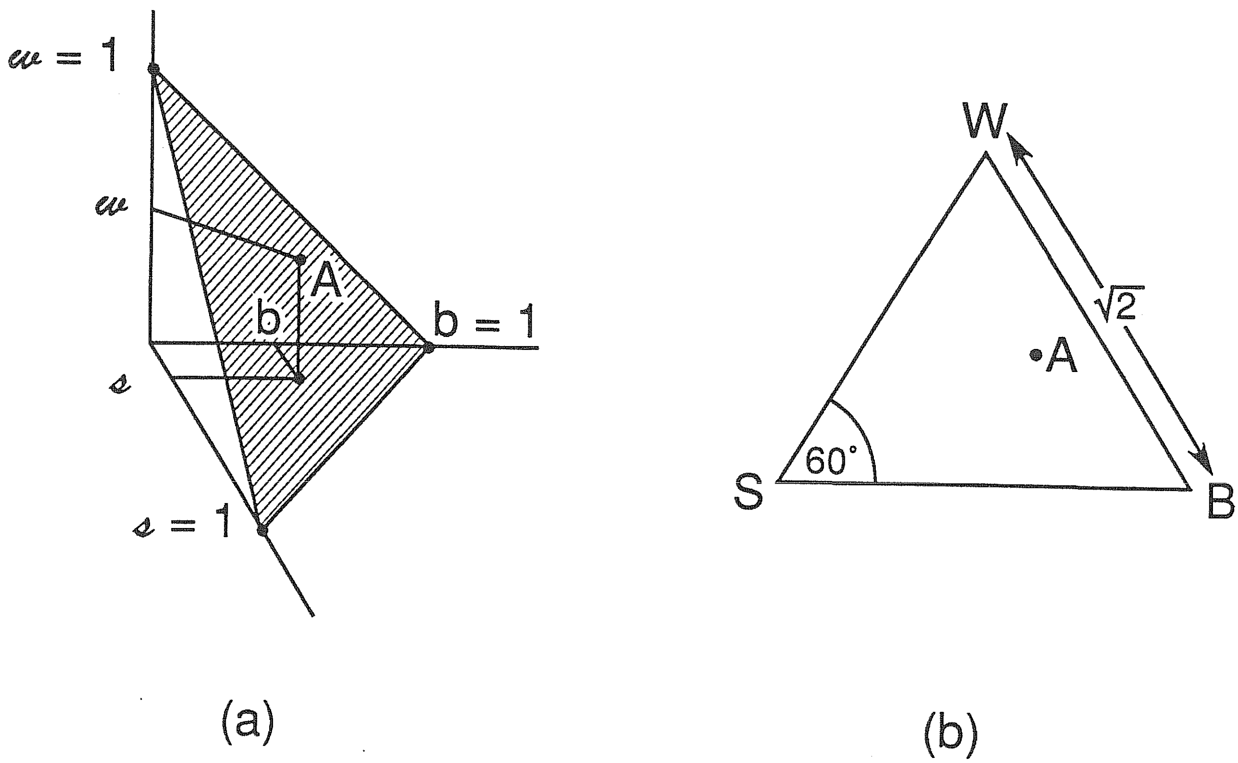

Fig. A-1. The core triangle in (a) three dimensions and (b) two dimensions.

Note: Use of different script for s, w, and b is an artist's error, of no significance, which could not be corrected in time for publication.

Figure A-1(b) redraws this triangle as a two-dimensional figure in the $s + w + b = 1$ plane. It is an equilateral triangle; each angle is 60° and the length of each side is $\sqrt{2}$. Each distinct set of values of s, w, and b that add up to one represents a unique point in the triangle. Conversely, each point in the triangle corresponds to a unique way of dividing the gain.

This correspondence can be expressed algebraically using the x-y axes shown in figure A-2. (The triangle is rotated 90° to simplify the algebra.) The point W lies at the origin ($x = 0$, $y = 0$). Given particular fractional shares s and b (w is then fixed at the value $w = 1 - s - b$), the corresponding position in the plane of the triangle is given by

$$x = \sqrt{\frac{3}{2}}\ (b + s)$$

$$y = \sqrt{\frac{1}{2}}\ (b - s).$$

Conversely, given a point such as A in the triangle with coordinates x and y, the three fractional shares are given by

$$s = \frac{x}{\sqrt{6}} - \frac{y}{\sqrt{2}}\ ,$$

$$b = \frac{x}{\sqrt{6}} + \frac{y}{\sqrt{2}}\ , \text{ and}$$

$$w = 1 - s - b\ .$$

It may be convenient to rescale the triangle, dividing each length by $\sqrt{2}$, to get a triangle with side of unit length. This is shown in figure A-3 along with a set of scales that shows how the position of any point represents a way of sharing the gain. For example, point A represents here the case where S gets 20 percent of the gain, W gets 40 percent, and B gets 40 percent. To read this from the figure, consider first the W percentage: draw a grid line through A parallel to the side of the triangle that is opposite the W corner. This line is 40 percent of the way up from the S-B base line (where W gets no share of the gain) to the W corner (where W gets

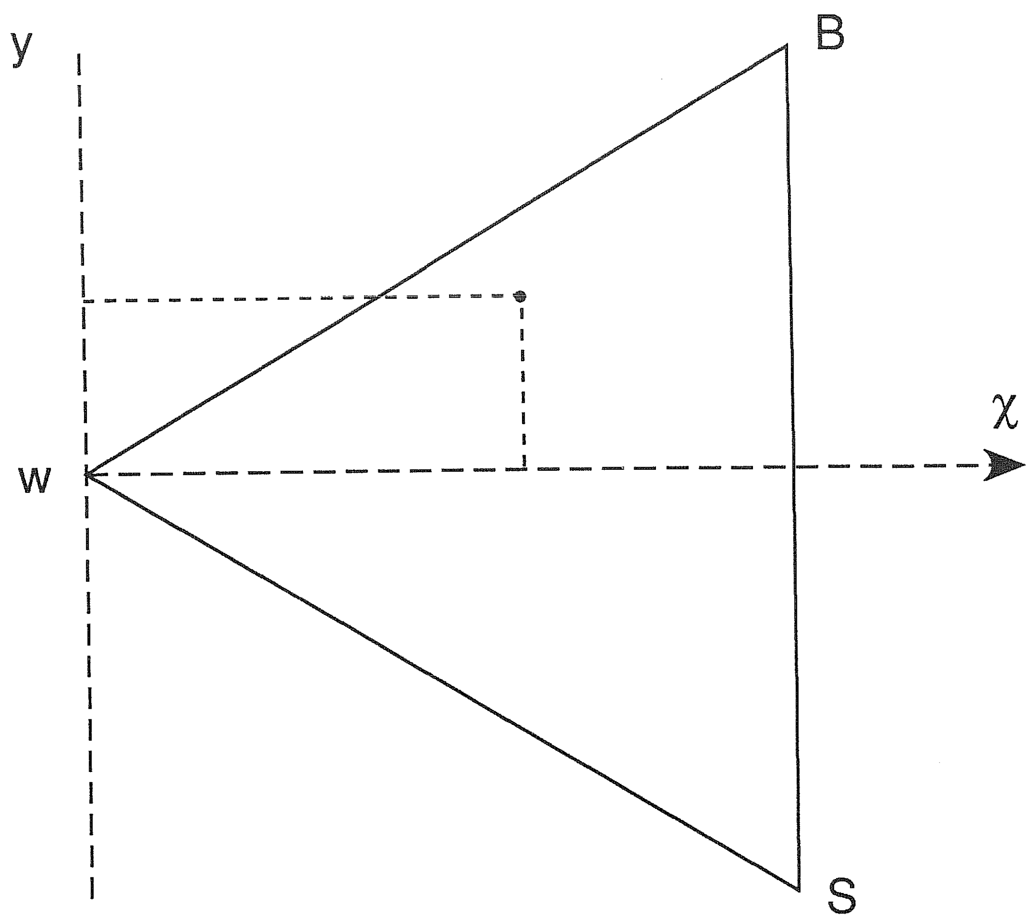

Fig. A-2. The core triangle with x and y axes

it all). This means that W gets 40 percent of the gain for all points on the grid line. At points on this grid line more to the left, S gets more of the remaining 60 percent and B gets less. B gets more at points to the right.

In the same way, a line through A parallel to the side opposite S is only 20 percent of the way from the W-B side to the S corner, indicating that S gets only 20 percent of the gains from power trades. Since this triangle is in the plane s + w + b = 1, it must be the case that the line through A parallel to the side of the triangle opposite the B corner is 40 percent of the way from that side to the B corner.

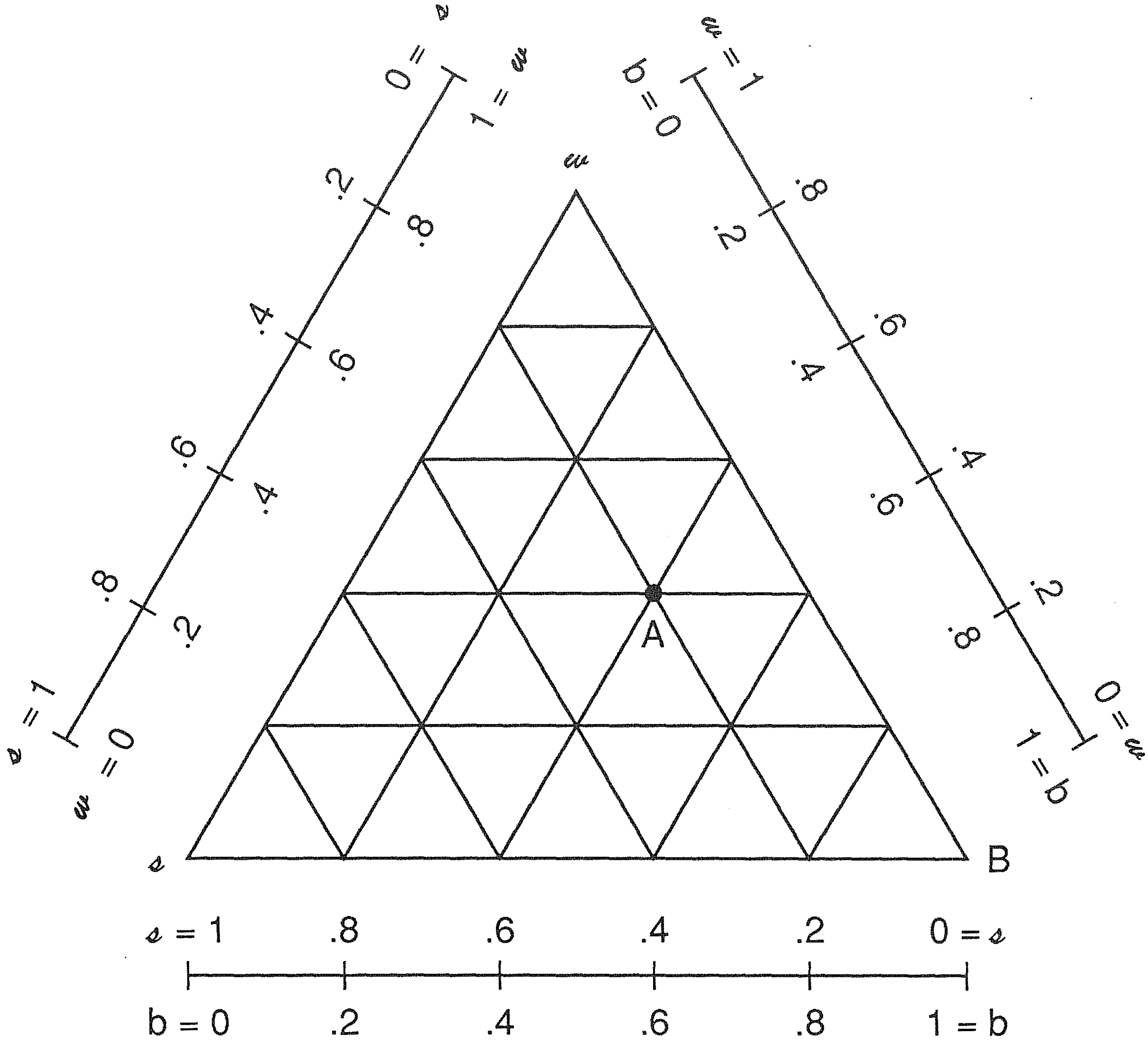

Fig. A-3. A core triangle with a grid. Point A corresponds to the values s = 0.2, w = 0.4, and b = 0.4.

APPENDIX B

A CASE STUDY OF THE EFFECTS OF NONFIRM ACCESS AND PRICING POLICIES ON EIGHT UTILITIES

The purpose of this appendix is to illustrate the ideas developed in chapter 4 with a case study involving eight real interconnected utilities. We examine the core, the Shapley value, the nucleolus, simultaneous buy/sell (SBS), and wheeling at a fixed fee (WhF) solutions using an actual set of utilities and realistic costs and demands. This analysis gives an indication of the magnitude of the gains that are possible from power transfers and how they might be split among the parties under various pricing rules. It is intended to enrich our analysis by complementing the simpler models and situations analyzed in the main body of the report. Because the results are consistent with those of the simpler analysis, we believe they add both credibility and perspective to our conclusions.

In fact, the utilities analyzed are already cooperating to some degree, so many if not all of these gains may already be realized. For this reason, we decided not to reveal the names of the companies. We want to avoid giving the impression that there is now no cooperation and that achievable gains are being ignored. (We did not try to find the current level of gain achieved by cooperation because this is a time-consuming effect that would not advance the purpose of this appendix.)

The first section of this appendix summarizes the analytical model. The second presents the data and assumptions made about demands, generation, and transmission. The final section presents the results, in the form of the cores of the games for the years 1987 and 2000, and their implications for the various transmission pricing models.

The Model

The model can be summarized as follows. It is a multicommodity (baseload and peak power are the two commodities) transshipment model, consisting of two transmission networks (one for peak power and one for base power), which interconnect sites, or "nodes," at which power is demanded and generated.[1] (The load duration curve could have been divided into more than two periods, but at the cost of additional computational time and model size.) This two-period approximation was used previously.[2] The peak period encompasses approximately 13 percent of the hours of the year. The decision variables for the year-1987 model are:

- The amount of generation from each generating unit in each period (MWh)
- The amount of power transmitted between each adjacent pair of nodes in each period

The objective of the year-1987 model is to minimize the cost of producing electricity among all the utilities in a coalition, given the existing mix of generating units and the existing transmission facilities and capacities. The coalition can be as simple as one utility acting alone, in which case this is a simple one-utility dispatch model; it can include all the utilities (the "grand coalition"); or it can be any subcoalition. The structure of the linear program for the year-1987 version of the model is then:

Minimize: Operating costs of existing units and transmission facilities and the capital cost of any new combustion turbines subject to constraints on generating output and transmission line loading, given shortly.

The model is used again in a year-2000 version. Our initial intention was for this version to represent a long-run analysis, as in chapter 5. Early runs of the year-2000 model showed, however, that at 2 percent load-growth rates virtually no additional transmission would be needed (within the limits of our crude attempts to model tie-line capacities) by the year 2000. Hence, we deleted transmission capacity expansion variables from the model to decreases the solution times, but retained generation capacity expansion variables. (It is easy to count the cost of short radial lines connecting new units to the grid as part of the generating unit capital

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[1] For details, see D. Anderson, "Models for Determining Least-Cost Investments in Electricity Supply," *Bell Journal of Economics and Management Science*, 3 no. 1, Spring 1972, 267-99 or see the similar models presented in B. F. Hobbs, "Network Models of Bertrand and Limit Pricing Equilibria in Spatial Markets," *Operations Research*, 34 no. 3, May/June, 1986, 410-25.

[2] See Hobbs, "Network Models" and B. F. Hobbs and R. E. Schuler, "Assessment of the Deregulation of Electric Power Generation Using Network Models of Imperfect Spatial Competition," *Papers of the Regional Science Association*, 57, 1985, 75-89.

cost.) Hence, transmission facilities are assumed to be fixed in both versions of the model, so that no transmission capacity expansion is considered. Further, we used the nonfirm pricing rules of each pricing model in the analysis. As a result, this analysis is an example of the short-run analysis of chapter 4, not the long-run analysis of chapter 5.

In the 1987 version, it is assumed that utilities can add combustion turbines to meet demand, and their capital costs are included in the short-run-cost-minimization objective. Both combustion turbines and new large coal-fired generating units can be added in the year-2000 version, and transmission costs and constraints are considered in selecting the least-cost (from the viewpoint of the whole group of utilities) site for the new units. In addition to the year-1987 variables, the year-2000 model includes variables describing the amounts of new combustion turbine and coal-fired thermal capacity constructed at each node.

The equations of the year-2000 model are:

Minimize: Capital costs of new generating units +
Operating costs of existing and new generating units and transmission facilities

subject to:

1. Power balances for each node and each load period:
   power generated + power imported (net of resistance losses) = power used + power exported
   (Note: resistance losses are crudely modeled as a constant fraction of flows over a transmission line)
2. Power limits for each generating unit (based on the "derating" approach):
   Peak Output $\leq$ Capacity x (1-Forced Outage Rate)
3. Energy limits for each generating unit:
   Annual energy output $\leq$ Capacity x 8,760 hrs x Maximum capacity Factor
4. Transmission limits for each network arc in each load period:
   Flows $\leq$ Tie-line capacity (see next section for description of how tie-line capacity is calculated)
5. Upper bounds to coal plant additions at each node:
   Additions $\leq$ Maximum amount of capacity that can be sited
6. Nonnegativity restrictions, all variables.

The 1987 model constraints are the same, but exclude the fifth constraint. Initial formulations of the year-2000 model originally included a reserve margin constraint, but since it was never found binding it was removed for later runs. Transmission capacity variables are also deleted, since they were rarely constraining (implying that transmission capacity additions are not justified by the average power flows calculated by this linear program).

The model is used to calculate the costs of meeting demands for each coalition of utilities that is considered. Then the core of the cooperative deregulated game is calculated as set out in the main body of this report. Other solutions under various pricing rules (such as simultaneous buy/sell) are also determined.

The analytical models used here are exactly analogous to those applied by Gately in his analysis of the gains that could be obtained by cooperation among southern India's electricity boards.[3] Not only did Gately calculate the core, he also obtained a number of point solutions to the game, including the nucleolus and Shapley value.

Gately's model, however, was a mixed-integer program; here, instead, a linear programming (LP) model is used because of its quick solution times. The LP is the classic spatial model developed by Anderson[4] and includes transmission and spatially dispersed demands and generation. It has been shown that such an LP produces fairly reasonable solutions even in the absence of integer variables, because most generation capacity additions are quite large.[5] Further (if degenerate solutions are avoided), the LPs yield useful dual variables, which can be interpreted as the marginal operating and capital cost of meeting demand; mixed-integer programs yield only short-run marginal costs (since capital investments are not decision variables in the LPs in the branch-and-bound algorithm).

Data and Assumptions

This section briefly describes the demand, generation, and transmission assumptions that were made.

The major part of the data base was taken from a previously existing data base.[6] The data base was augmented to include two utilities that

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[3] Dermot Gately, "Sharing the Gains from Regional Cooperation: A Game Theoretic Application to Planning Investment in Electric Power," *International Economic Review* 15 (February 1974): 195-208.
[4] Anderson, op. cit.
[5] See P. M. Meier, B. F. Hobbs et al., "The Brookhaven Regional Energy Facility Siting Model: Model Development and Application," *BNL-51006*, Brookhaven National Laboratory, Upton, New York 1979.
[6] See footnote 2.

were earlier omitted and to update demands and costs. In the earlier study, demands and facility locations were disaggregated to counties. Here, the data have been reaggregated to twenty-one multicounty subregions in order to reduce data preparation and solution times.

While actual data for eight utilities are used, the real names of the companies are not given, for reasons mentioned previously; instead utilities are given state code names. This is solely for convenience and is intended as a memory aid for the reader. There is no relationship at all between the utility with code name "California," for example, and the actual generating capacities, fuel types, and so on, of any California utility. The utilities are:

1. California (CA)
2. Utah(UT)
3. Colorado (CO)
4. Oregon (OR)
5. Arizona (AZ)
6. Nevada (NV)
7. Kansas (KS)
8. Missouri (MO)

The code names are selected to serve as a reminder of the actual geographical relations of the utilities. Below is a schematic diagram showing how the utilities are spatially arranged:

```
  OR
   |
CA/NV--UT--CO--KS--MO
   |
  AZ
```

The utilities are arranged in series, with the exception of CA and NV, whose plants and service territories (in the case of NV, its industrial and municipal customers) are inextricably intermingled. The companies on the left (to the west) are larger utilities (CA and especially NV) that have significant nuclear and hydro capacity in excess of their needs. The companies on the right (to the east) serve large urban areas: KS and MO depend on high-cost oil-fired steam plants and turbines. As a result, there are economic opportunities for wheeling from left to right through UT and CO, which are strategically located in a narrow geographic corridor.

In actuality, some of this trading already takes place, but we assume that the utilities are not cooperating initially in order to determine what market power the wheelers might have in this instance, as an illustration of the gains and market power that might be wielded in a real power market.

The 1987 demands are extrapolated from U.S. DOE Energy Information Agency documents. The year-1987 total peak demand for the whole group was about 23.3 GW. The assumed subregion demands for 1987 are given in table B-1. In the year-2000 solutions, the demands are assumed to have grown by 2 percent each year in the period 1987-2000.

Table B-2 lists the existing power plants included in the model runs. Data were obtained from utilities in the region and U.S. Department of Energy sources. The plant/unit numbers were used as an index in the model and have no other significance. The "plants" in many cases combine a number of different facilities using the same fuel and having similar costs. The marginal costs include both fuel and nonfuel marginal costs. As can be seen, the costs vary by more than an order of magnitude. The region has a lot of expensive oil-fired capacity (including combustion turbines and heavy-oil-fired steam plants), but also has ample nuclear and

TABLE B-1

PEAK DEMAND BY SUBREGION

Subregion (Utility)	Peak Demand (MW)	Subregion (Utility)	Peak Demand (MW)	Subregion (Utility)	Peak Demand (MW)
1(NV)	283	8(AZ)	474	15(CA)	1,442
2(CA)	3,107	9(AZ)	71	16(UT)	108
3(AZ)	638	10(CA)	279	17(UT)	711
4(OR)	1,282	11(CA)	734	18(UT)	78
5(AZ)	472	12(AZ)	265	19(CO)	789
6(CA)	1,203	13(NV)	149	20(KS)	7,623
7(CA)	73	14(CA)	77	21(MO)	3,478

Sum of Noncoincident Peak Demands: 23,336 MW

Source: Utility-provided data and U.S. Energy Information Administration

TABLE B-2

UTILITIES' CAPACITIES AND MARGINAL COSTS, BY PLANT OR UNIT

Utility	Plant or Unit No./Fuel[a]	Capacity, MW	Marginal Cost, $/kW-yr[b]
1 CA	1 Oil	400	324
1	2 CT (Comb. Turb.)	146	421
1	4 Coal	600	152
1	8 Coal	785	190
1	16 Oil	358	315
1	18 Oil	1,821	424
1	20 Nuclear	1,695	114
1	25 CT	128	482
1	40 Hydro	151	33
1	42 Hydro	205	33
2 UT	9 CT	38	605
2	14 Oil	476	440
2	15 Oil	358	315
3 CO	17 CT	40	827
3	22 Oil	401	374
3	23 Oil	501	309
3	24 CT	37	1,413
3	43 Hydro	66	183
4 OR	11 Coal	340	181
4	12 CT	93	403
4	13 CT	9	468
4	19 Oil	204	430
4	30 Nuclear	470	113
4	39 Hydro	47	65
5 AZ	3 Coal	126	172
5	6 Coal	73	205
5	7 CT	7	731
5	10 CT	10	731
5	26 Coal	86	176
5	27 CT	27	731
5	28 Coal	290	134
5	29 CT	29	731
5	31 CT	205	183
5	37 Coal	625	172
5	45 Coal	925	146
6 NV	5 Coal	78	215
6	21 Nuclear	778	196
6	38 Hydro	2,316	25
6	41 Hydro	775	37
6	44 Nuclear	3	167
7 KS	32 Nuclear	864	245
7	33 Oil	3,933	418
7	34 Gas	2,321	1,493
8 MO	35 Oil	3,090	317
8	36 Gas	992	641
	TOTAL CAPACITY	26,922 MW	

Source: Utility-provided data and U.S. Energy Information Administration

Notes: a. Plant and unit numbers are arbitrary and have no meaning except as code numbers in the model.
b. Divide by 8760 hrs/year to obtain the marginal cost in dollars per kWh.

hydropower with very low running costs. (Some of the facilities lie outside the service territories of their owners. Thus, it is unavoidable that the calculation of costs for subcoalitions sometimes includes units owned by utilities outside the subcoalition and sometimes excludes units owned by the subcoalition, which lie outside their combined service territories. This results in some, but not significant error.)

In addition to existing facilities, the 1987 solution allows for the construction of new combustion turbines to meet peak demands. In the year-2000 solutions, both base-load coal-fired plants and combustion turbines may be added. Siting constraints due to population density or scarce water supplies prevent siting of coal units in much of the region. Even in those subregions where siting is feasible it is assumed that such constraints prevent more than 2,000 MW of coal capacity from being added in any single subregion.

The assumed costs of new power plants are based on the most recent EPRI *Technical Assessment Guide*. Construction and fixed operation costs are assumed to amount to $136.55/kW-year for new coal units and $34.16/kW-year for combustion turbines. Marginal operating costs for new coal plants are set equal to $134.7/kW-year, and for new turbines to $776/kW-year.

Power transfer capacities of transmission lines are based on an assumed power angle of 30°. Capacities are based on thermal limits for lines that are less than fifty miles in length, which constitute most of the lines. For a few longer lines, S.I.L. limits, based on the St. Clair curves, or stability limits supplied by the utilities are used instead. For a crucial corridor, assumed capacities at three critical interfaces are based on actual regional practice, which limits loadings to levels that can be sustained if one of the circuits in the corridor is lost. The assumed flow capacities are in table B-3.

The assumed loss rates are in most cases based on the actual conductor size for the highest voltage line in each link, a power angle of 30°, actual line lengths, and an expected peak utilization of 70 percent (based on utility-provided data).

As mentioned, no long-run transmission capacity expansion variables are included in the year-2000 model because the dual variables of trial solutions show that transmission capacity additions would be economically justified only in rare conditions and would not be large in size. Thus, inclusion of such variables would not significantly alter the cores of the games.

TABLE B-3

TRANSMISSION CAPACITIES BETWEEN SUBREGIONS

Subregions Connected	Tie Line Capacity (MW)	Subregions Connected	Tie Line Capacity (MW)
1,2	1,398	8,9	120
2,3	820	8,12	1,510
2,4	1,885	9,11	360
3,4	240	10,11	1,425
3,5	480	10,13	432
3,8	1,620	11,12	120
4,5	303	11,15	2,156
4,6	1,043	12,15	863
5,6	540	12,17	240
5,7	240	14,15	120
6,7	120	15,16	240
6,9	240	15,17	3,306
6,10	525	16,17	240
6,11	4,373	17,18	240
7,8	120	17,19	1,654
7,9	120	19,20	6,156
		20,21	2,403

Source: Utility-provided data, modified as explained in the text.

Note: Pairs of subregions not listed are not connected.

The system is simulated for years 1987 and 2000 in six separate runs of the model. More than one subcoalition can be considered in a single run if (1) no utility belongs to more than one subcoalition and (2) the transmission lines connecting the combined service territories of the subcoalitions are "severed" (deleted from the model) so that no power flows between the subcoalitions. In this case, the overall model yields the optimal solution for each subcoalition. The different subcoalitions for which total generation construction and operation costs are calculated are as follows:

Model Run	Coalitions considered
I	All utilities in a grand coalition
II	Subcoalitions: {1,4,5,6}, {2,3}, {7,8}
III	Subcoalitions: {1,4,6}, {5}, {2}, {3}, {7}, {8}
IV	Subcoalitions: {1,2,3,4,5,6}, {7,8}
V	Subcoalitions: {1,4,5,6}, {2,3,7,8}
VI	Subcoalitions: {1,2,4,5,6}, {3,7,8}

Note that not all possible subcoalitions are considered in these runs. Some subcoalitions (such as {KS,AZ}) do not need to be considered because their lack of interconnection assures that the subcoalition would have zero value. Other subcoalitions are not considered in order to limit the number of model runs to a reasonable number: eight utilities implies the existence of 255 (i.e., 2^8-1) subcoalitions. For example, utilities {1,4,6} (CA, OR, and NV) are assumed to cooperate always because they are in the same part of the region and their generation and transmission facilities are intimately intermingled. Separating them would be unlikely to yield significant insights.

Results

The results of the bulk power wheeling game for the eight utilities are presented in the following order:

1987 Solutions:

1. The 1987 cooperative solution (power flows and costs) and subcoalition solutions (costs alone) are summarized.
2. Cores of the three-party S-W-B (seller-wheeler-buyer) game for 1987 (where the following utilities each play the role of W in one game: CO, UT, and CO and UT together) are found under the Contract model with flexible pricing for generation and transmission.
3. The 1987 simultaneous buy/sell (SBS) and wheeling at a fixed fee (WhF) solutions are found where generation is assumed to be priced using the split-savings rule and transmission is priced under the Status Quo and Planning models.
4. The nucleolus and Shapley value of the 1987 four-party game with two wheelers in series: the "seller" S is a group of four westward utilities, namely, S=CA/AZ/OR/NV; the two wheelers are W_1=CO and W_2=UT; and the "buyer" is the two eastward urban/suburban utilities, that is, B = KS/MO.
5. The effect of wheeling fees that exceed the marginal cost of transmission is assessed.

2000 Solutions:

1. The 2000 cooperative solution (power flows and costs) and subcoalition solutions (costs alone) are summarized.

2. Cores of the three-party S-W-B (seller-wheeler-buyer) game for 2000 (where the following utilities each play the role of W in one game: CO, UT, CO and UT together, and KS)
3. The core, nucleolus, and Shapley value of the 2000 four-party game with two wheelers in series: S=CA/AZ/OR/NV; W_1=CO; W_2=UT; and B=KS/MO.

The split-savings-based solutions are not considered in the year-2000 case because such a pricing policy applies only to short term/economy transactions. In the year 2000, new plants are constructed in the west to sell power to utilities in the east; such sales would be priced on a firm basis. (However, it should be noted that some of the existing western capacity is, in reality, sold at present on a firm basis to utilities to the east. This fact is not accounted for here.)

<u>1987 Results</u>

The year 1987 results are for the case where generating and transmission capacity is fixed, except for combustion turbine capacity, which can be added in the short-run.

Overview of 1987 Solutions

Table B-4 shows the costs of various subcoalitions in the 1987 game. We reiterate here that there is no relationship between the state code names and the characteristics of any utility in these states.

If we calculate the gains from cooperation as the difference between the sum of the cost for the {CA,OR,AZ,NV}, {UT}, {CO}, {KS}, and {MO} subcoalitions minus the cost of the grand coalition, the gain to be split among the players is $710 million per year, or 15 percent of the total annual cost when the parties do not cooperate. Almost half the total gain ($266 million) is obtained if UT and CO cooperate, primarily because excess capacity in CO's service territory allows UT to avoid buying and running combustion turbines, which would otherwise be needed to overcome its capacity deficit. Another $44 million of the total gain is realized if KS and MO cooperate. If the subcoalitions {KS,MO} and {UT,CO} cooperate, then an additional $61 million of gain is realized, primarily because of the relatively low-cost capacity that is located in CO's service territory.

TABLE B-4

YEAR 1987 GENERATION COSTS BY COALITION

Coalition	1987 Generation Cost ($\$10^9$/yr)
Grand Coalition	4.056
{CA,OR,AZ,NV}	.863
{UT,CO}	.395
{UT}	.489
{CO}	.172
{KS,MO}	3.198
{KS}	2.397
{MO}	.845
{CA,OR,AZ,NV,UT}	1.129
{CA,OR,AZ,NV,UT,CO}	1.205
{UT,CO,KS,MO}	3.532
{CO,KS,MO}	3.047

Source: Authors' calculations using a linear program transshipment model

The remainder of the gain, $339 million, is obtained when the four western utilities join the eastern utilities. This large gain is due to the displacement of expensive eastern oil-fired generation by cheap western nuclear and hydropower. These estimates do not include the additional reliability benefits of cooperation and the added economy power benefits that result from peak diversity.

The power flows in the grand coalition are as follows (numbers above the arrows are peak-period flows, numbers below are base-period flows, both expressed in MW):

$$\{CA,OR,AZ,NV\} \xrightarrow[1490]{1611} \{UT\} \xrightarrow[800]{582} \{CO\} \xrightarrow[1469]{1752} \{KS,MO\}$$

Notice that in one case the off-peak flow exceeds the on-peak flow, emphasizing that economies are possible with off-peak coordination also.

Cores for 1987 Three-Player Games

Figures B-1, B-2, and B-3 show the cores for three different three-player games for 1987. They also display the SBS and WhF solutions, terms explained fully in chapter 4. The core solutions show the range of possible solutions under an unregulated ("flexible") pricing regime for both transmission *and* generation. (If generation sales were priced on a

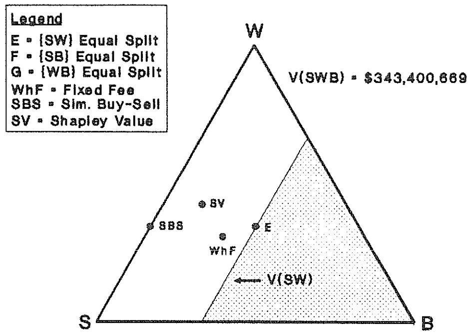

Fig. B-1. 1987 Core: S ={OR,CA,NV,AZ}, W={UT}, B={CO,KS,MO}

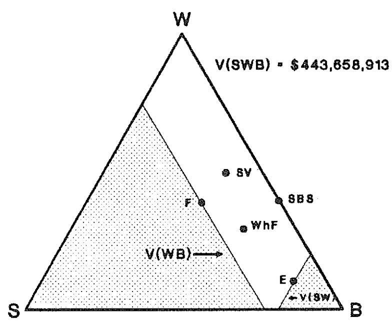

Fig. B-2. 1987 Core: S={OR,CA,NV,AZ,UT}, W={CO}, B={KS,MO}

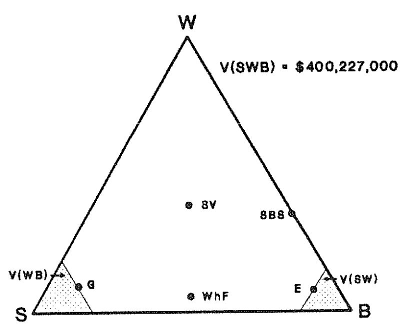

Fig. B-3. 1987 Core: S={OR,CA,NV,AZ}, W={UT,CO}, B={KS,MO} split-savings basis between S and B, with only wheeling fees being flexible, the locus of possible solutions would be more restricted: it would be a line (not shown in the figures) extending from the WhF solution toward W's corner point in each of these three figures. The WhF solution represents the case in which wheeling fees just cover the cost of wheeling, with B and S getting most of the gains of trade, while W's corner point is the situation in which W gets all of the gains from trade. WhF does not lie on the baseline of the triangle because W can get a share of the gains as a buyer or seller, even if it wheels at no gain.)

The cores are very different in terms of their shapes and the market power that W wields: as a result, these provide good illustrations of how wheeler market power is shaped by cost and demand conditions.

Figure B-1 shows the core that results if W has little or no power to sell to B, while W could economically buy a significant amount of power from S. In this case, UT is the wheeler and has no excess capacity it could sell to B, which is the coalition {CO,KS,MO}. As a result, the value of the {W,B} coalition is zero. On the other hand, the value of the {S,W} coalition, here {CA,OR,AZ,NV,UT}, is relatively high ($223 million) because UT could buy some of S's excess capacity. In this case, B has little market power, and most of the gains are split between W and S.

Figure B-2 shows the core that results if CO plays the role of W. In this case, W has a good deal of relatively cheap capacity it would like to sell to B, although W's costs are greater than S's (so that S's generation would displace W's if they cooperated without B). In this case, the value of the {W,B} coalition happens to be much higher than the value of the {S,W} coalition. As a result, S has relatively little market power, and W and B would split most of the gains.

Figure B-3 shows a situation in which the wheeler has the least market power--where CO and UT jointly act as W. In this case, UT uses up most of CO's spare capacity. As a result, there is little extra to sell to B in a {W,B} coalition, but there is also little benefit to buying from S in a {S,W} coalition. Most of the benefits are unrealized unless the grand coalition forms. The constrained core here is larger than in the other two cases, and the market power of the three parties is more nearly equal (that is, W's market power is less than in the last two situations). (The value of the grand coalition V(SWB) differs in figures B-1, B-2, and B-3. This occurs because of the different definitions of the parties and the relationship V(SWB) = C(S)+C(W)+C(B)-C(SWB), where C(x) is the cost of coalition x.)

Simultaneous Buy/Sell (SBS) and Fixed Wheeling Fee (WhF) Solutions

In this section, the solutions resulting from the Status Quo and Planning models are discussed. The Status Quo, for reasons outlined in chapter 4, often results in the simultaneous buy/sell (SBS) solution, unless that solution is not allowed (by regulation or contract) or wheeling fees are so high as to make wheeling at a fixed fee attractive to W. If SBS is not allowed, then W would choose either the most profitable subcoalition or the fixed wheeling fee solution, whichever was more profitable. W's profit under each subcoalition is indicated in figures B-1 through B-3 by the dot at the midpoint of the line-segment defining the core constraint which results from the subcoalition; this presumes that W and its partner split all savings evenly.

A Planning model in which the wheeling fee is set equal to the wheeling cost results in the WhF solution, assuming that B and S evenly split the savings from their transactions and W splits any savings evenly with its partner in any other transactions.

Computational Procedure. The derivation of the WhF and SBS solutions is discussed below, followed by a summary of the results. First, we define the variables that we need to solve for. Let the following prices represent the *average* price per kilowatt-hour sold. (Of course, in a split-savings system, different blocks of power would have different prices. However, for calculating total expenditures and revenue, only the mean price matters.)

P_{SB} = The average price charged by S to B for power that is wheeled by W at a fixed fee F.

P_{SW} = The average price charged by S to W for power that S sells directly to W (which could, if SBS is allowed, either be resold to B or consumed by W)

P_{WB} = The average price charged by W to B for power that W sells to B (which could, if SBS is allowed, either have been generated by W or bought by W from S)

Let the following variables represent the net cost to each party of meeting its demands, including any revenues or expenses resulting from split-savings transactions:

NC_S = Cost to S of meeting its demands, net of revenues received from split-savings transactions with W and/or B and wheeling fees paid to W

NC_W = Cost to W of meeting its demands, net of split-savings payments to S, split-savings revenues from B, and/or wheeling fees

NC_B = Cost to B of meeting its demands, including the cost of split-savings payments to S and/or W

The following variables define generation cost increases or decreases to each of the parties resulting from cooperation:

T_{savWB} = B's decrease in generation costs resulting from its purchases from W

T_{savSB} = B's decrease in generation costs resulting from its purchases from S

(Note that $T_{savWB}+T_{savSB} = C(B) - C(B|SWB)$ (1)

where: $C(B)$ = cost to B if it self-generates (no cooperation)

$C(B|SWB)$ = B's self-generation cost in the SWB coalition

This excludes the cost of power purchased from W and S.)

T_{savSW} = W's decrease in generation costs resulting from its purchases from S

T_{speWB} = W's increase in generation costs resulting from its sales to B

(Note that $T_{savSW}-T_{speWB}-FQ_{SB} = C(W) - C(W|SWB)$ (2)

where: $C(W)$ and $C(W|SWB)$ are W's cost of generation, excluding purchases from S, when it respectively does not and does participate in the coalition SWB, and

Q_{SB} = amount of power wheeled from S to B *net of* wheeling losses (the amount of power that S must inject into the grid is actually $Q_{SB}/(1-L)$, where L is a loss coefficient; thus, S is assumed to be responsible for making up any losses)

F = cost of wheeling, other than losses)

T_{speSB} = S's increase in generation costs resulting from its sales to B

T_{speSW} = S's increase in generation costs resulting from its sales to W

(Note that $T_{speSB}+T_{speSW} = C(S|SWB) - C(S)$ (3)

where the latter two parameters are S's self-generation costs in the grand coalition and when it does not cooperate, respectively)

These twelve variables require twelve independent equations in order to be solved for uniquely. Equations (1), (2), and (3) are the first three of these equations (their right-hand sides are obtained by calculating the total generation costs for each party for the appropriate solution). Three additional equations are:

$$NC_B = C(B|SWB) + P_{SB}Q_{SB} + P_{WB}(Y_{WB}-Q_{SB}) \tag{4}$$

$$NC_W = C(W|SWB) - FQ_{SB} + P_{SW}(Y_{SW}-Q_{WB}/(1-L)) - P_{WB}(Y_{WB}-Q_{SB}) \tag{5}$$

$$NC_S = C(S|SWB) - (P_{SB}Q_{SB}-FQ_{SB}) - P_{SW}(Y_{SW}-Q_{SB}/(1-L)) \tag{6}$$

where: Y_{SW} = total amount of power delivered by S to W at its interface with W. This power consists of two parts: the amount that is wheeled to B, $Q_{SB}/(1-L)$, and the direct sales to W, Q_{SW} ;

Y_{WB} = total power delivered by W to B at their interface. Y_{WB} consists of two parts: the amount wheeled from S, Q_{SB}, and the direct sales by W to B, Q_{WB}.

These equations define the net cost to each party as its total generation cost plus its net payments to other parties.

Three more of these twelve equations are:

$$T_{speSW}/(Y_{SW}-Q_{SB}/[1-L]) = T_{speSB}/(Q_{SB}/[1-L]) \tag{7}$$

$$T_{savSB}/Q_{SB} = T_{savWB}/(Y_{WB}-Q_{SB}) \tag{8}$$

$$T_{speWB}/(Y_{WB}-Q_{SB}) = T_{savSW}/(Y_{SW}-Q_{SB}/[1-L]) \tag{9}$$

These constraints basically say there must be no generation price discrimination. Equation (7) says that S's average generation expenditures associated with sales to W must equal S's average expenditures on sales to B. Equation (8) states that the average savings attributed to purchases by B from S must equal the average savings attributed to purchases by B from W. Equation (9) says that W's allocation of mean generation expenditures to its sales to B must equal W's allocation of its mean savings to its purchases from S. Note that equations (7) through (9) are not a necessary result of split-savings. For example, a split-savings system that first matches the largest-decremental-cost buyer with the smallest-marginal-cost seller might result in a different allocation. However, (7) through (9) are simple, easy to compute, and are fair by one definition.

The final three equations result from imposing the constraint that power sales are priced on a split-savings basis. This ties together the T variables and prices:

$$(T_{savWB}+T_{speWB})/2 = P_{WB}(Y_{WB}-Q_{SB}) \tag{10}$$

$$(T_{savSB}+T_{speSB}+FQ_{WB})/2 = P_{SB}Q_{SB} \quad (11)$$

$$(T_{savSW}+T_{speSW})/2 = P_{SW}(Y_{SW}-Q_{SB}/[1-L]) \quad (12)$$

These say that the revenue that the seller earns from the transaction (on the right-hand side of each equation, which equals the mean price times the quantity of sales) equals one-half of the net savings resulting from the transaction plus the costs of generation and, if applicable, wheeling (the left-hand side).

The difference between the WhF and SBS solutions can be explained as follows. The WhF solution is found by setting:

$$Q_{SB} = \mathrm{MIN}(Y_{SW}[1-L], Y_{WB}),$$

which states that as much as possible of the amount that S sells is wheeled to B (no simultaneous buy/sell). In this case, W either just buys from S or just sells to B, in addition to wheeling.

The SBS solution is found instead by setting $Q_{SB}=0$ (no wheeling), subject to the following adjustment. If the above equations yield a negative share of the gains from cooperation for any party, then its share is raised to zero and the gains to W are lowered by the same amount (so that the sum of the shares still equals 100 percent). This situation can arise (and indeed does in figures B-1 through B-3) when W's marginal cost is not between that of S and B. For example, in figure B-1, UT's marginal cost is higher than both S's and B's. As a result, there are apparently negative savings to split in any sale from W to B. Solving the above equations in a mindless fashion yields the following shares of the gains: 67.4 percent to S, 50 percent to W (as always occurs in SBS), and -17.4 percent to B. In this case, we made the following adjustment: assuming that S sells to W using "split savings" as usual and W sells power to B at B's marginal cost (and no more), B gets none of the gains, S gets the gains calculated using the equations (67.4 percent), and W's gains are lowered to 32.6 percent to account for the absence of profit in its resale of power to B.

In figures B-2 and B-3, the reverse situation applies. W's marginal cost is lower than both S's and B's. As a result, W would not be able to buy power from S using split savings (since the apparent savings are negative), and the equations yield a negative profit for S as a result. Therefore, we assume that S sells its power at its own marginal cost to W (so the gain to S is zero), but W continues to resell to B using the split-savings rule; the result is that most of the gain goes to B, as shown in the figures.

In our solution, we assumed that costs other than wheeling fees are zero, so that F=0.

In the SBS version of this model, an indeterminacy could result if $Y_{SW}/(1-L) = Y_{WB}$, where W has no sales or purchases other than the purchases from S that it is reselling to B. In this case, equations (2) and (9) are identical. To solve this problem, the additional constraint $T_{savSW} = MC_W(Y_{SW}-Q_{SB}/[1-L])$ can be imposed, where MC_W is W's marginal cost. But, this procedure was not necessary for the cases considered in this appendix.

1987 Results. The resulting WhF and modified SBS points are shown in figures B-1 through B-3. As mentioned, the WhF point here represents wheeling at short-run marginal cost. Unlike some of the simple models, the WhF points result in positive gains for W, mainly because W either obtains some gains by buying some power from S (figure B-1) or by selling some of its extra capacity to B (figures B-2 and B-3). In all cases, WhF is in the core. If W charges more than the marginal cost of wheeling to convey power from S to B (and assuming that despite the inefficient fees, all efficient transactions still take place), then the possible outcomes lie on a line (not drawn) running from the point WhF in the general direction of the W corner.

If wheeling is voluntary (as in the Status Quo), it appears that W is not made better off by wheeling in figures B-1 and B-2, as compared to forming a subcoalition with just S or B. The extreme case is for W (CO) in figure B-2; here W may be as well off forming a subcoalition with B rather than wheeling (even if it still can sell some of its excess capacity to B in the grand coalition). The solution to this problem under the Status Quo is to somehow share the gains more evenly so that W has an incentive to joint in the grand coalition. (This is a solution that actually has been adopted by the utilities studied here; it is expressed in a pooling agreement.) In the other two figures, the WhF solution is only slightly less advantageous to W than forming a subcoalition.

Note that in all the WhF solutions, either S or B gets exactly 50 percent of the gains. S gets half of the gains if it is the only seller of power (W buys from S rather than selling to B); otherwise B gets half (as it is the only buyer of power).

Because W's marginal costs are either above both S's and B's or below them in these real-life examples, the standard SBS solution does not apply, for reasons discussed under "Computational Procedure." Instead, the "modified" SBS solutions are calculated, which result in zero gain for either B or S (rather than the negative gain that the equations calculate) and less than half the gain for W (instead of 50 percent as in the standard SBS solution).

In every case examined, the SBS solution is more attractive to W than is WhF, but only in one case (figure B-3) is it significantly more attractive than forming a subcoalition with just one partner. The credibility of the SBS procedure as two distinct transactions (a purchase and an unrelated sale) may be questionable here as it is an obvious means for W to charge a high price for wheeling: the amount wheeled is a large fraction of W's demand and W's marginal costs are not between those of the other parties.

1987 Nucleolus and Shapley Value of the Four-Party Game

The above results are for fairly arbitrarily defined three-party games. Next, we consider a four-party game with two wheelers in series: S=CA/AZ/OR/NV; W_1=CO; W_2=UT; and B=KS/MO. Because it is difficult to portray the three-dimensional core that results in a four-party game, we use the nucleolus and the Shapley value as indicators of the relative market power of the different parties.

The value of the grand coalition is calculated to be \$666 million each year. As a percentage of this value, the values of those subcoalitions with positive values are:

$V(S,W_1) = 33\%$ $\qquad V(S,W_1W_2) = 48\%$

$V(W_1,W_2) = 27\%$ $\qquad V(W_1,W_2,B) = 33\%$ $\qquad V(W_2,B) = 32\%$

The values of subcoalitions obviously affect each party's share of the total gain (\$666 million) obtainable if all the parties cooperate. We calculated two standard ways of sharing the total gain (though there are, of course, an infinite number of allocations that satisfy the core constraint). The nucleolus share to each party, calculated with a linear programming package, is:

$S = 20\%$ $\qquad W_1 = 22.5\%$ $\qquad W_2 = 37.5\%$ $\qquad B = 20\%$

The Shapley value shares are similar but not identical:

$S = 20\%$ $\qquad W_1 = 25\%$ $\qquad W_2 = 33\%$ $\qquad B = 22\%$

As would be expected, the wheelers obtain most of the gains, mainly because there is no value to an {S,B} coalition. W_2 (CO) gets the largest share, primarily because large gains occur if it joins in a subcoalition with B. This is because CO's excess capacity is very valuable in the eastern part of the region.

1987 Effects of Wheeling Fees That Exceed Marginal Wheeling Costs

In the solutions above, it is assumed that only the short-run marginal costs of wheeling (losses and, in a very few cases, congestion costs) are recovered by the wheeler. If in addition wheeling fees that include an embedded capital cost component are charged for all transmission flows, some economically justified transactions are prevented because the fee exceeds the marginal benefit from the transaction.

This kind of wheeling fee is simulated by adding terms to the objective function for the grand coalition that equal the product of the transmission flow and the fee. The fees include capital cost components that are derived from the following assumed capital costs for interconnections at various voltages:

115KV: $148,000/mile
230KV: $199,000/mile
345KV: $330,000/mile
765KV: $729,000/mile

(These values were taken from an earlier study and do not necessarily represent current replacement costs.) In addition, the costs of circuit breakers are added. Based on experience elsewhere, the average loading of 115 KV lines is assessed to be 40 percent of capacity during peaks. Data from the utilities in the example show that, for EHV lines (230 KV and over), the ratio of peak to capacity is about 70 percent. These figures, when combined with the calculated line capacities, an average load factor of 0.626 for the utilities in the region, the mileage for each tie line, and an annual charge rate of 0.153 for capital recovery and O&M, allow us to calculate the wheeling charge for each link. For example, for a 230-KV line, the charge is $105/peak-MW/mile/year (which is 50 percent to 100 percent higher than actual wheeling fees charged by some of these utilities in 1981). For 345-KV lines, most charges are in the range of $60 to $90/peak-MW/mile/year.

With wheeling fees in excess of marginal wheeling costs, the new minimized total generation cost when all utilities cooperate (that is, the total production cost for the grand coalition) is $4.40 billion. Of this, $0.30 billion is wheeling fees, which are really just transfer payments.

Thus, the real cost (generation operation plus the construction of combustion turbines) is \$4.11 billion, an increase of 1.2 percent over the cost of \$4.06 billion that occurs if there is no embedded-cost surcharge that blocks some economic transactions. This extra expense is \$50 million, which is small compared to the gains from cooperation that are an order of magnitude higher. This implies that if fees must be set at reasonable embedded costs to obtain the wheelers' cooperation, the efficiency losses may be small relative to the potential losses that might occur if utilities decide not to cooperate at all.

The power flows in the wheeling fee solution are shown below. The top numbers are the peak flows in megawatts, and the bottom numbers are the base flows.

$$\{CA,OR,AZ,NV\} \xrightarrow[1175]{1606} \{UT\} \xrightarrow[497]{571} \{CO\} \xrightarrow[1170]{1742} \{KS,MO\}$$

The differences compared to the case of no embedded-cost rates, presented earlier, are:

$$\{CA,OR,AZ,NV\} \xrightarrow[-315]{-5} \{UT\} \xrightarrow[-303]{-11} \{CO\} \xrightarrow[-299]{-10} \{KS,MO\}$$

The decreases in sales occur almost entirely in the base period, when the differences in the value of power are less (as reflected in the dual variables for the energy balance constraints).

Year-2000 Results

The year-2000 results differ from the 1987 results in that now new coal-fired power plants can be built (subject to siting constraints) and demands are higher.

Summary

The year-2000 costs associated with the grand coalition and each subcoalition considered are in table B-5. If we calculate the gain from cooperation as the difference between the sum of the costs for the {CA,OR,AZ,NV}, {UT}, {CO}, {KS}, and {MO} subcoalitions minus the cost of the grand coalition, the gain to be split among the parties is \$814 million. As in 1987, this is 15 percent of the total cost when the parties do not cooperate.

TABLE B-5

YEAR-2000 GENERATION COSTS BY COALITION

Coalition	Year-2000 Generation Cost ($$10^9$/yr)
Grand Coalition	5.219
{CA,OR,AZ,NV}	1.596
{UT,CO}	.488
{UT}	.265
{CO}	.225
{KS,MO}	3.712
{KS]	2.982
{MO}	.965
{CA,OR,AZ,NV,UT}	1.860
{CA,OR,AZ,NV,UT,CO}	2.082
{UT,CO,KS,MO}	3.638
{CO,KS,MO}	3.407

Source: Authors' calculations using a transshipment model

But the source of the gain is quite different from the 1987 case. Before, only $44 million out of $710 million came from KS and MO cooperating. Now, $235 million of the $814 million is realized if KS and MO cooperate, primarily because generation capacity is built by MO to meet KS's urban needs. In contrast to the 1987 situation, UT and CO now realize almost no gains if they cooperate. This is primarily because the cost to UT of building new capacity is roughly equal to the running cost of the excess capacity in CO's service territory. If the subcoalitions {KS,MO} and {UT,CO} cooperate, then an additional $562 million of gains is realized, which represents the majority of the total gains. This is mostly because of the existing excess capacity that is located in CO's service territory and the availability of river sites for new power plants in UT's. (Recall that the UT code name has nothing to do with the state of Utah.) Hence UT and CO can team up to supply power to KS and MO, which are in urban and suburban areas that have few suitable new generating sites. The remainder of the gain, $15 million, is obtained when the four western utilities join the eastern utilities. This incremental gain is much smaller than in 1987. This is because the demand growth in the west absorbs the low-cost excess capacity there, making western marginal costs (the cost of new coal plants) similar to the marginal costs of the central utilities, UT and CO.

The power flows in the grand coalition are as follows (again, numbers above the arrows are peak flows, numbers below are base period flows, all expressed in megawatts):

$$\{\mathrm{CA,OR,AZ,NV}\} \xrightarrow[480]{411} \{\mathrm{UT}\} \xrightarrow[953]{1178} \{\mathrm{CO}\} \xrightarrow[2399]{3077} \{\mathrm{KS,MO}\}$$

The flows from the west are smaller than in 1987, but eastward flows from UT and CO are much larger, for the reasons just discussed.

Cores for Year-2000 Three-Player Games

Figures B-4 through B-7 show the cores for four different three-player games. Figures B-4, B-5, and B-6 correspond to figures B-1, B-2, and B-3 and show the outcomes if UT, CO, and {UT,CO}, respectively, play the role of W. In each case, W has a good deal of relatively cheap capacity (either existing or potential in the form of power plant sites) that it would like to sell to B, with W's marginal costs being about the same as S's. In this case, the value of the {W,B} coalition is now the only significant constraint on the core, as the value of the {S,W} coalition in each case is very small. The {W,B} coalition is so valuable because KS and MO are unable to build sufficient coal (or other baseload) capacity to meet their needs due to siting constraints. The result is that S has relatively little market power, and W and B would split most of the gains.

Figure B-7 shows a unique situation in which the urban utility KS is the middle utility, or "wheeler," W. Actually, it is a buyer between two sellers: the western utilities and MO. The core takes on a very different shape. Since KS could meet about a third of its needs for cheap capacity from MO, the value of the {W,B} coalition is about one-third the value of the grand coalition. However, since western utilities could meet nearly all of KS's needs, the value of the {S,W} coalition is nearly as large as that of the grand coalition, V(SWB). These results imply that B (MO) has nearly no market power, and that W can share the gain with S (with W probably getting most of it). (Figure B-7 is unusual because the V(SW) and V(WB) constraints overlap; this occurs because W actually buys from both S and B. This cannot occur if W's costs are between those of S and B so that W buys from S and sells to B. Note that the Shapley value is not in the core in this case.)

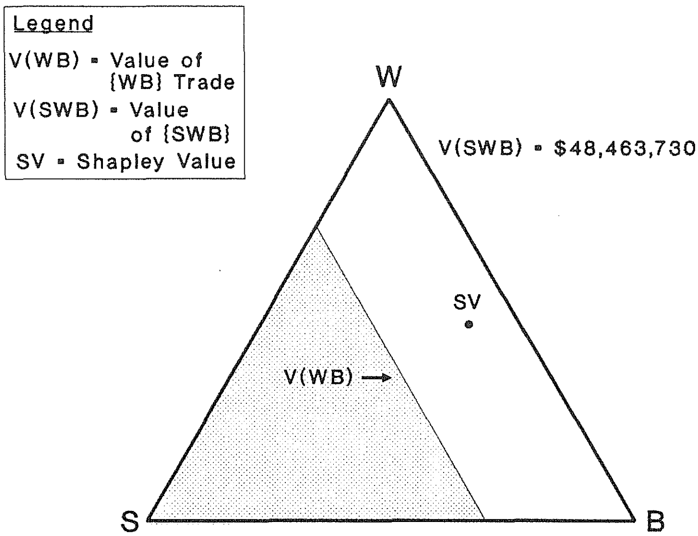

Fig. B-4. 2000 Core: S={OR,CA,NV,AZ}, W={UT}, B={CO,KS,MO}

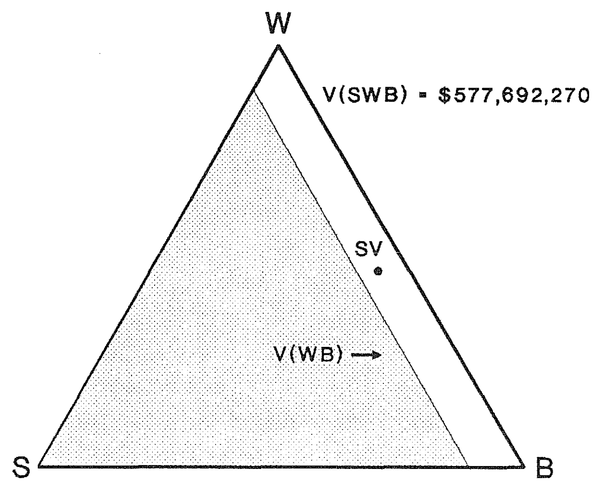

Fig. B-5. 2000 Core: S={OR,CA,NV,AZ,UT}, W={CO}, B={KS,MO}

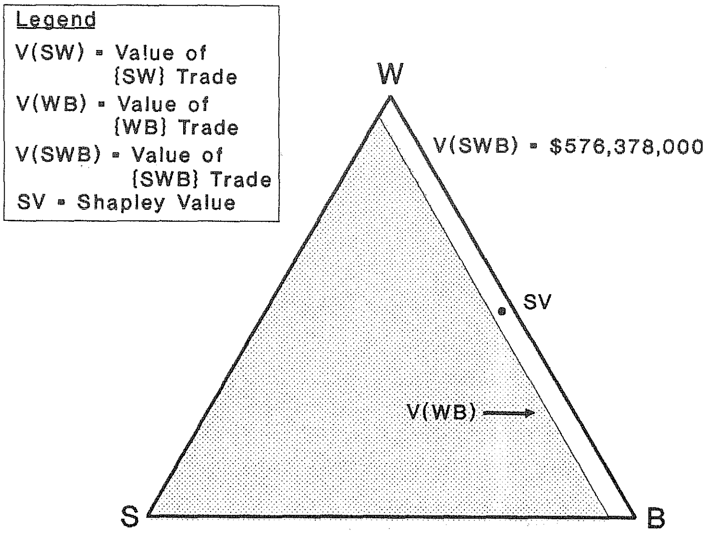

Fig. B-6. 2000 Core: S={OR,CA,NV,AZ}, W={UT,CO}, B={KS,MO}

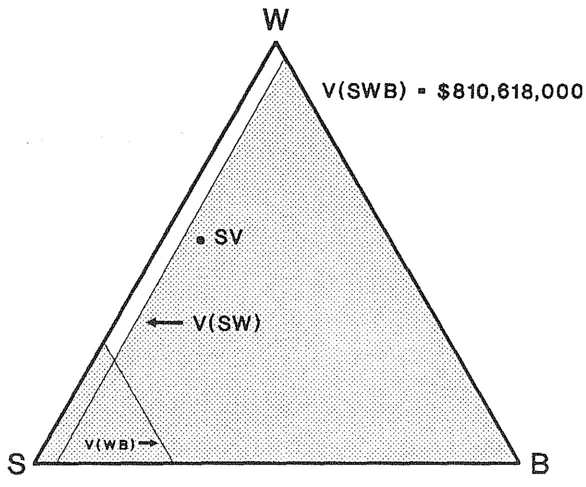

Fig. B-7. 2000 Core: S={OR,CA,NV,AZ,UT,CO}, W={KS}, B={MO}

Shapley Allocation for the Year-2000 Four-Player Game

The total gain from the four-player game, with S={CA,AZ,OR,NV}, W_1=UT, W_2=CO, and B = {KS,MO}, is $579 million. As a percentage of that total gain, the gains to the subcoalitions are:

$V(S,W_1) = 0.2\%$ $\quad$ $V(S,W_1,W_2) = 0.7\%$

$V(W_1,W_2) = 0.3\%$ $\quad$ $V(W_1,W_2,B) = 97.4\%$ $\quad$ $V(W_2,B) = 91.5\%$

The Shapley method of dividing the total gain gives:

$S = 0.7\%$ $\quad$ $W_1 = 2.7\%$ $\quad$ $W_2 = 48.4\%$ $\quad$ $B = 48.2\%$

(Because of the tightness of the $V(W_1,W_2,B)$ and $V(W_2,B)$ constraints, the nucleolus would be similar, dividing most of the gains between W_2 and B.[7]) The Shapley results can be interpreted as follows. Because the most valuable transactions occur if CO builds generating capacity in its service territory to meet MO's and KS's urban needs, CO and B receive nearly all the gains. There is little benefit to subcoalitions not involving CO and MO.

Year-2000 Effect of "Excess" Wheeling Fees

This concluding discussion explores again for the year 2000 the effect of wheeling rates that contain an embedded capital cost component and so, for most tie lines, are above the marginal costs of transmission. (For a few congested links, such rates would be below the true marginal cost; this does not affect the solution significantly.)

The total production cost for the grand coalition with this kind of "excess" wheeling fee is $5.36 billion, of which $0.12 billion is from wheeling fees in excess of marginal costs, which are really just transfer payments. (The amount of transmission and, thus, the amount of excess revenue are less than half those values in the 1987 solution.) Thus, the real cost (generation operation plus the construction of coal plants and

[7] We did not calculate the nucleolus method of sharing the gain because of computational problems in the particular linear program package. It was calculated for the three-player game between UT, CO, and {KS,MO}, which must be close to that of the four-person game because the other utilities add nearly nothing to the solution in this case; it gives 3 percent of the total gain to UT, 48.5 percent to CO, and 48.5 percent to {KS,MO}.

combustion turbines) is \$5.24 billion, an increase of 0.4 percent over the cost that occurs if excess wheeling fees do not prevent economic transactions. This means there is \$19 million of extra expense because of inaccurate wheeling rates. But, as in 1987, this is relatively small compared to the gains from cooperation, which are about forty times higher. This implies that if fees are set using embedded costs, the losses are small relative to the potential losses that might occur if utilities decide not to collaborate. (This assumes that long-run differences in generation costs between regions persist, perhaps because of siting restrictions.)

The power flows under this wheeling fee scenario are shown below. (Here again, the top numbers are the peak flows in megawatts, and the bottom numbers are the base flows.)

$$\{CA,UT,AZ,NV\} \xrightarrow[0]{0} \{UT\} \xrightarrow[496]{677} \{CO\} \xrightarrow[1948]{3077} \{KS,MO\}$$

The differences are shown below:

$$\{CA,UT,AZ,NV\} \xrightarrow[-480]{-411} \{UT\} \xrightarrow[-455]{-501} \{CO\} \xrightarrow[-453]{0} \{KS,MO\}$$

Unlike the 1987 solution, significant decreases in wholesale sales occur in both pricing periods.

APPENDIX C

ANALYTICAL METHODS FOR EVALUATING CAPACITY EXPANSION FOR NONFIRM SERVICE

Early in chapter 6, an integral equation is presented that expresses W's profit-maximization objective for the case where W might wheel to another control-area utility. W profits the most by constructing the optimum amount of transmission capacity, y_{sw} and y_{wb}, under flexible nonfirm transmission pricing. In particular, we want to find "the best y_{wb}," that is, the optimal amount of transmission capacity for W to earn profits on its transmission service by wheeling coordination energy to B. The integral is solved here analytically and numerically in appendix D, where the results are set out in tabular form. All results are discussed in chapter 6.

Immediately following the presentation of the integral in chapter 6, four versions of the integral (I through IV, some with parts a and b) are described. The best of these is the optimal solution for the original integral in chapter 6. This appendix gives the details of this approach, using the variables defined in chapter 6.

If any of the expressions below yields a value of y_{sw} or y_{wb} that is less than zero, the value of that decision variable is set to zero, and, if necessary, the model is resolved for the other decision variable. (Note that the expressions for Versions Ib, IIb, and IIIb could yield a y_{sw} and/or y_{wb} that is greater than Q_{sm}; in that case, the expression has yielded a minimum profit rather than a maximum, and the actual optimum is $y_{sw}=y_{wb}=0$. This could happen if the fee ceiling F_u is low enough. These possibilities are not discussed further in this report, but they are accounted for in the calculations that implement the formulas.)

1. Version Ia: Neither the fee ceiling nor W's demands constrain the optimal solution

W's profit is given by the following expression:

$$\frac{8760P_f}{Q_{sm}} \left[\int_0^{y_{wb}} (F_{sw}+F_{wb})y\,dy \quad + \quad \int_{y_{wb}}^{Q_{sm}} (P_{bo}-My_{wb})y_{wb}\,dy \right.$$

[Fees earned when y_{wb} is not used to capacity] [Fees earned when y_{wb} is used to capacity]

$$+ \int_{y_{wb}}^{y_{sw}} 0.5(C_w+F_{sw})(y-y_{wb})dy$$

[Cost saved by purchases from S, y_{sw} not used to capacity]

$$+ \int_{y_{sw}}^{Q_{sm}} 0.5(C_w+F_{sw})\ (y_{sw}-y_{wb})dy] \quad - \quad CC_{sw}y_{sw}-CC_{wb}y_{wb} \quad - \quad C_wD_w$$

[Cost saved by purchases from S when y_{sw} used to capacity] [Transmission line construction cost] [Cost of generation if no purchases from S]

Integrating this expression and then taking partial derivatives with respect to y_{sw} and y_{wb} and setting them equal to zero yields two equations, which are solved for the optimal values of y_{sw} and y_{wb}. For most parameter values, the best y_{wb} is the smallest positive root of the following quadratic equation:

$$3M(y_{wb})^2 + [F_{sw}+F_{wb}-2P_{bo}-2MQ_{sm}+.5(C_w+F_{sw})]y_{wb} + Q_{sm}[P_{bo}+.5(C_w+F_{sw})-CC_{wb}/(P_f8760)] = 0 \tag{1}$$

(For some parameter values, this may actually yield the y_{wb} that yields minimum profit; the second-order conditions must be checked.) The best y_{sw} is:

$$y_{sw} = Q_{sm}\{1-CC_{sw}/[8760P_f0.5(C_w+F_{sw})]\} \tag{2}$$

The marginal benefit of additional y_{sw} is related only to the savings that W gets from buying additional power from S on a split-savings basis--just as in the case of simultaneous buy/sell. In this case, what W does with the inframarginal transmission capacity that is devoted to B's needs (using it to wheel power on a simultaneous buy/sell or fixed fee basis) does not affect the marginal benefit of the last unit of transmission capacity. (However, this last point is not true for Versions IIa, IIb, IIIa, and IIIb to follow, in which the marginal benefits of the last unit of y_{sw} are affected by the value of y_{wb}.)

2. Version Ib: The fee ceiling binds, but W's demands do not constrain the optimal solution

W's profit is as follows:

$$\frac{8760P_f}{Q_{sm}} \Big[\int_0^{y_{wb}} (F_{sw}+F_{wb})y\,dy \quad + \quad \int_{y_{wb}}^{Q_{sm}} (F_u)y_{wb}\,dy$$

[Fees earned when y_{wb} is not used to capacity]

[Fees earned when y_{wb} used to capacity]

$$+ \int_{y_{wb}}^{y_{sw}} 0.5(C_w+F_{sw})(y-y_{wb})\,dy$$

[Cost saved by purchases from S, y_{sw} not used to capacity]

$$+ \int_{y_{sw}}^{Q_{sm}} 0.5(C_w+F_{sw})\ (y_{sw}-y_{wb})\,dy\Big] \quad - \quad CC_{sw}y_{sw}-CC_{wb}y_{wb} \quad - C_wD_w$$

[Cost saved by purchases from S when y_{sw} used to capacity]

[Transmission line construction cost]

[Cost of generation if no purchases from S]

The only difference between this integral and that of Version Ia is that the wheeling fee ceiling F_u has been substituted for the marginal benefit of B's consumption, P_{bo}-My_{wb}, in the second term because F_u is now smaller. (Recall that the fee, during times of congestion, is the smaller of the ceiling F_u and P_{bo}-My_{wb}, the marginal worth of power to B.)

Integrating the above expression, taking the appropriate derivatives, and setting them equal to zero yields the following equation for the best y_{wb}:

$$y_{wb} = \frac{Q_{sm}}{[2F_u-.5(C_w+F_{sw})-F_{sw}-F_{wb}]} [F_u-.5(C_w+F_{sw})- CC_{wb}/(8760P_f)] \qquad (3)$$

unless this value is greater than D_{bo}; in the latter case, $y_{wb}=D_{bo}$, the maximum amount that B will demand. (This constraint $y_{wb} \leq D_{bo}$ also applies to Versions IIb and IIIb, which follow; see equations (6) and (9).) The optimal y_{sw} is the same as in Version Ia (which, as previously noted, is identical to the simultaneous buy/sell solution).

It is possible that the solution just given is not feasible from a pricing policy standpoint because at that level of y_{wb} the marginal benefit is less than F_u, the fee ceiling. If that is so, then the Version Ib solution is defined as the "corner" solution that results if y_{wb} is set at the level at which B's marginal benefit just equals F_u. This is

$$y_{wb} = (P_{bo} - F_u)/M \ . \tag{4}$$

The optimal y_{sw} does not change, however. In general, reference to the "Version Ib" solution means equation (3), unless it is infeasible, in which case, the "Version Ib" solution is instead calculated using equation (4).

Note that the version Ia solution may be subject to a similar infeasibility in that the marginal benefit used as the congestion charge may be higher than F_u. In that case, we might substitute the corner solution (4) for Version Ia. However, that is rendered unnecessary by the above definition of Version Ib for the following two reasons. First, if equation (3) is feasible, it is better than the corner solution and thus the latter solution need not be considered. Second, if (3) is infeasible, Version Ib's solution is the corner solution, which therefore does not also need to be considered in Version Ia. This latter point also applies to the corner solutions in Versions IIa and IIIa below; they are already implicitly or explicitly considered in the definitions of Versions IIb and IIIb.

3. Version IIa: The fee ceiling does not bind, but W's demands do constrain the optimal solution

Here, W's profit is given by the following expression:

$$\frac{8760P_f}{Q_{sm}} \left[\int_0^{y_{wb}} (F_{sw}+F_{wb})y\,dy \qquad + \qquad \int_{y_{wb}}^{Q_{sm}} (P_{bo}-My_{wb})y_{wb}\,dy \right.$$

[Fees earned when y_{wb} is not used to capacity] [Fees earned when y_{wb} used to capacity]

$$+ \int_{y_{wb}}^{y_{wb}+D_w} 0.5(C_w+F_{sw})(y-y_{wb})\,dy$$

[Cost saved by purchases from S, y_{sw} not used to capacity]

$$+ \int_{y_{wb}+D_w}^{Q_{sm}} 0.5(C_w+F_{sw})D_w dy] \qquad - CC_{sw}(y_{wb}+D_w) - CC_{wb}y_{wb} \qquad - C_w D_w$$

[Cost saved by purchases from S when y_{sw} used to capacity] [Transmission line construction cost] [Cost of generation if no purchases from S]

The only difference between this integral and that for Version Ia is that $y_{wb}+D_w$ has been substituted for y_{sw} wherever it appears.

Integrating this expression, taking a derivative with respect to y_{wb}, and setting it equal to zero yields the following equation for the best y_{wb}:

$$3M(y_{wb})^2 + [F_{sw}+F_{wb}-2P_{bo}-2MQ_{sm}]y_{wb} +$$

$$Q_{sm}[P_{bo}-.5(C_w+F_{sw})D_w/Q_{sm}-(CC_{wb}+CC_{sw})/(P_f 8760)] = 0 \qquad (5)$$

(Under some parameters, this may be a profit minimizing rather than maximizing value.) The best y_{sw} is, be definition, equal to $y_{wb}+D_w$.

4. <u>Version IIb: The fee ceiling binds and W's demands constrain the optimal solution</u>

W's profit is given by the following expression:

$$\frac{8760P_f}{Q_{sm}} [\int_0^{y_{wb}} (F_{sw}+F_{wb})y dy \qquad + \qquad \int_{y_{wb}}^{Q_{sm}} (F_u)y_{wb} dy$$

[Fees earned when y_{wb} is not used to capacity] [Fees earned when y_{wb} used to capacity]

$$+ \int_{y_{wb}}^{y_{wb}+D_w} 0.5(C_w+F_{sw})(y-y_{wb})dy$$

[Cost saved by purchases from S, y_{sw} not used to capacity]

$$+ \int_{y_{wb}+D_w}^{Q_{sm}} 0.5(C_w+F_{sw})D_w dy] \qquad - CC_{sw}(y_{wb}+D_w) - CC_{wb}y_{wb} \qquad - C_w D_w$$

[Cost saved by purchases from S when y_{sw} used to capacity] [Transmission line construction cost] [Cost of generation if no purchases from S]

The two differences between this integral and that for Version Ia are that (1) the wheeling fee ceiling F_u has been substituted for the marginal benefit of B's consumption, $P_{bo}-My_{wb}$, in the second term, and (2) $y_{wb}+D_w$ replaces y_{sw} throughout.

Integrating the above expression, taking the appropriate derivative, and setting it equal to zero yields the following equation for the best y_{wb}:

$$y_{wb} = \frac{1}{[2F_u-F_{sw}-F_{wb}]} \{Q_{sm}F_u[1 - (CC_{wb}+CC_{sw})/(8760P_fF_u)] - .5(C_w+F_{sw})D_w\} \quad (6)$$

unless D_{bo} is less, in which case $y_{wb}=D_{bo}$. The optimal y_{sw} is $y_{wb}+D_w$, by definition.

As in Version Ib, it is possible that the solution just given is not feasible from a pricing policy standpoint because, at this level of y_{wb}, the marginal benefit might be lower than F_u. If so, then the "corner" solution that results if y_{wb} is set at the level at which B's marginal benefit just equals F_u should be checked. This is:

$$y_{wb} = (P_{bo} - F_u)/M \quad (7)$$

The optimal y_{sw} is $y_{wb}+D_w$. In general, the Version IIb solution refers to equation (6), unless it is infeasible, in which case the "Version IIb" solution is instead obtained using equation (7).

5. <u>Version IIIa: The fee ceiling does not bind, but the optimal $y_{sw} = y_{wb}$</u>

W's total generation equals its demand in this case, and W's profit is as follows:

$$\frac{8760P_f}{Q_{sm}} [\underbrace{\int_0^{y_{wb}} (F_{sw}+F_{wb})ydy}_{\text{[Fees earned when } y_{wb} \text{ is not used to capacity]}} + \underbrace{\int_{y_{wb}}^{Q_{sm}} (P_{bo}-My_{wb})y_{wb}dy}_{\text{[Fees earned when } y_{wb} \text{ used to capacity]}} \underbrace{- CC_{sw}y_{wb}-CC_{wb}y_{wb}}_{\text{[Tran. Line Construction Cost]}} \underbrace{- C_wD_w}_{\text{[W's cost of genrtn]}}$$

This integral differs from that for Version Ia in that all savings terms for W are deleted and y_{wb} is substituted for y_{sw} throughout.

The resulting equation for the best y_{wb} is:

$$3M(y_{wb})^2 + [F_{sw}+F_{wb}-2P_{bo}-2MQ_{sm}]y_{wb} + Q_{sm}[P_{bo}-(CC_{wb}+CC_{sw})/(P_f 8760)] = 0 \quad (8)$$

This is the same as for case IIb, except for the deletion of a $0.5(C_w+F_{sw})$ term. The best y_{sw}, by definition, equals y_{wb}.

6. <u>Version IIIb: The fee ceiling binds and the optimal $y_{wb} = y_{sw}$</u>

W's profit equals:

$$\frac{8760P_f}{Q_{sm}} \left[\int_0^{y_{wb}} (F_{sw}+F_{wb})y\,dy + \int_{y_{wb}}^{Q_{sm}} (F_u)y_{wb}\,dy \right] - CC_{sw}y_{wb} - CC_{wb}y_{wb} - C_wD_w$$

[Fees earned when y_{wb} is not used to capacity] [Fees earned when y_{wb} used to capacity] [Tran. Line Construction Cost] [W's cost of genrtn]

This integral is distinguished from that for Version IIIa in that the fee ceiling F_u replaces B's marginal benefit of consumption, $P_{bo}-My_{wb}$, in the second term.

The best y_{wb} satisfies:

$$y_{wb} = \frac{Q_{sm}}{[2F_u-F_{sw}-F_{wb}]} [F_u - (CC_{wb}+CC_{sw})/(8760P_f)] \quad (9)$$

unless D_{bo} is smaller, in which case $y_{wb}=D_{bo}$. The optimal y_{sw} is y_{wb}, by definition. In general, this y_{wb} is quite insensitive to the assumed ceiling F_u; this result is explored in chapter 6 where it is assumed that $F_{ij}=0.5(CC_{ij}/8760)$, so that the two terms in square brackets cancel and y_{wb} is constant at $MIN(Q_{sm}/2,D_{bo})$.

As in Versions Ib and IIb, it is possible that the solution just given is not feasible from a pricing policy standpoint because, at that level of y_{wb}, the marginal benefit might be lower than F_u, the fee ceiling. If so, then the "corner" solution that results if y_{wb} is set at the level at which B's marginal benefit just equals F_u should be checked. This will be:

$$y_{wb} = (P_{bo} - F_u)/M \quad (10)$$

The optimal y_{sw} still equals y_{wb}, of course. In general, the "Version IIIb" solution refers to equation (9), unless it is infeasible. In the latter case, the "Version IIIb" solution is instead equation (10).

7. Version IV. W chokes off B (y_{wb}=0)

W earns the following profit in this case:

$$\frac{8760P_f}{Q_{sm}} \left[\int_0^{y_{sw}} 0.5(C_w+F_{sw})(y)dy \quad + \quad \int_{y_{sw}}^{Q_{sm}} 0.5(C_w+F_{sw})(y_{sw})dy \right]$$

[Cost saved by purchases from S, y_{sw} not used to capacity] [Cost saved by purchases from S when y_{sw} used to capacity]

$$- \quad CC_{sw}y_{sw} \quad - \quad C_wD_w$$

[Transmission line construction cost] [Cost of generation if no purchases from S]

Terms involving wheeling fee revenues have been deleted, and y_{wb} is assumed to be zero throughout. The resulting solution is the minimum of D_w (W's power demand) and the value of y_{sw} given in equation (2).

APPENDIX D

CAPACITY EXPANSION FOR NONFIRM SERVICE--SCENARIO RESULTS

An integral equation is presented early in chapter 6, which expresses W's profit-maximization objective for the case where W may wheel to another control-area utility. In addition to the analytical solutions for special cases discussed in appendix C, solutions for ten more general cases were found using numerical integration with a variety of assumptions about the model's parameters. The results for these ten scenarios (with variations) are presented here in tabular form. These results are discussed in chapter 6.

The following five tables, D-1 through D-5, show the numerical results of the two-stage analysis under the assumptions presented in chapter 6. Table D-1 shows the results for the socially optimal (total cost minimizing) case for several scenarios. Not all scenarios are relevant for all tables, so scenario numbers are not always consecutive. Scenario 1 is considered the "Base Case" and is defined in chapter 6. The other scenarios constitute a sensitivity analysis. These scenarios are reapplied under various pricing rules: table D-2 covers simultaneous buy/sell, table D-3 covers wheeling at a fixed rate, table D-4 covers flexible pricing that recovers congestion costs (which includes the NRRI model), and table D-5 covers gain-sharing flexible pricing.

A brief caveat on the results is that, because fairly coarse numerical integration steps (20 MW) were used to perform the numerical integrations and search procedures, the values of the optimal transmission capacities are accurate only within 10 MW. The reported capacity values were obtained by first fitting a quadratic profit function to the calculated profits for values of y_{sw} and y_{wb} in the immediate vicinity of the optimal solution, and then solving for the y_{sw} and y_{wb} that maximize that function. The profit and welfare calculations, however, are for the values of y_{sw} and y_{wb} closest to the optimum that are integer multiples of 20 MW. Therefore, there may be some slight error in the reported profit and welfare (but no more than 1 percent or so).

TABLE D-1

TRANSMISSION CAPACITY ADDITIONS (IN MW) AND GAINS FROM TRADE (IN MILLIONS OF DOLLARS PER YEAR) IN A TWO-STAGE NUMERICAL SIMULATION OF A WHEELER'S DECISION TO CONSTRUCT TIE LINES FOR FUTURE COORDINATION POWER TRADES OF UNCERTAIN AMOUNT: THE SOCIALLY OPTIMAL CASE

Scenario	Description	Trans. Cap. (MW) y_{sw}	Trans. Cap. (MW) y_{wb}	Total Gain ($\$10^6$)
1	Base Case	933	473	234
2	High Q_w (=1000)	933	486	259
3	Low Max Q_s (= 500)	467	416	152
6	Inelastic D_b (P_{bo} =.150)	933	484	325
7	Elastic D_b (P_{bo} =.050)	922	429	143
8	High D_w (750), Low D_{bo} (250)	933	242	115
9	Low D_w (250), High D_{bo} (750)	924	690	340
10	High F_{sw}, F_{wb} (each=0.008)	933	473	234

Source: Authors' calculations using hypothetical data set out in chapter 6.

Note: Total gain is the increase in social welfare (decrease in total cost) compared to the case where both transmission line capacities, y_{sw} and y_{wb}, are zero.

Units: Q_w, Q_s, D_w, and D_{bo} are in MW; Fee Ceiling (F_u), Price Intercept (P_{bo}), F_{sw}, and F_{wb} are in \$/kWh.

TABLE D-2

TRANSMISSION CAPACITY ADDITIONS (IN MW) AND GAINS FROM TRADE (IN MILLIONS OF DOLLARS PER YEAR) IN A TWO-STAGE NUMERICAL SIMULATION OF A WHEELER'S DECISION TO CONSTRUCT TIE LINES FOR FUTURE COORDINATION POWER TRADES OF UNCERTAIN AMOUNT: THE CASE OF SIMULTANEOUS BUY/SELL

Scenario	Description	Trans. Cap. y_{sw}	Trans. Cap. y_{wb}	Loss of Welfare	Gain to S	Gain to W	Gain to B
1	Base Case	882	474	0	56	120	57
2	High Q_w (=1000)	882	476	0	56	134	68
3	Low Max Q_s (= 500)	441	394	0	28	77	46
6	Inelastic D_b (P_{bo} =.150)	882	484	0	56	165	103
7	Elastic D_b (P_{bo} =.050)	882	426	0	56	74	12
8	High D_w (750), Low D_{bo} (250)	882	243	0	56	27	31
9	Low D_w (250), High D_{bo} (750)	882	665	0	56	206	78
10	High F_{sw}, F_{wb} (each=0.008)	895	500	0	48	135	51

Source: Authors' calculations using hypothetical data set out in chapter 6.

Notes: 1. Loss of welfare is defined as the total gain under this pricing model less the gain under the socially optimal case, reported in table D-1.

2. The gain to S, W, and B is the gain each experiences (revenue less marginal cost) compared to the case where no transmission tie lines link S, W, and B.

Units: Q_w, Q_s, D_w, and D_{bo} are in MW; Fee Ceiling (F_u), Price Intercept (P_{bo}), F_{sw}, and F_{wb} are in \$/kWh.

TABLE D-3

TRANSMISSION CAPACITY ADDITIONS (IN MW) AND GAINS FROM TRADE (IN MILLIONS OF DOLLARS PER YEAR) IN A TWO-STAGE NUMERICAL SIMULATION OF A WHEELER'S DECISION TO CONSTRUCT TIE LINES FOR FUTURE COORDINATION POWER TRADES OF UNCERTAIN AMOUNT: THE CASE OF WHEELING AT A FIXED PRICE

Scenario	Description	Trans. Cap. y_{sw}	Trans. Cap. y_{wb}	Loss of Welfare	Gain to S	Gain to W	Gain to B
1	Base Case	500	0	144	-13	-73	-57
2	High Q_w (=1000)	0	475	115	-56	-58	0
3	Low Max Q_s (= 500)	443	0	95	0	-48	-46
6	Inelastic D_b (P_{bo} =.150)	500	0	193	-56	-34	-103
7	Elastic D_b (P_{bo} =.050)	500	0	12	-56	57	-12
8	High D_w (750), Low D_{bo} (250)	750	0	70	-3	-36	-31
9	Low D_w (250), High D_{bo} (750)	250	0	221	-31	-112	-78
10	High F_{sw}, F_{wb} (each=0.008)	665	162	56	28	-80	-4

Source: Authors' calculations using hypothetical data set out in chapter 6.

Notes: 1. Loss of welfare is defined as the total gain under this pricing model less the gain under the socially optimal case, reported in table D-1.

2. The gains in this table are reported as increases or decreases from the gains under simultaneous buy/sell, reported in table D-2.

Units: Q_w, Q_s, D_w, and D_{bo} are in MW; Fee Ceiling (F_u), Price Intercept (P_{bo}), F_{sw}, and F_{wb} are in \$/kWh.

TABLE D-4

TRANSMISSION CAPACITY ADDITIONS (IN MW) AND GAINS FROM TRADE (IN MILLIONS OF DOLLARS PER YEAR) IN A TWO-STAGE NUMERICAL SIMULATION OF A WHEELER'S DECISION TO CONSTRUCT TIE LINES FOR FUTURE COORDINATION POWER TRADES OF UNCERTAIN AMOUNT: THE CASE OF FLEXIBLE WHEELING PRICES THAT CAN INCLUDE A CONGESTION CHARGE

Scenario	Description	Trans. Cap. y_{sw}	Trans. Cap. y_{wb}	Loss of Welfare	Gain to S	Gain to W	Gain to B
1	Base Case	737	235	28	-3	9	-34
2a	High Q_w (=1000)	790	290	23	-6	18	-36
2b	High Q_w, F_u=0.050	854	360	10	1	13	-24
2c	High Q_w, F_u=0.040	882	420	3	10	-3	-10
2d	High Q_w, F_u=0.030	882	451	1	23	-30	6
2e	High Q_w, F_u=0.020	882	451	1	39	-61	22
2f	High Q_w, F_u=0.015	882	421	3	47	-76	27
2g	High Q_w, F_u=0.010	500	0	169	-13	-87	-68
3	Low Max Q_s (= 500)	441	165	27	0	5	-32
4	High Fee Ceiling (0.050)	857	357	6	13	-7	-11
5	Low Fee Ceiling (0.025)	800	300	15	35	-56	8
6	Inelastic D_b (P_{bo}=.150)	727	226	58	7	5	-70
7	Elastic D_b (P_{bo}=.050)	768	269	7	-18	13	-2
8	High D_w(750), Low D_{bo}(250)	865	130	16	-3	8	-21
9a	Low D_w(250), High D_{bo}(750)	572	317	51	-8	2	-45
9b	Low D_w, High D_{bo}, Low F_u	654	401	29	45	-82	9
10	High F_{sw}, F_{wb} (each=0.008)	741	238	28	-1	1	-28
11a	NRRI, Unrestricted	729	228	34	-5	7	-36
11b	NRRI, F_u = 0.050	840	344	8	14	-12	-10
11c	NRRI, F_u = 0.025	750	250	28	31	-59	0

Source: Authors' calculations using hypothetical data set out in chapter 6.

Notes: 1. Loss of welfare is defined as the total gain under this pricing model less the gain under the socially optimal case, reported in table D-1.

2. The gains in this table are reported as increases or decreases from the gains under simultaneous buy/sell, reported in table D-2.

Units: Q_w, Q_s, D_w, and D_{bo} are in MW; Fee Ceiling (F_u), Price Intercept (P_{bo}), F_{sw}, and F_{wb} are in \$/kWh.

TABLE D-5

TRANSMISSION CAPACITY ADDITIONS (IN MW) AND GAINS FROM TRADE (IN MILLIONS OF DOLLARS PER YEAR) IN A TWO-STAGE NUMERICAL SIMULATION OF A WHEELER'S DECISION TO CONSTRUCT TIE LINES FOR FUTURE COORDINATION POWER TRADES OF UNCERTAIN AMOUNT: THE CASE OF FLEXIBLE WHEELING PRICES THAT PERMIT GAIN SHARING

Scenario	Description	Trans. Cap. y_{sw}	Trans. Cap. y_{wb}	Loss of Welfare	Gain to S	Gain to W	Gain to B
1	Base Case	800	426	3	44	-41	-6
2	High Q_w (=1000)	800	471	2	2	-22	18
3	Low Max Q_s (= 500)	433	354	1	38	-25	-13
6	Inelastic D_b (P_{bo}=.150)	800	455	3	75	-56	-21
7	Elastic D_b (P_{bo}=.050)	793	302	4	13	-24	8
8	High D_w(750), Low D_{bo}(250)	800	223	3	30	-25	-7
9	Low D_w(250), High D_{bo}(750)	800	590	4	52	-56	1
10	High F_{sw}, F_{wb} (each=0.008)	800	426	3	44	-41	-6

Source: Authors' calculations using hypothetical data set out in chapter 6.

Notes: 1. Loss of welfare is defined as the total gain under this pricing model less the gain under the socially optimal case, reported in table D-1.

2. The gains in this table are determined by Shapley value allocations. (See the discussion of the Shapley value in the introduction to core analysis.) The resulting gains are reported as increases or decreases from the gains under simultaneous buy/sell, reported in table D-2.

Units: Q_w, Q_s, D_w, and D_{bo} are in MW; Fee Ceiling (F_u), Price Intercept (P_{bo}), F_{sw}, and F_{wb} are in \$/kWh.

APPENDIX E

WHEELING OF COORDINATION POWER TO A REQUIREMENTS CUSTOMER--
A GENERAL MATHEMATICAL PROGRAM

This appendix presents the analysis of wheeling for requirements customers that underlies the results presented in outline in the last section of chapter 6. The situation, set out fully in chapter 6, is that the wheeler W, after satisfying B's needs for firm generation, firm wheeling, or both, must decide how much transmission capacity y_{sw} to construct to meet its own and B's future desire for coordination power from S.

For the Ideal, Status Quo, Planning, and at least one version of the Contract (flexible pricing) models, a mathematical program is set up from which very general results can be obtained by analyzing the marginal conditions for optimality. The mathematical program is, in technical terms, called a "linear program with recourse."[1] A math program with recourse has the type of structure shown in figure 6-1, where an initial decision is made, and some other decisions are made later after the true state of nature is known: here, the amount of hydropower and the actual demands.

The mathematical program makes no specific assumptions about the probability distribution of hydropower and demand. The general solutions to this program are presented in the first section of this appendix. However, this procedure cannot be used to derive results for most flexible pricing models and the NRRI model; for these cases, specific probability distributions have to be defined. We do so in the second section of this appendix.

General Model and Its Results

The general ideal is the solution that minimizes expected generation and transmission costs for S, W, and B together. The objective function

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[1] G. B. Danzig and A. Madansky, "On the Solution of Two-Stage Linear Programs under Uncertainty," *Proceedings of the Fourth Berkeley Symposium on Mathematics, Statistics, and Probability*, Vol. I (Berkeley, California: University of California Press, 1961).

would be to minimize the expected present worth of the cost of generation (across all possible realizations of hydropower availability and demand) minus the cost of immediately constructing line S-W. With no loss of generality, we instead formulate the problem as one of maximizing the expected annual generation cost savings minus the annualized cost of transmission.

The notation used is listed below. All quantities are in kW, unless otherwise noted. Decision variables are denoted by lower-case letters, and fixed parameters are represented by upper-case letters.

- y_{sw} = amount of transmission capacity built by W between S and W
- CC = annualized cost of transmission line y_{sw} [$/kW/yr]
- θ = random state of nature θ [no units]
- $f(\theta)$ = probability density of state of nature θ [no units]
- $Q_s(\theta)$ = amount of hydropower available under state of nature θ
- $D_w(\theta)$ = power demanded by W under state of nature θ
- $D_b(\theta)$ = power demanded by B under state of nature θ
- $x_w(\theta)$ = amount of hydropower bought by W from S under state of nature θ
- $x_b(\theta)$ = amount of power bought by B from S and wheeled by W
- C_f = energy cost of firm power [$/kWh]
- F = wheeling fee charged by W for transmitting power over line S-W. (Note: no additional charge is made for line W-B, since that line's capacity is assumed to be adequate and already provided for under a firm power contract at a fixed cost per year. Some pricing models would make a different assumption, but at any rate it is only the total wheeling fee ($F=F_{sw}+F_{wb}$) that matters, not its components.)

Note that Q_s, D_w, and D_b are all random variables, which may or may not be correlated depending on the forms of $f(\theta)$, $Q_s(\theta)$, $D_w(\theta)$, and $D_b(\theta)$.

The model used to obtain the ideal solution is:

$$\underset{\{y_{sb},x_w(\theta),x_b(\theta)\}}{\text{MAXIMIZE}} \quad 8760 \int_\theta C_f[x_w(\theta)+x_b(\theta)]f(\theta)d\theta \quad - \quad CCy_{sb}$$

[Expected generation cost savings, $/yr] [Transmission capital cost, $/yr]

subject to:

$$\begin{aligned} x_w(\theta)+x_b(\theta) &\le Q_s(\theta) && \forall\ \theta \text{ (hydropower availability)} \\ x_w(\theta)+x_b(\theta)-y_{sw} &\le 0 && \forall\ \theta \text{ (transmission capacity)} \\ x_w(\theta) &\le D_w(\theta) && \forall\ \theta \text{ (W's demand constraint)} \\ x_b(\theta) &\le D_b(\theta) && \forall\ \theta \text{ (B's demand constraint)} \end{aligned}$$

plus the usual non-negativity conditions. In words, the objective is to maximize the value of the firm power displaced by hydropower less the cost of transmission.

The optimal solution to this model is to expand y_{sw} until the marginal benefit of additional transmission capacity equals (or first falls below) the marginal cost:

$$8760 \int_{\substack{\forall \theta \text{ such that} \\ y_{sw} < \mathrm{MIN}(Q_s(\theta),\ D_b(\theta)+D_w(\theta))}} C_f f(\theta) d\theta = CC$$

In words, expand y_{sw} until the marginal generation cost savings just equals the marginal cost of transmission. The smaller y_{sw} is, the higher the marginal benefit, since there are more occasions when limited transmission capacity prevents the purchase of hydropower.

General Status Quo Model

Under the Status Quo, W chooses y_{sw} to maximize its expected cost savings, including any revenues from wheeling. We assume that any power sales are on a split-savings basis and that a "wheeling" fee F, paid by S to W, is used as the transmission cost in the split-savings calculations. (Of course, for a bilateral sale between S and W there is no explicit wheeling fee in reality, but there is a transmission cost, which one or both of the parties must bear, especially with new construction. For simplicity, we assign all of this cost to W. S could either build half the tie line and charge W a higher rate for its power to recover the cost, or W could build the whole tie line and require S to pay W a fee when S uses the tie line to make a sale. We assume the latter.) This fee is applied in all S-W transactions. No separate fee is assumed for W-B transactions, as mentioned. All "wheeling" takes place via simultaneous buy/sell under the Status Quo. It is assumed that in the short-run game W decides how much to buy and sell and S and B must accept W's decision.

W's problem then is:

$$\underset{\{y_{sb}, x_w(\theta), x_b(\theta)\}}{\text{MAXIMIZE}} \quad 8760 \int_\theta \{C_f x_w(\theta) \quad - \quad 0.5(C_f+F)\ [x_w(\theta)+x_b(\theta)]$$

[W's expected generation cost savings]   [Payments to S for power purchased by W]

$$+ F[x_w(\theta)+x_b(\theta)] \quad + \quad C_f x_b(\theta) \quad \} d\theta \quad - \quad CCy_{sw},$$

[Wheeling fee paid by S to W] [Payments by B for power resold by W] [Transmission Cost]

subject to the same constraints as in the Ideal solution. Note that the split-savings price paid by B to W is C_f--this is because there are no apparent savings in buying from W, as W and B's marginal costs both equal C_f. (However, any other scheme in which W gets half of the overall power transfer savings, net of F, yields the same result.)

This objective function can be simplified, yielding:

$$\underset{\{y_{sb}, x_w(\theta), x_b(\theta)\}}{\text{MAXIMIZE}} \quad 8760 \int_\theta 0.5(C_f+F) \; [x_w(\theta)+x_b(\theta)] d\theta \quad - \quad CCy_{sw}$$

[W's expected generation cost savings, including payments from B and to S] [Transmission Cost]

The optimal solution to this model is to expand y_{sw} until the marginal cost savings (net of payments) equals or first falls below the marginal transmission cost:

$$\underset{\substack{\forall\, \theta \text{ such that} \\ y_{sw} < \text{MIN}(Q_s(\theta),\ D_b(\theta) + D_w(\theta))}}{8760 \int} 0.5(C_f+F)f(\theta)d\theta \;=\; CC$$

Note that for any given y_{sw} the left-hand side of this expression is less than the left-hand side of the optimal condition for the Ideal model. Thus, y_{sw}'s marginal benefit to W is less than the system cost savings that it yields. As a result, W decides to build less transmission capacity than is optimal. How much less depends on the values of the parameters; examples are provided later.

Because B pays C_f for the wheeled power, it obtains none of the gains. (B might actually save something if its avoided cost is more than W's, or if S or W make side-payments.) W and S split the gains, although the split is not even depending on whether the wheeling fee F results in W being under- or overcompensated for its transmission costs.

(Recall that the simultaneous buy/sell solution for the short-run game is the same under these cost conditions as the Shapley value and the nucleolus of the unrestricted core. See chapter 4.)

Planning Models

Planning Model I

In version I of the Planning model, it is assumed that B has no preferential access to S's power. As a result, for most values of F, W buys all the power it can for its own needs and then, if any is left over, wheels to B. W's problem is to maximize its net cost savings,

$$\underset{\{y_{sb},x_w(\theta),x_b(\theta)\}}{\text{MAXIMIZE}} \quad 8760 \int_{\theta} \{ \underbrace{C_f x_w(\theta)}_{\text{[W's expected generation cost savings]}} - \underbrace{0.5(C_f+F)x_w(\theta)}_{\text{[Payments to S for power purchased by W]}}$$

$$+ \underbrace{F[x_w(\theta)+x_b(\theta)]\}d\theta}_{\text{[Wheeling fees paid by S to W]}} - \underbrace{CCy_{sw}}_{\text{[Transmission Cost]}},$$

subject to the same constraints as in the Ideal model. W pays for the power it purchases using the split-savings rule. The same wheeling fee F is charged S for its sales to both W and B.

The objective can be simplified, resulting in:

$$\underset{\{y_{sb},x_w(\theta),x_b(\theta)\}}{\text{MAXIMIZE}} \quad \underbrace{8760 \int_{\theta} [0.5(C_f+F)x_w(\theta)+Fx_b(\theta)]d\theta}_{\text{[W's expected generation cost savings, including payments from B and to S]}} - \underbrace{CCy_{sw}}_{\text{[Transmission Cost]}}$$

The solution to this model is to expand y_{sw} until marginal benefits (including payments) to W equal or first fall below the marginal cost of transmission:

$$\underbrace{\underset{\substack{\forall\, \theta \text{ such that} \\ y_{sw} < \mathrm{MIN}(Q_s(\theta),\ D_w(\theta))}}{8760 \int 0.5(C_f+F)f(\theta)d\theta}}_{\text{[Marginal benefit of additional S-W sales]}} + \underbrace{\underset{\substack{\forall\, \theta \text{ such that} \\ y_{sw} < \mathrm{MIN}(Q_s(\theta),\ D_b(\theta) + D_w(\theta)) \\ \text{and } y_{sw} > D_w(\theta)}}{8760 \int Ff(\theta)d\theta}}_{\text{[Marginal benefit of additional S-B wheeling]}} = CC$$

For a given y_{sw}, these two integrals cover the same domain of θ as the optimality conditions for the Ideal and Status Quo models. As long as the second integral above is nonzero and $F < C_f$, the marginal benefit of y_{sw} here is less than the marginal benefit under the Status Quo (and also the Ideal) solution. Hence, it can be expected that W would choose an optimal y_{sw} in this case that is less than the values it would choose under the Status Quo, resulting in even greater losses of production efficiency relative to the ideal.

However, B is likely to be better off under this Planning model than under the Status Quo because it pays only $(C_f+F)/2$ for power under the Planning model, thereby saving on expenses (because the energy cost for firm power is C_f). Whereas, under the Status Quo, it pays C_f for wheeled power and saves nothing.

Planning Model II

Here, S must sell to B first, with W buying any power that is left over. The objective function is the same as in Planning Model I, but there are the additional constraints. Let M be a very large number and $z(\theta)$ be an integer variable denoting whether B has its needs entirely satisfied $[z(\theta)=0]$ or not $[z(\theta)=1]$. Then we require that

$$x_w(\theta) \quad - \quad Mz(\theta) \leq 0 \qquad \forall\ \theta$$

$$x_b(\theta) \quad - \quad D_b(\theta)z(\theta) \geq 0 \qquad \forall\ \theta$$

$$z(\theta) \quad = \quad 0 \text{ or } 1 \qquad \forall\ \theta$$

These constraints ensure that W's purchases are positive only if B has fulfilled all of its needs.

The optimality conditions are:

$$\underset{\substack{\forall\ \theta \text{ such that} \\ y_{sw} < \mathrm{MIN}(Q_s(\theta)\ D_b(\theta))}}{8760 \int Ff(\theta)d\theta} \quad + \quad \underset{\substack{\forall\ \theta \text{ such that} \\ y_{sw} < \mathrm{MIN}(Q_s(\theta),\ D_b+(\theta) + D_w(\theta)) \\ \text{and } y_{sw} > D_b(\theta)}}{8760 \int 0.5(C_f+F)f(\theta)d\theta} \quad = \quad CC$$

Again, we conclude, for reasons similar to those set out for Planning Model I, that less transmission capacity is installed than under the Status Quo. However, whether more or less is installed than under Planning Model I depends on the precise values of the parameters and probability distributions.

This game is described by game theorists as a noncooperative Stackelberg game.

General Contract Model with Flexible Pricing

One way of analyzing the Contract model (with flexible pricing for nonfirm transmission service) is, after defining the (long run) core of the firm power game, to assume that players can make side-payments to assure that the most efficient solution is obtained.

Long Run Core

In the parlance of game theory, this is a cooperative game with side-payments. With side-payments, y_{sw} is expanded to its ideal value. The only constraint on the core is the value of the subcoalition {SW}, which equals the expected cost savings if S just sells to W and no power is transferred to B.

Wheeler Charges a Fixed Fee G

How can W be motivated to expand y_{sw} to the optimal value if explicit side-payments are not legally allowed? Next, consider the case where side-payments can occur but must be disguised as a fixed embedded-cost surcharge, in cents per kilowatt-hour, on the wheeling rate. With this restriction, the ideal value of y_{sw} may not result.

Perhaps S and B could pay a fixed demand charge (¢/kWh) for the transmission capacity, buying it on a firm basis, even though this is economy power. B would be in the position of buying more firm transmission capacity than the minimum that is necessary for its needs. In this case, there are no payments among the players except in the form of a fixed fee G, not equal to F, for wheeling transactions. G might or might not be cost-based. It is necessary to assume G is the former in order to formulate the mathematical program. Because this restricts the form of payment to a charge per kilowatt or per kilowatt-hour, the socially optimal y_{sw} does not necessarily result.

In order to formulate a mathematical program for the flexible pricing case, it must be possible to specify the wheeling price that is charged for each θ. Unfortunately, this cannot be done in general, since the solution to the short-run game is a region (the core), not a single point. The approach taken here is to find the solution that results if W charges a constant wheeling fee, no matter what θ is. This solution is tractable for the general Contract model. In order to consider solutions in which the wheeling fee depends on market conditions (for example, if prices are increased when transmission is congested), specific assumptions have to be made about the distribution of θ and how demands and hydropower availability depend on it. This we do in the last part of this appendix.

In this model, it is assumed that one wheeling rate F (probably cost-based) is assessed by W for sales from S to W, while a different rate G (\$/kWh) is charged for sales from S to B. G is between the ceiling and floor prices of the particular flexible pricing model being considered; here, we consider those bounds to be between 0 and C_f, the latter being the difference between S and W's marginal costs. The resulting model is

$$\underset{\{y_{sb},x_w(\theta),x_b(\theta)\}}{\text{MAXIMIZE}} \quad 8760 \int_\theta \{\underbrace{C_f x_w(\theta)}_{\text{[W's expected generation cost savings]}} - \underbrace{0.5(C_f+F)x_w(\theta)}_{\text{[Payments to S for power purchased by W]}}$$

$$+ \underbrace{Fx_w(\theta)+Gx_b(\theta)\}d\theta}_{\text{[Wheeling fees paid by S to W]}} - \underbrace{CCy_{sw}}_{\text{[Transmission Cost]}} .$$

Simplifying yields

$$\underset{\{y_{sb},x_w(\theta),x_b(\theta)\}}{\text{MAXIMIZE}} \quad \underbrace{8760 \int_\theta [0.5(C_f+F)x_w(\theta)+Gx_b(\theta)]d\theta}_{\text{[W's expected generation cost savings, including payments from B and to S]}} - \underbrace{CCy_{sw}}_{\text{[Transmission Cost]}} ,$$

and the condition for optimality becomes

If $G < 0.5(C_f+F)$, implying that W meets its own needs first:

$$\underset{\substack{\forall\ \theta \text{ such that} \\ y_{sw} < \mathrm{MIN}(Q_s(\theta),\ D_w(\theta))}}{8760 \int 0.5(C_f+F)f(\theta)d\theta} \quad + \quad \underset{\substack{\forall\ \theta \text{ such that} \\ y_{sw} < \mathrm{MIN}(Q_s(\theta), D_b(\theta)+D_w(\theta)) \\ \text{and } y_{sw} > D_w(\theta)}}{8760 \int Gf(\theta)d\theta} \quad = \quad CC$$

If $G > 0.5(C_f+F)$, implying that W wheels to B first:

$$\underset{\substack{\forall\ \theta \text{ such that} \\ y_{sw} < \mathrm{MIN}(Q_s(\theta), D_b(\theta)+D_w(\theta)) \\ \text{and } y_{sw} > D_b(\theta)}}{8760 \int 0.5(C_f+F)f(\theta)d\theta} \quad + \quad \underset{\substack{\forall\ \theta \text{ such that} \\ y_{sw} < \mathrm{MIN}(Q_s(\theta), D_b(\theta))}}{8760 \int Gf(\theta)d\theta} \quad = \quad CC$$

For $G < F < C_f$ (which is not credible), the marginal benefit of y_{sw} is even less than it is under regulation; a smaller y_{sw} and fewer cost savings would result than under any other model. A relatively small G seems unlikely (as long as the regulatory ceiling is not too low) because the resulting solution might violate the core constraint that the imputations to S and W must exceed what they would gain under the subcoalition {SW}.

A more credible G would be $F < G < 0.5(C_f+F)$. In that case, the marginal benefit is greater than under regulation, but less than under the Status Quo; thus, the y_{sw} and production efficiency that results would be between the outcomes of the other models.

Under flexible pricing, G might exceed $0.5(C_f+F)$. For example, it could go as high as C_f (especially if the transmission line often operates at capacity). Then, the marginal benefit would be larger than under the Status Quo (simultaneous buy/sell), resulting in more capacity and cost savings than any other model, except the Ideal model. However, the ideal level of benefit would not be achieved because the marginal benefit to W of sales from S to W would still be less than C_f (if F is less than C_f).

The income distribution would depend on the value of G. Higher values result in W getting more of the gains, and B less.

Results for Uniform Distribution of Hydropower Availability and Fixed Demands

In order to consider pricing models in which the wheeling price is not fixed, it is necessary to specify a particular distribution for D and particular functional forms for $Q_s(\theta)$, $D_b(\theta)$, and $D_w(\theta)$.

Assumptions

We make the following assumptions:

- The only random variable is Q_s, which has the following distribution:
  - -Probability P_h of a positive amount of hydropower available at a given time, with the probability density $f(Q_s)$ being uniform:

$$f(Q_s) = P_h/Q_{smax}, \text{ for } 0 \leq Q_s \leq Q_{sm}$$

$$= 0, \text{ for } Q_s \geq Q_{sm}$$

  - -Probability $(1-P_h)$ of zero hydropower being available

- The demands D_b and D_w are fixed; $D_b+D_w \geq Q_{sm}$ (that is, there is never more hydropower than there is demand for it).

For each of the pricing models, the following questions are addressed:

1. How much transmission capacity y_{sw} is built by W?
2. What is the welfare loss (defined here simply as the production efficiency loss) relative to the Ideal solution?
3. What is the distribution of the gains from trade among S, W, and B?

First, we discuss the general results of the models and then present, for illustrative purposes, the outcomes under particular values for the parameters. It is always assumed that the optimal solution in each pricing model yields a positive y_{sw}--that the parameters are such that some transmission capacity is justified. Thus, we ignore cases where, for some parameters, the best y_{sw} is zero. (This simplifies the presentation since we do not have to consider the possibility of that "corner solution" in discussing the answers to the questions. However, the qualitative nature of the results would not be changed by that possibility; rather, the magnitude of the welfare loss would be less than we state and, of course, the gains to trade would be zero.)

General Results

The models below are versions of the more general models of the previous section that result from the use of a uniform distribution of hydropower availability. We consider the Ideal model, the Status Quo, Planning models I and II, several cases of the Contract model with flexible pricing, and the NRRI model.

Ideal Model

With the notation and assumptions given previously, the Ideal solution maximizes the expected generation cost savings minus the expense of transmission, that is,

$$\underset{\{y_{sw}\}}{\mathrm{MAX}}\ 8760[\underbrace{\int_0^{y_{sw}} (P_h/Q_{sm})C_f q\,dq}_{\text{[Savings if } Q_s < \text{ Transmission Cap.]}} + \underbrace{\int_{y_{sw}}^{Q_{sm}} (P_h/Q_{sm})C_f y_{sw}\,dq]}_{\text{[Savings if } Q_s > \text{ Transmission Cap.]}} - \underbrace{CCy_{sw}}_{\text{[Trans. Cap. Cost]}}.$$

After a little algebra, we obtain the following answers to the three questions:

1. The optimal $y_{sw} = Q_{sm}[1 - \dfrac{CC}{8760P_qC_f}]$. That is, if transmission capacity were free, ideally W would build enough to accommodate all the hydropower. The lower the cost of transmission and the higher the avoided energy cost or probability of positive amounts of hydropower, the more transmission capacity should be built.
2. The cost savings, equal to the above objective function, is

$$\text{Savings} = y_{sw}[8760P_hC_f(1-(y_{sw}/2Q_{sm})) - CC] .$$

   This is true for all models since, as it turns out, all available transmission capacity is used in each pricing model. This results in a cost savings to the system of C_f (\$/kWh), no matter who gets the hydropower.

   Substituting the above optimal value of y_{sw} into this expression gives the savings:

$$\text{Savings} = 0.5P_hQ_{sm}8760C_f[1 - CC/(P_h8760C_f)]^2 .$$

3. The distribution of gains cannot be assessed because no prices have yet been assumed for the model. It can be assessed if, for

example, we assume marginal-cost pricing for transmission and generation. Then the transmission price would be zero when neither capacity constraint--y_{sw} or Q_s--binds, and C_f when either binds. If Q_s is binding, then S would receive a congestion-based, marginal-cost price of C_f for its hydropower. But if y_{sw} is binding, then W would receive it instead. Under these pricing assumptions, where $D_b+D_w>Q_{sm}$, the price never falls to zero (that is, zero profit for S's power and for W's transmission). Thus, B receives no gains at all at any time.

B receives a gain only under the more general mathematical program introduced in the first section of this appendix. B receives a gain only if (1) there is a positive probability of $Q_s>D_b+D_w$, and (2) demand is modeled as a random variable, which we have not done in this section. If demand is fixed, W would never build more transmission capacity than the sum of its and B's demands and, hence, the delivered price of hydropower to B would never fall below C_f under strict short-run marginal cost pricing.

Status Quo Model

This is based on the same assumptions as in the Status Quo model developed in chapter 6. W's cost savings objective becomes

$$\max_{\{y_{sw}\}} 8760\Big[\underbrace{\int_0^{y_{sw}} (P_h/Q_{sm})0.5(C_f+F)q\,dq}_{\text{[Savings if } Q_s < \text{Transmission Cap.]}} + \underbrace{\int_{y_{sw}}^{Q_{sm}} (P_h/Q_{sm})0.5(C_f+F)y_{sw}\,dq}_{\text{[Savings if } Q_s > \text{Transmission Cap.]}}\Big] - \underbrace{CCy_{sw}}_{\text{[Trans. Cap.Cost]}}.$$

With this pricing policy, the answers to the three questions are as follows:

1. The optimal $y_{sw} = Q_{sm}\left[1 - \dfrac{CC}{8760P_q 0.5(C_f+F)}\right]$,
   which is similar to the ideal result, except that 0.5 (C_f+F) (the portion of the savings accruing to W under the split-savings rule) is substituted for the true cost savings C_f. As a result, less transmission capacity is built if $F<C_f$, as we would expect it to be.

2. The loss in production efficiency compared to the ideal is:

$$\frac{Q_{sm}CC^2}{2(8760P_qC_f)}\ [(C_f-F)/(C_f+F)]^2$$

If $F=C_f$, then there would be no loss of efficiency.

3. As in the general model of the previous section, B earns none of the gains and, if the wheeling fee just covers the cost of the transmission line, S and W split the gains evenly. Otherwise, W gets more or less than half the gains if F is higher or lower than that level.

Planning Model I

Here, W satisfies its own demand for hydropower D_w before it wheels any power to B. If $y_{sw}<D_w$, then the objective is the same as in the Status Quo model because all power that can be transmitted is purchased by W using the split-savings rule. If $y_{sw}>D_w$, then the objective instead becomes:

$$\underset{\{y_{sw}\}}{\text{MAX}}\ 8760[\underbrace{\int_0^{D_w}(P_h/Q_{sm})0.5(C_f+F)q\,dq}_{\text{[Savings if } Q_s < \text{Transmission Cap.]}} + \underbrace{\int_{D_w}^{y_{sw}}(P_h/Q_{sm})[0.5(C_f+F)D_w+F(q-D_w)]dq}_{\text{[Savings if } D_w < Q_s < \text{Trans. Capacity]}}$$

$$+\underbrace{\int_{y_{sw}}^{Q_{sm}}(P_h/Q_{sm})F(y_{sw}-D_w)dq]}_{\text{[Savings if } Q_s > \text{Transmission Cap.]}} \quad - \quad \underbrace{CCy_{sw}}_{\text{[Trans. Cap. Cost]}}\ .$$

There are three possible solutions y_{sw} to this problem (ignoring the possibility that the best y_{sw} = 0), depending on which of the following applies:

Case a: $y_{sw} < D_w$

Case b: $y_{sw} = D_w$

Case c: $y_{sw} > D_w$

The answers to the three questions differ with the solution for y_{sw}, depending on which of these conditions applies. The answers are described next for each case.

Case a. $y_{sw} < D_w$:

This yields the same answers to the solution, productive efficiency, and income distribution questions as the Status Quo model, since only purchases by W from S are involved. B gains nothing.

Case b. $y_{sw} = D_w$:

1. This is a "corner solution," which results because the marginal benefits of $y_{sw} < D_w$ are high (equal to the split savings that W gets by buying from S) while those of $y_{sw} > D_w$ are low (because they represent wheeling of power from S to B).
2. The cost savings equal $D_w[8760P_hC_f(1-(D_w/2Q_{sm}))-CC]$, which is less than the savings under the Status Quo (since if this $y_{sw} = D_w$ is the optimal Planning solution, then the Status Quo solution for y_{sw} exceeds D_w).
3. No power is wheeled to B, therefore S and W split the entire gain.

Case c. $y_{sw} > D_w$:

1. The optimal solution is $y_{sw} = Q_{sm}[1-(CC/(8760P_hF))]$. If F is significantly less than C_f and transmission cost is high, this solution is significantly smaller than in the Ideal and Status Quo cases.
2. The loss in production efficiency compared to the Ideal solution is

$$\frac{Q_{sm}CC^2}{2(8760P_qC_f)}\,[(C_f-F)/F]^2 \,.$$

   The loss is proportional to the square of the difference between the avoided generation cost and the wheeling rate. If we divide this loss by the Status Quo's efficiency loss, we find that the Planning solution's loss is $(C_f+F)/F$ times as large as the Status Quo's.
3. However, B is better off than under the Status Quo because it now obtains some of the gains from trade. It splits with S most of the gains that it gets from its purchases from S, while W only

obtains the wheeling fee. However, W still gets some portion of the gain if W's wheeling fees exceed its cost of transmission.

Planning Model II

Here, S must sell to B under a "preference power" arrangement. Thus, W only gets to buy power from S once B's needs are met.

As in Planning Model I, there is more than one type of solution that can occur. Here, two types are possible, corresponding to the optimal y_{sw} being less than or greater than D_b (rather than D_w). The solution $y_{sw} = D_b$ does not occur because the marginal benefits for smaller y_{sw} (based on wheeling fees) are likely to be much less than marginal benefits for larger y_{sw} (based on split savings between S and W). Consequently, if increasing y_{sw} to D_b is justified, a further increase in y_{sw} would also be attractive.

The answers to the three questions are shown below for each of the two possible cases.

Case a. $y_{sw} < D_b$

1. In this solution, only a relatively small amount of transmission capacity is provided for some wheeling from S to B. W only builds capacity until the expected marginal wheeling fees equal the cost of construction. Since the marginal wheeling fees, F, are likely to be much less than the marginal benefits of wheeling, C_f, far too little capacity is constructed. The amount constructed equals that given in the formula for "Case c: $y_{sw} > D_w$" in Planning Model I.
2. The production efficiency loss is the same as given by the formula for "Case c: $y_{sw} > D_w$" in the Planning Model I. The loss is the largest of any model considered here.
3. Most of the gains are split between S and B; W gets only a small portion, which equals the excess of the wheeling fee collected over the cost of transmission. This excess is positive, or W would not build any transmission.

Case b. $y_{sw} > D_b$:

1. This solution is identical to the Status Quo solution.
2. So too is its production efficiency.
3. But its income distribution is not. This is because B obtains a large portion of the gains resulting from the first D_b of

capacity, as W must wheel that for a fee. In contrast, B gets none of the gains in the Status Quo case because "wheeling" is via a simultaneous buy/sell mechanism, and B's marginal cost is the same as W's. S gets half the gains that are net of the profits W gets from the wheeling fees. W also earns some of the gains from its purchases from S.

An important question is: what are the efficiency implications of a "preference power" policy that favors B? This can be answered by examining the difference between the Planning Model I and Planning Model II solutions. Two cases are considered here: B and W's demands are equal in size ($D_b=D_w$), and W's demands are much larger, which might be the case, for example, if B is a requirements customer of a large investor-owned utility.

Under the assumption that B and W's demands are the same (say, equal to D), the effects of changing policies from Planning I to Planning II are considered for each combination of possible solutions. Unless stated otherwise, the impact of a policy change to II is to decrease y_{sw}, decrease production efficiency, and shift more of the gains from W to B. Below, these are termed the "base case" effects.

Optimal Value of y_{sw} under:		Effect of change in Policy from I to II When W's and B's Demands Are Equal
Planning I	Planning II	
$y_{sw} < D$	$y_{sw} < D$	Base case effects occur. B's gains go from zero to positive, and most of W's gains are eliminated.
$y_{sw} < D$	$y_{sw} > D$	This combination does not occur because, if W is willing to build more transmission capacity than D under II, it would also be willing to do so under I.
$y_{sw} = D$	$y_{sw} < D$	This has the same effects as combination "$y_{sw}<D, y_{sw}<D$", above.
$y_{sw} = D$	$y_{sw} > D$	This increases transmission capacity and production efficiency while simultaneously increasing B's gains from zero to a significant amount. It can occur if W incurs fewer losses from wheeling power to

		B than W gains from the purchases it makes from S.
$y_{sw} > D$	$y_{sw} < D$	This does not occur because, if the expected marginal wheeling fees are such that it is worthwhile to build transmission under policy I, it certainly would be worthwhile to build at least the same amount of capacity under II (assuming that F is not greater than $(C_f+F)/2$).
$y_{sw} > D$	$y_{sw} > D$	Base case effects occur. B's gains are positive under both models, but much larger under II. What B gains, W loses.

From an efficiency viewpoint, under the assumptions of this analysis preference power is undesirable in all but one case, as set out in chapter 6. Surprisingly, it is beneficial in one circumstance, because in that case it makes W the marginal purchaser of power rather than B, which increases W's incentive to expand the transmission grid. But no matter what solutions occur, B is always a big gainer if preference power policies are adopted. (The only exceptions to the last conclusion are the trivial ones in which the cost of transmission either is zero or is so high as to prohibit transmission under either policy.)

If B's demands are smaller than W's, the picture is somewhat more complicated, as set out below. The main difference is that there is one situation in which a switch in policies has no impact on y_{sw} or on production efficiency.

Optimal Value of y_{sw} under:		Effect of Change in Policy from I to II when W's Demand Is Larger than B's
Planning I	Planning II	
$y_{sw} < D_w$	$y_{sw} < D_b$	Base case effects occur. B's gains go from zero to positive, and most of W's gains are eliminated.
$y_{sw} < D_w$	$y_{sw} > D_b$	This combination *can* occur in this case if the optimal y_{sw} is greater than D_b under policy I (although it is less than D_w).

		The result would be the same amount of transmission capacity and production efficiency under either policy, but policy II would shift a large amount of the gains from W to B.
$y_{sw} = D_w$	$y_{sw} < D_b$	Same effects as combination "$y_{sw}<D, y_{sw}<D$", above.
$y_{sw} = D_w$	$y_{sw} > D_b$	As in the $D_w=D_b$ situation, this results in an increase in production efficiency.
$y_{sw} > D_w$	$y_{sw} < D_b$	This does not occur because, if the expected marginal wheeling fees are such that it is worthwhile to plan on wheeling under policy I, here again it would be worthwhile to do so under II.
$y_{sw} > D_w$	$y_{sw} > D_b$	Base case effects occur. B's gains are positive under both policies, but much larger under II (at W's expense).

Contract Model with Flexible Pricing, Case 1

It is assumed here that payments are made from B and S to W in such a way as to motivate W to build the ideal amount of capacity. Such payments cannot be a fixed rate per kWh wheeling fee, which would yield a less efficient decision by W. Like the first general Contract model with flexible pricing presented earlier in this appendix, this case is represented by the core of the unrestricted game.

The answers to the standard questions are as follows:

1. The ideal amount of capacity is built.
2. There is no loss of production efficiency relative to the ideal.
3. The only constraint on the distribution of gains is the possible formation of the subcoalition {SW}; its gains are a constraint on the gains that W and S would obtain. If the optimal y_{sw} is less than D_w, the value of the grand coalition and the subcoalition would be the same and S and W would earn all the gains. But if the best y_{sw} exceeds D_b, B could get up to the amount of the gains

accruing from the increment of y_{sw} that exceeds D_b; this is the difference between the value of the grand coalition and that for {SW}.

Contract Model with Flexible Pricing, Case 2

Here, W charges the following fees for wheeling:

F, if Q_w is less than y_{sw}
C_f, if Q_w equals or exceeds y_{sw} .

That is, a cost-based (perhaps embedded cost-based) fee is charged if the link is not used to capacity, and the social opportunity cost (short-run marginal cost) is charged if it is used to capacity. (Note that the social opportunity cost is greater than W's if W buys its power on a split-savings basis.) B has the right to satisfy its need for S's power before W can buy any power from S.

The objective function has two different forms, depending on whether the optimal y_{sw} is less, equal to, or greater than D_b. Both should be solved, and the best solution chosen (note that the corner solution $y_{sw} = D_b$ might be best).

If $y_{sw} < D_b$, then the objective is:

$$\underset{\{y_{sw}\}}{\mathrm{MAX}}\ 8760\left[\int_0^{y_{sw}} (P_h/Q_{smax})Fq\,dq + \int_{y_{sw}}^{Q_{sm}} (P_h/Q_{sm})C_f y_{sw}\,dq\right] \quad - \quad CCy_{sw}$$

[Fees if $Q_s < y_{sw}$] [Fees if $y_{sw} < Q_s$] [Trans. line cost]

In this case, the answers to the questions are:

1. The optimal $y_{sw} = Q_{sm}[C_f/(2C_f\text{-}F)][1 - CC/(P_h 8760 C_f)]$, which is less than the ideal level by a factor of $C_f/(2C_f\text{-}F)$. (Note that if $F=C_f$, the Ideal solution results). Compared to the Status Quo solution, this one is smaller only if $8760P_h(C_f\text{-}F)(C_f+F)/(3C_f\text{-}F) <$ CC. Notice that, if F is much smaller than C_f, this is equivalent to saying that $8760P_hC_f/3$ is less than CC--which is the same as saying that the ideal y_{sw} is less than two-thirds Q_{sm}.
2. Production efficiency is less than the ideal level.

3. B gets all of the power. It also gets roughly half the gains (as does S) when transmission is not used to capacity--but W gets all the gains when the line is completely used. This provides a powerful incentive to W to restrict the amount of capacity to less than the ideal level. (See also the discussion in chapter 6.)

Another possibility is that the optimal $y_{sw} = D_b$. The income distribution is qualitatively the same as for the case $y_{sw} < D_b$.

The third possibility is that the optimal $y_{sw} > D_b$. The objective function is then:

$$\underset{\{y_{sw}\}}{\text{MAX}}\ 8760\Big[\int_0^{D_b} (P_h/Q_{sm})Fq\,dq + \int_{D_b}^{y_{sw}} (P_h/Q_{sm})FD_b\,dq + \int_{y_{sw}}^{Q_{sm}} (P_h/Q_{sm})C_f D_b\,dq$$

[Fees if $Q_s < D_b$] [Fees if $D_b < Q_s < y_{sw}$] [Fees if $y_{sw} < Q_s$]

$$+\int_{D_b}^{y_{sw}} (P_h/Q_{sm})0.5(C_f+F)(y-D_b)\,dq + \int_{y_{sw}}^{Q_{sm}} (P_h/Q_{sm})0.5(C_f+F)(y_{sw}-D_b)\,dq - CCy_{sw}$$

[Split Savings if $D_b<Q_s<y_{sw}$] [Split Savings if $y_{sw}<Q_s$] [Tran. Line Cost]

The answers to the questions in this case are as follows:

1. The optimal y_{sw} is

$$Q_{sm}[1-CC/(8760P_h 0.5(C_f+F))] + D_b(F-C_f)/(0.5(C_f+F)).$$

If F=0, this simplifies to

$$Q_{sm}[1-CC/(8760P_h 0.5C_f)] - 2D_b.$$

This is a good deal less than the Ideal solution.

2. Productive efficiency is less than the Ideal solution.
3. Clearly, B does better than in the previous situation ($y_{sw}<D_b$), since (a) all its demands are met and (b) the transmission line constraint is less likely to be binding, which means that B is more likely to pay F for its wheeling.

Contract Model with Flexible Pricing, Other Cases

Case 3. Suppose W always charges the ceiling C_f for wheeling. The objective function looks just like the Planning Model I objective presented earlier, except that C_f rather than F appears in the second integral (the wheeling revenues term).

For completeness and for contrast with other cases, we assume initially that W first buys enough power to meet its own needs and then wheels (although this violates economic rationality--W earns more profit by wheeling than by buying). There are two possible solutions to this model; the three questions are answered briefly for each. If the optimal y_{sw} is greater than D_w, the same solution occurs as in the Ideal model, and there is no efficiency loss. However, B gets none of the gains. If, on the other hand, the best y_{sw} is less than D_w, the same solution results as in the Status Quo model, and there is some efficiency loss. Once again, B gets none of the gains.

If, instead, W chooses to wheel and satisfy B's needs before meeting its own, then the results are reversed. If the optimal y_{sw} is greater than D_b, the Status Quo transmission capacity and efficiency result. If the optimal y_{sw} is less than D_b, the solution is the same as under the Ideal model. In both cases again, B gets no share of the gains.

Case 4. This case, which has the same wheeling fee structure as case 2, allows W to buy or wheel, according to which is more profitable. Clearly then, if the transmission is at capacity, it would rather wheel (at rate C_f) than buy (saving only $0.5(C_f+F)$); but if the transmission constraint is slack, the reverse would be true.

NRRI Marginal Cost Pricing

Here, again, we examine the NRRI model by assuming that neither S nor B asks for firm transmission capacity for nonfirm power. Then W acts under the assumption that short-run marginal cost pricing would be in effect for any capacity it chooses to build for nonfirm power. This would result in the same solutions as flexible pricing, either cases III, IV, or V, depending on what rule W uses to determine if it buys or wheels under the various circumstances. Because W earns less from wheeling than under flexible pricing if capacity is adequate, the amount of y_{sw} (and therefore the amount of production efficiency) cannot be greater than under flexible pricing--and, indeed, it could be less.

Note however, that the actual NRRI model gives the customer a choice, allowing B to obtain firm transmission capacity at long-run marginal cost. (This is disallowed by assumption here and in chapter 6.) Then B would pay a demand charge or a fixed annual fee for capacity, and so would be able to influence (or "bribe") W to build the socially optimal amount of capacity. B would be buying at cost more transmission capacity than is absolutely necessary for just reliability purposes (since this is for economy energy)--an option not permitted under some versions of the Contract model.

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