

DISCUSSION PAPERS ON COMPETITIVE BIDDING AND  
TRANSMISSION ACCESS AND PRICING ISSUES  
IN THE CONTEXT OF INTEGRATED RESOURCE PLANNING

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## PREFACE

The proper role of competitive bidding for electric capacity, and transmission access and pricing in the integrated resource planning process is not entirely clear. The NRRI, under contract to the Ohio Public Utilities Commission, has prepared a set of discussion papers addressing key elements of state and federal policies on transmission access and pricing. Chair Jolynn Barry Butler of the PUCO has generously made available these discussion papers for dissemination to our full clientele.

I believe that you will find them of interest.

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May 4, 1990

## Introduction and Content

The PUCO is considering opening investigation into what role competitive bidding, and transmission access and pricing can play in Ohio's integrated resource planning process. To assist the PUCO staff, the NRRI has identified critical issues about whether competitive bidding for generation facilities and possibly demand side-management facilities is an effective means of integrated resource options, and how competitive bidding could affect Ohio's integrated resource planning process. The NRRI has also identified key issues about how different state and federal policies on transmission access and pricing might affect Ohio's integrated resource planning. Discussion papers on each of the issues identified by the NRRI follow. The purpose of these discussion papers is to provide useful background information and to be used as an agenda for meetings on competitive bidding, and transmission access and pricing issues.

The following is a list of the issues on competitive bidding identified by the NRRI, together with the page where each issue can be found:

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Issue: COMPETITIVE BIDDING AND THE OBLIGATION TO SERVE

Competitive bidding to determine a utility's supply sources would in no way affect a utility's obligation to serve its retail customers. The utility's obligation to serve all existing and future retail customers within its service area, and to plan for and acquire the facilities necessary to serve those customers adequately and reliably in the future, would still exist whether or not competitive bidding was implemented.

However, the ability of a utility to fulfill its obligation to serve is affected by its ability to be certain of supply sources. When a utility does not own and operate its own generation facilities, its supplies are acquired in wholesale sales under the FERC's jurisdiction. The current policy of the FERC is that no obligation to serve wholesale customers exists.

Utilities would have to rely on contracts to ensure that their supply sources were reliable. Performance bonds, a security interest in the plant, liquidated damages clauses, and a contractual right to enter and operate the plant are some of the contractual means to assure reliable service necessary to fulfill an obligation to serve. The possibility of a successful bidder going into bankruptcy is still troublesome, particularly if its insolvency was caused by high fuel costs. Then, the costs of running the plant might not be fully recoverable and the trustee in bankruptcy might be reluctant to operate the plant.

The effects of competitive bidding on the utility's ability to fulfill its obligation to serve influences how competitive bidding might be made a part of an integrated resource planning process. For example, a utility might consider a successful bidder to be a less reliable source and requiring a higher reserve margin; or the utility might wish to have only a proportion of its future power needs met by competitive bidding. Commission oversight of the design of the bidding process might be necessary to make bidding a viable process, balancing the concern that the utility is able to meet its obligation to serve. Also, some commission oversight of utility contracts with successful bidders might be necessary to ensure that the utility is taking proper precautions to fulfill its obligation to serve, without making the contract so onerous that bidders cannot obtain financing.

Issue: COMMISSION INVOLVEMENT IN THE COMPETITIVE BIDDING PROCESS

A wide range of alternatives exists for commission involvement in the competitive bidding process from complete control of the process from solicitation to contracting to simply reviewing the choices made by the electric utility. The bidding process may be divided into four parts, each having a different level of commission involvement. First is the bid solicitation. Most commissions allow the utility, with commission approval, to send out a Request for Proposals (RFP). The RFP is based on the power requirements of the utility and may be initiated by the utility or the commission. Second is the evaluation of the submitted project proposals. In this step the various attributes of the projects are measured by prearranged criteria. Third is project selection. This involves considering all the projects together to determine the optimal arrangement of the projects to meet power requirements and other goals. Fourth is the contracting with the successful bidder(s). This involves the selection and negotiation of contract provisions that will appear in the final contract with the supplier. PUCO's choice of involvement for each step may ultimately depend on the Commission's preferred level of involvement in the supply options of electric utilities in the state.

Obviously, the bidding regulations and the general rules of implementing solicitation are usually the joint product of state regulators, utilities, consumer groups, and other interested parties. But given the complexities involved in integrating nonutility power generation with the utility system and possible variations in bids submitted, it is difficult to design a perfectly transparent and mechanical bid evaluation and selection process. As a result, some discretion must be exercised in the bidding process. The control of such discretion is a critical issue in competitive bidding. Different states have adopted quite different approach as toward assigning responsibility to the host utility in evaluating and selecting bids. In some states, such as Connecticut, the responsibility for bid evaluation and selection is principally the commission's.

Issue: DETERMINATION OF SUPPLY BLOCKS FOR COMPETITIVE BIDDING

Under most bid selection methods, one selects "all or nothing." In other words, say 50 megawatts (MW) of capacity is put out for bids. A bidder is finally selected to supply this capacity.

There may be several advantages in selecting more than one bidder to supply capacity. One obvious advantage is risk spreading. The other more important advantage is that of optimal selection.

If bidders are encouraged to bid in quantum blocks (5 MW at some price, an additional 10 MW at some other price, etc.) one might be able to select an optimum combination of bids from more than one supplier. Of course, such a selection is possible only when the bids have the characteristics of increasing average cost.

The question, then, is whether a single successful bidder should be selected, or a combination of several bidders.

Issue: SELECTING PARTICIPANTS FOR COMPETITIVE BIDDING

The commission must decide who is eligible to participate in a bidding process. Potential sources of power include FERC qualified facilities (QFs), independent power producers (IPPs), the local electric utility that requires the power, and other utilities. QFs are industrial and commercial cogenerators and small power producers that qualify under FERC rules implementing the Public Utility Regulatory Policies Act (PURPA). PURPA requires that electric utilities purchase power and interconnect with a QF. Many states are now using competitive bidding to determine the rate paid to QFs for power sold back to the utility rather than the commission setting or approving an avoided cost rate. If a QF wants to interconnect with a utility, it must, in these states at least, participate in the bidding process.

An independent power producer is any producer of electricity that is not a QF and that is not a primary affiliate of the local utility (although it may be affiliated with another utility). Currently there are only a few independent power producers in the country. However, if the proposed changes to the Public Utilities Holding Companies Act (PUHCA) are approved by Congress, then IPPs (or Exempt Wholesale Generators--EWGs) have the potential of becoming a significant source of power in the future.

In an all-source bid, a local utility may participate in the bidding process along with all other sources. The reason for allowing a local utility to participate is that since it is well acquainted with the process of building new facilities, it has cost advantages that include a lower cost of capital and expertise in building and operating a new facility. These same reasons apply to allowing other utilities to participate in the bidding process. The major reason for not allowing a local utility to participate is that it may have an incentive to misstate its power needs and/or avoided cost to influence the outcome of the bid.

Issue: PRESERVING THE UTILITY AS A SOURCE FOR RESOURCE EXPANSION

If all the foreseen requirements of capacity were put out for bids, the utility would be reduced to the position of an intermediary bid taker. In the longer term, the utility cannot retain technical staff with expertise in the area of power plant planning and construction of this situation were to continue for a long time.

Therefore, should there be come guarantees that the utility itself would build some capacity or should it build only when bidders cannot bid a lower price than the cost of construction by the utility itself? Should the utility also be allowed to bid?



Issue: QUALIFYING FACILITIES AS BIDDERS

One of the principal concerns about the legality of competitive bidding programs is whether state implementation of competitive bidding is inconsistent with either PURPA section 210 or its regulations. PURPA itself is silent as to whether a competitive bidding process is permitted to determine incremental costs. One definition of incremental costs is the cost to the utility of generation or purchase from another source. Nothing in the statutory language would prevent another source from being a purchase from another qualifying facility (QF). In other words, PURPA leaves open the possibility of QF-on-QF competition through competitive bidding or otherwise.

The 1980 full avoided cost regulations implementing PURPA section 210 are silent about the possibility of a utility buying from a QF as another source to determine full avoided cost. While not explicitly prohibited, competitive bidding was not contemplated under the 1980 regulations. However, the regulations left it up to the state commissions to determine the method of calculating avoided costs. One of the methods used was a purchased power approach, in which full avoided costs were set at the cost of purchased power from other utilities. In many respects, a competitive bidding process merely sets the avoided cost for power at the cost of purchased power, whether that power is from a utility or a QF. In its 1988 Notice of Proposed Rulemaking on Competitive Bidding, the FERC made clear that it considered a competitive bidding process to be consistent with PURPA, particularly if certain procedural safeguards explicitly set out in the NOPR are followed. The FERC has taken no action to make its NOPR a final rule.

Under PURPA, QFs are exempt from provisions of the Public Utility Holding Company Act (PUHCA).

The implication for the integrated resource planning process is that competitive bidding poses few legal problems when bidding is confined to QFs. However, if few QFs have been attracted thus far by administratively determined avoided cost rates, there might be reason to suspect that few QFs will submit bids to a competitive bidding process. Because of the PURPA requirement that the utility buy power from QFs, a utility might be required

to give preference to a QF in case of a tie in bidding. However, there is no requirement that a QF be more paid for capacity or energy than would need to be paid for power from another source.

Issue: INDEPENDENT POWER PRODUCERS AS BIDDERS

When nonQFs win in a bidding process, the legal situation becomes complex. A successful nonQF bidder is subject to the provisions of the Federal Power Act because a sale from it to a utility is a wholesale sale in interstate commerce. Rates for successful nonQF bidders would be subject to FERC review under section 205 of the FPA, and the nonprice provisions of the FPA would also apply. In its NOPR on Independent Power Producers (IPPs), the FERC proposed to deem an IPP's rates just and reasonable if the rates were at or below the purchasing utility's avoided cost, whether determined administratively or by a bidding process. The FERC also proposed to streamline or partially exempt the IPP from nonprice regulation. Thus, if the NOPR becomes a final rule the FERC in essence would defer to the decisions reached in the state competitive bidding process. However, the NOPR has not become a final rule.

More troubling are PUHCA provisions. Successful nonQF bidders could, and in most cases would, be subject to provisions of the PUHCA. Most utilities and other corporations that might set up IPPs wish to avoid becoming registered holding companies under the PUHCA, because of the requirement that they comply with comprehensive, ongoing regulation by the Securities and Exchange Commission. In particular, utilities wishing to set up IPPs outside of their own franchise area would be prevented from doing so by the PUHCA's prohibition of utility ownership of nonintegrated facilities. While nonutility-owned IPPs might sidestep the PUHCA by setting up a separate division of each company, such a strategy might be unavailable in states requiring companies to be incorporated in that state. Because companies naturally wish to avoid the PUHCA, many that otherwise would have bid will probably not do so. With fewer bidders, there is a greater likelihood of both collusion and a competitive bidding process that does not achieve lower costs because not all source alternatives are considered. In other words, without IPPs bidding, a bidding process may not be workably competitive and may not achieve an efficient result.

Issue: BIDDING BY UTILITY SUBSIDIARIES IN HOST UTILITY'S SOLICITATION

This issue concerns whether a utility subsidiary should be allowed to submit bids in its parent utility's solicitation for power and capacity. Some argue that the potential for self-dealing and the regulatory safeguards needed to overcome the possible abuses are too great to justify such a policy. A host utility can give preferential treatment to its subsidiary in bid preparation, bid evaluation, bid selection, and post-bidding contract negotiation. Furthermore, there does not appear to be any net economic or technical advantages in allowing a subsidiary to bid in its parent's service territory. After all, the subsidiary is owned and controlled by the host utility. Any new generation technologies, special zoning permits, or unique environmental clearances that could be obtained by the subsidiary could also be made available by the host utility.

However, some argue that the bid evaluation and selection process can be made perfectly transparent to all bidders and state regulators alike so that no possibility exists that preferential treatments will be bestowed by the host utility on its own subsidiary. There also may be instances where the utility subsidiary, as an independent power producer, is subject to different regulatory oversight from what traditional regulation accords utility-owned power plants. Consequently, a subsidiary arrangement may provide certain regulatory advantages to the host utility.

Issue: INITIAL QUALIFICATION OF BIDDERS--SITING AND FINANCING CONSIDERATIONS

One issue frequently raised by regulators and utilities alike concerning competitive bidding is whether winning bidders actually can obtain necessary permits, financing, and technical expertise to complete the power generation facilities as promised. Consequently, some qualification standards are usually specified in requests for proposals to assure that all bidders are bona fide power producers that can perform as promised after their selection.

These qualification requirements may be in the form of written statements from registered professional engineers, certified public accountants, or attorneys all supporting the bidder's ability to build and operate the proposed facility.

Specifically, the bidder's legal counsel needs to submit a report stating what rights, permits, licenses, and other documents are needed and when they should be procured. A certified public accountant needs to prepare statements explaining the project's financing, and may include letters of commitment from financial backers and partners or past proof of the bidder's ability to market stock and partnership interests. The bidder also may be asked to submit a report describing in full detail the facility's design, construction, equipments, fuel needs, and its potential environmental effects. This report may be reviewed and supported by a registered professional engineer.

Entry fees are often required to help defray the cost of evaluating the entries. Security deposits and bonds may be required to ensure that the participants are serious candidates able to obtain the necessary financing. This also has the effect of reducing the number of bids submitted by a single participant. Deposits and bonds are refunded after the bidding process is complete; entry fees are not refunded.

Issue: BINDING AVOIDED COST ON THE HOST UTILITY

This issue concerns the utility's own avoided cost estimates and cost recovery for a host utility's own supply options. Avoided cost reflects the cost of the best alternative available to a host utility. Since it can constitute the upper limit for payment to nonutility power producers, some argue that fairness would require that avoided cost also be an upper limit for the cost of adding new supply capacity by the host utility.

There are several advantages in making avoided cost binding on a host utility's own supply options. A binding avoided cost can provide an incentive for a host utility to prepare a comprehensive and realistic integrated resource plan for calculating the avoided cost. A binding avoided cost that is published as part of the utility's bid solicitation also serves to control construction and operating costs of the utility's own generation plants in the event that the host utility cannot obtain capacity from nonutility producers and has to build the power plant itself.

On the other hand, some argue that such a treatment may be illegal in denying the recovery of investment costs prudently incurred in providing service by the host utility, and that it can impose too great a risk on the host utility to undertake new power plant construction projects.

Issue: FREQUENCY OF SOLICITATION

This issue concerns the timing of utility solicitation. Bidding regulations in place in several states use different approaches to the frequency of bidding. In general, since competitive bidding can be a part of the utility's resource planning process, a solicitation for nonutility capacity and power should occur only when there is a need for a certain amount of additional generation capacity within the planning horizon.

There are four factors to be considered in setting the frequency of utility solicitations. The first is that the amount of capacity solicited should allow various generation technologies of different sizes (such as a large coal-fired plant versus a small-sized gas turbine) to compete with one another in a fair and equitable environment. The second is to reduce any tendency of collusive behavior among bidders. Frequent bidding inevitably involves the same group of bidders, making some tacit cooperation among nonutility power producers more likely.

The third consideration is the coordination of utility solicitation with the expansion of local industrial plants. A fourth factor is the transaction costs associated with bid solicitation and evaluation. Nonutility producers must spend a great deal of time and effort preparing bids and collecting relevant information. The host utility also incurs substantial expenses in preparing a request for proposal, publicizing the solicitation, evaluating bids, and negotiating a power purchase agreement.

Issue: AN OPEN VERSUS A CLOSED BIDDING PROCESS

Open bidding allows participants to know in advance how the bids will be evaluated and the winning bids selected. Some states have participants score themselves when completing proposals for the power facility. In a closed bid, conversely, participants are not informed of the evaluation and selection criteria. The advantage to open bidding is that the participants know in advance if their proposal is a viable one and allows them to adjust the facility (i.e., size, fuel source, etc.) to suit the requirements. The disadvantage, however, is that the facility may be changed inappropriately.

A closed bidding process is more likely to force participants to design optimal facilities based on the requirements provided in the request for proposals (such as needed megawatts for a particular power block). Another advantage to closed bidding is that it makes it less likely that participants will collude among themselves on who will be awarded the contract. This behavior has been observed in other industries where the same participants have bid against each other over the course of several years and have decided that it is in their interest to rotate who the "winner" will be in each bid. The more closed the bidding process is, the more difficult collusion among participants becomes. Of course, measures can be taken to prevent collusion, such as more extensive monitoring of participants. However, this increases the cost of the process.



Issue: PITFALLS OF COMPETITIVE BIDDING: COLLUSION AND OTHER PROBLEMS

While it is commonly perceived that competitive bidding leads to an improvement in economic efficiency, that result depends on how well a competitive bidding process works. Competitive bidding can work imperfectly. After all, competitive bidding generally assumes that the universe of potential bidders is large and that all bidders are equally well-informed. In actuality, there may be few potential bidders and information may not be evenly available to all participants, particularly if the utility has an ownership interest in a bidder, say an IPP. Also, the bid evaluation process, if it takes into consideration past experience and performance, may raise entry barriers to new firms.

Issue: PREVENTION OF LOW-BALL BIDS

A phenomenon that has been noted in the implementation of competitive bidding in other industries is "low-ball bidding" or the "hungry firm" phenomenon, which describes a situation where certain bidders intentionally submit an unreasonably low bid to win a contract and then try to make it whole through cost escalation provisions. So-called "extra scope" add-ons and "change orders" become the vehicles for higher cost recovery and perhaps higher profits.

Eliminating such behavior is important because it can prevent the truly most efficient options from being selected to provide electric service. What is more the final cost to ratepayers may be higher even though the initial winning bids are rather low.

Issue: EVALUATION FACTORS AND WEIGHTS

Many factors should be considered when evaluating project proposals. Many of these are discussed in a report by the Lawrence Berkeley Laboratory.\* Some of the more important and often used factors include price for power sold, prospects for successful project development, participant's guarantees for system performance, affect on system reliability, fuel type, environmental impact, dispatchability, and contract length. A weight is usually attached to each factor that conveys the relative importance of each factor. The weights may be different for each bid solicitation, depending on the power requirements of the utility and the goals of the commission. The factors that are chosen reflect both practical considerations (such as obtaining a secure power supply for the lowest cost) and the goals of the commission that are not embodied in the cost of the power (such as environmental protection or fuel diversity).

\* Kahn, E.P. et al., Evaluation Methods in Competitive Bidding for Electric Power, Lawrence Berkeley Laboratory, LBL-26924, UC-101, June 1989.

Issue: FRONT-LOADED PRICING

A bid with front-loaded pricing means the host utility pays more than its avoided cost during the project's early service years and less in later years. It is essentially a loan provided by the host utility (ratepayers) to the nonutility power producer. Front-loaded pricing is not unusual and can be beneficial where a host utility's financing cost is significantly lower than that of a nonutility power producer. It is also possible that some projects, though economical in the long-run, may have unfavorable cash-flow characteristics without front-loaded pricing. An outright prohibition of front-loaded pricing may not be justified. Nevertheless, some minimum financing qualifications should be set for all bidders. After all, existing capital markets are more likely to provide financing if a bid proposal has sufficient technical and economic merits.

Issue: FUTURE RELIABILITY CONSIDERATIONS OF ELECTRIC POWER SUPPLY

When selecting from among the projects, most commissions will consider factors that affect power supply reliability. This involves both the reliability of that single source and its effect on the overall system reliability. Fuel source for the proposed project is important not merely from the standpoint of the project itself but also from the perspective of the system. This is especially true for those utilities and states that depend on one or two fuel sources. Overdependence on one or two fuel sources may put ratepayers at risk of supply interruption or drastic high cost. One way to alleviate the concern for insufficient fuel diversification as a result of competitive bidding is to set aside a certain percentage of the supply block (total capacity being bid) for facilities using specific fuels. Another approach is to give more favorable ranking to those bids using specific fuels. It may be determined that projects using fuel sources different from the utility's primary source should be given more weight. For utilities that already have a diverse fuel supply, this may be considered an unimportant factor.

Prospects for successful project development is important when considering the reliability of an individual project. The probability of a facility coming on-line can be calculated by considering factors such as financial viability, management quality and experience, and maturity of the technology proposed. To enhance system reliability, therefore, the utility would contract for more power than is required by using the expected power supply (probability of development times contracted power) rather than contracted power supply for system planning. This allows for the loss of some projects based on the utility's and commission's best project forecast. Also, recall that provisions can be placed in the power supply contract that legally obligate suppliers to fulfill their contract or that allow the utility to take over the operation of the facility in the event that the owners cannot continue operation.

Incorporating cost-sharing provisions in a post-bidding power purchase contract refers to the intention of a host utility in achieving three interrelated goals in securing new electric generating capacity: to encourage competition among bidders, to reduce moral-hazard behavior on the part of winning bidders, and to allocate risk to the party that can better bear risk. A fixed-price contract discourages moral hazard on the part of nonutility power producers since the total payment is unaffected by the winning bidder's post-bidding actions. Thus, the winning bidder has the strongest incentive to minimize cost. On the other hand, the advantages of a cost-sharing contract are the possibility of allocating risk to the party that can best bear it, and the encouragement of more aggressive bidding by reducing the risk associated with the bidders' own cost estimations.

The best contract format in acquiring generating capacity depends on the emphasis on controlling these three factors. Since many nonutility power producers participate in a typical utility solicitation, the bidding competition effect is probably of less concern. In the absence of specific information about the risk-taking attitude of the bidders and the host utility, the risk-allocation effect may not be a critical consideration either. So the dominant consideration is the control of moral-hazard behavior. Consequently, a fixed-price contract is preferred. Another reason favoring such a contract is that it is easier to evaluate two fixed-price contracts than two contracts with various cost-sharing and escalation clauses.

Issue: COST ESCALATION CONTRACT PROVISIONS

Future cost escalation provisions are usually inserted into a contract when negotiating with the selected bidders. These provisions are intended to provide for future increases in the cost of fuel and, for long-term projects increased construction costs. In the early 1980s, just after PURPA was implemented by FERC, many utilities entered into long-term contracts with QFs that turned out to have excessive fuel-cost increase provisions. As a result these utilities are locked into long-term agreements where they pay a buyback rate to the QF that is higher than the utility's current avoided cost.

Of course, no one can forecast precisely future fuel and construction costs. However, provisions can be inserted into a contract that are either long term with escalation clauses dependent on the actual rise in costs or that are short term with fixed rates of growth. Either type of provision will protect ratepayers from paying higher rates in the long term because of excessive increases paid to power suppliers.

Issue: PLANT EMISSION ALLOWANCES FOR NONUTILITY GENERATORS

As of this writing, proposed changes to the Clean Air Act are still pending in Congress. It is highly likely, however, that there will be an emission cap provision and tradable emission allowances for SO<sub>2</sub> and NO<sub>x</sub> in the final legislation. The original endowment of trading allowances will most likely be based on a plant's past emissions. As a result, electric utilities will be the primary holders of the allowances. Since independent power producers (IPPs) will also most likely be required to have emission allowances, they will have to purchase them primarily from electric utilities. Assuming that commissions will have some control over the sale of emission allowances by utilities in their state (currently a controversial matter in Congress), PUCO may decide to 1) require utilities to sell, at a reasonable price, allowances to IPPs, 2) force IPPs to purchase allowances in markets that may develop for the purpose of buying and selling allowances, 3) force utilities to provide allowances to IPPs, or 4) auction off the state utility endowment of allowances in an auction that includes utilities and IPPs. (Presumably the IPPs would be the winning participants in a competitive bidding process for power supply.)



Issue: ASSURANCE OF CONTRACT PERFORMANCE BY WINNING BIDDERS

In addition to screening out bidders with inadequate qualification, certain financial incentives and collateral provisions usually are incorporated into a post-bidding power supply contract to guard against nonperformance or poor performance by winning bidders. For example, a commission might require a bidder to pledge a lump-sum surety bond, in a manner acceptable to the host utility, shortly after signing the power supply agreement to prevent unilateral contract termination by the bidder before making any power deliveries. Other provisions may allow the host utility to terminate a contract for nonperformance, to collect a previously agreed to amount for damages for poor or nonperformance (a liquidated damages clause), to take control of the power generation facilities, and to dispatch power from nonutility facilities.

Issue: LENGTH OF POST-BIDDING CONTRACT

For the host utility, the decision on the length of a power purchase contract is a trade-off between having more flexibility in selecting new alternatives to meet future demand and having more predictable prices and supplies of electricity. A short-term contract tends to give new technologies a greater opportunity to compete, and future favorable economic conditions (such as lower capital costs and fuel costs) can be adequately reflected in new power purchase arrangements. The benefits of a long-term contract are the assurance of power supply, predictable cost, and protection from unexpected economic events (such as an oil embargo or acid rain legislation) that can drastically increase the future price of electricity.

For a nonutility power producer, a short-term contract may require it to recoup a larger share of its capital investment over a shorter period of time than under a long-term contract. As a result, a bidder may require either a higher risk premium or a higher depreciation rate to compensate for the risk of losing the current contract only a few years after completing the power generation facility. The disadvantages of a long-term power purchase contract are the difficulty in correctly estimating future costs over an extended period and the possibility of losing an opportunity to receive higher payment for electricity in a changed market place.

One way to determine the proper length of a power supply contract is to examine power purchase arrangements entered into between utilities and the typical depreciation rate of a utility's own generation plants. A comparable contract length would allow a fair comparison between the annual capacity costs associated with the utility-owned facilities and those owned by nonutility power producers.

Issue: DEMAND-SIDE MANAGEMENT AS A RESOURCE IN THE BIDDING PROCESS

Demand-Side Management (DSM) programs can be considered as a resource in the bidding process along with various supply options. The expected power savings and cost of the DSM program can be submitted as a bid and evaluated in a manner similar to supply projects. DSM proposals can be submitted by the utility or by third parties such as firms that specialize in conservation technologies or other utilities. Some states are considering qualifying DSM projects in a similar manner to PURPA qualifying facilities with supply options. If such a program is implemented, the value of the power saving to the utility might be determined in the competitive bidding process; a process similar to what is now being used in states that use competitive bidding to determine avoided-cost rates for QFs.

A related issue is whether the utility should finance or pay rebate to demand-side management (DSM), energy efficiency, and conservation programs?

A utility can choose from two alternatives. The first is to give appropriate rate incentives or relief for DSM, energy efficiency and conservation programs. The second is to undertake the installation and the execution of such programs. The two alternatives have different economic consequences.

Another concern is whether the utility should pay avoided cost for KWh reductions bid or the difference between the marginal cost and price?

Additional Reading: Larry E. Ruff, "Least Cost Planning and Demand-Side Management: Six Common Fallacies and One Simple Truth", Public Utilities Fortnightly, April 28, 1988.

Issue: DEMAND-SIDE MANAGEMENT BID SELECTION

Is there an optimal mix selection for DSM bids? Should all the bids that save more than a certain sum per KWh be accepted?

To elaborate this further, if there are two bidders each attempting to save 4 MW, one may want \$20 per MW and the other \$30 per MW. Let the avoided marginal cost minus price be \$25 per MW. Should both be accepted or only the cheapest bidder? Furthermore, if the latter of the two bidders reduced demand at the time of system peak, it may be more economical to accept the latter bid. What should be bid selection criteria?

Issue: TRANSMISSION PRICING POLICY IS UNDER FEDERAL JURISDICTION

Under the Federal Power Act section 205, the Federal Energy Regulatory Commission (FERC) has authority to set prices for transmission service in interstate commerce. Except for transmission service in Hawaii, Alaska, and certain parts of Texas (ERCOT), all transmission service is in interstate commerce because it involves the integrated interstate transmission grid. In a recent case, Florida Power and Light Co., et al., 29 FERC para. 61,140 (1984), the FERC held in a declaratory order that it has sole jurisdiction over rates for transmission services in interstate commerce and that state regulation of rates for transmission is preempted. Because the FERC has sole jurisdiction over pricing transmission service, any policy that the PUCO develops on transmission access and the role of transmission service in an integrated resource plan will be heavily influenced by federal policy. It is therefore important for the PUCO to take the FERC's policies into account. Current FERC policy prices transmission service at its embedded costs, with shared savings available for short-term transactions. The FERC has recently commissioned a staff task force to reexamine its pricing policies, particularly for short-term transmission service. Flexible pricing up to a long-run incremental cost price cap is under discussion.

Additional Reading: Federal Energy Regulatory Commission, The Transmission Task Force's Report to the Commission (Washington, D.C.: FERC, 1989).

Robert E. Burns, "Legal Impediments to Power Transfers," Non-Technical Impediments to Power Transfers (Columbus, Ohio: NRRI, 1987).

Issue: TRANSMISSION ACCESS POLICY UNDER STATE OR FEDERAL JURISDICTION

Under sections 203 and 204 of the Public Utility Regulatory Policies Act (PURPA), the FERC has limited authority to order wheeling of power. But because difficult statutory requirements must be met, the FERC's authority to order wheeling and bulk power transfers is for all practical purposes ineffectual.

Many state commissions have asserted that they have the authority to require a utility to wheel power. However, a state commission's authority is limited by the Commerce Clause. Also, their authority to order wheeling is uncertain because of the possible federal preemption. Because of Commerce Clause concerns, a state commission probably could not order wheeling if the buyer, seller, and utility all were not located in one state. Otherwise, the state commission order might represent an excessive burden on interstate commerce. Further, if the wheeling or bulk power transfer order were to adversely affect the reliability of an out-of-state utility, the order would probably violate the Commerce Clause. Because the issue of federal preemption of a state's authority to require transmission access, wheeling, or bulk power transfers has not yet been argued before the FERC or the federal courts, there is still uncertainty as to whether state commission authority is subject to preemption. Thus far, the FERC has been willing to avoid the issue of state commissions ordering access to transmission service. However, recent proposals by the FERC Task Force concerning FERC use of its "conditioning" authority to encourage utilities to provide transmission service may indicate a new willingness by the FERC to preempt the states by totally occupying the field.

The jurisdictional issue concerning whether states can order access to transmission facilities and services is important to integrated resource planning. Without such authority, utilities could refuse to deal with independent power producers, provide transmission service, or take other actions which might frustrate the implementation of an integrated resource plan.

Additional Reading: Robert E. Burns, "Legal Impediments to Power Transfers," Non-Technical Impediments to Power Transfers (Columbus, Ohio: NRRI, 1987).

Issue: FERC'S CONDITIONING AUTHORITY ON TRANSMISSION PRICING

In The Transmission Task Force's Report to the Commission, the FERC Task Force suggested that the FERC consider using its conditioning authority to require utilities to provide adequate long-term transmission service to all customers seeking it. In return, the FERC would allow utilities that voluntarily provide transmission service to engage in flexible pricing for short-term transactions. The proposed price cap on the flexible rates would prevent rates from exceeding long-run incremental costs. If a utility lacked sufficient transmission line capacity for long-term transmission service requested by third parties, the FERC would require that the utility's short-term coordination sales be curtailed to allow for the long-term transmission requests. Such a curtailment would raise costs to retail customers, who usually benefit from coordination sales.

The FERC policy under consideration would affect Ohio's integrated resource planning by making power purchased through short-term coordination sales a less attractive resource option. It also might increase the load on existing transmission lines so that upgrading transmission line capacity or constructing new lines might be needed.

Issue: TRANSMISSION NEEDS FOR NONUTILITY GENERATORS

The transmission needs of nonutility generators, particularly independent power producers, are addressed in the FERC Transmission Task Force report.\* The report states that

[f]irst and foremost, a competitive market will be severely hampered if suppliers have only a single option of where to sell their power. The market power of the host utility is mitigated to some extent by the IPP's initial choice of where to locate the power plant. In the absence of transmission service, however, an IPP may be concerned about the lack of alternative buyers should future circumstances upset the original power supply contract or when the contract runs out (p. 57).

Thus, there are two reasons for transmission access and pricing policies that address the needs of independent suppliers. First, to foster a competitive generation market in a given service area, independent suppliers must be assured future access to other markets. The transmission lines that carry the power may or may not be owned by the utility they sell the power to, either initially or in the future. Assurance is required from a coherent transmission policy that IPPs and others can rely on for present and future generation transactions. Second, to mitigate future market power of the "transmission monopolist" that would most likely be used against an IPP dependent on the transmission-owning utility. This may occur in the form of monopolistic pricing (that is, extracting economic rent from the IPP) for transmission service, or denying access to transmission facilities.

Transmission policy options available to state commissions stem from the control they have over the siting of new transmission facilities and the earnings of transmission-owning utilities within a commission's jurisdiction. Access and pricing of interstate wholesale transactions, of course, are regulated by FERC, whose policies on these issues are still being formulated.

\* The Transmission Task Force's Report to the Commission, Electricity Transmission: Realities, Theory and Policy Alternatives, Federal Energy Regulatory Commission, October 1989.



Issue: TRANSMISSION PRICING FOR NONUTILITY GENERATORS

Pricing transmission services has a significant impact on the decisions that generators make with regard to fuel choice and use, technology choice, and facility siting. Generators include PURPA qualifying facilities, independent power producers, and transmission dependent electric utilities. Of importance in encouraging economic efficiency in emerging competitive generation markets is sending correct price signals to current and future generators. Also, transmission-owning utilities base their decisions for future transmission capacity additions on the price they will be able to charge for services.

Another important aspect to pricing transmission services is whether new users of transmission facilities, including transmission dependent utilities, should be charged incremental cost, while retail customers of the transmission-owning utility are charged embedded cost. If so, after a transmission-dependent utility has been using the facility for as long as some retail customers, should they continue to pay incremental cost-based rates? IPPs and QFs most likely will be subject to this same treatment. Some have charged that this would be discriminatory.

Future transmission pricing policy, therefore, must balance the risk to retail customers, avoid price discrimination against new users of the transmission facilities, and send correct economic signals to current and future operators of generation facilities.

Issue: RESALE OF TRANSMISSION CAPACITY

Transmission-owning utilities have argued that they can provide transmission services from a source to a user or another utility. But allowing third-party sales cannot be done without jeopardizing system reliability. For this reason these utilities will not permit contract provisions for resale of transmission capacity. The FERC Transmission Task Force\* pointed out that allowing resale may be another way to mitigate the market power of a transmission monopolist (in addition to independent supplier access to other markets for their power, see TRANSMISSION NEEDS FOR NONUTILITY GENERATORS above). Also, like efficient pricing, reselling transmission capacity can promote efficiency in the generation sector.

The FERC's Transmission Task Force report, however, points out a paradox within the secondary market for transmission capacity. A perfect secondary market would completely mitigate the transmission-owning utility's market power over short-term transmission service with little or no inefficiency in the generation market. As the secondary market became more imperfect the transmission monopolist's ability to price discriminate would increase and lead to more inefficiency in generation. No secondary market, however, allows the transmission monopolist perfect price discrimination leading to generation efficiency again, as in the case of perfect secondary markets.

FERC suggests that the most effective transmission policy to mitigate the market power of a transmission monopolist and encourage an efficient and competitive generation market would combine several policy instruments that would 1) promote an as close to perfect secondary market as possible, 2) require mandatory access, and 3) allow flexible prices for short-term interruptible transmission sales. To be most effective these policies would require a combination of actions from both FERC and state commissions. It currently may not be within PUCO's authority unilaterally to require resale of transmission capacity.

\* The Transmission Task Force's Report to the Commission, Electricity Transmission: Realities, Theory and Policy Alternatives, Federal Energy Regulatory Commission, October 1989.

ISSUE: RELIABILITY & TRANSMISSION ACCESS

What reporting should the regulatory agencies stipulate in regard to the reliability impacts by IPPs, and QFs?

It is opined that the dispatchability and operational flexibility of nonutility generation could impact the reliability of the system to a great extent. How does the regulator measure such impacts on a continuing basis? What data reporting system would be required?

## The National Regulatory Research Institute

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Date: January 17, 1990  
To: Bob Burns  
From: Kevin Kelly *K.K.*  
Subject: Transmission Issues for PUCO

Bob, in addition to the technical and pricing issues that Dr. Rau and Dr. Rose are writing about for the PUCO, I want to add my own thoughts about transmission issues. The most efficient (for me) and least cost (for PUCO) way to do this is to send PUCO a copy of a paper that I have already written on this subject. This paper is based on a presentation I made to two NARUC Staff Subcommittees, Electricity and Economics & Finance. While it does not follow the format of the other issue papers, it has the content you want. More importantly, it serves the purpose of preparing PUCO staff for our face-to-face discussions. Perhaps you would want to send this memo by way of explanation.

Let me give you an overview of the paper. As we identified in our *Non-technical Impediments* report, the three most important economic issues in the transmission debate are access, pricing, and siting. Dr. Rose (with you) is covering these in the papers being prepared for the PUCO. Also, there is the issue of engineering reliability that Dr. Rau is covering, and there are the important federal/state authority questions that you are covering. The attached paper acknowledges the primary importance of these issues and explains each briefly, but focuses on the secondary issues that arise from the interactions among these primary issues. These secondary issues may not be treated by the other NRRI analysts, and I want to use this memo to put these issues "on the table."

Before continuing, I should explain that to me the "access issue" is not a single issue but three distinct issues: supplier access, requirements customer access, and retail customer access. These are described in the first few pages of the paper.

Now look at page 7. The diagram there shows seven circles, one for each of the primary issues. The lines connecting the circles are the secondary issues. There are fourteen of these, each labeled with a simple name. All this will seem unduly complicated at first. But the transmission policy debate is complicated just because it does not concern a single issue; rather, it concerns a bunch of interconnected issues. It is this interconnectedness that the paper is intended to show.

An outline of these secondary issues follows. They are grouped according to where they are in the diagram.

#### ECONOMIC ISSUES

INCENTIVES - how pricing affects transmission capacity expansion

EFFICIENCY - relation of pricing and obligation to serve

EQUITY - when is a utility not a utility?

COALITIONS - when is a nonutility a utility?

#### ENGINEERING ISSUES

ADEQUACY - capacity expansion for reliability

RESERVE MARGIN - transmission reserves may decrease

COOPERATION - AT&T and MCI don't have to use the same network

CONTROL - who follows variations in load?

COORDINATION - how many independent users can get on the grid?

#### REGULATORY ISSUES

INTERUTILITY CONSTRUCTION - who approves multistate lines?

GENERATION PRICING - guarding against anticompetitive rates

BRIGHT LINE - authority may shift from PUCO to FERC

STRANDED PLANT - who is left holding the bag?

FRANCHISES - what's a franchise worth these days?

# WHY ELECTRIC TRANSMISSION QUESTIONS ARE SO HARD TO ANSWER

by  
Kevin Kelly  
Associate Director  
The National Regulatory Research Institute

The nation has been struggling 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 struggle is partly due to the complexity of the technology. But we are struggling also because many interrelated policy questions, which may need to be answered together, are being considered piecemeal.

In this paper, I review the main policy questions very briefly because these have been more than adequately discussed elsewhere by me and many others. My main purpose here 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.<sup>1</sup>

## 1. Transmission Policy Questions

The key questions in the national debate on electricity transmission policy involve access, pricing, and siting.<sup>2</sup> The central question concerns

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<sup>1</sup> This paper is based on a presentation made by the author to the NARUC Staff Subcommittees on Economics & Finance and Electricity at the NARUC Summer Meeting in San Diego, July 1988.

<sup>2</sup> These three questions were identified as key in an NRRI report: see Kevin Kelly, ed., *Nontechnical Impediments to Power Transfers* (Columbus: NRRI-87-8, September 1987). In addition, these three questions were the subject of the NARUC Transmission Conference held in Washington, D.C., June 1988.

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.

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 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 able to compete with utilities as electric power suppliers. Many 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.

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 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. It is 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 quasi-retail customer status to independent utility status?

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 U. S. 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.

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;<sup>3</sup> 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.

A distinct but important transmission policy question concerns the growth of the nation's transmission system, particularly the siting and certification of new lines. Most transmission lines have been built historically to ensure service reliability and to minimize generation capacity needs. Now, demands are growing for new lines to enhance trading opportunities.

Many electric utilities are experiencing great difficulty in acquiring rights of way for new transmission lines. This is particularly true for long multistate lines, where the benefits of transmission are obtained at the sending and receiving ends of the lines but the siting difficulties and the 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 need for planning, locating, and constructing new lines expeditiously? Who ultimately decides if new transmission lines are needed and where they go?

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<sup>3</sup> Regulators can 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.

## 2. Engineering and Jurisdictional Questions

Access, pricing, and siting are key policy questions, but not the only important questions that affect the transmission policy debate. Two others are the electric system reliability question and the question of the appropriate balance of federal and state regulatory authority over electric systems.

The question most often asked by utility engineers 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 heavily interconnected with one another and require careful planning and coordination for reliable operation. Decreasing reliability means more frequent brownouts and blackouts, perhaps over large geographic areas.

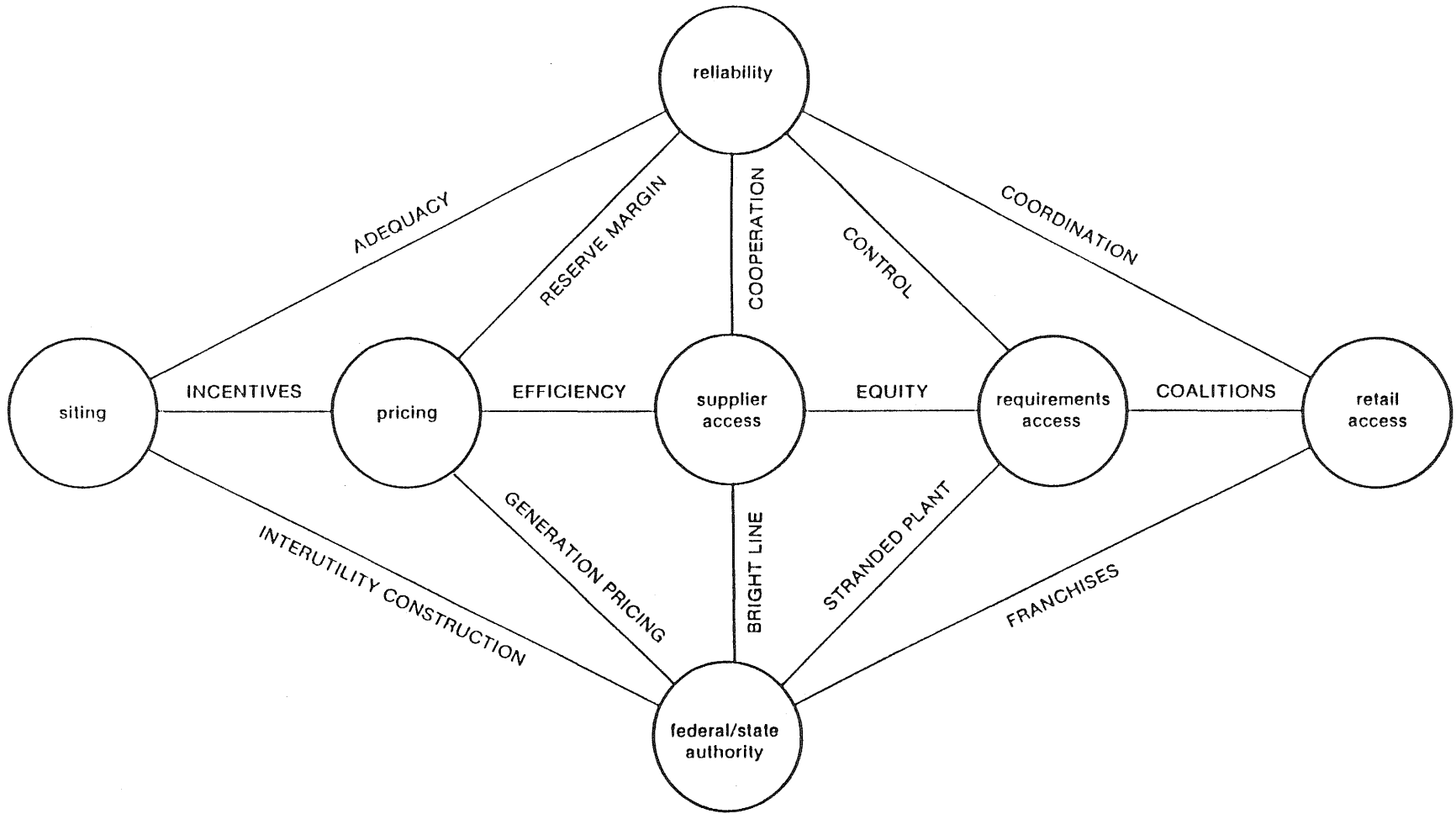
The final policy question is the appropriate balance between federal and state regulatory authorities over electric utilities generally, and over transmission networks in particular. States have authority over generation and transmission facility need and siting, the obligation to serve retail customers, 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.

### 3. Relationships among Policy Questions

With so many policy questions, it can become difficult to sort them out and to see how they are related. The accompanying diagram may help. The principal objective of this paper 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 the authority question--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 set without considering the effects of pricing policy, the goals of the siting policy may not be achieved and may even be thwarted. Setting pricing policy in isolation can also yield poor results if the relation of pricing to other policies is ignored.

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, therefore, represents an issue. The figure illustrates fourteen such issues and, to facilitate discussion, each issue is labeled with a simple name. The



four issues (Incentives, Efficiency, Equity, and Coalitions) on the main horizontal axis of the diagram are economic issues, relating 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.

#### 4. Economic Issues

Four economic issues arise from the interplay between the five key economic questions. 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 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 is then not used, costs may not be recovered after all or may be recovered from the wrong people. Risk 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.

Why would a utility try hard to build a line just to recoup a fraction of its costs? Yet, this is the case 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 when competition for transmission service exists 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.

Mandatory access at cost-based rates is the traditional U.S. 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.

## *Equity*

The equity issue links the supplier access and requirements access questions. Some would 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, however. 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 argue 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 at 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 they 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.<sup>4</sup>

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

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<sup>4</sup> See the Wisconsin Wheeling and Stauffer Chemical case studies in *Nontechnical Impediments to Power Transfers*, op.cit.

## 5. 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. 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 lines are in effect kept on standby because it costs less to construct standby transmission than to construct 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 magnetic fields exacerbate the problem.

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 U.S. electric system is too reliable and too high priced.<sup>5</sup> 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 one.)

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. If economic pricing forces systems to operate "on the margin", more brownouts and blackouts may be expected.

U.S. 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 pay lip service to maintaining reliability as a constraint on policy options. But if reliability turns out in fact to be

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<sup>5</sup> See, for example, A. Kaufman, L. T. Crane, B. Daly, *Are Electric Utilities Gold Plated?* (Washington: U.S. Library of Congress, Congressional Research Service, April 1979).

uneconomically high, a direct conflict would emerge between reliability policy and pricing policy.

### *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. For one insight about how competition can eliminate cooperation, see "Spying on Competitors," *Electrical World*, November 1988.

Reliability councils are groups of cooperating utilities. They are a forum for centralized 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?

#### *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 200 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 U.S., 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 not realistic to expect the outside supplier to follow the moment-to-moment variations in the 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 3400. 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 become independent users of the transmission system. Many small buyers may each 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 the case that these can be developed so that retail access would be technically possible. But it is unclear whether such a policy passes a cost-benefit test.

## **6. 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. These are the issues of state authority constraining federal policy regarding interstate commerce in 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. 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*

In the future, a strong tension may emerge 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 multi-state 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.



## *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 are set separately, it may be possible for utilities that can both generate and transmit power 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 is 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 gradually eroded 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 some 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 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 has 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 restricts monopoly abuse. 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 prohibitive 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 skim off the cream, 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.

### 7. Perspectives

The seven policy questions corresponding to the seven circles shown in the diagram are placed at three different levels in that drawing. The access, pricing, and siting questions are at the center level, 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 do. 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 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 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.

The 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 may at first 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. 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 four 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. The siting and retail access questions can be addressed after these five primary questions are satisfactorily answered.

Development of a consensus on transmission policy, then, requires consideration of all the questions, their interrelatedness, and the legitimacy of the various perspectives.