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IMPLEMENTING A COMPETITIVE BIDDING PROGRAM FOR ELECTRIC POWER SUPPLY

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EXECUTIVE SUMMARY

Passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) began a series of events that has shaped the current restructuring of the electric utility industry and the way the industry is regulated. While the legislation's primary intent was to conserve energy, it also had the effect of encouraging alternative sources of generation beyond the original intent. Initially, all public utility commissions required utilities to pay PURPA-qualified facilities (QFs) an administratively determined avoided-cost rate. Increasingly, however, many commissions and utilities are turning to competitive bidding to determine a rate for purchased power from either QFs, independent power producers (IPPs), or both.

An NRRI survey found that as of March 1990, competitive bidding programs operated in twenty-six states. In eight states, both the public utility commissions and the utilities had rules for competitive bidding. In the remaining eighteen states, only the utilities had developed competitive bidding programs. Solicitations had occurred in sixteen states of which only five had commission rules on the subject. Eight commissions and eleven utilities were developing rules.

The competitive bidding process has five stages: solicitation, evaluation, selection, negotiation, and contracting. Designing a competitive bidding program for power supply requires the public utility commission and/or utility to consider many interdependent elements that occur in each of these stages.

For the solicitation stage, the commission should consider who is allowed to participate. Disagreement centers on whether utilities and/or their subsidiaries should be allowed to participate. Utilities and their subsidiaries may be allowed to participate because of their considerable experience in planning, building, and operating power facilities. Utility participation in competitive bidding, however, may be inappropriate in some cases because of the danger of utility self-dealing. The host utility may misstate its power needs or avoided cost to gain an advantage in the bidding process, believing that the commission will allow the actual higher cost to be passed through to ratepayers. A utility may also give preferential treatment to a subsidiary in the evaluation, selection, negotiation, and contracting of bids. Because it is difficult for the commission to detect such treatment, some argue that the risk is too great to allow subsidiaries of the host utility to participate in their own bidding program.

With respect to the evaluation and selection of projects, the commission or utility must decide how much information about the selection process should be revealed to bidders. Most current bidding programs reveal some information. There are several advantages to a more opaque program. First, bidders are more likely to submit their best and most realistic proposals, reducing the chance that bidders will try to maximize their score inappropriately. Second, revealing little information to bidders allows the host utility some flexibility in choosing projects that a more rigid system would not allow. Third, it reduces the chance that participants will collude among themselves since they are unaware of the selection criteria used in the evaluation. The primary disadvantage of an opaque process is that it increases impossible to develop. Each state commission should develop its own bidding approach based on its own specific needs. Moreover, given the relative novelty of competitive bidding for power supply, no current bidding program can yet be called ideal.

Public utility commissions and utilities therefore must develop programs that have flexibility built into them to allow for the inevitable corrections that will be needed. The most successful bidding programs will likely be those able to adapt and learn from trial and error as well as from others' experiences.

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FOREWORD

This is a follow-on study to a 1988 NRRI report on competitive bidding for new electric capacity. The present study considers the main implementation issues of bid solicitation, evaluation, negotiation, and selection. Special attention is given to actual contracting and to the siting and certification-of-need processes and how all of this may impact industry restructuring.

Included in the study are the results of our survey of state public utility commissions and investor-owned utilities as to their current competitive bidding practices.

We believe the study will be useful both to those who are developing bidding programs and to those who have them but are considering modifications and corrections.

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CHAPTER 1

COMPETITIVE BIDDING FOR POWER SUPPLY: SETTING AND ISSUES

There is a growing consensus among regulators and electric utilities that competitive bidding is an appropriate alternative for securing future electric power supply. In many regions of the country, the debate has shifted from whether competitive bidding is an appropriate means to secure future power supply to how a competitive bidding process is best implemented. Many states have included in their least cost or integrated resource plans a provision for securing new power sources through competitive bidding rather than traditional utility construction and purchasing.[1]

To date, twenty-seven utilities have a bidding system in place and a total of thirty-eight solicitations have been issued.[2] Several utilities in particular have had extensive experience with competitive bidding over a period of several years. Competitive bidding appears to be the preferred means of acquiring new capacity for some utilities. While much of the bidding thus far has been done by other utilities or by qualified facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA), the proposed changes in the Public Utility Holding Company Act of 1935 (PUHCA) currently under consideration would significantly increase participation from independent power producers.

This report does not analyze the merit of competitive bidding as an appropriate means of acquiring least-cost generation capacity or attempt to develop

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[1] It should be noted that what is often called "competitive bidding" in the context of power supply additions is better characterized as "competitive procurement." Throughout this report, however, the term competitive bidding is used, as it is by most analysts, to refer to the developing competitive process used by states and utilities to acquire capacity or energy.

[2] National Independent Energy Producers, *Bidding for Power: The Emergence of Competitive Bidding in Electric Generation* (Washington, D.C.: National Independent Energy Producers, March 1990).

an optimal auction design.[3] The focus of this report will be to identify and discuss the various issues that state commissions and/or utilities consider when implementing a competitive bidding program for electric power supply.

This report is organized according to stages in the competitive bidding process: solicitation, evaluation, selection, negotiation, and contracting. State commissions and/or utilities face a variety of choices that must be addressed at each of these stages of the bidding process. For example, for solicitation, who can participate in the bidding; for evaluation and selection of submitted bids, price and nonprice factors to include and appropriate weighting techniques; and for negotiation and contracting, performance assurances and enforcement provisions in power supply contracts. Issues are presented in this report in a manner that will aid the design and implementation of a competitive bidding process. The pros and cons of each of these issues, examples of current competitive bidding programs, and the recommendations of others are presented and discussed.

History and Background of Competitive Bidding

The increasing use of competitive bidding is an effort to introduce competitive forces into an industry which traditionally had been protected from the rigors of a competitive market. The desired result from supplanting regulation with competition is a lower cost for generating electricity that will, be beneficial to ratepayers. It is believed, therefore, that competitive bidding provides a means to determine a utility's true avoided cost.

Before competitive bidding was used, determining the price for the power sold back to utilities from nonutility power producers (mostly PURPA-qualified facilities--

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3 For a discussion of these points see, Lawrence Berkeley Laboratory, *Designing PURPA Power Purchase Auctions: Theory and Practice*, 1987; Daniel Duann, Robert E. Burns, Douglas N. Jones, and Mark Eifert, *Competitive Bidding for Electric Generating Capacity: Applications and Implementation* (Columbus, OH: The National Regulatory Research Institute, 1988). An excerpt of the LBL report by Rothkopf et al. is in *Competition in Electricity: New Markets & New Structures*, eds. James L. Plummer and Susan Troppmann, (Arlington, VA: Public Utilities Reports, Inc. and Palo Alto, CA: QED Research, Inc., 1990.)

QFs) was usually determined by an administrated avoided cost rate.[4] This method, in general, functioned reasonably well and many states, particularly those which do not anticipate capacity additions in the near future, still calculate avoided cost rates in this manner for QF power. However, with an increasing share of the power being generated by nonutility sources in many regions of the country and a need for additional capacity, utilities and commissions are increasingly turning to competitive bidding to determine the price for purchased power and secure new capacity.

The Maine Public Utilities Commission in 1984 became the first state commission to allow utilities to conduct a competitive bid for power supply. Central Maine Power, shortly after the Commission's action, conducted the first solicitation. Several other state commissions and utilities adopted procedures shortly thereafter. In March 1988, FERC issued its *Notice of Proposed Rulemaking: Regulations Governing Bidding Programs* (RM88-5-000). This Notice of Proposed Rulemaking (NOPR) was intended to develop guidelines for the states to follow while allowing states considerable flexibility in instituting a bidding program. No implementing action has been taken by FERC since this NOPR was issued. Most observers believe the changeover of FERC commissioners and the lack of need (since states have been acting on their own) have rendered the NOPR unnecessary. (There were two other FERC NOPRs issued at about the same time that appear to have met the same fate.) Since then, state commissions and, if allowed, utilities have taken the lead in designing, initiating, and conducting competitive bidding.

Competitive bidding is seen by some as a means to choose among potential power suppliers and to insert into the procurement of power supply competitive forces where previously there had been none.[5] This is based on the belief that the electric utility is given little or no incentive to minimize its cost of production by the traditional regulatory process. The competitive pressure of the marketplace, it is believed, will result in lower production cost, either from alternative suppliers or the utility. It should be recognized, however, that competitive bidding for power supply, as it is currently practiced, in most cases is conducted as a tightly

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4 This met PURPA and Federal Energy Regulatory Commission (FERC) requirements. Often, there would be negotiation between the host utility and power generators where the administrated avoided cost rate was used as a starting point.

5 Competitive bidding is also seen by some utilities as a means to avoid new rate-based construction.

controlled process (by the PUC, host utility, or both) that bears little resemblance to a free and unfettered market. Competitive bidding continues alongside a price regulated industry, and is not necessarily going to lead to deregulation of the industry. Some, however, see it as part of a "bottom up" structural change for the industry characterized by increasing competition.[6]

Changing Structure of the Electric Utility Industry

The electric utility industry structure was relatively stable from the 1920s through the early 1970s. Rising energy cost, in the 1970s, however, prompted Congress to pass the Public Utility Regulatory Policies Act (PURPA) in 1978. The primary intent of the act was to conserve fuel and encourage the use of renewable energy sources. PURPA encouraged cogeneration and small power production by guaranteeing firms and developers interconnection with their host utility along with an administrated avoided cost. While industrial self generation (both cogeneration and single purpose facilities) has been in use as long as central station power production, PURPA renewed interest and development of nonutility power production.

By the early 1980s the electric utility industry had been altered only slightly from its traditional structure, as shown in figure 1-1. The only significant change was the addition of a new entity, the small power producer (SPP). Customer self generation, primarily from industrial plants, had fallen to about 3 percent of total electricity production from all sources just after PURPA was enacted from almost 60 percent just after the turn of the century.[7]

Until recently, QFs and others received payment for power sold to the utility through administratively set rates. These rates were based on the utility's avoided cost as specified by PURPA or agreed on by the QF and electric utility.

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6 See, for example, James Plummer and Susan Troppmann, eds., *Competition in Electricity*.

7 Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry, 1986* (Washington, D.C.: Edison Electric Institute, 1987) and U.S. Department of Commerce, *Bureau of the Census: Historical Statistics of the United States, Colonial Times to 1970* (Washington, D.C.: U.S. Government Printing Office, 1976).

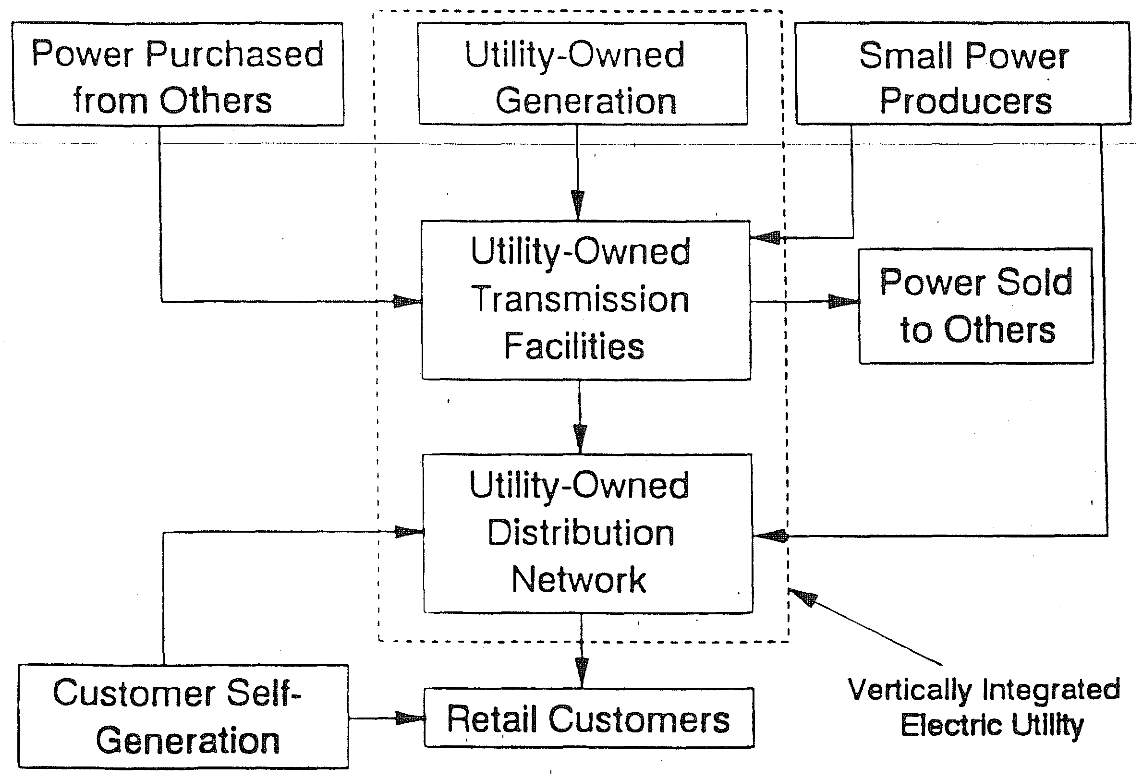

Fig. 1-1. Post-PURPA/prebidding electric utility industry structure.

In figure 1-1 the solid lines in the flow chart represent the actual flow of electricity. The three rectangles within the dashed-line rectangle represent a typical vertically integrated electric utility. In many cases the utility generates most of its own power needs and purchase some power from other utilities, SPPs, and customer self-generation. The amount of power purchased from others was usually a small proportion of the total amount produced for the utility's service territory.

Recent state and federal regulatory changes have altered the industry's structure to what is depicted in figure 1-2. Several states have begun to allow firms that are separate from the host utility, either affiliated or unaffiliated, to

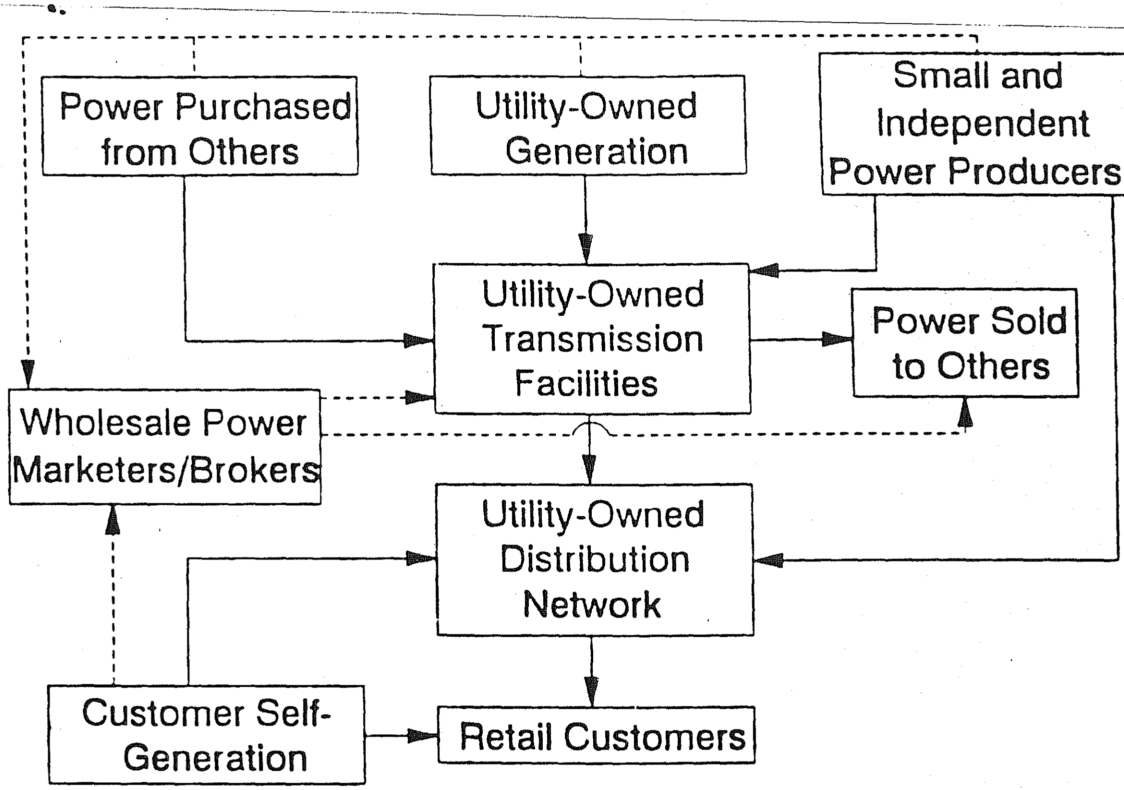

Fig. 1-2. Present electric utility industry structure.

supply power to the utility. These firms, or independent power producers (IPPs), are single purpose facilities that are usually not PURPA qualified facilities. They are similar, therefore, to small power producers but without the PURPA restrictions of energy source and plant size.

Figure 1-2 also depicts the wholesale power marketer/broker. This is a firm that arranges transactions between utilities and other utilities or IPPs and is unaffiliated with an electric utility. In principle, the marketer/broker can also arrange a sale between customer self-generators and a utility. To date there are only a few firms operating with FERC approval as marketers/brokers and only one is allowed to take title to the power being transferred. The dashed lines in figure 1-2 represent the possible contract links between buyers and sellers that the marketer/broker can arrange. The actual power flows are still represented by the solid black lines using utility-owned transmission and distribution networks. Note that electric utilities are becoming facilitators of power transfers to and from others while still providing power for their service territories. Increasing volumes of power are being bought and sold through the transmission grid[8] and are generated by nonutility power producers. The transmission link is a critical component of the emerging competitiveness of the industry since it increases the possible sources of (lower cost) power. Currently, however, access to transmission facilities is still strictly voluntary and will remain so barring action from FERC and/or Congress.[9]

The future of the industry appears to be headed toward increasing amounts of power being generated by nonutility sources and transferred between utilities through the transmission grid. Utilities will most likely become increasingly segmented into the three component parts of generation, transmission, and distribution services (dubbed "gencos," "transcos," and "discos" by some industry analysts).[10]

Figure 1-3 depicts one possible future of the industry. The structure is identical to the previous figure except that there are additional dashed lines (again,

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8 Kevin Kelly, Benjamin F. Hobbs, and Mark Eifert, *Electric Transmission Access and Pricing Policies: Issues and a Game-Theoretic Evaluation* (Columbus, OH: The National Regulatory Research Institute, 1990).

9 Most observers believe that FERC lacks the authority to order access and that Congressional action is required. See Kevin Kelly, Robert E. Burns, and Kenneth Rose, *An Evaluation for NARUC of the Key Issues Raised by the FERC Transmission Task Force Report* (Columbus, OH: The National Regulatory Research Institute, 1990) for further discussion of this topic.

10 See, for example, Richard M. Montague, "GENCO, TRANSCO, DISCO--RECO? Unregulated Retailing of Electric Power," *Public Utilities Fortnightly*, 124, 6 (14 September 1989): 33-38.

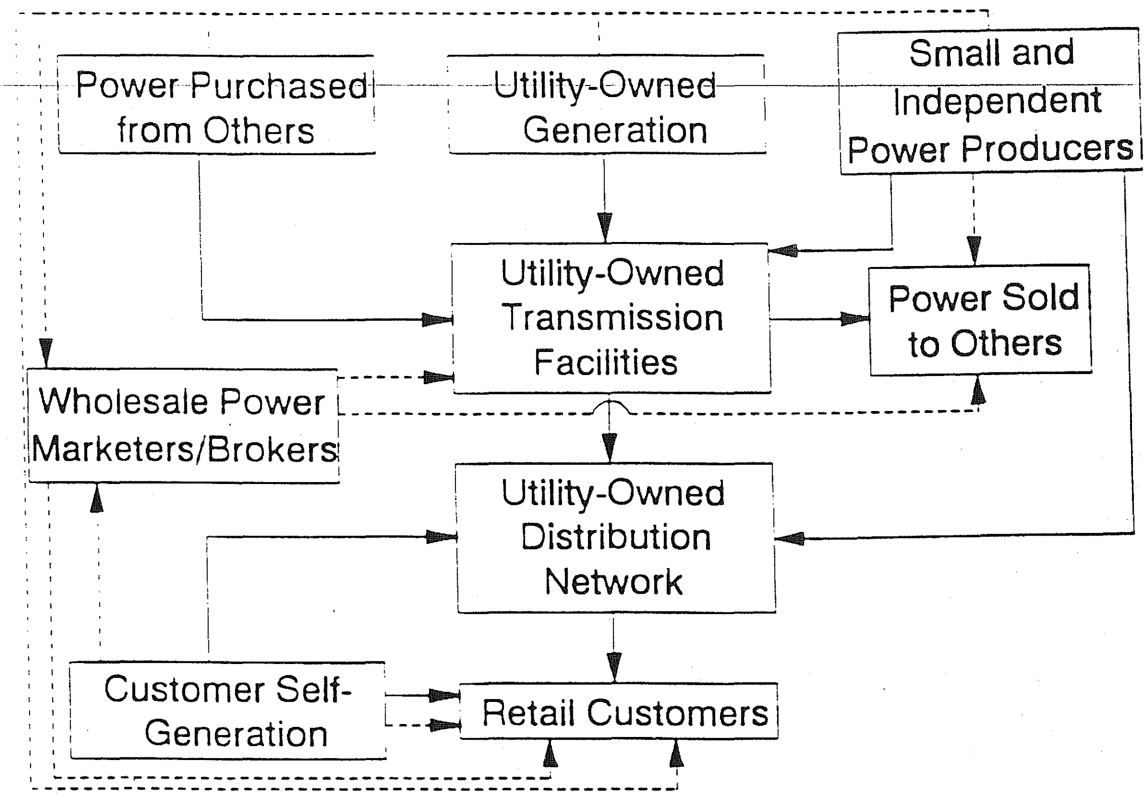

Fig. 1-3. One possible future scenario for the electric utility industry.

representing possible contract paths) depicting retail access, primarily for large commercial and industrial customers. This would allow large retail customers of the utility to purchase power from other sources through the utility's facilities. This could be arranged independently between the buying and selling parties or through marketers/brokers. It should be pointed out that many utilities and utility organizations strongly oppose retail access. However, it may be a necessary component for fostering competition in the industry at the retail level. It would provide the correct economic signal to retail customers who can choose between purchasing from the host utility, from another generating source (another utility, IPP, QF, and so on), or producing the power themselves. This would ensure their access to the lowest cost power. At the very least, it increases the options for utilities and their ratepayers.

Public Utility Commission Involvement

The level of involvement by a public utility commission is a critical issue in developing a competitive bidding program. Unfortunately there is no general consensus on the level of involvement. Factors such as the type of resources available to a utility, the need for capacity, timing of the need, and number of potential bidders all will affect a commission's involvement in the process. Also, the history of a commission's previous relations with its utilities may affect the choice; that is, states that traditionally have been more aggressively involved in the regulation of their utilities generally prefer detailed rules and procedures, while those that traditionally have taken a more laissez-faire approach may prescribe more general and less prescriptive rules. As will be discussed later, however, the extremes of both positions have limitations.

The object here is to point out the benefits and limitations of the choices that a commission or utility face when choosing their level of involvement in a competitive bidding program. For example, a completely hands-off approach risks self-dealing, that is, favorable contracts given to affiliates of the host utility or to itself. Overly restrictive rules, on the other hand, risk reducing the flexibility of the utility to respond to its resource needs or take advantage of potentially beneficial bids, perhaps unforeseen in the rulemaking. Considerable commission discretion is called for when making these choices which can only be made by the individual commissions.

The bidding regulations and general rules of implementing solicitations are usually the joint product of state regulators, utilities, consumer groups, and other interested parties. 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 mechanized 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.

In general, investor-owned utilities and some analysts[11] favor a voluntary competitive bidding program with considerable utility flexibility in the solicitation, evaluation, selection, and negotiation of contracts with bidders. In this view, the commission's role is limited to monitoring and approval of the process and to dispute resolution. An example is the Virginia State Corporation Commission's limited role in that state's competitive bidding program.

A commission has a choice between how involved it wants to become in the process and how much discretion it wants to allow the utility. At one end of the spectrum, the commission can prescribe, in detail, what the request for proposal (RFP) should contain. Connecticut and New Jersey, for example, have a self-scoring system, prescribed by each Commission, with no postbid negotiation allowed. At the other end of the spectrum, some utilities have initiated competitive bidding with no commission involvement. Based on NRRI's 1990 survey of PUCs and IOUs (see appendix A), Florida, Indiana, Iowa, Minnesota, Nevada, New Hampshire, North Carolina, North Dakota, South Dakota, and Vermont are states where a utility has conducted a bid without that state's commission adopting rules or procedures for bidding.

Utility Responsibility

There is a concern that if the commission is overly prescriptive in the development and implementation of the competitive bidding process, the utility will no longer be accountable for its actions. For this reason, the commission may choose to limit its role to one or more of the following: (1) prescribing an overall framework for bidding, (2) reviewing the utility developed procedure for solicitation (including the RFP and allowed participants), (3) choosing criteria for the evaluation and selection process, and/or (4) overseeing the negotiating and contracting process. If the commission becomes too involved in the process (perhaps choosing to become involved in all four of the above options), then it may no longer be independent of the decisions made. To avoid this, utilities might be given some flexibility and then

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11 See, for example, Richard P. Rozek and Lori L. Nordgulen, "The Importance of Flexibility in Competitive Resource Procurement," *The Electricity Journal* 3, 5 (June 1990): 48-59.

be held accountable for their decisions; in this case the utility, and not the commission, would make the critical decisions in the process.

Nonutility generators (NUGs), however, believe that if the utility is held responsible for an unsatisfactory decision (at least in the commission's view) and the NUG's contract is subject to possible disallowance in a prudence review, then financing could be difficult or impossible. For this reason some argue for the commission to certify the process and selection made by the utility and reduce the uncertainties associated with the NUG's revenues. In addition, this uncertainty has an impact on the host utility's own financial condition which is constantly being appraised by investors.[12]

This balance of utility responsibility on the one hand and commission assurances to NUGs on the other underscores the importance of commission involvement and the possible consequences of a decision.

Voluntary versus Mandatory Bidding

There are three basic positions that the commission can take on the issues of voluntary versus mandatory bidding: (1) the process could be voluntary, (2) the commission could require competitive bidding when the utility requires any significant increase in capacity, or (3) the commission could take a voluntary approach with a regulatory or economic incentive to conduct competitive bidding.

Voluntary Bidding

Those who support voluntary bidding cite the fact that the utility knows its resource needs best and will implement a competitive bidding process when most appropriate, while mandatory bidding would prevent the utility from exercising prudent management discretion.

Critics point out that given complete control over when to have bidding, a utility may choose not to bid at all since it receives no incentive for bidding from (most) current ratemaking processes. When the utility builds a plant that is allowed in its rate base, the utility expects to earn a return on that investment. With a

12 "Moody's Sets Guides to Weigh Credit Risks of Utility Power Purchases," *Inside F.E.R.C.* (20 August 1990): 7.

nonutility generator, however, the cost incurred to purchase the power is treated as an expense rather than an investment and passed through to ratepayers (ignoring any regulatory lag in adjusting rates). Therefore, the utility has little incentive to conduct a bidding program voluntarily. However, in some cases the rate of return that a utility may expect to earn on its new plant may be less than its cost of capital. Only in those cases, utilities would be more supportive of purchasing power from nonutility generators.

Mandatory Bidding

The solution to possible utility reluctance, as some view it, is to require utilities to conduct a competitive bid for any significant increases in capacity. Supporters of this position believe that forcing utilities to conduct competitive bidding for all significant capacity additions will provide a "market test" to determine the lowest cost producer(s).

The arguments against mandatory bidding are basically the same as those for voluntary bidding mentioned above.

Voluntary Bidding with a Regulatory and/or Economic Incentive

Five alternatives are presented below that mitigate some of the limitations and capture some of the above-mentioned advantages of both voluntary and mandatory bidding. These alternatives are primarily designed to provide a utility with an incentive to conduct competitive bidding voluntarily.

First, the commission can provide a regulatory incentive for the utility to conduct bidding. Such a regulatory incentive can take a variety of forms. One is for the commission to have a policy that capacity additions acquired from a bidding procedure that meets commission guidelines are presumed to be prudent. (Note that this also solves the problem NUGs have with financing mentioned above.) Capacity additions that are arrived at by some other mechanism would not have such a presumption of prudence in their favor. Unless a capacity addition was the result of competitive bidding, the utility would have to demonstrate why its decision to acquire this capacity was consistent with its obligation to provide customers reliable power at the lowest reasonable cost. This would be true for capacity additions that are built by the utility for rate base inclusion or for capacity additions that are negotiated with third parties outside of the bidding process. However, there should be some recognition that situations exist where bidding might not be practical, particularly if a utility is suffering from a capacity shortage that requires immediate action. In that instance, there may be no time to conduct a bidding program. Such situations, however, are likely to be rare.

A second alternative combines a regulatory incentive with an economic incentive by giving a utility a higher rate of return if it engages in a bidding process to acquire additional capacity. If competitive bidding does indeed result in lower-cost reliable capacity, then utilities choosing to engage in competitive bidding should be rewarded. On the other hand, utilities that choose not to engage in competitive bidding would receive a lower rate of return.

A third alternative is again to give the host utility an economic incentive to conduct a competitive bid. One way is for the commission to focus its attention on price rather than cost, similar to proposals for price cap regulation.[13] Under this proposal, the commission would not continue to regulate by "micromanaging" the cost that the firm incurs. This would provide an incentive for the utility to find the lowest cost solution to meeting its demand obligation. If the utility's management determines that the most appropriate and lowest cost means of acquiring future capacity is with competitive bidding, then it would choose to use competitive bidding voluntarily.

There is a potential problem associated with this approach, however. While the firm will have an incentive to minimize its cost, the price would no longer be connected with the cost actually incurred by the firm. Since profit is no longer regulated, it is difficult if not impossible for the commission to resist the inevitable pressure to restrain the profit of the firm if deemed "excessive."[14] Moreover, if profit regulation is reinstituted, then the same lack of incentive to

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13 Symposium on Price-Cap Regulation, *The RAND Journal of Economics* 20, 3 (Autumn 1989): 369-472.

14 Raymond Lawton, "Alternatives to Rate Base/Rate of Return Regulation: What Will Be the Needs of Utilities, Regulators, and Consumers?" presented at the Forum on Alternatives to Rate Base/Rate of Return Regulation, sponsored by the Public Service Commission of Michigan, 19 May 1990.

have a competitive bid returns as discussed above.[15] In addition, there is the practical difficulty of calculating a productivity index usually required by this type of regulation.

A fourth alternative approach for the commission to consider, again using economic incentives, is to base the price of electricity on the cost of power determined in a competitive bidding procedure. Rather than simply passing through the cost of purchased power, the utility is allowed to earn a profit on the sale, that is, a retail mark-up. But this is *only* available as an option if the utility chooses competitive bidding. The mark-up should not exceed the difference between the winning bid price(s) and the avoided cost of the utility. To insure that ratepayers receive some of the benefit from competitive bidding, this difference should be shared between the utility and ratepayers (for example, in an ex post sharing of benefits).

This approach has several advantages. First, the mark-up would be considerably less complicated to calculate than a productivity index associated with price cap regulation. Second, the host utility would have the discretion to choose between competitive bidding or traditional rate-based construction and an incentive to choose bidding if it is advantageous. Third, ratepayers would benefit from the lower cost of generation likely to be acquired through competitive bidding. Fourth, nonutility generators would be encouraged and able to participate in future resource decisions. Finally, this method is consistent with current FERC policy on determining wholesale prices for coordination power purchases.

One problem with this method is that the utility may have an incentive to overstate its avoided cost. This may be true especially if it is believed, as many do, that recent prudence reviews and actual or threatened disallowances have made utilities reluctant to build their own facilities. However, if it is considered likely that the utility will still prefer to build its own generation facilities, the utility, to be competitive in a bidding process with other bidders, has an incentive to reveal its true avoided cost. Moreover, the problem of the utility's lack of incentive to build its own generation facilities is a separate problem from designing a competitive bidding program and one that cannot be solved by competitive bidding.

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15 Kenneth Rose, "Regulated Utility Pricing Incentives with Price Cap Regulation: Can It Correct Rate of Return Regulation's Limitations?" presented at the Forum on Alternatives to Rate Base/Rate of Return Regulation, sponsored by the Public Service Commission of Michigan, 19 May 1990.

The fifth alternative to provide an incentive to conduct competitive bidding is to allow the utility to provide financial assistance to nonutility generators. For utilities that are "cash rich" this could be in the form of loans. An advantage to this approach is that utilities, due to their experience in this field, are likely to be good at assessing the viability and riskiness of a proposed project. Two potential problems with this type of incentive are a NUG's reluctance to provide detailed information to a competitor in possible future bids and legal barriers to utility diversification in this area or in general.

The NRRI Survey on Competitive Bidding

In February 1990, the NRRI sent a survey on competitive bidding to all state public service commissions, including the District of Columbia, and to most investor-owned electric utilities. A total of forty-nine state commissions and eighty-six utilities from forty-eight states responded. All the states had at least one respondent, and in forty-six states, both parties responded. Eighty-six utilities responded, a 60 percent response rate, with some regions more heavily represented than others. Special effort was made, however, to collect information from as many utilities with bidding programs as possible in order to strengthen the survey result. For this reason and because the survey was voluntary, it should not be considered an unbiased scientific sample, but rather a means to collect information on current competitive bidding practices.

The purpose of the survey was to collect information about the status of program development in each state and about the various solicitation, evaluation, selection, and contracting practices in use. The responses to questions on program development reflect the level of bidding activity across the nation and indicate potential growth. The responses to questions on solicitation, evaluation and selection, and negotiation practices bring forth the similarities and differences among competitive bidding programs, enabling fruitful comparisons. The responses to questions on the strengths and weaknesses of competitive bidding allow those with programs to learn from one another and provide helpful information to those planning to develop programs.

The questions about solicitation practices cover their occurrence, participant eligibility, information disclosure, and entry fee requirements. The questions about evaluation and selection practices concern the request for proposal, the relative importance of price and nonprice factors, the inclusion of demand-side offers, the responsibility of evaluation and selection, and the disclosure of final results. The questions about negotiating and contracting practices cover the approval process, payment and security provisions, operation and maintenance standards, and the legal rights of the host utility.

State Commission and Utility Development of Competitive Bid Programs: NRRI Survey Results

As of March 1990, competitive bid programs operated in twenty-six states. In eight states, both the commissions and the utilities had rules in place to govern solicitation activities. For the remaining eighteen states, only the utilities had developed competitive bid programs. So far, solicitations have occurred in sixteen states of which only five had commission rules.

Based on the survey, eight commissions and eleven utilities were developing rules which will raise the total number of states involved to thirty-four. Table 1-1 lists by state the status of program development for commissions and utilities and the occurrence of solicitations.

Although there are thirty-five commissions not currently involved with competitive bidding, the survey shows that ten were considering the development of rules or will consider them when generation capacity becomes needed. Only six commissions have considered and rejected competitive bidding primarily due to sufficient capacity and/or a preference for other approaches. Sufficient capacity was also the most cited reason for not considering competitive bidding. As a way to conveniently summarize both development and solicitation activities, figures 1-4 and 1-5 present maps of the United States delineating by state the status of development for commissions and utilities respectively. Figure 1-6 depicts the states where solicitations have occurred.

Regional Analysis of Development Activities

Most development and solicitation activity occurs in the North Atlantic region of the United States. As table 1-2 shows, five of twelve commissions and utilities operating in eight states have rules to govern solicitation activities. Currently, utility activities with competitive bidding surpass that of state commissions. In the

TABLE 1-1
THE STATUS OF COMPETITIVE BIDDING BY STATE, MARCH 1990

State	Rules in Place	Developing Rules: Have Draft	Developing Rules: No Draft	No Action	Have Conducted a Solicitation
AL				B	
AK				C	
AZ				B	
AR				B	
CA	U	C			X
CO	B			U	
CT	B				
DE			C		
DC				C	
FL	U		U	B	X
GA				B	
HI				U	
ID	U[1]		U	C	
IL			U	B	
IN	U			B	X
IA	U		U	B	X
KS			C	U	
KY				B	
LA				B	
ME	B	U			X
MD		C	U		
MA	B				X
MI			C	U	
MN	U			B	X
MS				B	
MO				B	
MT	U[1]		U	B	
NE				B	
NV	U				X

TABLE 1--Continued

State	Rules in Place	Developing Rules: Have Draft	Developing Rules: No Draft	No Action	Have Conducted a Solicitation
NH	U			C	X
NJ	B				X
NM				B	
NY	B	U			X
NC	U[2]		U	B	X
ND	U[3]			B	X
OH			C	U	
OK				B	
OR	U[1]		B		
PA	U		B	U	
RI	U[4]			C	
SC			U	B	
SD	U[3]			B	X
TN				B	
TX				B	
UT	U			C	
VT	U			C	X
VA	B			U	X
WA	B				
WV			U	B	
WI				B	
WY	U			C	

Source: Responses to the 1990 NRRI Survey on Competitive Bidding.
Note: "C" = state commission; "U" = utility; "B" = both;

1 PacifiCorp Electric Operations, based in Oregon, operates through subsidiaries in California, Idaho, Montana, Utah, Washington, and Wyoming.
2 Virginia Electric Power Company, based in Virginia, supplies some power to North Carolina and has solicited capacity.
3 Northern States Power Company, based in Minnesota, supplies some power to both North Dakota and South Dakota and has solicited capacity.
4 Narragansett Electric Company and Blackstone Valley Electric Company, both located in Rhode Island, are controlled by holding companies whose other subsidiaries have solicited capacity.

Fig. 1-4. Map of the United States showing the status of state commissions in competitive bidding as of March 1990.

Fig. 1-5. Map of the United States showing the status of utilities in competitive bidding as of March 1990.

Solicitations

Fig. 1-6. Map of the United States showing the states in which utilities either based or operating therein have held solicitations as of March 1990.

TABLE 1-2

COMMISSIONS AND UTILITIES WITH BIDDING RULES BY REGION

Handy-Whitman Regions	States in Region	States with Commission Rules	States with Utility Rules
N. Atlantic	12	5	8
S. Atlantic	9	1	2
N. Central	12	0	3
S. Central	4	0	0
Plateau	8	1	2
Pacific	3	1	3
Total	48	8	18

Source: Responses to the 1990 NRRI survey on competitive bidding.

Pacific region, for example, only one commission has final rules, yet utilities from all three states have bidding programs. The greatest disparity in activities, however, occurs in the South Atlantic and interior regions of the United States. Only two of thirty-three commissions had rules in place while utilities operating in fifteen states had competitive bid programs. Perhaps even more noteworthy, over one-half of states having had a solicitation came from these regions. In fact, almost one-third of states with a solicitation come from the North Central region alone, yet no commission there had rules in place. In the Plateau region, all the states but one had utilities with competitive bid programs, but only one commission had final rules to govern solicitation activity.

Although commissions may seem to lag behind utility activities, commission development of rules is growing. As table 1-3 shows, eight commissions are currently developing rules while another ten are considering the idea. Much of this recent activity was occurring in the South Atlantic and interior regions where involvement is thinnest. Three commissions from the North Central region are developing rules with one other considering them. Four commissions from the Plateau region and three from the South Atlantic region are currently monitoring the activities of other commissions and considering rulemaking. There is continual activity occurring in the North Atlantic and Pacific regions. When completed, eight

TABLE 1-3

THE STATUS OF COMMISSION RULEMAKING BY REGION

Handy-Whitman Regions	States in Region	With Rules	Developing Rules	Considering Rules	Total
N. Atlantic	12	5	3	2	10
S. Atlantic	9	1	0	3	4
N. Central	12	0	3	1	4
S. Central	4	0	0	0	0
Plateau	8	1	0	4	5
Pacific	3	1	2	0	3
Total	48	8	8	10	26

Source: Responses to the 1990 NRRI survey on competitive bidding.

of twelve commissions from the North Atlantic region and each commission from the Pacific region will have final rules in place. Also, two commissions from the North Atlantic region are considering rules which would bring total commission involvement in that region to ten.

CHAPTER 2

DESIGN AND SOLICITATION OF THE BIDDING PROCESS

General Design Characteristics

Based on the NRRI survey, all eighteen states with rules or drafts of rules in place use a sealed-bid format in which bids are kept secret until the solicitation period ends, usually from two to four months, although this varies. Bidders are restricted to one bid per solicitation in most states but may enter as many ongoing solicitations held by the same or different utilities as they desire. Demand-side bidders may participate in six states although they typically are evaluated separately from supply side offers, and some states may require a separate solicitation. In ten states, bidders are aware of the utility's avoided cost and selection criteria before making offers. In three states, avoided costs are made public to bidders but not the selection criteria; in three states the opposite holds. In two states, neither avoided cost nor the selection criteria is disclosed, and the only bidding rules are the utilities'. The NRRI survey serves as the primary source of information on solicitation practices by state commissions and utilities (appendix B). This is summarized by state in table 2-1.

The Request for Proposal

A critical component of the solicitation stage and of the entire competitive bidding process is the request for proposals (RFP). The RFP usually contains, among other items, a description of the power needs of the host utility, procedures for bidders to follow, eligibility requirements, descriptions of the evaluation process, and a sample or standard power supply contract. Because the RFP is the most important link between the host utility and potential bidders, great care should be exercised in developing its contents. The discussion to follow centers on the major components of an RFP and on how practices differ across states.

TABLE 2-1

SUMMARY OF SOLICITATION PRACTICES BY STATE

Solicitation Questions	CA	CO	CT	FL[u]	IN[u]	IA[u]	ME	MA	MD	MN[u]	NV[u]	NH[u]	NJ	NY	PA[u]	VT[u]	VA	WA
The need to solicit power is determined?																		
Annually								X					X					
Biennially	X		X															X
Based on capacity needs		X	X	X	X	X	X		X	X	X	X		X	X	X	X	
The state commission																		
Sets guidelines for RFP	X	X			X		X	X					X	X				
Reviews RFP		X	X	X				X	X		X		X	X	X	X	X	X
Must approve RFP		X	X	X		X		X			X		X	X	X			X
No involvement										X								
Bidding is sealed (S) or open (O)	S	S	S	S	S	S	S	S	S	S	S	S	S	S	S	S	S	S
Avoided costs are known to bidders[1]	X		X	X	X			X	X		X	X	X	X	X	X		X
The host utility can submit a bid[2]			X	X	X	X					X	X		X		X		X
Other utilities can submit bids[3]			X	X	X	X	X		X	X	X	X		X		X	X	X
Bidding is all source			X		X	X	X		X		X	X		X		X	X	X
Solicitation is for QFs only	X	X						X							X			

TABLE 2-1--Continued

Solicitation Questions	CA	CO	CT	FL[u]	IN[u]	IA[u]	ME	MA	MD	MN[u]	NV[u]	NH[u]	NJ	NY	PA[u]	VT[u]	VA	WA
A bidder can submit multiple bids[4]		X		X	X	X	X		X	X	X	X		X	X	X	X	X
Demand-side options are allowed			X			X	X						X	X				X
An entry fee or bond is required	X	X		X	X				X				X		X	X	X	
The length of solicitation period in months[5]	3	3	4	18	3	3	2	4	6		2	6	12		6	2	5	
The following details are available to the public before selecting winners[6]																		
Selection criteria	X	X	X				X	X	X			X	X	X	X	X	X	X
Price	X		X						X				X					X
Participant identities		X	X	X									X					X
All information			X															
No information					X	X				X	X							

Source: Responses to the 1990 NRRI survey on competitive bidding.

The table includes only those states in which either the commission and/or utility drafted rules. When only the utility drafted rules, the superscript "u" appears by the state abbreviation.

Note: "X" = yes; "NR" = no response. When state commission and utility responses differed, commission responses are reported.

[1] The practice varies in New York. Some utilities provide avoided cost information and some do not.
[2] Commission and utility responses differed in the following states: Connecticut, Indiana, Maine, and Massachusetts.
[3] The New Jersey Board answered "no" but both utilities responding to the survey answered "yes."
[4] Commissions in California, Connecticut, Massachusetts, and New Jersey allow multiple bids but the bids must be for different projects.
[5] The solicitation period varies in length for utilities in Minnesota, New York, and Washington.
[6] There is considerable disparity between commission and utility responses. Please see appendix B for further details.

State Commission Involvement

State commissions typically oversee in various ways the utility's efforts to write an RFP. As table 2-1 shows, commission involvement occurs in sixteen of the seventeen states in which RFPs have been designed.[1] The commissions may set guidelines to write the RFP (seven states), review drafts and recommend changes (twelve states), and require approval before issuance to the public (ten states). Most commissions combine several of these tasks to assure adequate oversight. In four states, the commissions perform all three.

The degree of oversight varies across task and commission. Writing guidelines vary from rigid and specific to flexible and general to none at all. The review process may be public and open to all parties or private and closed to all but the commission. The approval process varies from assuring the presence of certain provisions to thoroughly scrutinizing the entire RFP--see chapter 1 on commission involvement and utility flexibility.

The New York PUC, for example, performs all three tasks. The state's utilities each are required to draft an RFP. Once drafted, a public hearing open to all interested parties (including commission staff, nonutility generators, consumer groups, and other utilities) is held to review the RFP and recommend changes. The utility must then revise its RFP and submit to the commission a final version for approval.

The Maine PUC, by contrast, prefers less involvement. The commission requires utility participation and has written guidelines identifying its rules and expectations. Even so, the utility has flexibility to design and write the RFP. The commission does not review or approve the RFP prior to the solicitation.

Frequency of Bidding

The frequency of bidding depends on the utilities' need for capacity in most states. Based on the NRRI survey, fourteen of eighteen states tie bidding directly

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1 Although the utility respondent reports no direct PUC oversight, the utilities in Minnesota must show in their biennial least-cost-planning filings consistent evaluation procedures for all power purchases.

to the need for capacity while the remaining states prefer a more continuous, periodic bidding process that occurs annually or biennially.

There are several advantages to a periodic bidding process. Periodic bidding enables the utility to be more responsive to market volatility or structural changes and enables a closer parity between the utility's cost and the market cost of generation. As such, shorter-term supply offers become a viable option to utilities to stabilize and lower generation costs and maintain system reliability. Periodic bidding also makes learning more rewarding, and therefore, more likely. It becomes economical for utilities to learn ways to streamline and standardize the solicitation process to reduce risks and lower administrative costs. Likewise, it becomes economical for potential suppliers to invest and learn about the short-term and long-term needs of utilities since this information has repeated use. A periodic bid helps ensure the good contract performance of previously selected projects because their actual costs become a part of the utility's current avoidable costs. This clearly reduces risks to the utility but also to the supplier. Suppliers with uneconomic contracts could, for example, use a periodic bid to replace their original offer in a way that minimized renegotiation cost and assured a competitive price.

Commission mandated periodic bidding forces utilities to consider other sources of power. This eliminates the concern of a reluctant or disinclined utility never having a bid. Although a utility has no need for additional capacity, there may be less costly power available from nonutility sources. Periodic bidding may reveal the options available to the utility. This explicitly recognizes that the existing plant is a sunk cost, and a comparison of the existing capital cost with the possible alternatives should be made for future system planning only. Ratepayers may benefit if a nonutility generator can provide power at a lower cost than the host utility from an *existing* plant. This option also requires the utility to submit an avoided cost for comparison (discussed later in this chapter).

Although a periodic bid process has potential advantages, it has potential disadvantages too. Limiting the frequency of bid solicitations can promote inefficient long-term system planning and result in a capital-fuel mix that does not minimize generation cost. A periodic process tends to be incremental and favor small, low capital cost additions. This bias can misdirect system expansion and raise system cost in the long run by not taking advantage of economies of scale. A periodic process can increase transaction costs for power purchases even when administratively streamlined. The cost to solicit small blocks of power may outweigh the savings from selected supply offers. This, of course, occurs less often when bidding is tied directly to the capacity needs of the utility. Periodic billing may involve the same participants and can encourage collusive behavior as bidders become more familiar with each other in the course of bidding experience. Frequent bidding makes retaliatory behavior by members of a cartel a more credible threat to those contemplating cheating because detection and punishment can occur quickly.

Entry Fees

States and utilities with bidding programs often charge an entry fee to help pay processing expenses and prevent frivolous bids. The NRRI survey found that nine of eighteen states require entry fees or bonds. Fixed entry fees, however, tend to reduce participation, especially among small projects. Thus an excessively high entry fee can encourage collusive behavior by limiting participation. Also, this can cause a mismatch between the power needs of the utility and the supply offers that result. Commissions may want to guard against utilities setting unnecessarily high entry fees.

An efficient entry fee, therefore, must balance these concerns. Entry fees tied to a bid's size (its megawatts, for example) will screen out frivolous bids but not small, economic ones. Entry fees that are regressive, progressive, or proportional in design can better match supply offers and utility needs and thereby economize on evaluation expenses. A progressive fee, one that levies a higher per-megawatt charge on larger capacity offers, is useful to utilities seeking primarily replacement power to lower energy costs. Bidders with larger projects, in this case, are less inclined to participate which helps streamline the bid process. A regressive entry fee, such as a fixed entry fee, encourages larger projects which is desirable when large capacity additions are sought. Thus, a proportional entry fee, such as a dollar-per-megawatt charge, places proportional burdens upon all bids regardless of size and is more commensurate with the actual cost of evaluation.

Prequalification or Prescreening of Bidders

Another means that can prevent the host utility from incurring the expense of evaluating inappropriate or frivolous bids is a prequalification or prescreening mechanism. As with entry fees, however, the commission may want to prevent the host utility from either overtly or inadvertently making the requirements too stringent.

Prequalification requirements may include disallowing bids whose net present value of payments (factoring in an escalation component) is greater than the net present value of the projected avoided cost of the host utility; restricting the amount that payments can be front-loaded; and setting minimum and maximum contract length, minimum and maximum facilities size (MW), financial requirements, minimum site status (permits and licenses), operating standards (interruptibility and dispatchability), fuel availability, and in-service dates. Many programs also limit participation to QFs only.

Sources of Electric Power and Participation in Competitive Bidding

Several sources of nonutility power have emerged or reemerged in the last decade. The most noteworthy in the context of competitive bidding include PURPA qualifying facilities, cogenerators, small power producers, and independent power producers. The following sections describe each source to clarify their differences and discuss their participation in and contribution to competitive bidding. Much of this information appears in tables 2-2 and 2-3. A discussion on the merits of each power source to competitive bidding appears last. We begin, however, by describing in more general terms the extent of participation in competitive bidding.

Table 2-2 describes the participation of small power producers, cogenerators, and independent power producers in competitive bidding as of June 1989. It aggregates by facility type and ownership structure the number of bids and the capacity offered for all RFPs, completed RFPs, and winning projects. Table 2-3 maintains the same format but simplifies comparisons by converting the totals of table 2-2 into percentages.

TABLE 2-2

NUMBER OF PROJECTS AND CAPACITY BY FACILITY TYPE DURING BIDDING PROCESS
(Current to June 1989)

Facility Type	All Bids		Bids in Completed RFPs		Winning Projects	
	Bids	MW	Bids	MW	Bids	MW
Small Power Producers						
QF(1)	302	5,402.7	215	3,030.6	58	642.8
QF/Utility(2)	4	57.4	3	32.4	2	16.0
Total SPPs	306	5,460.1	218	3,063.0	59	658.8
Cogenerators						
QF(1)	273	16,953.2	195	12,943.4	40	2,293.3
QF/Utility(2)	37	1,510.1	25	877.1	9	535.1
Total Cogen.	310	18,463.3	220	13,820.5	49	2,828.4
Independent Power Producers						
IPPs(1)	53	8,367.8	50	7,060.5	-	-
IPPs/Utility(2)	3	688.2	2	488.2	2	488.2
IPPs-Util. Owned(3)	22	2,073.0	14	1,488.0	1	440.2
Total IPPs	78	11,129.0	66	9,036.7	3	928.4
Total-All Sources	694	35,052.4	504	25,920.2	111	4,415.6

Source: National Independent Energy Producers, *Bidding for Power: The Emergence of Competitive Bidding in Electric Generation, Working Paper Number Two*, (Washington, D.C.: National Independent Energy Producers, March 1990).

(1) No utility or utility subsidiary participation.
(2) Some type of utility and/or utility subsidiary participation. (The QF and IPP category may include projects with utility and/or subsidiary involvement since some utilities did not provide a break down by ownership.)
(3) Total ownership by utility and/or subsidiary.

TABLE 2-3

PERCENT OF TOTAL PROJECTS AND CAPACITY BY FACILITY TYPE DURING BIDDING PROCESS
(Current to June 1989)

Facility Type	All Bids		Bids in Completed RFPs		Winning Projects	
	Bids	MW	Bids	MW	Bids	MW
Small Power Producers						
QF(1)	43.5	15.4	42.7	11.7	52.3	14.6
QF/Utility(2)	0.6	0.2	0.6	0.1	0.9	0.4
Total SPPs	44.1	15.6	43.3	11.8	53.2	14.9
Cogenerators						
QF(1)	39.3	48.4	38.7	49.9	36.0	51.9
QF/Utility(2)	5.3	4.3	5.0	3.4	8.1	12.1
Total Cogen.	44.7	52.7	43.7	53.3	44.1	64.1
Independent Power Producers						
IPPs(1)	7.6	23.9	9.9	27.2	-	-
IPPs/Utility(2)	0.4	2.0	0.4	1.9	1.8	11.1
IPPs-Util. Owned(3)	3.2	5.9	2.8	5.7	0.9	10.0
Total IPPs	11.2	31.7	13.1	34.9	2.7	21.0

Source: National Independent Energy Producers, *Bidding for Power: The Emergence of Competitive Bidding in Electric Generation, Working Paper Number Two*, (Washington, D.C.: National Independent Energy Producers, March 1990).

(1) No utility or utility subsidiary participation.
(2) Some type of utility and/or utility subsidiary participation. (The QF and IPP category may include projects with utility and/or subsidiary involvement since some utilities did not provide a break down by ownership.)
(3) Total ownership by utility and/or subsidiary.

Response to Competitive Solicitations

Competitive bidding programs have elicited responses from 694 distinct projects offering more than 35,000 MW of capacity, almost the power equivalent of the Mid-Continent Area Power Pool (MAPP). As the totals from table 2-2 show, 111 projects with slightly over 4,400 MW of capacity have been selected, about 13 percent of total capacity offered. This alone suggests that nonutility generators have a strong interest in competitive bidding and the potential to supply considerable amounts of power. On average, one of six bids is awarded a final contract, a success rate of 16 percent, although the rate is somewhat higher (20 percent) for projects with utility affiliation.

The extent of participation varies across nonutility generators. As table 2-3 shows, most participation comes from small power producers and cogenerators. Together they account for 89 percent of all bids placed, 69 percent of all capacity offered, and 79 percent of all capacity selected. Independent power producers participate mostly on large projects. Although they account for only 11 percent of all bids placed and 3 percent of bids selected, they represent 32 percent of capacity offered and 21 percent of capacity selected.

Together, the groups offer utilities multiple ways to expand their power systems. Small power producers, as expected, specialize in small, incremental system needs. Their bids average 18 MWs in size with 11 MWs the average winning project. Cogenerators enable more intermediate system expansion and average 60 MWs per bid and 58 MWs per winning project. Independent power producers enable large system additions averaging 143 MWs per bid and 310 MWs per winning project.

Most state commissions and utilities recognize the benefits that occur when SPPs, IPPs, and cogenerators participate in competitive solicitations. As table 2-1 reports, eleven of eighteen states allow all-source bidding, and in only four states is participation restricted to PURPA QFs only.

PURPA Qualified Facilities

PURPA and FERC rules provide qualifications of some facilities for special regulatory treatment--qualified cogenerators and small power producers. This includes a guarantee that a QF be allowed to: 1) interconnect and operate in parallel with an electric utility, 2) sell power to the utility and receive supplemental, backup, maintenance, and interruptible power, and 3) receive nondiscriminatory prices for both purchased power and for power sold to the utility. All qualified facilities are either cogenerators or small power producers.

Some competitive bidding programs in the country initially were intended to determine an avoided cost rate for QFs, and several states only allow QFs to bid (see table 2-1). Often in such cases, QFs with the lowest costs are selected and the remaining QFs receive only an avoided energy rate, thus fulfilling the utility's obligations to a QF under PURPA. This replaces the administratively determined method of avoided-cost rate calculation.

PURPA does not state whether a competitive bidding process is permitted to determine an avoided cost rate for QFs, and FERC rules do not prevent the possibility of QFs and nonQFs competing in a competitive bid.

Several state programs exempt small QFs from the bidding process. This is because the cost of preparing a bid may impose an excessive economic burden on small QFs. This is also done to comply with the PURPA requirement of encouraging economic QFs. With such an exemption made for small QFs, the winning price (highest, lowest, or average of winning bids if there is more than one winner) determined in the bidding process can be used to determine the avoided energy payment given to exempt QFs. Paying both a capacity and energy rate to a QF may, if paid without regard to other factors, overvalue the QF's capacity and not represent the utility's avoided cost, as PURPA requires.

A small QF, of course, would be eligible to participate in the bidding to receive capacity payments if it chooses. The small QF that participates in a bid and is not selected still would have the option of receiving the energy payment. In this case capacity payments are only available to the bidding participants. This satisfies the twin PURPA goals of encouraging QF resources while not burdening the host utility's ratepayers.

The state commission would have to define what a "small" QF is. State practices used in setting administrative avoided cost rates for QFs prescribe standard rates for QFs at or below a certain threshold size. Depending on the state, this threshold size can range from 500 kilowatts to 5 megawatts. To be consistent with prior practice, state commissions might set a threshold size within the same range.

Cogenerators

Cogeneration is a self-generating process that simultaneously produces useful thermal energy (steam or heat) and electricity from a single fuel source used by either a commercial or industrial firm. Electricity produced by the plant is used to supplant purchased electricity. If an excess of electricity is produced, it may be sold to an electric utility. Not all cogenerators are qualified facilities; a utility may agree to interconnect with a facility without QF status. To receive FERC qualification and PURPA benefits, a cogenerator must meet specific operating and ownership requirements.

Cogenerators are the largest participatory group in competitive bidding based on the number of bids submitted and the amount of capacity offered and selected. About 53 percent of the capacity offered and about 64 percent selected comes from cogenerators. As table 2-2 shows, most cogeneration projects (88 percent) have no ownership affiliation with the host utility, although affiliated cogenerators do rather well in the selection process. For cogenerators as a whole, only 8 percent of the capacity offered but 19 percent of the capacity selected came from affiliated projects (see table 2-2).

Self-generation is a general term now used to describe stand-alone single-purpose generation facilities and cogeneration used by retail customers (usually commercial and industrial). In-plant electricity generation by industrial firms has been used since the 1880s. Self-generators may or may not be QFs or sell power to an electric utility.

Small Power Producers (SPPs)

An SPP is a single-purpose facility, defined by PURPA, that is required to be no more than either 30 or 80 megawatts, depending on energy source, and use a renewable energy source (that is, biomass, waste, renewable resource, or geothermal). However, this megawatt capacity cap has been temporarily lifted for certain eligible solar, wind, waste, or geothermal facilities.[2]

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2 PURPA section 210(e)(2) and FPA section 3(17)(E), as amended by P.L. 101-575, November 15, 1990.

Although small power producers account for 44 percent and 53 percent of the bids submitted and selected, they account for only 15 percent of the capacity selected (see table 2-2). Almost all small power producer projects are unaffiliated--about 99 percent. Because so few projects are affiliated, the effects of affiliation on selection remain vague.

Independent Power Producers (IPPs)

An IPP is a single-purpose facility that is not a QF. IPPs can be, depending on state laws, affiliated with the host utility or another utility, or can be completely independent. Currently there are only a few IPPs in the country (table 2-2). However, if proposed changes to the Public Utility Holding Company Act of 1935 (PUHCA) are approved by Congress, then the number of IPPs (called exempt wholesale generators--EWGs--in one proposed bill) might increase significantly. Currently there are no provisions in federal utility law explicitly governing IPPs. State commissions, thus far, have generally not regulated IPPs as utilities and have encouraged them to enter into contracts with utilities if they are winning bidders in a state-supervised bidding program.

Independent power producers accounted for 11 percent and 32 percent of the bids and capacity offered, respectively, and 3 percent and 21 percent of the bids and capacity selected (see table 2-3). For independent power producers as a group, about 68 percent of the bids and 75 percent of the offered capacity comes from unaffiliated projects, however, all selected projects had utility affiliations.

The Commissions and/or host utility must decide who is eligible to participate in a bidding process. In general, the more bidders participating in a bid, the less likely there will be collusion among bidders.[3] Also, a restrictive competitive bidding process risks missing the opportunity to benefit from lower-cost producers because not all alternatives are being considered. In other words, a bidding process may not be sufficiently competitive and may not achieve the most efficient results when supply options are restricted too severely. Possible sources of supply include the host utility and its affiliates, QFs, nonQF self-generators, IPPs, and other electric utilities.

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[3] See chapter 4, "Benefits and Pitfalls of Competitive Bidding," of Daniel J. Duann et al., *Competitive Bidding for Electric Generating Capacity: Application and Implementation* (Columbus, OH: The National Regulatory Research Institute, 1988).

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 Federal Power Act (FPA), and the nonprice provisions of the FPA would also apply. Successful nonQF bidders could, and in most cases would, be subject to provisions of the PUHCA. Most utilities and others that set up IPPs will most likely want 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 areas would be prevented from doing so by the PUHCA's prohibition of utility ownership of nonintegrated facilities. While nonutility-owned IPPs might avoid 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. This would result in fewer bidders because firms most likely would want to avoid the PUHCA requirements; many that otherwise would have bid will probably not do so.

Electric Utilities and Affiliates

Most of the disagreement among electric industry analysts over who should be allowed to participate centers on whether utilities and/or their subsidiaries should be allowed to participate. A public utility commission typically adopts formal rules on host utility, other utilities, and affiliate participants. The NRRI survey found that nine states (both utility and commission responses) allowed the host utility to submit a bid and thirteen states allowed other utilities to submit bids. Six states prohibited utility affiliates from bidding and four states limited participation to just QFs. Table 2-1 presents a summary of responses to the survey on solicitation practices by state.

There are several reasons given for allowing host utilities and their subsidiaries to participate. First, most utilities have had considerable experience in planning and building power facilities[4]. Some may also have cost advantages that include a lower cost of capital and expertise in building and operating a new

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4 QFs and other nonutility generators may have more or special experience in building nontraditional power facilities, e.g., wind, solar, biomass, etc.

facility. These same reasons apply to allowing other utilities to participate in the bidding process. Another reason is that the more bidders participating in the process, the more competitive the environment, which again should result in lower generation cost. Some programs use the host utility's avoided cost as a reference price. The utility then is, in effect, a participant since the utility usually becomes the "winner" if it is the preferred option. The danger, of course, is host utility self-dealing.

Utility Self-Dealing

There is a potential for abusive self-dealing when either the host utility or its subsidiaries is allowed to participate in its own competitive bid. The host utility may have an incentive to misstate its power needs and/or its avoided cost to influence the outcome of the bidding. The host utility also can give preferential treatment to itself or one of its subsidiaries in the evaluation, selection, negotiating, and contracting of bids if it has sufficient control of the bidding process. Since the host utility often develops the RFP and designs the scoring system, the potential for abuse can be significant. Abusive self-dealing can lead to a suboptimally designed system and higher generation cost.

If the host utility is allowed to be a participant, it may be advisable to make the submitted avoided cost binding on the utility. The host utility then has an incentive to reveal its true avoided cost. Without a binding avoided cost, the utility may understate its avoided cost to "win" the bid in the belief that it could recover its losses later from ratepayers. This may occur when a more suitable and lower-cost power source should have been selected. A binding arrangement should also be considered for other generators with respect to their bid price. The commission can always allow for unusual circumstances if or when they arise, such as a sudden and/or unforeseen jump in fuel or construction costs.

There is also a potential for abusive self-dealing when the firm is a subsidiary of the host utility. The host utility (again if it has sufficient control of the bidding process) could give preferential treatment to its own subsidiary. There may be, however, instances where the utility subsidiary, as an IPP, is subject to different regulatory oversight from what utility-owned power plants are subject to. For example, since FERC sets the rates for wholesale power, the utility may believe that a subsidiary selling wholesale power to the parent firm could receive a more favorable regulatory treatment from FERC than from the utility's PUC. Consequently, a subsidiary arrangement may provide certain regulatory advantages to the host utility. Also the utility's experience will benefit the affiliate firm and, again, could result in lower generating cost. This raises questions of who owns the utility's experience, who should receive (or pay) resulting benefits (or costs), and the possible cost to ratepayers from cross-subsidization of the unregulated subsidiary by the regulated firm[5].

A way to reduce the potential for self-dealing to a subsidiary of the host utility is to limit IPP ownership by a utility, or group of utilities, to 50 percent. This would be similar to the limit imposed by FERC for QF ownership. It is not clear if this alone would prevent abusive self-dealing, however. Increased commission oversight of the RFP and selection process would also reduce the likelihood of abusive self-dealing, but at the risk of decreasing the host utility's flexibility (see discussion in chapter 1 for why some utility discretion may be desirable). If the bid evaluation and selection process can be made sufficiently transparent to all bidders and to the public utility commission, the possibility of preferential treatment given to the host utility's subsidiary can be reduced. However, many observers have argued that the possibility of abusive self-dealing is too great and its potential cost too high to warrant any expected gain from host utility and/or subsidiary participation in competitive bidding.

According to public utility commission responses to the NRRI survey (table 2-1), one commission (the New Jersey Board) expressly prohibits subsidiary participation. The survey also found that of the states where commissions have a draft or rules in place, three states (Connecticut, New York, and Washington) allow the host utility and other utilities to submit bids and three states (Maine, Maryland, and Virginia) allow other utilities to submit bids but not the host utility. Three other state commissions (California, Colorado, and Massachusetts) allow only QFs to participate. Since FERC rules allow utilities to own up to 50 percent of a QF, utilities are still allowed to participate as part owners of QFs.

It is also important for the commission to guard against the host utility "daisy chaining" bids with other utilities. This is a form of collusive behavior that occurs

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5 For a discussion of this and a survey of public utility commission treatment of subsidiaries of regulated utilities see Robert E. Burns et al., *Regulating Electric Utilities with Subsidiaries* (Columbus, OH: The National Regulatory Research Institute, 1986).

if other utilities are allowed to participate in a bid. In a typical daisy-chain scenario, the host utility unduly gives another utility, or subsidiary of another utility, preferential treatment in exchange for receiving unduly preferential treatment in the other utility's bid. This kind of reciprocal agreement could be extremely difficult to detect since it could happen over a long period of time and could be particularly difficult to detect if it involves utilities in different states. Again, if a commission chooses to allow other utilities and/or their subsidiaries to participate, then sufficient vigilance by the commission can reduce the opportunity to daisy-chain bids. Also, since commission review and oversight increases the prospect of detection, utilities may be reluctant to enter into such a reciprocal agreement due to their concern over future commission retribution. Utilities themselves may be reluctant to form such agreements because of different capacity needs and timing of the needs by the different utilities. This would make such an arrangement inherently difficult but not altogether implausible.

Disclosure of Host Utility's Avoided Cost

The NRRI survey (table 2-1) found that thirteen states (both utility and state programs) have competitive bidding programs that disclose the host utility's avoided cost to bidders; five do not reveal it. States and utilities that do disclose the utility's avoided cost often use a self-scoring method (see chapter 3) where the host utility's avoided cost is used as a benchmark to determine the number of points for the price component of the evaluation of the bidder's project proposal.

There is an advantage to requiring the host utility to state its avoided cost to the commission and not disclose it publicly until after the winning bids are selected. When the host utility's avoided cost is disclosed, bidders potentially will not present their lowest price, particularly when there are few bidders. Rather, they may simply state a price just below the avoided cost and capture the difference between their bid price and what would have been their best price. It is more likely that bidders will reveal an accurate estimate of the cost of their proposed facility if the host utility's avoided cost is not disclosed.

CHAPTER 3

EVALUATION AND SELECTION OF PROJECTS

The project evaluation and selection process gives the host utility a means to choose the best option(s) given the requirements of the host utility. External factors, such as environmental effects, may also be required if considered necessary by the commission. This necessitates a careful development of the evaluation and selection process with input from the host utility, Commission, and other interested parties. All current bidding programs consider both price and nonprice attributes when evaluating bids.

This chapter contains three principal sections: 1) the level of disclosure concerning the evaluation criteria revealed to bidders, 2) pricing options, and 3) a review of factors frequently used in supply bidding by states and utilities across the country, as well as a summary of the survey results concerning the relative importance of evaluation and selection factors.

Undisclosed versus Disclosed Evaluation Process

An undisclosed evaluation does not allow participants to know in advance specifically how the bids will be evaluated or the winning bids selected. Instead, participants are informed only of the general criteria used in the evaluation. Conversely, in a disclosed evaluation, participants are informed of the specific evaluation and selection criteria. (This is not to be confused with an open versus a sealed bidding process, with bidders either informed of other bidders' offers during the bidding process or not. This topic is discussed later in this chapter.) In one form of disclosed bidding, some states have participants score themselves when completing proposals for the power facility.

Among states and utilities that have implemented competitive bidding, disclosure of the details of the evaluation procedures varies widely. No state or utility uses either complete secrecy or complete disclosure of the evaluation criteria. In Maine, Massachusetts, and New York, the host utility issues a detailed RFP that is either partially or completely self-scoring. Bidders with the highest score become part of an initial "award group." The host utility then negotiates and selects the winning projects from this group.

From the survey, thirteen of the eighteen states with either commission or utility rules disclose the selection criteria and the utility's avoided cost to bidders prior to the solicitation. There is, however, a noticeable difference among states with and without commission rules, particularly with regard to disclosure of selection criteria. For the ten states with commission rules either drafted or finalized, all require disclosing the selection criteria to bidders, whereas just three of eight states with utility rules do so. Seven of ten states with commission rules and six of eight with utility rules require disclosure of avoided-cost information. Overall, ten states disclose both the selection criteria and avoided-cost information to bidders prior to the solicitation.

Of the firms examined, the evaluation procedure that Virginia Power Co. (VP) uses is the most opaque to bidders. Bidders are told in an outline in the RFP what factors VP considers and the approximate weights assigned to each factor to evaluate bids. VP maintains complete discretion when selecting bidders. The RFP states in its instructions to bidders that:

> [t]he Company reserves the right, without qualification, to select any Proposals or to reject any and all Proposals, or waive any formality or technicality in Proposals received. Bidders who submit Proposals do so without recourse against the Company for either rejection by the Company or failure to execute an Agreement for the purchase of electricity for any reason, except that nothing herein shall be construed as requesting a waiver of any rights a Qualifying Facility may have under the Public Utility Regulatory Policies Act of 1978.[1]

Utilities generally favor this type of bidding procedure, arguing that it assures that bidders will submit their best and most realistic proposals. Also, this type of evaluation is favored because it allows the utility considerable flexibility and control of the selection process, enabling it to select projects that a more detailed evaluation procedure may not have anticipated. A common and important feature of many closed procedures is the use of an initial selection of a subset of bidders for negotiation, similar to some self-scoring programs.

Another advantage of undisclosed bidding is that it makes collusion on who will be awarded the contract less likely among participants. Since bidders are not

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1 Virginia Electric and Power Company, Request For Proposal, 1989, 13.

informed of the specifics of the evaluation procedure (barring collusion between a bidder and the host utility), bidders are unable to determine beforehand who will be selected. In some other industries the same participants have bid against each other over the course of several years and have decided to "rotate" who the winner or winners will be in a bid.[2] The more closed the bidding process is to the participants, the more difficult collusion becomes. Of course, measures can be taken by the commission to detect and discourage collusion, such as more extensive monitoring of participants. However, this increases the cost of the process.

A disadvantage of an undisclosed evaluation process is that it may increase the chance of utility self-dealing if the utility is allowed to participate in the bidding and is in complete control of selecting projects. Close commission oversight, however, can significantly reduce this chance (see chapter 2 on mitigating self-dealing).

The other extreme is a transparent or disclosed evaluation procedure. Several competitive bidding programs, (for example, those in New York, New Jersey, and Connecticut) reveal a great deal of information on how the bids will be scored. These programs have detailed RFPs that include a self-scoring evaluation section. The winning bidder(s) is determined by the number of points the project received. There is usually postbid negotiation.

An advantage of disclosed bidding is that the participants know in advance if their proposal is suitable, allowing them to adjust the facility (that is, size, fuel type, and so on) to suit the utility's requirements outlined in the RFP. The disadvantage, however, is that the bid may be altered inappropriately or suboptimally. This could result in a poorly designed facility that, in the long term, is a burden on the utility's system. An undisclosed 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). Of course, a well designed scoring mechanism can prevent this from occurring.

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2 See chapter 4, "Benefits and Pitfalls of Competitive Bidding," of Daniel Duann et al., *Competitive Bidding for Electric Generating Capacity: Application and Implementation* (Columbus, OH: The National Regulatory Research Institute, 1988).

The level of disclosure can be seen on a continuum with full disclosure associated with a high probability of collusion at one extreme and complete secrecy associated with a high probability of utility self-dealing at the other (again, our survey indicates that no competitive bidding in the country employs either extreme).

Appendix A contains three examples of evaluation procedures used by three investor-owned utilities (Virginia Power, Central Maine Power, and Rochester Gas & Electric). These were chosen because they illustrate both the difference in public utility commission involvement in the process and the degree of disclosure of the evaluation process.

Pricing Options

In evaluating bids, price is usually used with other factors to determine which to select. The bid price for a new facility depends on the proposed facility's other design features (dispatchability, for example). Most states and utilities have adopted a first-price sealed-bidding arrangement with the price and terms determined by the offered price in the bidding process. Many programs also allow or require negotiation between the host utility and selected bidders. As a result of negotiation, the agreed-on price may be different from the original offer as other nonprice factors are adjusted. Three important decisions to make with regard to pricing are discussed here: uniform versus contract pricing, open versus sealed bidding, and binding versus negotiated pricing.

Contract versus Uniform Pricing

Under a contract pricing arrangement, bidders are paid the offered or agreed-to price. A uniform pricing arrangement is when all successful bidders are paid the same amount for their power. Currently, all state and utility programs except one (California) use contract pricing. Advantages to contract pricing include its familiarity to participants and its appearance of fairness because of its similarity with an open English auction where bidders are bound by their offers. The method is also seen as fair because the lowest (or offered) price is being paid for the power. If bidders bid their true cost, then the benefits of lower cost generation can be passed on to ratepayers or shared between ratepayers and the utility's shareholders.

An alternative pricing arrangement is uniform pricing. A common form of this technique is a second-price or Vickrey auction. Under this scheme, the price for the winning bidder(s) is set at the lowest price of the losing bidder(s). There are two principal advantages cited of this type of auction design.[3] One is its "truth revealing" property: bidders are given an incentive to reveal their true cost since it is not to their advantage to bid a price different from their actual cost. With first-price bidding, bidders may try to "game" their bid by bidding strategically (that is, trying to anticipate what a winning bid price will be). A second advantage is that it encourages more efficient producers, since lower cost producers are rewarded by being allowed to retain the difference between their cost and the uniform price they receive. For these reasons, second-price bidding is considered (at least theoretically) to be a more efficient auction design.

California is currently the only state that has a draft of rules with this type of auction for power supply competitive bidding (for QFs only). To date, however, California has not put this auction design into practice. A group of investor-owned utilities has suggested that the California Public Utility Commission (CPUC) adopt a multiattribute selection process with a contract pricing arrangement for all possible resources. The CPUC reportedly is considering these changes.

There are, however, several limitations to implementing a second-price auction for power supply. First, it may be inconsistent with the fact that electricity is a multiattribute commodity, and as a result difficult to implement. Besides price there are prospects for successful development of the project, effect on system reliability, dispatchability, and environmental impacts to consider, among other factors (items discussed later in this chapter and in appendix A).

Advocates of second-price bidding for power supply contend that a multi-attribute system can be designed that ranks bids according to the value of the facility's characteristics (this would be similar to scoring systems used in first-price bidding programs, see appendix A). The winning bid(s) (those with the highest value) is then selected and paid a uniform price determined by the lowest losing

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[3] William Vickrey, "Counterspeculation, Auctions, and Competitive Sealed Tenders," *The Journal of Finance* 6 (March 1961): 8-37. Also see chapter 6 of Daniel J. Duann et al., "Design of an Optimal Bidding Program," in *Competitive Bidding for Electric Generating Capacity*, or Daniel J. Duann, "Designing a Preferred Bidding Procedure for Securing Electric Generating Capacity," *Managerial and Decision Economics* 12 (1991): 1-13.

bid. This, of course, assumes it is possible to calculate a project's value accurately. Some factors, such as dispatchability, are relatively more disposed to valuation (for example, using simulation models[4]). Other factors, such as environmental impact, have values that are extremely difficult to measure and therefore involve a great deal of subjective judgement. While it is important in any multiattribute auction system to estimate these factors as accurately as possible, it is particularly critical with a second-price power supply auction since all winning bidders would be paid a uniform price based on the determined value (and offered price) of the lowest losing bidder.

In addition, since the price itself for most bidders is interrelated with other factors, determining a uniform price becomes even more difficult. For example, many commission and utility programs consider the prospects for developing the project when evaluating bids (see tables 3-1 and 3-2 later in this chapter). Embedded in this evaluation factor are, among other considerations, the probability of receiving project financing, siting approval, and environmental permits. Projects with a higher probability of success will most likely have a correspondingly higher bid price. Conversely, projects with a lower probability of success will likely have a relatively lower price. Thus, in this example, there is a trade-off between risk and price; when the risk is low the price is relatively high and vice versa. Similar trade-offs exist between bid price and other factors. This trade-off between price and other evaluation factors combined with the reality that determining these probabilities is inevitably and inherently subjective, makes calculating the actual value of the projects (to make comparisons across projects) and determining a uniform price (based on the value of the lowest losing bidder which, of course, would not be negotiated with) difficult, if not impossible.

Rothkopf, Teisberg, and Kahn[5] suggest also that bidders may fear cheating by the bid taker, in this case usually the host utility, and/or collusion with other

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4 See chapter 4, "Modelling Dispatchability Attributes," of E. P. Kahn et al., *Contracts for Dispatchable Power: Economic Implications for the Competitive Bidding Market*, LBL-29447 (Berkeley, CA: Lawrence Berkeley Laboratory, October 1990).

5 Michael H. Rothkopf, Thomas J. Teisberg, and Edward P. Kahn, "Why Are Vickrey Auctions Rare?" *Journal of Political Economy* 98, 1 (February 1990): 94-109.

bidders.[6] If there is a sealed-bid auction, as all power supply auctions currently are, the bidder may fear that the host utility will invent a fictitious bidder or use a confederate's low bid to reduce the uniform price paid by the host utility. This fear may make bidders reluctant to reveal their best price and give them an incentive to bid strategically (which, of course, second-price bidding was designed to avoid). No actual cheating need occur; the fear of it is enough to induce this inefficient behavior. Of course, the regulatory commission can act as the bid taker or auctioneer. However, as discussed earlier, there are good reasons behind having the host utility select the winners.[7]

Finally, Rothkopf, Teisberg, and Kahn suggest a second reason why bidders may be reluctant to reveal their true costs with a second-price power supply auction. A bidder, anticipating negotiations with the host utility, lenders, construction contractors, and other third parties, may be concerned about being at a disadvantage in these negotiations, potentially reducing the winning bidders' "economic rent." If this occurred, the truth-revealing effect of second-price bidding again would be countered. The ability of the third parties to induce this type of bidder behavior, however, depends on their ability to exploit any market power they may possess. If all input markets are considered to be sufficiently competitive, then the impact of third parties may be negligible. The host utility, nevertheless, usually does posses significant market power. In addition, the bidder may anticipate participating in future bids. These factors alone may induce bidders not to reveal their true cost.

Thus, difficultly in implementation, fear of host utility cheating, and bidder reluctance to reveal costs may explain why a second-price power supply auction has, thus far, never been used for power supply bidding. While contract pricing with first-price bidding may be imperfect, it may be preferred simply because it is manageable and well-suited for a multiattribute commodity such as electricity.

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6 Also see Lawrence Berkeley Laboratory, *Designing PURPA Power Purchase Auctions: Theory and Practice*, prepared for the U.S. Department of Energy under contract no. DE-AC03-76SF00098 (Berkeley, CA: Lawrence Berkeley Laboratory, November 1987) and Kahn et al., "Auctions for PURPA Purchases: A Simulation Study." *Journal of Regulatory Economics* 2 (June 1990).

7 See chapter 1 on commission involvement.

Open versus Sealed Bidding

In an open auction bidders are aware of the offers made by others. The most common example is the traditional oral English or Dutch auction. This type of auction is obviously impractical for an electric supply auction because of the myriad nonprice factors tied to the technology being sold. It would be impossible for a host utility to consider all the factors (reliability, dispatchability, probability of project success, and so on) needed to make a quick and informed decision. An open auction, however, could also occur where the bidders are informed of the proposals being offered by other bidders. Currently, all competitive bidding programs in the United States are sealed-bid auctions; that is, all information submitted by bidders is confidential until after the selection. The complex nature of the industry alone suggests that an open bidding arrangement is impractical, because of the transactional costs involved in revealing other bid information to all participants.

An additional reason for having a sealed bid is because of the possibility of collusion among bidders. If bidders are aware of other proposals they can effectively enforce a collusive pact among themselves. Also, there may be an incentive to alter their bid to gain an advantage over competitors. While this competition could benefit the host utility, it also could result in serious harm if the evaluation procedure used by the utility was unable to detect all the flaws in a project's proposal. For example, a bidder may try to maximize its environmental score by switching to a different fuel than it has ready access to (say coal or natural gas). If it actually does not have a means to secure this different fuel and the evaluation gives no or insufficient weight to fuel source security, then there is an increased probability of the project failing. This may not be recognized by the host utility. Since most bidding programs are still evolving with experience, it is plausible that current evaluation procedures will miss important details. As evaluation procedures develop over time, the chance of this problem occurring diminishes and more open procedures can be considered.

Also, bidders may "game" their bid and not offer their best price, adjusting it to be just under their competition. This also could result in bidders submitting multiple bids, adding to the host utility's evaluation and selection expense. For these same reasons, it may be advisable also not disclose the utility's avoided cost (see chapter 2).

Binding versus Negotiated Pricing

In Maine, Massachusetts, New York, and Virginia negotiation is an integral part of the process. Since, as noted above, the selection of bids is a complex process with many factors to consider, to skip the negotiation phase would require an extremely detailed and exhaustive evaluation process. Again, given the limited experience of even the most experienced states and utilities, it is unlikely that this can be accomplished successfully.

Negotiation also gives the utility more discretion in selecting final parties and setting the terms of an agreement. To prevent self-dealing in the event that the host utility and/or subsidiaries are allowed to participate, the process, as noted before, may require increased oversight by the commission.

Another issue arises when the utility is determined to be the best alternative. Some observers have suggested that the host utility should be required to submit a binding avoided cost to the state commission before the selection process; this becomes its bid. Since the utility is the best informed party when it comes to its own needs, negotiation would be unnecessary. Making it binding would give the utility an incentive to reveal its best price. Without binding avoided cost the utility may understate its cost knowing that, if selected, it could go to the public utility commission later for a rate increase and recoup the loss.

For a similar reason, nonutility bidders also should be bound to their agreement with the host utility. If the host utility chooses to negotiate with a bidder, it should be understood that changing one project attribute will affect other attributes. However, bidders should be expected to adhere to the terms of their proposals. Thus, the host utility and bidders should face the same risk-reward equation.

Evaluation and Selection Factors: NRRI Survey Results

Evaluation Practices

The NRRI survey asked commissions and utilities to select the relative importance of various factors commonly used in project evaluations. The factors cover many financial, operational, design, and security features found in RFPs. Tables 3-1 and 3-2 summarize the survey findings on relative factor importance for

TABLE 3-1

RELATIVE IMPORTANCE OF EVALUATION FACTORS FOR STATE COMMISSIONS

Factor	Extremely Important	Important	Somewhat Important	Not Important
Price	78 (%)	22 (%)	0 (%)	0 (%)
Prospects for development	22	67	0	11
Financial viability	11	67	11	11
Project longevity	0	45	33	22
Management experience	0	67	22	11
Performance guarantees	11	45	22	22
In-service date guarantees	0	56	22	22
Progress toward location	11	45	22	22
Planning flexibility	0	33	33	33
Maintenance scheduling	0	56	33	11
Reliability affects	11	56	11	22
Maturity of technology	0	45	33	22
Impact on power quality	0	45	22	33
Fuel type	11	45	33	11
Fuel flexibility	0	45	22	33
Fuel supply security	0	67	22	11
Compatibility w/fuel goals	0	45	33	22
Environmental impact	33	33	22	11
Dispatchability	22	56	11	11
Contract length	0	56	33	11

Source: Responses to the 1990 NRRI survey on competitive bidding. Percentages based on the nine state PSCs with final or drafted rules in place that responded to evaluation questions.

TABLE 3-2

RELATIVE IMPORTANCE OF EVALUATION FACTORS
FOR UTILITIES

Factor	Extremely Important	Important	Somewhat Important	Not Important
Price	83 (%)	17 (%)	0 (%)	0 (%)
Prospects for development	46	42	0	12
Financial viability	33	54	4	8
Project longevity	22	52	22	4
Management experience	8	63	21	8
Performance guarantees	12	51	16	21
In-service date guarantees	9	65	4	22
Progress toward location	13	50	24	13
Planning flexibility	4	42	30	24
Maintenance scheduling	4	58	21	17
Reliability affects	17	67	4	12
Maturity of technology	8	58	21	13
Impact on power quality	16	42	25	16
Fuel type	13	58	25	4
Fuel flexibility	0	50	34	16
Fuel supply security	21	50	21	8
Compatibility w/fuel goals	8	42	21	29
Environmental impact	13	63	17	8
Dispatchability	33	42	21	4
Contract length	17	33	42	4

Source: Responses to the 1990 NRRI survey on competitive bidding. Percentages based on the twenty-four IOUs with final or drafted rules in place that responded to evaluation questions.

state commissions and utilities, respectively. (See appendix A for examples of the factors and importance of each factor used in three utility bidding programs).[8]

In general, commissions and utilities alike view the financial features of a project as more important than its operational, design, or security features. For both, a project's price, financial viability, and prospects for development are considered most important. Planning flexibility, fuel flexibility, and compatibility with fuel goals are considered least important to both. The two show further similarities with regard to dispatchability, contract length, management experience, performance guarantees, and supply security ranking these as important evaluation considerations.

There are, however, differences in factor valuations. Utilities place relatively more importance on operational and design considerations, such as reliability, project longevity, in-service date, maturity of technology, fuel supply type, and power quality impacts. This is not to say that commissions do not consider these factors important, although perhaps not to the extent utilities do. Commissions, on the other hand, place more importance on environmental impacts; one recent study found that five state commissions currently incorporate environmental externalities in their bidding programs--California, Colorado, Massachusetts, New Jersey, and New York.[9] The Clean Air Act Amendments of 1990 likely will increase the relative

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8 Also see Edward P. Kahn et al., *Evaluation Methods in Competitive Bidding for Electric Power*, LBL-26924 UC-101 (Berkeley, CA: Lawrence Berkeley Laboratory, June 1989) or E. P. Kahn et al., *Contracts for Dispatchable Power: Economic Implications for the Competitive Bidding Market*, LBL-29447 (Berkeley, CA: Lawrence Berkeley Laboratory, October 1990), for discussions of price and several nonprice factors used in project evaluation, such as project viability, fuel choice and flexibility, environmental factors, dispatchability, front loading of payments, and contract length.

9 S. D. Cohen et al., *A Survey of State PUC Activities to Incorporate Environmental Externalities into Electric Utility Planning and Regulation*, prepared by Lawrence Berkeley Laboratory for the NARUC Committee/Staff Subcommittee on Energy Conservation (Berkeley, CA: Lawrence Berkeley Laboratory, July 11, 1990). For a review of techniques used to estimate environmental costs see Jonathan Koomey, *Comparative Analysis of Monetary Estimates of External Environmental Costs Associated with Combustion of Fossil Fuels*, LBL-28313 UC-310 (Berkeley, CA: Lawrence Berkeley Laboratory, July 1990) or Ajay K. Sanghi, "The Role of Externalities in Utility Bidding Programs," presented at the Ninth Annual Conference of the Advanced Workshop in Regulation and Public Utility Economics, New Paltz, New York, 31 May 1990.

importance of operational and design features to commissions and environmental impacts to utilities.

Table 3-3 provides a ranking of evaluation factors for state commissions and utilities. The factor values ranked are computed by subtracting the percentages in the "not important" column from the summed percentages in the "extremely important" and "important" columns. This ranking approach, although somewhat arbitrary, offers a reasonable and concise comparison of commission and utility views.

Selection Practices

Among the states having rules, all but one use a first-price bidding mechanism in which selected projects receive their bid price for capacity and energy; California currently uses a second-price bidding mechanism. All states but one leave the responsibility of selecting winning projects to the utilities; in Colorado a third party chosen by the utility and approved by the commission evaluates and selects winning projects.

Four states, all without commission rules, hold public hearings to review selections following the utility's solicitation. In six states, the commissions modify utility selections by changing the selection criteria (four states), amending successful bids (two states), or selecting alternative projects (four states). Only the Colorado commission reports it has recourse to use all three options.

All states except two (Minnesota and Nevada) publicly disclose details of the solicitation following the selection of winning projects: neither exception has commission rules in place. Thirteen states disclose the selection criteria, seven the winning prices, and twelve the identity of participants. Eight states (five with commission rules) disclose all three to the public, and four states (three with commission rules) disclose the selection criteria and identity of participants only. Among states with commission rules, Virginia (implemented by Virginia Power Co.) discloses the least amount of information making only the selection criteria public.

Table 3-4 summarizes the responses of commissions and utilities on questions about selection practices. The complete responses are available in appendix B.

TABLE 3-3

RANKING OF EVALUATION FACTORS FOR STATE COMMISSIONS AND UTILITIES

Factor	Commission Ranking	Utility Ranking
Price	1	1
Prospects for development	2	3
Financial viability	3	2
Project longevity	15	6
Management experience	5	9
Performance guarantees	12	16
In-service date guarantees	12	11
Progress toward location	12	13
Planning flexibility	20	19
Maintenance scheduling	8	15
Reliability affects	8	4
Maturity of technology	15	12
Impact on power quality	19	16
Fuel type	8	7
Fuel flexibility	18	18
Fuel supply security	5	9
Compatibility w/fuel goals	15	20
Environmental impact	5	7
Dispatchability	3	5
Contract length	8	14

Source: Responses to the 1990 NRRI survey on competitive bidding. Percentages based on the nine commissions and twenty-four utilities with final or drafted rules that responded to evaluation questions.

TABLE 3-4

SUMMARY OF COMMISSION AND UTILITY SELECTION PRACTICES BY STATE

Evaluation and Selection Questions	CA	CO	CT[u]	FL[u]	IN[u]	IA[u]	ME	MA	MD	MN[u]	NV[u]	NH[u]	NJ	NY	PA[u]	VT[u]	VA	WA
Is first-price (F) or second-price(s) bidding used in evaluation?	S	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F	F
Does the utility (U), the commission (C), or another party (A) select successful bids?	U	A	U	U	U	U	U	U	U	U	U	U	U	U	U	U	U	U
Which details are made public after selection?[1]					NR													
Selection criteria	X	X	X				X	X	X			X	X	X	X	X	X	X
Price	X	X	X						X				X		X			X
Participant identities	X	X	X	X			X	X	X			X	X	X	X			X
All information		X	X			X												
No information										X	X							
Is a public hearing held to review selections?[1]			X	X		X										X		
Can the commission																		
Select alternative bids?		X					X	X	X									
Amend successful bids?		X						X										
Change selection criteria?		X							X							X		X

Source: Responses to the 1990 NRRI survey on competitive bidding.

The table includes only those states in which either the commission and/or utility drafted rules. When only the utility drafted rules, the superscript "u" appears by the state abbreviation.

Note: "X" = yes; "NR" = no response. When state commission and utility responses differed, commission responses are reported.

[1]For states in which more than one utility responded, contradictory responses occurred often. This is particularly true for utilities operating in California, Massachusetts, Maryland, New Jersey, and New York.

CHAPTER 4

NEGOTIATION AND CONTRACTING

This chapter deals with issues of negotiation and contract practices. Negotiation is the process by which a utility that issued a request for proposals bargains with the winning bidder or bidders in the evaluation and selection process. In particular, the chapter examines the advantages and disadvantages of having a commission rather than a utility negotiate contract terms. The chapter also examines a commission's oversight role in reviewing the contract terms for consistency with the request for proposals. Contracting practices refer to the practice of the utility to include certain contract provisions that one would expect to find in a purchase power contract between a utility and a winning bidder. A variety of contract provisions are examined including provisions dealing with performance assurance and enforcement. Some contract provisions include unsecured property liens, secured property interests, the right of entry and control in default, the right to inspect, specific maintenance standards, specific operation standards, liquidated damages provisions, performance security bonds, and force majeure clauses. There is also a discussion of the desirability of specificity in contract terms, as well as take-or-pay provisions and the desirability of cost escalation clauses for fuel and construction.

Negotiations

Several different degrees of commission oversight of the negotiation process are possible. The appropriate one for a state commission depends on several factors. One factor is the specificity with which the request for proposal laid out the basic contract terms desired by the utility. If the utility laid out with great specificity the desired contract terms, there might be little need for commission involvement in negotiating the final contract. Presumably, the state commission already would have reviewed the sample contract contained in the request for proposal. The bidder would respond with a bid price and by marking up the sample contract to reflect nonprice terms that it considers acceptable. The utility in the evaluation and selection processes would have evaluated the price and the nonprice terms before entering into negotiations. Thus, the utility would already know the bidders' initial negotiating position and would try to secure final contract terms that it considered desirable. The negotiations should primarily center around the nonprice terms, because the price likely would have been heavily weighted in the selection and evaluation process. Price should only be readdressed when the inclusion of nonprice terms would affect the cost of the bidder.

Another factor in deciding the desirable degree of commission involvement is whether the commission is willing to shift risks from the utility and the bidder to itself. As shown in table 4-1, there are two basic approaches: a retrospective contract review, either in a separate prudence review or a fuel adjustment hearing, or in a rate case and contract preapproval.

Contract Preapproval

The use of a contract preapproval approach for new generating facilities is not a new idea. The advantages and disadvantages of such an approach were discussed in detail in a 1981 NRRI report entitled *Commission Preapproval of Utility Investments*.[1] In that report, the authors pointed out that commission preapproval of major utility investments could be divided into "preapproval of actions" and "preapproval of expenditures." A preapproval of actions refers to a state commission's review of a utility decision to invest and agreement to support expenditures prudently and reasonably undertaken to complete the approved project. A preapproval of expenditures denotes a formal decisionmaking process by a state public service commission in approving the investment decision of a utility before the expenditures take place, and to approve the expenditures without a retrospective examination of whether the expenditures were prudent and reasonable.

The 1981 report noted that preapproval of actions is similar to what state commissions do when they issue certificates of convenience and necessity and engage in prior approval of utility security issuances. A preapproval of actions

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[1] Russell J. Profozich et al., *Commission Preapproval of Utility Investments* (Columbus, OH: The National Regulatory Research Institute, 1981, reissued 1987). In effect, contract preapproval takes place where there is a commission-approved standard contract as a part of the utility's request for proposal.

TABLE 4-1

SUMMARY OF COMBINED COMMISSION AND UTILITY RESPONSES ON NEGOTIATING AND CONTRACTING PRACTICES BY STATE

Negotiating and Contracting Questions	CA	CO	CT	FL^u	IN^u	IA^u	ME	MA	MD	MN^u	NV^u	NH^u	NJ	NY	PA^u	VT^u	VA	WA
Does the PUC approve final contracts?	X	2	X	X	X	X		X	X		X		X		X	X		X
When are contracts approved?				NR		NR									NR			
Pre-approval	X		X		X			X	X				X			X		
Fuel adjustment hearing																		
Rate case																		X
Prudence review											X							X
Does the contract include the following provisions?																		
Secured property lien			2	X			S	X	X			X	S	X		X	X	X
Unsecured property lien							S						S	X			X	X^2
Other secured property holds			X^2				S		X				S	X				X
The right of control in default		2	X	X	X		S		X			X	S	X		X	X	
The right to inspect	X		X	X	X	X	X	X	X			X	X	X	X	X	X	X
Specific maintenance standards	X	X	X	X		X	X	X	X			X	X	X	X		X^2	X
Specific operation standards	X	X	X	X	X	X	X	X	X			X	X	X	X		X^2	X
Liquidated damage provision	X	X	X	X	X	X	X					X	X	X	X	X	X	X
Performance security bond		X	2	X			X	X	X		X	X	X	X	X		X	X
Force majeure clauses	X		X	X	X		X	X	X		X	X	X	X	X	X	X	X
Front loading of payments	X		X	X		X	X	X	X		X	X	X	X	X	X	X	X

Source: Based on the 1990 NRRI survey on competitive bidding. The table includes only those states in which either the commission and/or utility drafted rules. When only the utility drafted rules, the superscript "u" appears by the state abbreviation.

Note: "X" = yes, "S" = sometimes, "NR" = no response. When state commission and utility responses differ, state commission responses are reported. The number "2" denotes such instances either as a superscript when the commission answers affirmatively or alone when not.

would guarantee commission support for reasonable and prudent expenditures made toward the completion of a project.

A preapproval of expenditures, on the other hand, would be quite different from the current regulatory process in most states. Such a preapproval would involve a state commission providing a prospective guarantee that a utility's expenditures would be included automatically in rate base without a retrospective review of whether the expenditures were prudent and reasonable. The authors noted that a preapproval of expenditures represents a major shift of risk from the utility and its stockholders, who are compensated to bear risk, to the commission and ultimately to the ratepayers, who are not. A shift of risk from investors to the general public would likely result in a deterioration in efficiency, because of decreased specialization in risk bearing.

The authors noted in 1981 that preapproval of expenditures is unlikely to be implemented by a state public service commission, unless accompanied by a day-to-day assessment of the prudence and reasonableness of the utility's expenditures by the commission staff. Such day-to-day involvement would lead to an intrusion into the managerial prerogatives of the utility and would likely coopt the commission staff. Also, commission preapproval of expenditures could act as an estoppel, because a utility that justifiably might rely on a commission order to make expenditures on a preapproved plant could bind the commission to allow its expenditures on the plant. Such an approach could be undesirable for a state commission, particularly if retrospection would have shown imprudence. Another version of this approach, called a rolling prudence review, has the undesirable trait of not allowing a state commission to have enough retrospection so that "hidden imprudence," such as bad welds, come to light.

As noted, preapproval shifts risks away from the utility to the ratepayer. Risks thus shifted include those related to technology and demand, as well as to regulation. Commission preapproval of expenditures also involves an abandonment by a commission of its traditional role of providing oversight and acting as holders-of-accountability.

The preapproval of competitively bid contracts for new generating facilities is somewhat different from preapproval of major utility investments. When a commission preapproves a competitively bid contract, it abandons its traditional cost-of-service regulatory role as a holder-of-accountability to assure utilities that the contracts entered into will be passed through as prudent purchased power costs, without any subsequent retrospective prudence review. The use of a preapproval process in a competitive bidding situation is sought by the National Independent Energy Producers (NIEP), a national organization representing potential bidders, to complement its desire to prohibit utilities from including "regulatory-out" clauses in power purchase contracts with winning bidders.[2] Regulatory-out clauses would relieve a utility of its legal obligation to purchase from winning bidders if a pass-through of purchased power costs is denied by a state commission, in whole or in part. Such clauses have been identified correctly by the NIEP as a major problem. Contracts containing regulatory-out clauses will make it difficult to obtain financing from banks and other financial institutions for power projects, because there is no guarantee that the utility will not walk away from the contract at some future time.

Indeed, some suggest that the use of contract preapproval, whereby a commission and utility agree to a price cap on the construction cost up front, might be a way of reestablishing the social contract or regulatory bargain between state commissions and electric utilities. Such a price cap on new construction would be most valid when the construction contract is reached by a competitive bidding process. By permitting or requiring a utility to conduct competitive bidding, a commission is assured that there has been an adequate assessment of the cost estimate of a new plant and that the plant cannot be built by someone else, who is more efficient, for less. A competitively bid contract would have the effect of setting a fixed price for a new power plant. Such a contract would tend to shift risks away from the ratepayer and the stockholder, as well, if the utility were permitted to bid and does not submit a winning bid. Even so, the utility still would have an obligation to serve its retail customers. That obligation to serve would need to be protected by the utility negotiating for the inclusion of contractual

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2 National Independent Energy Producers, *Bidding for Power: The Emergence of Competitive Bidding in Electric Generation, Working Paper Number Two* (Washington, D.C.: National Independent Energy Producers, 1990), 36. The National Independent Energy Producers is an association of the electric energy industry's publicly traded and privately held corporations that develop projects generating electricity from hydro, biomass, geothermal, gas, wood, coal, municipal solid waste, and solar technologies.

provisions that ensure performance by the winning bidder.[3] (Types of contract provisions that can ensure bidder performance or mitigate the damage of nonperformance are discussed in the next section.)

Several state commissions have taken the contract preapproval approach to bidding.[4] The Massachusetts Department of Public Utilities adopted such an approach as a part of its competitive bidding process in 1986.[5] The Michigan Legislature required that once the Michigan Public Service Commission has preapproved a capacity payment in a contract with a qualifying facility (QF), the decision cannot be reconsidered during the financing period of the project, which is considered to be 17.5 years. This would have the same effect as a contract preapproval.[6] Competitively bid contracts do not become operative in New Jersey until the New Jersey Board of Public Utilities preapproves pricing terms. The Board of Public Utilities has stated that its preapproval of a contract is not subject to reconsideration in subsequent rate proceedings.[7] According to table 4, the contract preapproval approach is also used in California, Connecticut, Indiana, Maryland, and Vermont.

If a commission decides to engage in preapproval of competitively bid contracts, it might choose to be more involved in the contract negotiations, because it is abandoning its traditional regulatory role as holder-of-accountability. In abandoning this role, it behooves a state commission to assure itself up-front that the terms of the contract serve the public interest, particularly the interests of the ratepayer. It is desirable from the point of view of the independent power producer not to have regulatory-out clauses in the contract. As noted, if such

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3 For further discussion of the role of competitive bidding in revising the regulatory compact, see Robert E. Burns, "Sorting Out Social Contract, Deregulation, and Competition in the Electric Utility Sector," *Proceedings of the Sixth NARUC Biennial Regulatory Information Conference Volume 4* (Columbus, OH: The National Regulatory Research Institute, 1988), 737-41.

4 National Independent Energy Producers, *Bidding for Power*, 36-37.

5 Bernice K. McIntyre, "Contract Preapproval: A Regulatory Innovation in Massachusetts," *Public Utilities Fortnightly* (10 November 1988): 17. The proposed regulation on preapproval of competitively bid contracts went into effect in May 1988. See Mass. DPU. Docket 86-36-E.

6 See Mich. Stats. Ann. sec. 22.13(6j)(13)(b).

7 See New Jersey BPU Docket No. 80810-687B.

clauses are included a winning bidder probably will not be able to secure financing for its project. From the utility's point of view, contract preapproval shifts any regulatory risk that the commission might find the contract to be imprudent on retrospective review. Similarly, technological and demand risks are shifted. Commission preapproval would shift these risks to ratepayers, who are not compensated for bearing these risks. Of course, one could compensate the ratepayers for these risks by allowing the utilities a lower rate of return. If a commission chooses to engage in contract preapproval, it bears a heavy burden in the contract negotiation process to make certain that the contracts are in the interest of the ratepayer. One would expect that commissions engaged in contract preapproval would be fully involved in the negotiation process.

Retrospective Contract Review

A more traditional approach to commission oversight of the contract negotiation process is some form of retrospective contract review. Such a review can occur in several forums. Three are noted in table 4-1: the fuel adjustment hearing, rate case hearing, or prudence review. Only two states were identified in table 4-1 as using this approach: Nevada and Washington.

A retrospective contract review would take place at one of the reviews or hearings listed above. It would take the traditional approach of examining whether or not a purchased power agreement was prudent. To determine prudence it would follow the prudence guidelines noted in an NRRI report on the prudence test.[8] Those guidelines are that a prudence inquiry include: 1) a rebuttal of the presumption of prudence, 2) a rule of reasonableness under the circumstances, 3) a proscription against hindsight, and 4) a retrospective, factual review.

Because of the presumption of prudence, a commission would not be expected to review a purchased power contract for prudence unless affirmative evidence showed mismanagement, inefficiency, or bad faith. In most cases, if a utility follows the competitive bidding procedures approved by the commission, no issue of imprudence should be raised. If the contract contains provisions making the price terms binding based on a construction cost cap, construction cost overruns would

8 Robert E. Burns et al., *The Prudent Investment Test in the 1980s* (Columbus, OH: The National Regulatory Research Institute, 1985), 55-61.

also not be available to create a serious doubt about the prudence of the contract. Only when a utility acts in bad faith or mismanages the contract selection, evaluation, or enforcement process would one expect the commission to question the prudence of a competitively bid purchased power contract. Indeed, one would expect a commission to examine more closely purchased power contracts that are negotiated outside of a competitive bidding process and a utility's decision to build its own plant if reached outside of a competitive bidding. In each circumstance, there is no assurance that the utility sought, let alone obtained, reliable energy at the lowest reasonable cost. In both circumstances it might be shown that there were lower-cost reliable alternatives that either were not sought or were ignored (although available) when the decision to enter into the contract or to build was made.

The "reasonableness under the circumstance" guideline for a prudence review is almost automatically met by a purchased power contract reached by means of competitive bidding. A utility can easily show that its contract is based on a reasonable decision under the circumstances which were known at the time. The competitive bidding process itself creates a benchmark by which the utility can show what alternatives were available and what was known about alternative sources of supply at that time. The corollary to this guideline, the proscription against hindsight, would also be met.

Thus, if approached properly a commission can exercise oversight over contract negotiations by allowing the utility to negotiate the contract subject to prudence reviews. If a commission takes such an approach it may find it advantageous to make certain things clear. First, the commission should state that although it is not engaging in a contract preapproval process it believes in the sanctity of contracts and that a contract between a utility and a winning bidder is binding. A commission might also choose to state that it would find the inclusion of a regulatory-out clause to be against public policy. Such a clause would permit utilities to abandon a contract upon any commission disallowance.

Regulatory-out clauses create not only financing problems for individual projects, but perverse incentives as well. For example, a utility might bring to the attention of a commission the fact that a purchase power contract is no longer the best available source of power or may be unneeded due to demand forecast errors. This may be done in the hopes of having the contract declared imprudent, so that the utility can exercise its regulatory-out clause.[9] If such clauses were widespread, competitive bidding would result in no new sources of generation, other than QFs, from whom the utilities are required by law to purchase.

Finally, whether a contract preapproval approach or a retrospective contract review approach is used for the purpose of commission oversight, the commission must make it clear that the utility continues to have a statutory or common-law obligation to serve its customers. This obligation to serve stems from the franchise rights granted to the utility by the state and is a fundamental part of the regulatory bargain between the utility and commission. To assure that the utility can meet its obligation to serve, the utility must enter into a purchased power contract that provides it with contractual rights to assure that the winning bidder will perform up to expectations or that it can obtain the equivalence of such performance. The next section discusses these contract provisions and other contracting issues for competitively bid purchase power contracts.

Contracting

As mentioned, nothing in the competitive bidding process absolves the utility from its most fundamental obligation, the obligation to serve. It is in the interest of both the utility and the state commission to see to it that the power purchase contract between the utility and the winning bidder contains contractual provisions assuring the utility that the winning bidder will perform, or remit damages that will allow the utility to purchase power on the open market. Without such contractual assurances enforceable in every situation, a utility cannot rely solely on the winning bidder to provide energy and capacity when needed. Unless a utility can enforce a contract when the winning bidder is insolvent or even bankrupt, it might feel that it still needs to build its own plant or to purchase more power than otherwise necessary to meet its obligation to serve.

A contract is not a power plant, and the utility's obligation to serve requires it instantaneously to match generation with demand as well as to transmit and distribute the power to those who demand it. Because of the utility's obligation to provide instant service, contractual provisions and rights do the utility no good

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9 Conversations with Mark Reeder in Albany, New York at the offices of the New York State Public Service Commission, September 25, 1990.

unless they are enforceable without going to court. A major concern of utilities is whether the utility will be able to enforce the contract should the winning bidder become insolvent or bankrupt. That question will be answered for each type of contract provision discussed in the subsections below. These contract performance assurance and enforcement clauses include secured and unsecured property liens; the right to inspect, to require specific operations and maintenance standards, and the right of entry and control; performance security bonds; and liquidated damages provisions. The use of take-or-pay, cost escalation, and force majeure clauses will also be discussed.

Secured and Unsecured Property Liens

As shown in table 4, utilities and state commissions commonly require that a power purchase agreement for a competitively bid contract include a secured property lien. Unsecured property liens are less useful and less common.

The reason that a utility would wish a secured property lien on the property of the winning competitive bidder, particularly its power plant site, is to protect the utility from other creditors in case the winning bidder becomes insolvent or bankrupt. The actual mechanism for perfecting a security interest or a property lien varies from state to state, but almost all require that notice of the security interest or property lien be filed with the appropriate office. In most cases, the lien would be considered a property lien and would be filed with the county recorder's office in the county where the plant is located.

Another option that serves the same purpose is the issuance of a mortgage to the utility. The mortgage would be in partial consideration of the granting of the contract between the utility and the winning bidder. Such a mortgage should be junior (a second or third mortgage) to any other mortgage held by institutions providing the competitive bidder with financing. If the winning bidder becomes insolvent or files for bankruptcy, the utility might be able to take possession of the land either through its lien or, better still, its mortgage. While it is likely that there would be other creditors with a security interest or mortgage senior to the utility's, other creditors might consent to the utility's operation of the plant. Utility possession and operation of the plant might be preferable to liquidation of the plant in a bankruptcy proceeding. Such a scenario might be advantageous to the utility too, particularly if sources of lower-cost power are unavailable or inaccessible. It might also be advantageous to other creditors, because if the plant continues to operate at least partial payments to them might be possible. In this manner, even in the cases of bidder insolvency or bankruptcy the utility might be able to secure power from the bidder to meet the utility's obligation to serve.

To properly draft and perfect a secured property lien, the utility should consult legal counsel. While it may be possible to state a choice-of-law provision in a power purchase contract which specifies the law governing the contract and the jurisdiction and venue of cases arising because of a contract dispute, it may still be necessary to file notice of a secured property lien in the appropriate office of the local jurisdiction, often a county recorder's office.

An unsecured property lien offers the utility and its ratepayers little protection against the possibility of the bidder becoming bankrupt or insolvent. In the case of an unsecured lien, the utility simply would be in line to recover its rights under the contract. Its unsecured property lien rights would be subordinate to more senior liens and secured interests. An unsecured property lien also gives the utility little protection in the case of bidder insolvency or bankruptcy. The effect is to jeopardize the utility's ability to meet its obligation to serve, absent other contractual provisions that assure bidder performance.

The Right to Inspect and to Specify Maintenance and Operations Standards

One major concern that a utility has is whether a winning bidder will be a reliable producer of power. Without assurances that the winning bidder will operate and maintain its plant at the same standards as those of the utility itself, the utility might feel that system reliability is degraded and that it is less able to fulfill its obligation to provide its customers with low-cost reliable power.

One method of assuring that the winning bidder is operating and maintaining its plant at acceptable standards is to require the winning bidder contractually to operate and maintain the plant in a manner specified in the contract. As shown in table 4, most state commissions and utilities have specific maintenance and operating standards in their contracts. While it is impossible to lay out every type of operating contingency, the utility can require the winning bidder to inform it about its daily operating availability and expected maximum generation capability of its facility, including any anticipated forced outage.[10] The utility can require a written maintenance schedule for the first year of the facility's operation, require written notification of planned maintenance shutdowns, and prohibit scheduling of planned maintenance shutdowns during the months of system peak if it would cut the facility's net electric output to a level below the dependable capacity level established by prior testing of the plant. The contract can also require the winning bidder to operate at voltage levels that are set in advance by a voltage schedule. Such a voltage schedule should be based on the normal expected operating conditions for the winning bidder's facility and the utility's reactive power requirements. Also, the contract can require the winning bidder to operate its facility so it does not adversely affect the utility's voltage level or voltage wave form.

The utility and the winning bidder can provide that prior to the anticipated commercial operation date they develop a mutually agreed upon operations manual based on the facility's design and the design of the interconnection to the utility's bulk power system. The operating procedures in the manual would act as a guide to future operation of the plant on matters such as method of day-to-day communications, key personnel for the facility and utility operating centers, clearance and switching practices, outage reporting and scheduling, daily capacity and energy reports, unit operations log, and reactive power support. The contract can then provide that the winning bidder operate and maintain its facility according to the agreed upon operating procedures. The contract might also require the winning bidder to meet the operating and maintenance standards recommended by the facility's equipment suppliers, as well as to engage in prudent utility practices, including synchronizing, voltage, and reactive power control. The contract can also contain a clause that the winning bidder conform to all applicable federal, state, and local laws, as well as rules and regulations, at its cost. The utility can also require the winning bidder to provide it with copies of maintenance evaluations or reports, including those performed by third parties.

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[10] Much of the following discussion is based on contractual provisions found in the "Model Power Purchase and Operating Agreement" that Virginia Electric and Power Company utilized during its August 15, 1989 solicitation for new capacity. The Model Agreement can be found in Reid & Priest, Floyd L. Norton, IV, ed., *Electric Power Purchasing Handbook* (New York: Executive Enterprises Publications Co., Inc., 1989), 146-214.

Further contract provisions are needed if the winning bidder's facility is dispatchable. The winning bidder would be required to keep an up-to-date operating log of real and reactive power production for each hour, changes in operating status, scheduled and forced outages, and any unusual operating conditions found during operation or inspection. The bidder would agree to operate the facility consistent with the utility's dispatch with speed governors and voltage regulators or automatic generation control. The winning bidder also would recognize that the utility belongs to the North American Electric Reliability Council to ensure continuous and reliable power. From time to time an emergency might be declared. In such an event, the winning bidder must cooperate with the utility to maintain safe and reliable load levels and voltages on the utility's system. The winning bidder would cooperate with the utility to establish emergency plans, including recovery from a local or widespread blackout, and voltage reductions to effect load curtailment. The winning bidder would make available technical references on start-up times, black-start capabilities, and minimum load-carrying abilities.

To assure that the winning bidder was fulfilling its contractual obligations concerning maintenance and operations, it might be desirable to have a contract provision giving the utility the right to enter and inspect the operation and maintenance practices of the winning bidder. As shown in table 4, a majority of state commissions and utilities have a contractual right of entry and control in the case of a bidder default. A strong provision providing for the right to enter and control the facility might also be necessary should the winning bidder default by failing to meet the contractually required operations and maintenance standards called for in the contract. Such a right of entry and control would help assure the utility and its ratepayers that the competitively bid purchase power contract is reliable. A utility might determine that it must evoke a right of entry and control when other contractual provisions to assure reliability fail.

Performance Security Bonds

One of the most important provisions that a utility should seek in a competitively bid purchase power supply contract is a clause requiring the winning bidder to have performance security bonds. As shown in table 4, a majority of state commissions and utilities engaged in competitive bidding require such a contract provision.

There are two purposes for performance security bonds. The first is to assure that the winning bidder will make its best effort to complete the project and bring the plant on-line as scheduled. The performance security bond might take the form of an unconditional and irrevocable direct pay letter of credit by a bank. That might relieve the winning bidder of the burden of making a direct cash outlay. The amount of the performance security bond, as with the entry fee (discussed in chapter 2), should not be set so high as to discourage qualified potential bidders. A performance security bond set at a dollar per kilowatt of capacity will reflect the cost to the utility of replacing the capacity should it not come on line in a timely fashion. Surrender of part of the performance security bond can be tied to the achievement of construction milestones in a timely fashion, or to the completion and commercial operation of the plant by the contracted-for operations date. The advantage of using construction milestones is that it provides the winning bidder with incentives in each step of planning, siting, and building the plant to stay on schedule. This approach would also provide the utility with an early warning if the winning bidder is falling behind schedule, allowing the utility more time to take remedial actions, if necessary. The advantage of having one date for surrender of the bond is administrative simplicity. Even if the winning bidder does fall behind schedule, it should be able to rely on the utility to fulfill the contract. Instead of declaring a total default, the utility would collect a portion of the performance security bond to reflect the cost of a temporary loss of needed capacity.

The second purpose in having performance security bonds is to assure the performance of the winning bidder once the plant comes on line. In particular, a performance security bond can reimburse the utility for the cost of replacement power if the winning bidder fails to produce power by the time called for under the contract. This is particularly important if the winning bidder was expected to provide energy and capacity on-peak. To make the utility whole, the utility should be allowed to recover the cost of replacement power less the amount the utility would have paid the winning bidder had the bidder been on-line. (If the utility did not experience a loss, it should not be permitted to recover from the performance security bond.)

Of course, the utility should also seek an indemnification clause for property or personal injury damages caused by the winning bidder due to any negligent, reckless, or intentional acts in fulfilling the contract. The utility should also require the winning bidder to be adequately insured for those events.

Liquidated Damages Provisions

The utility might seek to have a liquidated damages provision in the contract to specify the damages for one of two types of events.[11] The first relates to the winning bidder failing to meet its construction targets. The contract should state with specificity what the liquidated damages will be for failing to meet milestones. These milestones could include required dates on closing of financing, obtaining siting and permit approval, as well as key construction events that are widely known as construction milestones. In particular, the liquidated damages might be on a sliding scale so that the damages are set by the number of days that each construction milestone is missed. This sends a clear signal to the winning bidder that there is a cost of construction delay that increases by the amount of the delay.

The other event that liquidated damages are useful for is if the winning bidder fails to supply the contracted-for dependable capacity. The liquidated damages in this case ought to be set on a sliding scale according to the amount of deviation from the contracted-for dependable capacity: the greater the deviation, the greater the liquidated damages. The liquidated damages clause also ought to be set so that it reflects the higher value of the utility during summer and/or winter seasons, as well as peak hours.

In setting the amount of liquidated damages, care should be taken to set the provisions at a level that fairly represents the utility's good-faith estimate of the value of the winning bidder's capacity to the utility, not at a punitive level. In other words, the liquidated damages clause should be set to fairly reflect the value to the utility for the loss of capacity because of construction delays or because the

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11 Liquidated damages are a specific sum of money (or a formula which will result in a specific sum) that has been expressly stipulated by either party for a breach of the agreement by the other. Liquidated damages are a genuine covenanted preestimate of damages, as distinguished from a penalty clause whose sole purpose is to secure performance.

plant is not performing up to expectations. A liquidated damages clause would not be punitive if the utility were to presume that it would be forced to cover the bidder's capacity deficiency in a tight bulk power market.

Take-or-Pay Provisions

Except for the payment of capacity payments for meeting the required dependable capacity requirements under the contract, there should be no take-or-pay provisions in purchase power contracts. The major incentive and requirement for the winning bidder to receive payment is delivery of energy to the host utility. Take-or-pay provisions do not provide the bidder with incentives to be a reliable source of power. In addition, the utility would want to discourage take-or-pay provisions because they reduces the incentive that the bidder might have to hold its fuel costs down, particularly if the bidder is dispatched by the utility. (This assumes that cost escalation of fuel costs are provided for in the contract.) Finally, take-or-pay provisions transfer technological and demand risks to the utility. The shifting of these risks obviates some of the advantages for entering into competitively bid purchase power contracts.

In any event, should a utility find itself in a situation where, like the natural gas pipelines in the late 1970s, it is considering a take-or-pay provision in a purchased power contract, that contract should also include a market-out provision which allows the utility out of the contract if less expensive sources of power become available.

Alternatively, a long-term contract with an "evergreen clause" that allows the fuel costs to periodically be reset at some percentage of the market rate can provide a bidder with financial security, but without the onerous effects of take-or-pay provisions on the host utility.

Cost Escalation Clauses for Fuel and Construction Costs

Construction cost escalation clauses also tend to undermine one of the purposes of competitive bidding, that is, to provide more of an incentive to minimize costs than traditional regulation. This would also shift the risks associated with new construction costs to those best able to bear them. Construction cost escalation clauses would shift these risks back to the utility.

Worse still, most of the risks of new construction, including the risk of construction cost overruns, are within the control of the winning bidder, the builder. Furthermore, the winning bidder is being compensated for the other risks that are not totally within its control by receiving a higher price with an implicitly higher rate of return. (Recall that if a bidder is bound to its bid, the host utility's bid should be bound to its "bid," whether it is in the form of a separate sealed bid or an announced avoided cost.) On the other hand, front loading or levelization of capital costs may be appropriate if the front loading is secured by a performance bond and if the utility, in its evaluation of the bid, took time value of money into account when evaluating and selecting bidders.[12]

On the other hand, fuel price is not within the power of individual bidders to control. It is appropriate for a competitively bid purchased power contract to provide for periodic adjustments of fuel costs as a part of the energy charge for kilowatt hours actually produced. (There would also be some recovery of variable operation and maintenance expenses in the kilowatt-hour charge.) To the extent possible, the fuel price should be tied to a recognized index of market-based prices. Tying the fuel cost escalation clause to a market-based index still provides the competitive bidder with an incentive to attempt to secure reliable fuel sources at less than the market cost. If the facility is dispatchable by the utility, the winning competitive bidder might want to reveal its fuel costs so it can remain in the dispatch order and collect its energy charges.

Force Majeure Clauses

A well drafted force majeure clause that specifically states what the parties intend to include and exclude as grounds for force majeure is desirable in a contract.[13] Force majeure literally means superior or irresistible force. A force majeure clause in a contract recognizes that certain superior or irresistible forces beyond the reasonable control of either party can excuse performance of a contract. The suspension of performance should be of no greater scope nor longer duration

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12 See chapter 4 of Kahn et al., *Evaluation Methods in Competitive Bidding for Electric Power* (Berkeley, CA: Lawrence Berkeley Laboratory, June 1989).

13 Much of the discussion on force majeure clauses is based on the Virginia Model contract found in Reid and Priest, *Electric Power Purchasing Handbook*, 207-208.

than the circumstances giving rise to the force majeure. The nonperforming party is still required to make its best efforts to remedy its inability to perform. Grounds for force majeure include acts of God, unusually severe weather conditions, labor strikes, riots, actions or omissions by government authorities that prevent performance, inability (despite good faith diligence) to obtain required licenses, accident, or fire.

It is perhaps more important to specify what force majeure does not include. Force majeure cannot be caused by negligent, intentional acts or omissions of one party. It cannot be caused by a failure to comply with any law, rule, order, or regulation. It also cannot be caused by a breach or default of the purchase power contract. Force majeure should not be attributed to normal wear and tear or flaws randomly experienced in power generation materials or equipment. Most importantly, force majeure does not include changes in market conditions. It also does not include governmental actions that affect the cost or availability of fuel. It does not include unavailability of equipment, an inability to obtain or renew permits, labor strikes or slowdowns after the date of commercial operations, or the failure of transmission or distribution capability arranged by the parties.

After specifying what is and is not included in force majeure, the parties have mutually agreed to the allocation of risk for nonperformance of the contract. If a purchased power agreement were developed as described above, there should be an adequate balancing of risk between the utility, the ratepayer, and the bidder. The degree of commission involvement in the review of the contract depends on the commissions' view of contract preapproval as opposed to a retrospective review. However, in either case, a commission might find it advantageous to determine that the purchase power contract, at a minimum, include or exclude the contract provisions sketched out above.

CHAPTER 5

OTHER LEGAL ISSUES IN COMPETITIVE BIDDING

This chapter discusses legal issues in addition to those discussed in the previous chapter that affect the implementation of competitive bidding. These are issues that state commissions must concern themselves with, although in many cases, state commissions do not have the authority to solve the issues identified here.

Four legal issues are identified and discussed. The first section concerns transmission access. While access to transmission is not necessary for successful bidders located within the host utility's service area, access to transmission facilities is necessary for bidders located outside of the host utility's service area. Without transmission access, the economic advantages that can be gained from competitive bidding are likely to be limited, and in some service territories there may not be enough bidders with transmission access to make the bidding workably competitive.

The second section discusses a major legal issue that affects competitive bidding, that is, the regulatory impediment that the Public Utility Holding Company Act of 1935 (PUHCA) poses for the development of independent power producers. As mentioned earlier, the current strictures of the PUHCA retard development of an independent power production industry because potential owners of independent power production facilities do not want to be burdened with the legal requirements of being a registered holding company subject to the jurisdiction of the Securities and Exchange Commission.

The third section discusses how competitive bidding affects the siting and certification-of-need procedures of a state public utility commission. In particular, competitive bidding for new power supplies may necessitate a fresh look at these processes at state commissions. The need for a new look relates to several factors, including the conditions on which a bidder can site a generation facility before winning the bidding process, and the ability of a bidder to meet certificate-of-need criteria. A second problem that competition can raise is the ability of the host utility to site and build transmission facilities that might be necessary for the winning bidder to transmit its power. Such siting is difficult, if not impossible, without the host utility having some foreknowledge of where the generation site is likely to be. Another concern is the need to site and certify new interstate transmission lines that will be essential to preventing additional bottlenecks that inhibit a robust bulk power market consistent with competitive bidding.

The fourth section discusses special jurisdictional conflicts that arise because of competitive bidding. Specifically, the jurisdictional issue that we address concerns the interplay between the FERC--which has exclusive jurisdiction to set wholesale power rates--and the state public service commissions that have the power to review, if not require, that a utility's competitive bidding process provides the least-cost source of power supply subject to reliability and other nonprice constraints. The issue of jurisdictional conflict arises because one likely outcome of a competitive bidding process that is required or reviewed by a state commission is a wholesale power sale by the winning bidder. The price of power in such a sale is subject to FERC jurisdiction.

Transmission Access

In service areas with limited siting available for new power generation facilities, the host utility needs to have potential bidders both inside and outside of its service area. When the winning bidders to a utility solicitation are located within the host utility's service area, there really is no issue of transmission access. If the host utility can interconnect with the winning bidder without creating reliability problems and is willing to do so, transmission access should be a simple matter. If such an interconnection would cause reliability problems without upgrading the host utility's transmission facilities, then the host utility and the winning bidder can negotiate the details of the needed transmission upgrade, including recovery of its costs. Further, when the winning bidder is located within the service territory of the host utility, the creation of uncompensated parallel flows is less likely.

Instead, the issue of transmission access arises when the winning bidder is located outside of the service area of the host utility. For a winning bidder to be able to supply the host utility, it must be able to gain access to the transmission system of intervening utilities. If bidders are unable to obtain such access, there could be a limiting effect on the competitive bidding process. Potential bidders outside of the host utility's service territory are less likely to respond to bid solicitations, and a host utility will not evaluate bids from outside its service territory as favorably as those within because of the problems of providing transmission access. Such a limiting effect could lead to fewer bidders responding to each solicitation with the possible, if not likely, result that the utility will not have the lowest cost source of power as a supply option. Ultimately, because of a lack of transmission access, state regulators would recognize that a competitive bidding procedure does not obtain the desired goal of providing ratepayers with the lowest cost source of reliable power, since not all possible sources were considered in the bidding process.

Intervening utilities have an interest in restricting transmission access that goes beyond well recognized business justifications for denying access to an essential facility. Besides reliability constraints and first use of the facilities for the utility's own customers--recognized business justifications that permit a utility to deny access to its transmission system without violating the essential facility doctrine of section 2 of the Sherman Antitrust Act--a utility might want to engage in exclusionary behavior prohibited by the essential facility doctrine. The utility might deny access as an exercise of market power. This is likely if there are greater gains for an intervening utility if it were to deny access to its transmission system for purposes of wheeling and instead to buy and resell the winning bidder's power or sell its own power to the host utility.[1] Traditionally, the FERC has provided utilities with a greater incentive to act as a merchant to buy and resell power than as a transporter of power through the transmission system.

The FERC's power to mandate access to the transmission facilities is extremely limited, particularly when the transaction involves wheeling services.[2] However, if wheeling services were priced to create economic incentives for utilities to wheel power voluntarily, many of the nontechnical problems could be dealt with in other forums.[3]

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1 See Narayan S. Rau, *The Evaluation of Transactions in Interconnected Systems* (Columbus, OH: The National Regulatory Research Institute, 1988), 10-45, for a discussion of utility attitudes about acting as a merchant of power as opposed to a transmitter of power.

2 For a full explanation of FERC's limited authority to mandate wheeling, see Robert E. Burns, "Legal Impediments to Power Transfers," *Non-Technical Impediments to Power Transfers* ed. Kevin Kelly (Columbus, OH: The National Regulatory Research Institute, 1987).

3 For a complete discussion on how to price wheeling service so as to create the correct incentives for utilities to engage in wheeling voluntarily, see Kevin Kelly et al., *Some Economic Principles for Pricing Wheeled Power* (Columbus, OH: The National Regulatory Research Institute, 1987).

While the FERC has taken some initial steps toward providing utilities with greater incentives to wheel power through flexible pricing of transmission services, the suggestion that transmission service should be priced at more than the utility's embedded costs remains controversial.[4] The FERC has used its conditioning authority under sections 205 and 203 of the Federal Power Act to "entice" voluntary wheeling. By enticing voluntary wheeling, the FERC hopes to avoid the prohibition found in current case law that it cannot mandate wheeling unless the provisions of PURPA sections 202, 203, and 204 are met.[5] The FERC has used its conditioning powers to mandate transmission access in the context of utility mergers[6] and a proposal for greater wholesale rate flexibility.[7]

While the FERC's "conditioning approach" to transmission access has the virtue of gradualism, it is also a piecemeal, ad hoc, case-by-case approach that does not directly address a denial of transmission access. Because a conditioning approach to entice wheeling might not address the problem of denying transmission access in many competitive bidding situations, state commissions implementing competitive bidding for new power suppliers are likely to find it unsatisfactory. To enhance competitive bidding, state commissions may need to find an approach that guarantees winning bidders access to the transmission system, subject to reliability constraints.

When exploring their regulatory options state commissions must be keenly aware of the FERC's exclusive jurisdiction to set prices, terms, and conditions on

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4 For a discussion of some of the FERC initiatives, see Kevin Kelly, Robert Burns, and Kenneth Rose, *An Evaluation for NARUC of the Key Issues Raised by the FERC Transmission Task Force Report* (Columbus, OH: The National Regulatory Research Institute, 1990).

5 For a full discussion of these cases as well as FERC's conditioning authority, see Robert Burns, "'Access to the Bottleneck': Legal Issues Regarding Electric Transmission and Natural Gas Transportation," *Natural Gas Industry Restructuring Issues*, ed. J. Stephen Henderson (Columbus, OH: The National Regulatory Research Institute, 1986).

6 See, for example, Utah Power & Light Co., 45 FERC para. 61,095 (Order 318); 47 FERC para. 61,209 (Order 318-A); and 48 FERC para. 61,035 (Order 318-B).

7 See Public Service of Indiana Co., 49 FERC para. 61,346 (1989).

transmission service.[8] Any attempt by a state commission to set prices, terms, and conditions is subject to preemption by the FERC. However, the FERC has not ruled on the authority of state commissions to mandate transmission access and wheeling.

In addition to the status quo, there are three alternative paths that a state commission can take on transmission access. The path that the state commission takes should reflect the commission's goals and how risk-averse it is concerning the possibility of a judicial veto.

If the only goal of the state commission is to encourage use of wheeling transactions to facilitate competitive bidding, then a relatively safe approach is to require the host utility that is evaluating and selecting bidders to provide the wheeling for the successful bidders. The idea is that bidders could provide a bus bar price for their electricity and the utility selecting the bids could pursue whether transmission access would be available and at what cost.[9]

If the host utility cannot arrange transmission access for a nonutility generator, either because transmission access is being denied or transmission service is being offered at an unreasonable or exorbitant price, the host utility should be required to report the denial to the state commission. The state commission then would initiate an investigation requiring the utility to show cause why the wheeling service was denied. If the answer is unsatisfactory, the state commission could initiate an action before the FERC, turn the recalcitrant utility over to state and federal antitrust enforcement agencies, or alternatively take whatever action it felt appropriate. The principal problem with this approach, however, is the same as with the FERC's conditioning approach: it offers no immediate remedy for a refusal to wheel. The lack of transmission access is one of the major causes of project failure.[10] Once an economic power project fails, the opportunity for the economic power purchase that it represents could be lost

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8 Florida Power & Light Co. and Florida Public Service Commission, et al., 29 FERC para. 61,140 (1984); Florida Power & Light Co., 40 FERC para. 61,045 (1987).

9 It is expected that because of its ongoing relationships with its neighboring utilities the host utility can better arrange for wheeling services from the power site than the winning bidder.

10 National Independent Energy Producers, *Bidding for Power: The Emergence of Competitive Bidding in Electric Generation, Working Paper Number Two*, (Washington, D.C.: National Independent Energy Producers, March 1990) 20.

forever. The host utility might be forced to fall back on more costly or less reliable sources of power to provide service. Another possible problem is that the presumption that the host utility will bargain in good faith may be faulty.

A second alternative for state commissions is to create a policy that requires a utility to provide wheeling in the context of competitive bidding, but that also states that the prices, terms, and conditions of the wheeling service be determined by the FERC.[11] For this policy to pass muster under the Interstate Commerce Clause of the United States Constitution, the policy should be limited to situations where all of the parties--the host utility, the wheeling utility, and the successful bidder--are located within a single state. It is, of course, expected that a utility would deny access if it would have unreasonably degraded the reliability of the transmission system.[12] Part of the policy would be that when a utility denies access, it is duty-bound to justify its denial of access to the state commission. This approach would appear to solve directly the problem of a utility denying access to the transmission system. However, the approach pushes against the outermost bounds of state commission authority, and federal preemption conceivably could occur.

The third alternative that state commissions might consider is to emulate something akin to what some have called "the Wisconsin Advance Plan."[13] First, as suggested above, the major utilities are ordered to provide mandatory access and to file wheeling tariffs with the FERC.[14] Second, the major utilities are ordered to

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11 This was the approach ultimately taken by the Florida Public Service Commission. See Florida Public Service Commission Dockets EL 87-19-000 and Order No. 891049-EU, Proposed Revisions of Rule 25.17.082, 17.0825, 17.083, 17.0831, 17.088, 17.882, 17.091, and Creation of Rules 25-17.081, 17.0883, 17.0834, 17.0832, 17.0883, and 17.089; Cogeneration Rules, Memorandum at 10 (October 26, 1989).

12 A complete legal argument that explains why this approach may not be subject to federal preemption is contained in Robert E. Burns, "Legal Impediments to Power Transfers," *Non-Technical Impediments to Power Transfers*.

13 It is important to note that the Wisconsin Advance Plan is a result of the state's least-cost planning regulation. The Wisconsin Public Service Commission has rejected the use of competitive bidding. For a good description and discussion of the Wisconsin Advance Plan, see Michael Arny and Barbara James, "State Transmission Planning and Federal Power Policy: Turf War to Alliance?" *The Electricity Journal* (April 1990): 40-49.

14 In order to avoid federal preemption, care must be taken not to specify the price, terms, or conditions of the transmission service.

develop transmission joint use and cost-sharing agreements with neighboring utilities consistent with principles laid out in the commission's order. The specification of how the transmission system will be used and its costs shared might raise issues of federal preemption as noted above. Also, ordering joint-use and cost-sharing might be considered confiscatory in some jurisdictions. However, if a state commission were to implement something akin to the Wisconsin Plan on an incremental basis (for example, for new transmission capacity and upgrades) these potential legal problems might be avoided.

By using its power siting and/or certification-of-need authority, a state commission might require new entities, such as successful bidders, to finance and co-own future expansions of the existing transmission system. This approach would be particularly viable if the commission can condition the granting of a power siting or certificate of need. Such conditioning authority might allow the commission to require joint ownership of future expansions of the transmission system. Given the scarcity of transmission corridors in much of the nation, this is an environmentally sound practice that avoids unnecessary duplication of facilities and maintains economies of scale of the transmission network. Gradually a state could move toward a single-system planning approach to transmission pricing and access. By pursuing this incremental approach with new transmission capacity and upgrades and deferring to the FERC as to prices, terms, and conditions, issues of confiscation of utility property and federal preemption might be avoided.

Public Utility Holding Company Act of 1935 Reform

As noted in an earlier NRRI report on competitive bidding,[15] successful bidders that are not qualifying facilities under PURPA could be subject to the

[15] Daniel J. Duann et al., *Competitive Bidding for Electric Generation Capacity: Application and Implementation* (Columbus, OH: The National Regulatory Research Institute, 1988), 42-47. Some of the analysis in this subsection relies on work done by the author in the earlier report.

provisions of the PUHCA.[16] This is the case for IPPs as well as for utilities bidding outside of their own service territory.

From the point of view of would-be power suppliers, it is thought to be undesirable to become a registered holding company subject to the regulation of the Securities and Exchange Commission. Yet without special planning in the organization of an IPP facility, it would be simple for an owner of an IPP to become a holding company. To become a holding company, a person, corporation, or other legal entity need own only 10 percent or more of, or exercise a controlling influence over, an electric or gas utility.[17] Sections 9, 10, and 11 of the PUHCA set out an array of requirements that must be met before any acquisition of a utility is made. The most significant of these is section 10, which requires the SEC to apply six criteria for an acquisition to be approved. It requires that the acquisition must serve the public interest by tending toward the economical and efficient development of an integrated public utility system.[18] Under normal conditions, an integrated public utility is capable of being economically operated as a single interconnected and coordinated system confined in its operations to a single area or region. If a utility were to attempt to set up an IPP outside of its own service area, it would fail to meet the criteria of tending toward the development of an integrated system. If some other corporate entity, which falls under the PUHCA because it had set up one or more IPPs, were to build an additional IPP in another area or region, it too would fail to meet this criterion.

A registered holding company must comply with comprehensive, ongoing regulation by the SEC. This ongoing regulation entails advanced approval by the

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[16] For a brief historical background and perspective on the Public Utility Holding Company Act of 1935, see Robert E. Burns et al., *Regulating Electric Utilities with Subsidiaries* (Columbus, OH: The National Regulatory Research Institute, 1986), 189-97. For a more thorough description of the PUHCA and its implications, see Douglas W. Hawes, *Utility Holding Companies* (New York: Clark-Boardman Co., 1985) and Scott Hempling, "Corporate Restructuring and Consumer Risk: Is the SEC Enforcing the Public Utility Holding Company Act?" *The Electricity Journal* 40 (July 1988): 47-49. Qualifying facilities are exempt from the PUHCA pursuant to the FERC regulations implementing PURPA section 210(e).

[17] Public Utility Holding Company Act, section 2(a)(3). Notice that a large stockholder could become a holding company.

[18] PUHCA, section 10(c)(2).

SEC of certain issuances and sales of securities;[19] SEC review of interaffiliate transactions;[20] SEC review of service, sales, and construction contracts;[21] and detailed financial reporting requirements.

Most utilities and other corporations that might be interested in setting up IPPs wish to avoid becoming registered holding companies. Unless a means of avoiding the Act is used, many potential bidders that are not qualifying facilities will not enter the market as new capacity suppliers. And, as was recently observed by William Conway at the 1990 NARUC Annual Convention, "the need for PUHCA reform is quite compelling...there has been a 'mere' trickle of IPP development to date and the pool of qualifying cogeneration and small power production facilities is 'inherently limited.'"[22]

Without PUHCA reform, there are two ways that one can avoid this comprehensive, ongoing regulation by the SEC. The first is for a holding company to qualify as an exempt holding company.[23] The second is to avoid becoming a holding company.

There are five categories of exempt holding companies under section 3 of the PUHCA. Three are of concern to our analysis. The first is the "predominately intrastate" holding company, which is exempt from ongoing SEC regulation if it and its utility subsidiaries are confined substantially within one state. (There could be some insubstantial degree of out-of-state utility operations.)[24] To qualify for this exemption, a holding company would need to locate all its utility activities (IPPs) in one state.

The second exemption, known as the "predominately a utility" exemption, would be available to a utility setting up IPPs outside its own service territory. To

19 PUHCA, sections 6 and 7..

20 PUHCA, section 12.

21 PUHCA, section 13.

22 "Electricity Perestroika: PUHCA 'Reform', Competitive Bidding, Independent Power Production, Market-Based Pricing for Bulk Power, PURPA," *NARUC Bulletin* (10 December 1990): 5-7.

23 Becoming an exempt holding company does not apply to the Section 9 prior approval requirement of the PUHCA if the acquisition results in the person being an affiliate (the owner of 5 percent or more) of two or more utilities.

24 PUHCA, section 3(a)(1).

qualify for this exemption, a holding company would have to be primarily a utility operating in the state in which it was organized and in adjoining states.[25] Any IPP that a utility set up would have to be in the same or adjoining states, outside of its own franchised service territory, and operated as a part of a single interconnected and coordinated system. This might be possible in certain tight power pools.

The third exemption is the "only incidentally a holding company" exemption, which would be available to holding companies in which the utility is functionally related (incidental) to a nonutility business and where only a small part of the income is derived from the utility subsidiary.[26] An example of this exemption would be an aluminum company that sets up a subsidiary to generate its electricity. This exemption would be available only under very limited circumstances. While one can imagine individual special circumstances under which these exemptions would be available to IPPs and utility bidders, in a great majority of circumstances they would not apply.

The second method of avoiding PUHCA regulation is to avoid becoming a holding company under the Act.[27] One well-recognized strategy that could be used for setting up IPPs is to set up nonholding company entities, where each IPP is a division of the parent company and where the parent company's only subsidiaries are not jurisdictional to the PUHCA. However, such a strategy might not be available in some states that require companies providing utility services (including IPPs) to incorporate in that state, and become subject to state regulation. Even if such a strategy were available, it has the major disadvantage of not providing the parent corporation with liability protection from its nonutility activities. Finally, a major individual or institutional stockholder in such a company may inadvertently become a holding company subject to the PUHCA.

Another strategy to avoid becoming a holding company is to spread the ownership interest so that no single participant has more than a 5 percent or 10

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25 PUHCA, section 3(a)(3).

26 PUHCA, section 3(a)(3).

27 The PUHCA does not regulate the operations of utility companies as such. It is directed to the organization and structure of public utility holding companies and their subsidiaries. See Douglas Hawes and William Lamb, "Restructuring Under the PUHCA: Can the '35 Act Envelope Be Stretched?" *The Electricity Journal* 3, 5 (June 1990): 16-25. Much of the analysis that follows relies on this article.

percent ownership interest in the facility.[28] There are two problems with this strategy. First, it is difficult to create a corporation as a joint venture with such a multitude of corporate owners. Second, the SEC could still determine that one or more of the partners owns a controlling interest. To avoid such a finding, each of the owners would need to exercise actual control. Also, management by large groups precludes timely decisions and tends to doom such enterprises to failure.[29]

A variation on this approach is to have eleven or twenty-one partners who are project sponsors.[30] The partners would be general partners during the financing and construction stages but shift to limited partners once plant operations began. They would then surrender control to a general partner, while maintaining some degree of control through the limited partnership agreement. The most difficult part of this strategy is picking a trustworthy general partner, willing and financially able to accept the risks involved, who also has the requisite expertise in power production, and who is not subject or susceptible to regulation.[31]

Another way to avoid becoming a holding company is to set the facility up as a tenancy-in-common. The SEC views a tenancy-in-common as if each tenant directly owns an undivided interest in the plant. Because there is no separate company, there can be no holding company. Electric utilities have often used this form of ownership for joint ventures on large nuclear or coal power plants. This method is also available for nonutilities wishing to own independent power production facilities.

Tenancy-in-common has some limitations. First, there must be at least two co-tenants. Second, no co-tenant can be a registered holding company or its subsidiary. Third, none of the co-tenants should own more than 50 percent interest

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28 Less than a 5 percent interest is preferable if the entity plans to acquire more than one facility. Otherwise, the entity would be subject to Section 9 of the PUHCA as noted above. This strategy would require 21 or more owners, each owning less than 5 percent.

29 Douglas Hawes and William Lamb, "Restructuring Under the PUHCA," 21-22.

30 Eleven partners gets below a 10 percent ownership interest, while twenty-one partners gets below 5 percent.

31 Douglas Hawes and William Lamb, "Restructuring Under the PUHCA, 23 and also see, "To Avoid PUHCA, IPP Developers Can Pare Down Their Voting Interest," *Electric Utility Week* (26 November 1990): 12-13.

in a qualifying facility.[32] This approach has two disadvantages. A tenant-in-common is exposed to the full liability of plant failure and carries its investment on its own balance sheet.

Another approach is to obtain the benefit of ownership without voting shares or control, such as owning preferred stock that is convertible into voting common shares. A convertible security is not considered a voting or controlling ownership.[33] However, such an approach might be unsatisfactory because control would then rest in the voting shares, whose owners in turn still must avoid becoming a holding company.

One final method is available to electric utilities that are not subsidiaries of a holding company. They could set up a joint generating company pursuant to SEC Rules 14 and 15. The electric utility must own the project directly or through a tenancy-in-common, and the acquisition of securities must be approved by the appropriate state commission or the FERC. The voting shares of the securities must be owned by one or more electric companies to whom all the power is sold, although excess power may be resold or go into a power pool.[34] This last limitation makes this approach of limited usefulness in most competitive bidding situations, except where a utility submits a bid in its own solicitation.

Clearly, there are ways through the maze that the PUHCA poses for the development of IPPs, the presence of which are necessary for competitive bidding to result in the lowest cost reliable power source being selected. However, the prospect of dealing with the PUHCA is likely to discourage many potential bidders. The perception that this intricate system of regulation discourages the development of IPPs has led many to call for PUHCA reform.[35]

The topic of PUHCA reform, once raised, is extraordinarily complex. The PUHCA was enacted in 1935 to correct serious abuses that occurred as a result of

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32 This last limitation exists because a co-tenant owning 50 percent or more of a qualifying facility might be considered a utility and might lose its qualifying facility status due to the FERC ownership criteria. Douglas Hawes and William Lamb, "Restructuring Under the PUHCA," 22-23.

33 Ibid., 22.

34 Ibid., 22-23.

35 For example, see M. Willrich, "PUHCA Reform: Sine Qua Non of a Competitive Power Supply Industry," *The Electricity Journal* 3, 1 (January-February 1990): 32-39.

the holding company structure. The PUHCA has been successful in curbing those abuses, and some contend that any PUHCA reform would again expose ratepayers to the abuses.[36] However, the PUHCA was enacted approximately fifty years before state commissions began to experiment with competitive bidding; the effect of the PUHCA on competitive bidding was, of course, unforeseen. A surgical revision to the PUHCA allowing nonutilities to set up separate subsidiaries for independent power producers would allow establishment of single-asset subsidiaries, protect the parent company from liability, and go a long way toward encouraging IPP development. Yet, there are legitimate questions as to whether it is desirable to shield such IPP developers from liability.[37] Also, there are questions about whether utilities should be allowed a PUHCA exemption to develop IPPs. Such an amendment, if passed, might open the door for some of the same types of holding company abuses that the PUHCA was enacted to prevent. Until these issues are resolved, there will be less IPP development than what would be desirable for a competitive bidding process.

However, PUHCA reform requires that other issues also be considered. The National Association of Regulatory Utility Commissioners is on record as opposing PUHCA reform, unless (1) state commission rights to conduct prudence of purchase reviews are ensured, (2) state commission rights to conduct bidding programs and least-cost planning, including determining resource mix, and to restrict or prohibit affiliate transactions or asset transfers, also are free from federal preemption, (3) state commission rights of access to holding company and all affiliate books and records are provided, and (4) Congress' permission must be granted for state commissions to form multistate compacts to regulate cost allocations and the prudence of wholesale power purchases by integrated holding companies. The point here is that PUHCA reform is a complex topic, and encouraging IPP development is only one of the issues involved. A comprehensive review of the effect of a variety of PUHCA reform amendments is needed, but beyond the scope of this study. In

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36 See Scott Hempling, "Corporate Restructuring and Consumer Risk: Is the SEC Enforcing the Public Utility Holding Company Act?" *The Electricity Journal* for a fuller discussion.

37 The danger of an independent power producer defaulting on its contract and becoming insolvent may vary if it is carried on its parent company's balance sheet, depending on the long-term financial stability of the parent company.

the meantime, IPP development will likely be slower because of the hurdles posed by the PUHCA.

Siting and Certificate of Need

Use of competitive bidding will affect the considerations of both the utility and the commissions when they undertake siting and/or a certificate-of-need proceeding. Two of the major causes for the failure of a competitively bid project center around siting difficulties and the failure to get transmission access.[38] Both relate to how siting and certificate-of-need proceedings fit into the utility's planning process. As noted earlier, competitive bidding does not relieve the utility of its obligation to serve. The utility is still required to plan and, when necessary, to build to assure that its obligation to serve is fulfilled. In particular, the utility either must build sufficient flexibility into its system planning for inclusion of competitive bidding of power sources or it must make information about its preferences as to plant size and location available in its request for proposal.

It would be difficult, if not impossible, for a utility planning to upgrade and expand its transmission system for the purpose of purchasing power from the generating units of successful bidders to do so without knowing where those sites will be. A more sensible approach is to make the preferred size and location of the plant known in the request for proposal.[39] Such information would lead to better siting of proposed generation sources given the utility's current and planned future transmission system. However, even where such information is made available to the bidder, a new generation project, whether built by a successful bidder or a utility, sometimes causes impacts on neighboring utilities and on the regional grid.

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[38] National Independent Energy Producers, *Bidding for Power*, 20. Also see U.S. General Accounting Office, *Electricity Supply: The Effects of Competitive Power Purchases Are Not Yet Certain*, GAO/RCED-90-182 (Washington, D.C.: U.S. General Accounting Office, 1990), 20, which contains the results of a three utility survey as to why projects selected through competitive bidding fail. It concludes that projects have been cancelled for a variety of reasons, including the developers' 1) problems in obtaining financing, permits, or sites; 2) failure to post security deposits; 3) finding projects economically unfeasible; and 4) failure to meet interim project milestones. Still, the remaining projects for all three utilities are expected to provide about the same or more power than the utilities solicited.

[39] See, for example, the outline of Rochester Gas & Electric's RFP in appendix A.

Even if preferred plant size and location are provided in the request for proposal it may be difficult for the host utility, its neighboring utilities, and the regional grid to accommodate new power sources, unless the possibility of new generation sources is taken into consideration in planning the regional grid.

Another option would be for the utility to acquire desirable sites and to make the sites available to winning bidders. Of course, one would expect the successful bidder to provide adequate compensation to the utility for the site.[40] Another possibility would be for private firms, such as environmental consulting firms, to obtain sites, win preapproval for a range of technologies, and sell them.[41] However, the current siting and certificate-of-need laws were not enacted with an environmental preapproval of a power site in mind.

The most difficult problems relate to the siting and certificate of necessity processes themselves. Some state agencies provide a two- or multiple-step siting process. Conventional wisdom on utility planning holds these multiple-step siting and certificate of need processes in disfavor because they involve a multitude of proceedings to site a plant and are often a source of construction delay, which can compromise system reliability and lead to construction cost overruns. Yet, for those siting processes that separate environmental concerns about an individual site from the question of whether the site is needed, it might be possible, as suggested above, for a state agency (whether or not it is the utility commission) to preapprove sites on environmental grounds.

Such preapproval would involve an environmental review of the site for power plants of a certain range of sizes and technologies. The preapproval process would not involve a finding of the need for the plant, which can be better established after the forecasting or least-cost planning process and the subsequent competitive bidding. The more general review of whether the plant is in the public interest might also take place after the competitive bidding process, because it is often the most general, contentious, and protracted part of the procedure. By taking this approach of preapproving the environmental viability of sites, commissions can smooth the siting and certificate of need process and lessen the possibility of

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40 See "Competitive Bidding Sparks a New Look at Siting and Permitting Power Plants," *Current Competition* (May 1990): 11, 15. This approach was used by the Indiana Municipal Power Authority (IMPA) in its request for proposal. Bidders were offered the chance to bid on a site that IMPA had an option to buy.

41 Ibid.

project failure. If such an approach is taken, the utility should make it desirable for a bidder to secure and obtain an environmental review of its site. This can be done in the request for proposal and subsequent evaluation of bids.

Conventional wisdom holds that a one-stop siting and certificate of need process is the most efficient and fairest for all concerned. A one-stop process allows all of the affected parties to raise a multitude of factors, including environmental, engineering, public health and safety, development, economic need, and general public interest to be considered at one time. It allows a neutral decisionmaker (commission or administrative law judge) to weigh all of the factors together, with explicit tradeoffs between factors, and determine whether the statutory criteria has been met and whether to provide a certificate to this plant at this site. Use of a one-stop process also minimizes the amount of time necessary to site and certificate a plant. This minimizes delay in the process, leading to enhanced reliability and a lower probability of construction cost overruns.

However, a one-stop siting process might not lend itself easily to a competitive bidding process. Under a one-stop siting process, all of the necessary determinations necessary to site and certify a plant are done at once. As noted above, two of the major reasons that competitively bid projects fail is a failure to obtain siting and a lack of transmission access. A lack of transmission access can often be traced to a failure to foresee a power generation site leading to a failure to plan for the necessary transmission upgrades or additions needed to provide access to the site.

Under one-stop siting there are two approaches available for a potential bidder. The first is to attempt to site the plant under the one-stop siting regulations *before* submitting a competitive bid. However, under a typical one-stop siting statute, the potential bidder will be unable to obtain siting. Chapter 4906 of the Ohio Revised Code is an example of a one-stop siting statute. Under the statute, a potential bidder would need to meet eight criteria to obtain a siting certificate.[42] They are (1) that a need for the facility exists, (2) that the nature of the probable environmental impact must be affirmatively demonstrated, (3) that

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[42] These are found in Ohio Revised Code, section 4906.10. It is also worth noting that a power siting certificate is not necessary for electric generation plant of less than fifty megawatts capacity, or electric transmission lines of less than 125 kilovolts capacity. Siting is necessary when there is a substantial addition to an existing facility.

adverse environmental impacts will be minimized, considering the technology and the nature and economics of the various alternatives, (4) that a proposed electric transmission line of 345 kilovolts or above is consistent with regional plans of the power grid and will serve the interests of the electric system economy and reliability, (5) that the facility complies with statutes and rules governing air pollution, solid waste, hazardous waste, and water pollution, (6) that the facility will serve the public interest, convenience, and necessity,[43] (7) that the impact of the facility on the viability of certain agricultural land has been determined, and (8) that the facility incorporates the maximum feasible water conservation practices considering available technology, nature, and economics of various alternatives.

Until competitive bidding's selection of winning bidders has taken place, a potential bidder will be unable to demonstrate the need for the facility. The need for the facility as opposed to other potential candidate facilities is established by the competitive bidding process, which in turn relies on the utility's long-term forecast contained in its integrated resource cost plan. Also, until competitive bidding's selection of winning bidders has taken place, it would probably be unduly cumbersome to expect any potential bidder to submit to a full hearing on the public interest of its facility. Thus, a potential bidder is unlikely to be able to use one-stop siting to certificate a plant before a competitive bidding process. Even if it were possible for the potential bidder to meet all of the siting criteria before bidding took place, it might be unduly cumbersome to require them to do so. If the cost of complying with siting requirements were difficult enough, it could represent a significant regulatory barrier to entry for some potential bidders. As noted previously, it is desirable for all serious, potential bidders to be allowed to bid.

The second route that a potential bidder could take is to make no effort to site the plant until after the bid selection is completed. The difficulties that a potential nonutility bidder would face in siting a plant would be no different from those faced by a utility in siting its own plants. However, from experience, one might expect a higher failure rate in obtaining siting. Nonutility bidders might be less experienced than the utility in fulfilling the environmental requirements of the siting process. Unless there is some demonstration that the bidder has taken steps to secure its site and to meet the environmental requirements of siting a new plant,

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43 This is a catchall criterion used by intervenors to address concerns about the facility and problems that might result from its construction and operation that do not easily fit within the framework of other criteria.

a utility in the evaluation and selection process might consider a project being bid to be more prone to failure than one for which the site had been secured and environmental requirements met.

One potential solution for this dilemma is for states that have one-stop-siting or certificate-of-need processes to allow potential bidders to meet the environmental criteria for siting before submitting a bid, and then be allowed to fulfill the demonstration of need for the facility and public interest criteria after the bidder has been selected as a winning bidder. Such a partial certificate that indicates that a bidder has met the environmental requirements of the applicable siting process should be given an appropriate weight in the evaluation and selection process. (Without going through an environmental review before bidding, a utility only has the bidders' contentions concerning the relative environmental impacts of its plant.) Fulfilling the environmental review in a partial siting would not excuse a successful bidder from fulfilling the remaining siting requirements after it was selected by the utility. While such a partial environmental-impacts-only siting review option is desirable, even in one-stop siting states, it should not be required of all bidders. Bidders of small generation capacity increments may still find it unduly burdensome.

In addition, it might smooth a bidder's ability to get transmission access if its transmission needs were made known to the power siting commission or other appropriate state agency before the bid was submitted. Notifying affected utilities there will be an additional need on their transmission system that they should plan for places the planning burden of supplying adequate transmission facilities back on the utility. While the authors do not propose giving these suppliers a higher priority than native load customers, utilities should be required to plan electric transmission expansions and upgrades in a manner consistent with regional expansion of the electric power grid, including expansion required by new generation facilities that are selected by competitive bidding.

A further step that state commissions might consider when the results of competitive bidding creates the need for multistate transmission line expansions or upgrades, is to organize regionally to provide for the siting of the transmission line. By organizing regionally, ratepayers adversely affected by siting of transmission lines and receiving no benefits from the line might be compensated. States might wish to enact legislation that allows the state commissions to petition

Congress for joint federal-state boards to solve conflicts that might arise during state certification and siting of multistate transmission facilities.[44]

The Jurisdictional Conflict: Wholesale Power Rates and the Pike County Exception

There is the potential for jurisdictional conflict between the state commissions and the FERC concerning whether rates arrived at through the competitive bidding process are just and reasonable. This conflict arises in several contexts.[45] The first is when a competitive bidding process results in a QF becoming the successful bidder.

According to section 210 of the PURPA, electric utilities must interconnect with and purchase electric power from QFs. The rate for purchase from a QF must not exceed the incremental cost to the utility of alternative electric energy. The term "incremental cost of alternative electric energy" means the cost that the utility would have incurred either by generation or purchase from another source *but for* the purchase from the QF. PURPA then requires each state commission to implement FERC's rule for each electric utility over which it has jurisdiction. The FERC rules do not require the use of any particular method to calculate avoided cost, and specifically authorize state commissions to issue their own rules to fulfill the FERC's full avoided cost rules.

PURPA itself is silent as to whether a competitive bidding process is permitted to determine the incremental cost of alternative electric energy supply for a particular utility. However, nothing in the statutory language would prevent "the

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44 This suggestion was raised earlier in Robert E. Burns, "Legal Impediments to Power Transfers," *Non-Technical Impediments to Power Transfers*, 99. The idea has since picked up some momentum as being worthy of further exploration. See the comments of Commissioner William Badger, the current President of NARUC, in "Electricity Perestroika" *NARUC Bulletin*, 5-6; and a recent report entitled, "Transmission Planning, Siting, and Certification in the 1990s: Problems, Prospects, and Policies, by the Consumer Energy Council of America Research Foundation, cited in "Regional Coordination Touted for Multistate Transmission Development," *Inside F.E.R.C.* (27 August 1990): 1-2. A sample of the type of statute suggested here is Ohio Revised Code, section 4906.14.

45 Some of the analysis that follows is based on or is an extension of the author's previous research in chapter 3 of Daniel J. Duann et al., *Competitive Bidding for Electric Generating Capacity*.

purchase from another source" from being another QF. Thus, the language of PURPA itself leaves open the possibility of QF-on-QF competition through competitive bidding.

However, it is clear from the commentary on its full avoided cost rules that the FERC did not contemplate competitive bidding that involves QF-on-QF competition.[46] Neither was it expressly forbidden. State commissions implemented the FERC's avoided cost rules in a variety of ways, including the purchased power approach, in which the full avoided costs were set at the cost of purchased power from other utilities. State commissions eventually extended this purchased power approach to competitive bidding. While the FERC has not amended its 1980 full avoided cost rules to allow this extension, competitive bidding can be consistent with PURPA section 210, and it does have the FERC's support.

In our second situation, jurisdictional conflict becomes more explicit. If a nonQF (typically an IPP or possibly a utility) were a successful competitive bidder, it would be subject both to the rate and nonrate provisions of the Federal Power Act (FPA) because it would be making a wholesale electricity sale in interstate commerce.[47] We are concerned here about the rate provisions of the FPA. Section 205(a) of the FPA requires that all rates subject to FERC's jurisdiction be "just and reasonable," and states that rates that are not just and reasonable are unlawful. Section 205(b) of the FPA requires that rates not be unduly preferential or prejudicial. And, FPA section 205(e) imposes the burden of proving that a proposed rate is just and reasonable on the selling entity.

Traditionally, a judgment about whether rates are just and reasonable under the FPA has been based on the embedded costs of the seller, including a fair and reasonable return on equity.[48] However, the rates that are derived from

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46 The commentary states that, "if, by purchasing electric energy from a qualifying facility, a utility can reduce its energy cost or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs that the utility can thereby avoid." (Emphasis added.) 45 *Fed. Reg.* 12216.

47 Except, of course, for electricity sales for resale in Alaska, Hawaii, and the ERCOT portion of Texas.

48 See for example, Electricity Consumers Resource Council v. Federal Energy Regulatory Commission, 747 F.2d 1511 (D.C. Cir. 1984).

competitive bidding are market based, and are not necessarily related to the embedded cost of the seller.[49] Under a traditional FPA approach, the FERC would not accept the winning bidder's price as a binding wholesale rate, but would redetermine the rate administratively. Such an approach would place the state commissions and the FERC in an immediate jurisdictional conflict.

Fortunately, the FERC has recognized that its traditional approach is not appropriate for pricing IPPs that are involved in competitive bidding. In 1987, the FERC approved a market-based rate determined by a sealed bidding procedure for the purchase of the unused portion of a utility's transmission capacity.[50] Then in 1988, the FERC approved IPP rates that are based on the purchasing utility's avoided costs.[51] In that case, the FERC defined IPPs as

> [N]ontraditional public utilities that produce and sell electricity but have no significant market power. IPPs lack significant market power as suppliers of energy and capacity because they do not have captive customers. They do not have service franchises nor are they affiliated with franchised utilities in the markets in which IPPs sell power. IPPs also have limited or no control of transmission facilities essential to their customers.[52]

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49 Although the successful bidder's price could reflect its embedded cost of the entity and a reasonable rate of return on its equity, the real distinction is that competitive bidding relies on the market to determine the wholesale rate rather than on an administrative proceeding.

50 Baltimore Gas and Electric Company, 40 FERC para. 61,170 (1987).

51 Orange and Rockland Utilities Inc., 42 FERC para. 61,012 (1988). By using the purchasing utility's avoided cost as a price cap, the FERC has equated market-based prices derived from competitive bidding with just and reasonable rates because market-based rates derived from competitive bidding are consistent with the purchased power approach to calculating avoided costs. This would also appear consistent with the United States Supreme Court's definition of the "zone of reasonableness" that just and reasonable rates must fall within. For a further discussion of the zone of reasonableness, see J. Stephen Henderson and Robert E. Burns, *An Economic and Legal Analysis of Undue Price Discrimination* (Columbus, OH: The National Regulatory Research Institute, 1989), 43-46.

52 Orange and Rockland Inc., at 61,031.

The availability of market-based rates for independent power producers that are successful bidders in a state commission-supervised competitive bidding process clearly has been established by the FERC in its recent orders.[53]

The above decisions demonstrate that the FERC is willing to defer to the results of state commission-supervised competitive bidding programs when the winning bidders are either QFs or "true" IPPs. Problems can arise, however, when the winning bidder is neither a QF nor a true IPP. For example, the FERC initially rejected market-based rates for a three-way deal involving Seminole Electric Cooperative and two affiliates of TECO Energy Inc. not only because the deal was considered unduly preferential, but because the state-reviewed competitive bidding process was not competitive enough. The FERC said that the bidding process was sparse and thin and insufficient to demonstrate that TECO was not a dominant supplier in the relevant market.[54]

The FERC has recently reversed that ruling, and has indicated that it is sensitive that its original decision could undermine state bidding programs, and that the FERC is willing to defer to state commissions in areas that are appropriate, such as competitive bidding. The FERC also found that the market-based rates established by the bidding were consistent with traditional cost-of-service pricing principles, and avoided undermining its case-by-case policy on the market-based pricing for utility power marketing affiliates.[55]

If indeed the FERC shows deference to state-supervised competitive bidding programs for new power supply sources, then jurisdictional conflicts between the FERC and state commissions can be minimized. At the same time, the FERC's

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53 See "Doswell Gets FERC Approval for IPP Market Rate; Trabandt Has Concern," *Electric Utility Week* (12 March 1990): 7-8; "FERC Ruling Seen as Final Step to Market-Based Rates for IPPs," *Electric Utility Week* (16 July 1990): 1-2; and "Market Pricing Virtually Guaranteed to True IPPs, Trabandt Declares," *Inside F.E.R.C.* (16 July 1990): 1, 4-5.

54 See "Electricity Perestroika," *NARUC Bulletin*, 6. FERC was concerned that only eight bids were received, although the eight bids represented a four-to-one ratio of power bid to power sought.

55 "FERC Okays TECO Deal, But Avoids Undermining Stand on Affiliates," *Electric Utility Week* (19 November 1990): 1-3. For some discussion of the FERC's treatment of utility power marketing affiliates, see "Trabandt Urges FERC to 'Just Say No' to Power Market Affiliates," *Inside F.E.R.C.* (30 April 1990): 1-2; and "The Commission's 'Policy Retina Has Detached,' Trabandt Said," *Inside F.E.R.C.* (9 July 1990): 4-4a.

policy of encouraging increased competition into the power supply market will be enforced by state commissions having the same goal. In deferring to the state commissions, the FERC has made it incumbent on the state commissions to take responsibility for overseeing the design and review of competitive bidding for new power sources. As noted in the previous chapter, competitive bidding also minimizes the need for prudence reviews on the part of state commissions.

Competitive bidding also minimizes the need for state commissions to invoke the "Pike County exception."[56] Competitive bidding assures the state commissions that the local utility is obtaining a reliable source of power at the lowest costs and that it has examined all of the alternatives. So long as the FERC sets the wholesale rate at the market-based rate determined by competitive bidding (absent fraud or utility misconduct in the competitive bidding process itself) there is no reason for the state commission to hold that a FERC-approved wholesale transaction is not a prudent purchase by the buying utility.

This does not mean that the possibility of jurisdictional conflict does not still exist. The FERC has also made so called market-based rates available to true IPPs, outside the context of a state-supervised competitive bidding process.[57] There are three problems with these agreements. First, allowing an IPP to negotiate a contract for "market-based" rates outside of a state-supervised competitive bidding context gives an IPP every incentive to try to avoid a competitive bidding process. Second, there is really no assurance that these so-called "market-based" rates reached by arms-length agreements represent what would

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56 For more information on the "Pike County exception," see William W. Lindsay and Jerry L. Pfeffer, *The Narragansett Doctrine: An Emerging Issue in Federal-State Electricity Regulation, Occasional Paper No. 8* (Columbus, OH: The National Regulatory Research Institute, 1984); and William W. Lindsay and Jerry L. Pfeffer, *The Narragansett Doctrine: A 1986 Update* (Columbus, OH: The National Regulatory Research Institute, 1986).

57 See, for example, "The Commission Cannot Simply Disregard the Federal Power Act," *Inside F.E.R.C.* (27 August 1990): 7-8, for a discussion of a case where the FERC approved market based rates for an IPP selected in a competitive bidding program not supervised or reviewed by a state commission. And see, "FERC Approval of Market Pricing for IPP Projects Now Seen Routine," *Inside F.E.R.C.* (27 October 1990): 7-8, for a case where the FERC approved market based rates for an IPP selected without any competitive bidding whatsoever. However, the case may be less alarming if it is ultimately limited to its facts. The market-based rate approved by the FERC was set at 90 percent of the rate established by a state-supervised QF-only competitive bidding process.

truly be the price for power had there been a market test. The only way to be assured that one has discovered the market rate is to undertake a competitive bidding process. In those situations, state commissions might carefully examine whether or not the purchasing utility was prudent in buying from the IPP without fully examining other alternative power sources. If imprudence is found, the state commission should not disturb the underlying power purchase agreement, which has been judged reasonable for the seller by the FERC, but might impute a lower market-based purchase power rate for purposes of retail ratemaking.

If the goal of the FERC is to encourage competitive forces in bulk power supply, then market-based rates should be limited to situations where there exist state-supervised competitive bidding programs. Making so called "market-based rates" available to IPPs outside a competitive bidding process undercuts this effort.[58] However, it might be necessary to forego the competitive bidding process under unusual circumstances, such as when the power is needed quickly and there is insufficient time to issue a request for proposal or to negotiate with multiple bidders.[59] Under such circumstances, it might be appropriate for the FERC to approve "market-based" wholesale rates. But the flow-through of those rates to retail customers should be subject to a subsequent retrospective review by the state public service commission to assure that the utility picked the lowest cost alternative source of reliable power, and, if necessary, impute a lower rate. Once the competitive bidding process becomes well established and integrated into the utility's forecasting and planning, the situations where there is insufficient time to conduct competitive bidding should rarely occur.

The emissions trading provisions of the Clean Air Act Amendments of 1990 pose no special obstacle for an independent power producer, which is defined in the Amendments as an owner of a new facility required to hold allowances that sells 80 percent of its electricity wholesale, is nonrecourse (nonrate base) project-financed, and does not generate energy sold to an affiliate of the owner. First, an IPP can attempt to buy emissions allowances on the open market. If an IPP cannot

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[58] In the case cited above, the market rate was set as a percentage of avoided costs that was determined by a QF-only competitive bidding process.

[59] Such a case is now pending at the FERC. See "Mission Request for Market Rates Is Next Test for FERC Policy," *Electric Utility Week* (10 December 1990):
3-4.

obtain the required emissions allowances on the open market, the Amendments provide that the IPPs will have the first opportunity to purchase emission allowances from a special reserve set up by the EPA for direct allowance sales. IPPs proposing to construct new facilities for which allowances are required before the date of the first EPA-sponsored allowance auction and which have not received allowances as a result of written offers to purchase allowances for $750 are also entitled to an EPA guarantee of allowance availability at $1,500 per allowance.

CHAPTER 6

POLICY CONSIDERATIONS

Because competitive bidding is a relatively recent phenomenon there are a limited number of examples to learn from. Moreover, there has been insufficient time to fully determine the effect of various strategies that have been employed. Also, each state and utility has a different set of conditions, that is, resources available, capacity needs, type of capacity or energy needed, and so on. For these reasons, it is difficult to assert what is the "best" program design that will be appropriate in every circumstance across the country--or even across a given state or region. The limited experience with bidding makes each program implemented, in effect, an experiment. For this reason, the program should be designed with flexibility built into it so it can adapt as experience is gained.

Designing and developing a competitive bidding program for electric power supply does not, therefore, allow a cookbook approach. Rather, given the level of uncertainty and interrelatedness of the design features, putting together a program involves examining a network of options. Many options are not necessarily mutually exclusive; thus, for example, combining voluntary bidding with strict commission oversight of the bidding process is not inconsistent. However, some options are clearly in conflict. For example, host utility affiliate participation is most likely inconsistent with a low level of commission oversight.

Throughout this report some of these options that commissions face have been outlined and discussed. They can be viewed as a series of questions that become more specific and detailed as one proceeds down the list. These questions include:

- What should be the level of commission involvement?
- When and how often should bidding occur?
- Should bidding be voluntary or mandatory?
- Who should be allowed to participate?
- What measures should be taken to prevent abusive self-dealing and collusion?
- Should the host utility disclose its avoided cost to bidders?
- Should the disclosed avoided cost be binding on the utility?

- What pricing arrangement should be used?
- What nonprice factors should be used in the evaluation of bids?
- Who should write the RFP?
- Should there be negotiation between bidders and the host utility?
- Should there be preapproval or retrospective review of contracts?
- What contract terms should be used?

How a commission answers the questions toward the bottom of the list often depends on its answers to previous questions. The interrelated nature of the options is at least as important as the answers to the questions themselves and should be given special consideration when designing a bidding program.

In addition, each of the legal issues discussed in chapter 5--transmission access, PUHCA reform, siting and certification of need, and jurisdictional conflicts concerning wholesale power rates--affects state commission implementation of competitive bidding for new power supply sources. In most cases, state commissions alone cannot solve these problems. For state commission implementation of competitive bidding to be fully effective there must be a "shared vision" and increased cooperation with other federal agencies--particularly the FERC-- having jurisdiction over issues affecting competitive bidding. State regulators and the FERC in the 1990s have overlapping and shared responsibility for assuring that ratepayers are provided with a reliable supply of power at the lowest reasonable price. Competitive bidding for new power supplies provides state and federal regulators with one mechanism for meeting that shared responsibility. However, without increased state and federal cooperation on the above issues, it seems unlikely that competitive bidding for new power supplies can reach its *full* potential of providing a means for assuring reliable power at the lowest reasonable cost.

To foster greater cooperation, an ongoing federal/state commission dialogue is needed on the above issues. Such a dialogue has been suggested for transmission access and pricing policy issues. The use of a collaborative process, such as a joint problem-solving workshop, was suggested as a means for state and federal regulators to arrive at a mutual understanding, if not a meeting of the minds, on transmission access and pricing issues.[1] However, it would be more useful to both federal and state regulators to have an ongoing dialogue on these issues. One FERC commissioner has suggested that a consultative mechanism be established between the state commissions and the FERC on the above issues, and that such a mechanism be modelled after the consultative mechanism that FERC has with the Canadian National Energy Board (NEB).[2] The consultative mechanism allows for informal discussions between the FERC and the NEB on a multitude of energy issues.

If such a consultative mechanism is set up, it might be worthwhile to use a variety of collaborative procedures to help state and federal regulators gain a better understanding of each others' goals, if not agree on those goals and the means to reaching them. Such collaborative procedures include joint problem-solving workshops, technical conferences, task forces, and scientific panels.[3] By effectively using these procedures on an ongoing basis, state and federal regulators might be able to bridge their differences and regulate in tandem toward a common goal of providing ratepayers with reliable service at the lowest reasonable cost through the appropriate introduction of competition in power supply markets.

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[1] The suggestion that a collaborative process, such as a joint problem-solving workshop, be used was made in Kevin Kelly, Robert Burns, and Kenneth Rose, *An Evaluation for NARUC of the Key Issues Raised by the FERC Transmission Task Force Report* (Columbus, OH: The National Regulatory Research Institute, 1990). Also see, Robert E. Burns, "Opportunities for Federal and State Cooperation on Electric Transmission Pricing and Access Issues," *Proceedings of the Seventh NARUC Biennial Regulatory Information Conference* ed. David Wirick (Columbus, OH: The National Regulatory Research Institute, 1990). FERC Commissioner Charles Trabandt also called for a joint federal-state workshop on transmission pricing and access issues at the 1990 NARUC Winter Meetings. See, "Trabandt Proposes FERC/NARUC 'Consultative Mechanism' on Regulation," *Inside F.E.R.C.* (19 November 1990): 3-4.

[2] "Trabandt Proposes FERC/NARUC 'Consultative Mechanism'," *Inside F.E.R.C.*, 3-4.

[3] These procedures and their appropriate use are discussed in detail in an earlier NRRI report and subsequent article. See, Robert E. Burns, *Innovative Administrative Procedures for Proactive Regulation* (Columbus, OH: The National Regulatory Research Institute, 1988); and Robert E. Burns, "The Evolving Role of Dispute Resolution in Administrative Procedures," *Natural Resources & Environment* (Fall 1990): 26.

Commission and Utility Comments on the Perceived Strengths and Weaknesses of Competitive Bidding

All respondents were asked by the survey to list the main strengths and weaknesses of competitive bidding. Tables 6-1 and 6-2 combine and organize by state the responses from commissions and utilities. Table 6-1 lists the eight most reported strengths and how parties responded while table 6-2 concerns the reported weaknesses. The tables do not summarize all views nor list all perceived strengths and weaknesses. A complete summary that features actual responses is found in appendix B.

Perceived Strengths

The top three reported strengths when aggregating all responses were, in descending order, "lowering generation costs and the price to ratepayers," "widening the range of supply options to utilities," and "promoting competition in generation." The strengths least reported were, in ascending order, "considering nonprice factors," "increasing planning flexibility," and "lowering risk."

Although commissions and utilities share similar views about strengths, differences exist. State commissions viewed price competition and considering non-price items as strengths more so than utilities. In fact, utilities ranked price competition fifth and nonprice factors last in importance; commissions ranked these issues second and fourth in importance, respectively. Utilities, by contrast, viewed market-based avoided cost and administration efficiency as strengths more than commissions. Somewhat surprisingly, utilities considered lower risk as more of a strength than commissions; however, it is vague just what risk utilities considered to be lower.

Perceived Weaknesses

The three weaknesses most reported when combining responses were, in descending order, "supply uncertainty," "evaluation difficulties," and "less operation and planning flexibility." The three least cited weaknesses were, in ascending

TABLE 6-1

COMMISSION AND UTILITY COMMENTS ON THE
STRENGTHS OF COMPETITIVE BIDDING BY STATE

Strengths	AL	AK	AZ	AR	CA*	CO*	CT*	DE	FL	GA	HI	ID	IL	IN	IA	KS	KY	LA	ME*	MD*	MA*	MI	MN
Lower cost/price	C	C	C	C	B	B	C	C	U		U	B	U	U	B		B	U	C			C	C
Promotes price/ generation competition	B	C		C		C	C		U	B				C		C			C				C
Lower risks			C				C								U					C			
More supply options	U		C	C	U		C		U	U				U	U		C	U	U	C		C	U
Market-based avoided cost	U	C							U	U		U		B	U	C	U			C			U
Considers nonprice factors															C						U		
Greater planning flexibility														C				U					
Administratively efficient								C							B			U					C

Source: Responses to the 1990 NRRI survey on competitive bidding.

"C" = commission; "U" = utility; "B" = both. The asterisk denotes state commissions with bidding rules.

TABLE 6-1--Continued

Strengths	MO	MT	NV	NH	NJ*	NM	NY*	NC	ND	OH	OR	PA	SC	SD	TX	UT	VT	VA*	WA*	WV	WI	WY
Lower cost/price	U	B	U		B	C		B	C	B	C	U	C		U	U	C	B	B	B	U	
Promotes price/ generation competition		U			C	C	C			B		B	C	U	U		C		C			
Lower risks	B										U	U			U				U		U	
More supply options	C	U		C	B		U			B	C	B	C		U		U	C	U			C
Market-based avoided cost				U				C		B	U	U			U			U			U	
Considers nonprice factors				C	C		C															
Greater planning flexibility					U		C					B				U		U	U			C
Administratively efficient		U			U					U		U				U		B				

Source: Responses to the 1990 NRRI survey on competitive bidding.

"C" = commission; "U" = utility; "B" = both. The asterisk denotes state commissions with bidding rules.

TABLE 6-2

COMMISSION AND UTILITY COMMENTS ON THE
WEAKNESSES OF COMPETITIVE BIDDING, BY STATE

Weaknesses	AK	AR	CA*	CO*	CT*	DE	FL	GA	ID	IL	IN	IA	KS	KY	LA	ME*	MD*	MA*	MI	MN
Supply uncertainty; higher risk		C	U	B	U	C		B			U		C		U			U		
Higher long-term cost; lower reliability		C		U				U	U	U		U		C						
Lower operation/planning flexibility			U	U			U	U	B	U	U	U	C		U			U		
Difficult to administer and limit unqualified bids								C				B				U	C	U	C	C
Evaluation difficulty (price/nonprice items)	C				B	C		C			C	B					C	U	U	C
Utility self-dealing or market power									C							U			C	
Limited participation; too restrictive			B																	C
Transmission Access Problems												U								U

Source: Responses to the 1990 NRRI survey on competitive bidding.

"C" = commission; "U" = utility; "B" = both. The asterisk denotes state commissions with bidding rules.

TABLE 6-2--Continued

Weaknesses	MO	MT	NV	NH	NJ*	NM	NY*	NC	ND	OH	OR	PA	SC	SD	TX	VT	VA*	WA*	WV	WI	WY
Supply uncertainty; higher risk	B	U				C	B	C		B		B	C	U				U		U	C
Higher long-term cost; lower reliability	U						B			U					U					U	C
Lower operation/planning flexibility	U	B	U	U	U		U		C	C	U	U	C		U			U		U	
Difficult to administer and limit unqualified bids		U	U	C						C		U				U	B			U	
Evaluation difficulty (price/nonprice items)	C	U			U			U	C	U	C	B		U		B	B		C		
Utility self-dealing or market power					C		C														
Limited participation; too restrictive		C				C															C
Transmission Access Problems		U													U						

Source: Responses to the 1990 NRRI survey on competitive bidding.

"C" = commission; "U" = utility; "B" = both. The asterisk denotes state commissions with bidding rules.

order, "transmission access," "utility self-dealing," and "limited or restrictive participation."

State commissions viewed utility self-dealing or market power and too-limited or restrictive participation as more of a weakness than utilities, although neither was highly ranked as a weakness of competitive bidding.

Overall, it appears that the respondents agree with the basic idea that competitive bidding will reduce generation cost. The weaknesses cited are primarily the result of the relative novelty of competitive bidding for power supply. As experience is gained many of these weaknesses, particularly those connected with evaluation and system planning, will become less critical. This again underscores the need for flexibility in the development of a competitive bidding program which will allow adjustments to be made as the process evolves.

APPENDIX A

SUMMARIES OF EVALUATION METHODS USED BY THREE INVESTOR-OWNED UTILITIES

This appendix summarizes the evaluation procedures of three investor-owned utilities: Virginia Power, Central Maine Power, and Rochester Gas and Electric. Outlined are the evaluation factors, evaluation criteria, general methodology, project requirements, and data requirements. These summaries are intended to provide the reader with a general overview of the evaluation method used by the different utilities. This is not intended to replace the original RFP or be a complete representation of the RFP's content.

Virginia Power

The following is an outline of the factors and data requirements that Virginia Power (VP) considers when evaluating bids. It is derived from Virginia Power's 1989 solicitation RFP.

I. Price Factors -- approximately 70% weight in evaluation.

A. Prices for energy, capacity, and variable O&M.

B. Term of contract - prefers contracts that cover 25 years from the commercial operations date, differing contract lengths are considered.

C. Structure of capacity payments - prefers that the total present worth of the capacity payment over the 25-year term be such that not more than 90% of the present value of the payment will be levelized over the first 15 years of the term and the remaining portion of the present value be levelized over the remaining 10 years.

D. Dispatch

1. Dispatch includes factors such as the range of minimum and maximum operation, minimum time necessary between operating cycles, the amount of time needed to reduce to "minimum load" and to "no load," and the amount of time needed to reach minimum load and maximum load.

2. For any energy from a facility offered by a bidder that requires all or part of the facility's operation to be "must run," the energy price for such energy must be selected from one of the following:

   (1) For any portion of the facility's operation that is "must run," the energy price for such energy must be VP's cost of coal generation from its least cost fossil generating station.

   (2) The bidder may offer a stated price for each agreement year for generation during any portion of the facility's operation that is "must run." Any bidder proposing a "must run" facility is required to define the "must run" level and the hours to which such level will apply. For any portion of facility operation which is *not* "must run" (and is therefore dispatchable within the terms of the model agreement) the bidder must state an energy price.

3. For any facility with a design capacity of 75 MW or more, VP requires that the generators be equipped with automatic generation control capability. Automatic generation control is the automated regulation within predetermined limits of the power output of electric generators within a prescribed geographic area in response to changes in system frequency, tie-line loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or the established interchange with other geographic areas. This regulation is accomplished through communication links between VP systems operations center computer and each generator equipped for such control.

E. Timing/In-service date - VP will select proposals which offer the best means of meeting its power supply requirements.

F. Interconnection costs - Bidders for facilities inside VP's control area should not include interconnection costs (as defined in the Model Agreement) in their proposal. VP has determined that these costs should be direct costs to VP rather than unknown adjustments included in the capacity payments.

II. Nonprice Factors -- approximately 30% weight in evaluation

A. Viability of project - approximately 10% weight - based on the following:

1. Level of development - present stage of development of the proposed project.
2. Security - VP requires security in the form of an unconditional and irrevocable direct pay letter of credit issued by a bank in the amount equal to $36 per kilowatt (kW) of the estimated dependable capacity for the winter period specified by the bidder (section 13.3, 13.4, and 13.5 of Model Agreement). Also there is an obligation for suppliers of energy and capacity to reimburse VP for portions of payments made to the supplier disallowed by regulatory agencies (Article 18 of Model Agreement).
3. Financial status of the bidder - refers to the bidder and not to affiliated entity companies, unless the parent or affiliated entity company fully guarantees all obligations of the bidder.
4. Experience - VP considers the bidder's prior experience with constructing, financing, and operating power production facilities and the relevance of that experience to the technology proposed by the bidder. This includes both favorable and unfavorable experiences.

B. Fuel and fuel diversity - approximately 10% weight - VP prefers:

1. projects using fuel with stable prices and assured supplies, specifically solid fuels (coal, coal waste, wood) and those with no "fuel" cost (such as hydroelectric and municipal solid waste),
2. a mix of fuel types providing generation for its system to avoid undue reliance on any particular fuel,
3. multifuel-capable facilities for the flexibility they provide in future fuel markets, and
4. use of fuels from Virginia or North Carolina for facilities located in those states and within VP's control area.

C. Other factors - approximately 10% weight

1. Dispatchability - the operating effect of dispatchability will also be considered in the final evaluation of all proposals. If all other factors are equal, VP prefers projects which are fully dispatchable.

2. Ownership - VP has adopted a policy to diversify, as much as possible, the ownership of the capacity not owned by VP. VP, therefore, takes into account the cumulative amount of capacity owned by the bidder on VP's system in existing contracts (set out in the ownership diversification policy, attachment D in VP's RFP).
3. Location - proximity to transmission facilities and VP's load centers will be considered in the evaluation of proposals.
4. Exceptions to the model agreement - exceptions to the terms of the model agreement (provided in the RFP) are evaluated. Significant exceptions could render a proposal nonresponsive.
5. Commitments to steam users for cogeneration - cogeneration projects with large commitments to large, well-established, stable industrial steam users far in excess of QF minimums can enhance the evaluation of the project.

III. Required Information from Bidder for Evaluation

A. Technical description of facility - identify and describe major equipment, performance characteristics, nameplate rating, partial load performance, etc.

B. Siting - identify specific site; provide maps and charts of locations; whether site is owned, leased, or under option; and site's zoning status. VP will not award a contract to a bidder unless the site is owned or under option to purchase contingent only upon award of a power purchase agreement.

C. Permits, licenses, and regulatory approvals - bidder must identify and provide the status of required federal, state, and local permits, licenses, and regulatory approvals.

D. Experience - provide information on the bidder's experience in financing, engineering/designing, constructing, and operating/maintaining similar facilities.

E. Financing

1. Most current Securities and Exchange Commission form 10K of the bidder and all equity participants. If not available, a certified income statement and balance sheet of the bidder and any general

partners. Also, a diagram showing the relationships of all equity participants and their associated parent(s) or affiliate companies.

2. Status and plans for financing the proposed project during both the development period and the operations period.

F. Development schedule - detailed schedule of project development for each schedule proposed (preferred, earliest, latest) indicating financial, engineering, permitting/licensing, equipment procurement, construction, and start-up and test activities, as well as maintenance and outage activities for the first year of operation.

G. Organization - description of both the development and operating organizations, identifying all contract parties and their relationship to each other. Provide names and resume of all key development and operations people.

H. Fuel and fuel supply

1. Fuel types to be used or planned. Can other fuels be adapted?
2. Fuel supply and schedules, storage, etc., including strategy (spot/contract mix, origin, contract terms, control of reserves for dedicated supply, etc.).
3. Fuel transportation plans and contracts, etc., including site-specific transportation options.
4. Fuel resupply, including source, site unloading facilities, and transportation.
5. For fuels other than municipal solid waste, number 2 and 6 oil, wood, hydro, coal waste, natural gas, or coal, bidder should discuss source, availability, production process, or other data supporting the reliability of supply.

I. Maintenance - estimated number of scheduled maintenance outage days per year.

J. Economic impact

1. Estimated tax base addition.
2. Estimated local taxes payable in the first year of operation.
3. Estimated employment created per year by the project during construction.
4. Estimated full-time employment created by the operation of the plant.

Central Maine Power Company

Central Maine Power Company (CMP) uses a combination of utility scoring and self-scoring evaluation procedures. In the first part, the bidder provides CMP with information on the proposed facility. In the second part, the bidder checks off either Yes or No to a series of questions and enters the number of points for the given answer. The two parts are combined for a score that is used to select the order of participants for contract negotiating.

The following outline of factors and weights are drawn from CMP's May 26, 1989 RFP.

In Part I, the bidder is asked to supply the following information.

I. <u>Determination of Feasibility</u>

A. The location of the generating project and a specific physical description of the land on which the project and associated facilities will be located.

B. The overall physical design of the project, including maximum rating (kW), committed kilowatt-hours per year, and expected annual capacity factor and on-peak capacity factor in each year.

C. An engineering and economic feasibility study of the project, including specific descriptions of modification, reinforcement, or refurbishment of any existing or used equipment.

D. A technical description of the turbine generator upon which the feasibility study is based.

E. A description of the other major structures associated with generation (kWh) upon which the feasibility study is based.

F. Identification of the source of any water that will be used to directly generate electricity or cool a thermal facility.

G. A description of the amount of water that the project will require to generate electricity and a specific description of water intake and output locations and anticipated changes in water temperature.

H. A description of the atmospheric emissions that the project is expected to create, the noise level at which the project will operate, and any waste or by-products that the project will create.

I. The type and amount of fuel the project will require.

J. A legal opinion from the proposed facility's counsel stating that the information provided above has been reviewed and the bidder has both:

1. Ownership of right, title, or interest in all proposed facility lands and waters, or possession of an executed contract or option to acquire such right, title or interest, or proof of the right to use the power of eminent domain to acquire such right, title, or interest in the necessary lands and waters.
2. The right to use the applicable fuel source.

K. Approvals, licenses, permits, or variances

1. A statement from the proposed facility's counsel listing the approvals, licenses, permits, or variances and the specific requirements thereof that the proposed facility must obtain, including for IPP's any approvals or other regulatory actions required under the Public Utility Holding Company Act of 1935, FERC wholesale regulations, and Maine's laws concerning certificates of public convenience and necessity. With respect to each approval, license, permit, or variance indicate current status of each, date of application, date of administrative acceptance, and date of receipt (or expected receipt) of final approval of appropriate regulatory agency.
2. Where all necessary approvals, licenses, permits, or variances have not been applied for, please provide a demonstration based on prior experience, if any, that the bidder has the requisite ability, technical and financial resources, and experience to pursue successfully the necessary approvals, licenses, permits, and variances required for the project.
3. A document signed by a registered professional engineer stating that the information provided above has been reviewed, that the feasibility study is reasonable and consistent with statements concerning the characteristics of the boiler and turbine generator, water requirements, fuel requirements, emission, solid waste, site location, operating noise level, and other environmental requirements.

II. Availability of Fuel Supply

A. Please provide a detailed fuel supply plan that includes:

1. A description of the specific fuel characteristics that will be used to produce steam, if applicable, and generate electricity, to include supplemental or back-up fuels,
2. Annual fuel requirements,
3. Average and minimum fuel inventory stated in days of supply at normal facility output. State capacity factor used.

B. Please complete appropriate section or sections below.

1. Thermal generation:
   a. Fuel transportation distance (maximum and average in miles), mode of transportation, transporter (facility operators, fuel contractors, other).
   b. Existing fuel supply contractors who will be relied on (list by name, address, expected annual quantity).
   c. Plan for attracting and contracting with new fuel suppliers, number of potential new contractors, maximum and average distance from proposed facility to fuel resource (miles).
   d. Prior experience (if any) of the bidder in securing similar fuel supplies.
   e. Letter(s) of commitment from an experienced supplier(s) of fuel, to provide the project fuel requirements for the term of the power purchase agreement.
   f. Copy of long-term fuel contract with fixed price or other evidence demonstrating the long-term availability of fuel for the project.
2. Hydroelectric generation:
   a. Hydrological studies indicating the expected average, adverse, and favorable water supply conditions annually and monthly.
   b. A description of the water storage capability, the site of the headwater pond, and the number of hours of available drawdown at full generator output.
   c. The quantity of energy (kWh) that can be drawn from the pond in four hours, given nominal inflow conditions and meeting license and environmental constraints.

d. Any minimum outflow conditions imposed (or anticipated to be imposed) by regulatory authorities, including the period of the year, as appropriate.

3. Wind turbines

a. Meteorological studies of wind conditions. Provide site specific wind data, including incremental and average wind speeds over a year (or years).

b. The relationship between wind conditions and electrical output (kilowatts) for each wind turbine, and the total proposed (kilowatts) in response to this RFP. Note minimum wind velocity for electricity generation and maximum wind velocity before shutdown for each unit.

III. Financial Capability

A. A complete description of plans for financing the project.

B. A demonstration of financial capability to construct the project by at least one of the following:

1. Receipt and current effectiveness of a letter of commitment for financing the project from a recognized financial institution or investment source.

2. A statement from the bidder's certified public accountant that the bidder has sufficient capability to finance the project fully without relying upon external financial requirements.

3. Written commitments from individuals to purchase stock or partnership interests in the project or demonstrated past performance in marketing stock or partnership interests in similar projects.

4. Presentation of equivalent evidence that the bidder can successfully finance the project.

C. A demonstration of the ability to obtain the minimum level of insurance as described in Article XIX of the power purchase agreement.

IV. Construction and Operation Capability

A. A plan of construction of the facility by one or more qualified construction or development entities. Provide a summary of construction management to be performed. Please include the estimated cost of design and construction, including all financing costs at the time of project completion.

1. Project construction schedule, including licensing, design, and engineering phases, start and completion of construction and major intermediate milestones, start-up testing, and commercial operation.
2. Delivery schedule of major equipment components, including specifying any major equipment already purchased or on-site.
3. Qualifications of project manager and architect-engineer.

B. An operation and maintenance plan. Include executed agreements or other plans for the reliable operation and maintenance of the project for the duration of the power purchase agreement.

V. Additional Considerations

A. Bidders wishing to contract for a long-term power purchase agreement to supply firm capacity and energy may do so only if the capacity qualifies as New England Power Pool (NEPOOL) capacity in accordance with the Power Purchase Agreement and the capacity audit provisions of NEPOOL (CRS 4, as may be amended from time to time). (See Article IX of the PPA especially as it pertains to hydroelectric facilities.)

B. In addition, bidders of thermal facilities must guarantee deliveries at a capacity factor of 80% or greater during Central Maine's on-peak hours. (If 4.c or 4.d is elected in Part II of this RFP, then only if dispatched.) On-peak hours are currently defined as 8:00 a.m. to 9:00 p.m., Monday through Friday, during the months from April 1 through October 31; and 7:00 a.m. to 9:00 p.m., Monday through Friday, during the remainder of the year. On-peak hours do not include legal holidays which fall on weekdays. All other hours are defined as off-peak hours. (Note: at this time there are approximately 3,350 on-peak hours per year.)

C. Bidders must commit to a minimum annual generation level.

operational (not termination) liquidated damage provision in the power purchase agreement, which is designed to compensate CMP and its ratepayers for the project's failure to provide energy or capacity in accordance with the power purchase agreement provisions.
Yes = 0.5; No = 0.0

b. The bidder will provide an irrevocable letter of credit or other cash equivalent security acceptable to CMP to ensure the payment of the termination liquidated damage provisions in the PPA, which are designed to compensate CMP and its ratepayers for the loss of capacity and energy associated with pre-initial delivery date (IDD) or post-initial delivery date (IDD) termination of the project in accordance with the PPA provisions.
Yes = 0.5; No = 0.0

EI = 1 + 2.a + 2.b

3. Security index (SI)

a. The proposed facility's committed capacity is less than or equal to 100 kW.
Yes = 1.0;

b. If CMP determines that the proposal is front-end loaded in comparison with market price indicators, it will require the bidder to secure a suspense account and scores in Parts 3.b and 3.c will apply. If CMP determines that the proposal is not front-end loaded, CMP will disregard the aggregate numerical value determined for Parts 3.b and 3.c of the section. CMP will then substitute a value of 1.5 for the aggregate of Parts 3.b and 3.c and recalculate the total SI score accordingly.
Any required suspense account security may be in the form of:

i. Liquid security. Liquid security consists of cash in escrow under CMP's control or an irrevocable letter of credit.

ii. A third-party guarantee consisting of insurance or surety bonding.

iii. A first or second mortgage lien on the proposed facility's assets. The mortgage lien shall attach to all real and personal property assets of the bidder's proposed facility and any licenses or permits necessary for its operation. The mortgage lien shall be junior only to initial project construction financing (including term loan take-out refinancing) and working capital loans. The sum of prior mortgage liens and the amount of the suspense account not secured

Self-Scoring Section

If selected to negotiate with CMP, the bidder will assume all costs associated with interconnection studies undertaken to determine the feasibility of interconnecting to CMP's system.

State whether the bidder represents and warrants that the proposed facility will meet and will continue to meet the qualifications of a "qualifying facility" within the meaning of the Public Utility Regulatory Policies Act of 1978, 92 Stat. 3117, and any rules and regulations of the Federal Energy Regulatory Commission promulgated thereunder; and of the Small Power Production Act, Title 35-A, Maine Revised Statutes, Chapter 33, and any rules and regulations of the Commission promulgated thereunder; and that the bidder will make no modifications, alterations or other changes to the proposed facility or in the operation of its proposed facility or other proposed facilities of the bidder which changes would cause the proposed facility to fail to meet the criteria for qualification that may be in effect from time to time during the term of any resulting Power Purchase Agreement.

If the proposed project does not meet the requirements of a "qualifying facility," any agreement resulting from negotiations with CMP may be subject to approval by the Maine Public Utilities Commission.

The following is a summary of CMP's self-scoring method.

1. Capacity index (CI) -- This project guarantees CMP firm capacity by:
   a. All facilities -- Qualifying as NEPOOL capacity, to the full extent of the facility's committed capacity in accordance with the capacity audit criteria. Bidders answering "no" to this question will not qualify for a long-term PPA for capacity and energy.
   b. Thermal facilities only -- Being subject to a semiannual capability audit test and having a capacity factor of 80% or greater during on-peak hours.
   c. Hydroelectric facilities only -- Being subject to a semiannual capacity audit test and agreeing to an annual minimum generation level.

If the applicable questions above are answered yes, CI = 2.0; otherwise CI = 1.0.

2. Endurance index (EI)
   a. The bidder will provide an irrevocable letter of credit or other cash equivalent security acceptable to CMP to secure the payment of the

by liquid security or third-party guarantee shall not exceed 100% of the fair market value of the facility. Mortgage liens must be accompanied by documentation acceptable to CMP, including but not limited to a recognition agreement among bidders, lenders, and CMP protecting the rights of CMP regarding the amount of prior liens, amortization thereof, and foreclosure of prior liens. In all cases involving security for suspense accounts, bidders must provide opinions of counsel regarding the validity of security obligations and priority of any mortgage and other matters requested by counsel for CMP.

Bidders may elect to provide the security in one or a combination of forms described above. Indicate the type and maximum amount of security that the bidder will provide. Note that any suspense account balance must be retired within 15 years from the initial date of delivery.

3.b.1 Bidder will provide 100% liquid security:
Yes = 1.0 (go to 3.c); No = 0.0 (go to 3.b.2).

3.b.2 Bidder will provide 100% third party guarantee security:
Yes = 0.5 (go to 3.c); No = 0.0 (go to 3.b.3).

3.b.3 Bidder will provide 100% mortgage lien security:
Yes = 0.2; No = 0.0 (go to 3.b).

Bidder may elect to provide a combination of the above types of security. Attach a detailed description of the proposal including the percentage and maximum dollar amounts for each type of security. Bidders may also suggest a rating for 3.b not to exceed 1.0.

c. The proposed facility's committed capacity is less than or equal to 1,000 kW.

Yes = 0.2; No = 0.0

d. At any time after initial date of delivery, the amount of project debt financing will not exceed 75% of the total cost of the project.

Yes = 0.5; No = 0.0

SI = 1 + 3.a + 3.b + 3.c + 3.d

4. Operating index

a. CMP will have the ability to dispatch the facility, as described in the dispatchable (firm) standard PPA, including raising the output to the maximum rating (kW) when required.

Yes = 0.3; No = 0.0

b. CMP will have the ability to schedule maintenance of the facility. (The bidder may propose preferred scheduled maintenance outages prior to June 1 of the preceding year based on CMP's schedule.)

Yes = 0.2; No = 0.0

Note: There can be a "yes" answer to only one of the items 4.c through 4.g below. If the bidder answers "yes" to item 4.c or 4.d, and if negotiations result from this proposal, they will be based on the standard capacity/energy PPA. Also, the price proposal must show separate prices for capacity and energy payments. If the bidder answers "no" to both 4.c and 4.d, any resulting negotiations will be based upon the dispatchable (firm) PPA.

c. The bidder will dispatch the facility utilizing automatic generation control (AGC) to meet the needs of CMP's system during on-peak and off-peak hours. Dispatch may be from off-line to full output, although AGC may be from 60% to 90% of full output. Dispatch will be at a monthly capacity factor of between 25% and 95% and at an annual capacity factor of 75%, provided that the facility is available for operation during the dispatched hours.

Yes = 2.5; No = 0.0

d. The bidder will operate the facility in accordance with CMP's dispatcher's instructions from minimum load (25% of committed capacity) to full output during on-peak and off-peak hours. Dispatch will be at a monthly capacity factor of between 25% and 95% and at an annual capacity factor of 75%, provided that the facility is available for operation during the dispatched hours.

Yes = 2.0; No = 0.0

e. The bidder will maximize deliveries during on-peak hours. During off-peak hours, the facility will be off-line (reasonable ramping on or off-line will be permitted during off-peak hours), unless requested by CMP to operate at a higher level. The PPA will include a tiered rate structure to encourage on-peak generation.

Yes = 1.5; No = 0.0

f. The bidder will maximize deliveries during on-peak hours. During off-peak hours, the facility will be at a minimum load level not to exceed 25% of the committed capacity, (reasonable ramping to or from minimum will be permitted during off-peak hours), unless requested by CMP to operate at a higher level. The PPA will include a tiered rate structure to encourage on-peak generation.

Yes = 1.0; No = 0.0

g. The bidder will generate and deliver to CMP at least 55% of its generation (kWh) in each billing cycle during CMP's on-peak hours. The PPA will include a tiered rate structure to encourage on-peak generation.

Yes = 0.5; No = 0.0

OI = 1.0 + 4.a + 4.b + 4.c + 4.d + 4.e + 4.f + 4.g

5. Alternatives index (AI)

Information is attached which describes in detail alternative characteristics the bidder is incorporating into the proposal, in place of one or more of the preceding indices. The bidder may also suggest a rating to be associated with these characteristics. CMP reserves the right, in its sole discretion, to modify the proposed rating or to establish a rating, if one is not proposed, based upon these characteristics.

Yes = ________; No = 1.0

6. Overall rating index

Overall Rating Index = CI x EI x SI x OI x AI

7. Price proposal

Please attach information that describes in detail the pricing characteristics that you are incorporating into your proposal.

Bidders may base their bids on (1) annual rates, (2) a levelized rate, or (3) a base rate tied to a percentage of an index or indices which vary annually (e.g., GNP implicit price deflator). If the bidder answers "yes" to item 4.c or 4.d then the price proposal must separate total payment into capacity and energy payments.

Rochester Gas and Electric Corporation

Rochester Gas and Electric Corporation (RG&E) uses a two-step evaluation process. In the first step, qualifying projects are evaluated and ranked using a self-scoring process and an "initial award group" is selected. The self-scoring process consists of a series of worksheets provided in the RFP that the bidder completes. In the second step, RG&E conducts an in-depth analysis of the initial award group projects based on detailed project-specific data provided by the bidders. A "final award group" is then selected that will provide the best combination of needed resources.

The following outline of RG&E's supply project evaluation factors is drawn from their RFP issued September 11, 1990 (with a response deadline of March 11, 1991) for power supply projects (demand projects are evaluated separately with different factors).

Eligibility Requirements

The following is an outline of RG&E's eligibility requirements.

I. Project Location

Supply options may be sited in any location that permits electrical interconnection. RG&E prefers projects be located where they are most beneficial to the company's overall system operations. Any costs or savings RG&E incurs by receiving power at various locations will affect selection of the final award group, as will any interconnection and wheeling costs RG&E will incur. RG&E will be responsible for arranging and paying for the costs, if any, of transmission of electricity from the "interconnection point" to the "delivery point." Locations in descending order of preference:

A. preferred locations within RG&E's electric service territory coupled with an ability to interconnect with RG&E's electric system at the 115 kV transmission level,

B. locations within RG&E's service territory contiguous to Lake Ontario, and

C. other locations within the confines of the Northeast Power Coordinating Council.

II. On-Peak and Off-Peak Bid Capacity

The maximum on-peak bid capacity or bid capacity for an individual project is 100 percent of the resource block (50 MW in this solicitation). There is no minimum on-peak bid capacity. Projects with on-peak bid capacity of less than 2 MW can bypass the auction process. There is no maximum or minimum off-peak bid capacity, however, off-peak bid capacity must be reasonable given the on-peak bid capacity and consistent with that on-peak bid capacity.

III. On-Peak and Off-Peak Bid Energy

There is no maximum on-peak and off-peak bid energy for an individual project other than the technically feasible maximum energy production of the project. The minimum on-peak and off-peak bid energy will be the energy which would be supplied by the proxy project (specified by the bidder) multiplied by the on-peak bid capacity of the proposed project, unless the project achieves its capacity by energy storage.

The energy output ultimately purchased by RG&E from dispatchable facilities will depend on the dispatch criteria applied by the New York Power Pool to all dispatchable energy sources. The current criteria are first to dispatch units as necessary to maintain electric system security and stability throughout the state, and second to dispatch units to minimize the cost of electricity to all utility customers. The energy output ultimately purchased by RG&E from must-run facilities will depend primarily on the energy available from those facilities. Although projects may be either fully or partially dispatchable or operate on a must-run basis, RG&E prefers that projects be dispatchable facilities.

IV. Proposed In-Service Date

Projects with proposed in-service dates on or before the required in-service date may participate.

V. Contract Deposit

Within 90 days after contract execution and delivery, all bidders in the final award group will be required to post a contract deposit of $15 per kilowatt of on-peak or off-peak bid capacity (whichever is higher) with RG&E. Bidders also have the opportunity to increase project scores by offering an additional contract deposit of $3.75 or $7.50 per kilowatt of on-peak or off-peak bid capacity (whichever is higher), to be posted at the same time as the contract deposit.

VI. Front-Load Security

Front-load security is required on all contracts where front loading is expected to occur, that is, where expected payments by RG&E at any time are anticipated to exceed RG&E's projected avoided costs. At minimum, bidders must provide RG&E with a form of front-load security equivalent to 50 percent of the overpayment each year until the breakeven year. Bidders with such projects also have the opportunity to increase project scores by granting to RG&E additional front-load security. Security mechanisms may include, but are not limited to, a lien on any tangible project facilities, cash, irrevocable letter of credit, corporate parent guarantee, marketable securities, bonds, proof of basic business insurance, or a maintenance escrow account.

Front-load security will be required from bidders offering less than 2 MW of on-peak bid capacity and who chose to bypass the auction process. However, in the absence of a bid price, the amount of that security and the number of years it will be required cannot be determined. Front-load security requirements for these projects will be specified by RG&E when the price to be offered to bidders of these projects has been calculated.

VII. Threshold Requirements

Each project proposal must meet the following requirements in order to be considered an eligible project proposal.

A. Bid Price and Contract Term

Bidders must provide a bid price or bid price formula for a contract term that ends 15 years after the required in-service date, unless the technology has a lifetime of less than 15 years. Bidders may also submit additional project proposals offering reasonable alternative bid price formulae and contract terms for the same project. Bidders may not submit a single project proposal with more than one bid price, bid price formula, or contract term.

To minimize risk to RG&E's customers, bidders are required to document that the bid price and bid price formula are based on verifiable projections of all project-specific fixed and variable expenses (including environmental control, benefit, and mitigation costs and the costs of all equipment, testing, and maintenance necessary to enable RG&E to dispatch dispatchable facilities) and that the bid price and bid price formula have been structured to account for reasonable variations in those projections. Any escalation indices used in a bid price formula must bear a reasonable relationship to changes in bidder's costs in general, and fuel costs in particular.

Bidders may not propose changes to the standard contract that will effectively invalidate the bid price. Unacceptable clauses include provisions for future price renegotiation, most favored nation provisions that would increase the bid price if higher prices are accepted by RG&E in future resource auctions, or market-out provisions that would allow renegotiation of the bid price if the market changes.

The threshold requirement for a bid price is waived for bidders offering less than 2 MW of on-peak bid capacity who chose to bypass the auction process. The contract term threshold requirement is not waived.

Bidders may offer variable pricing for energy through quotes or dispatch mechanisms at which bidder will offer for sale and RG&E may purchase, at their mutual discretion, energy which may be available from the project in addition to the on-peak and off-peak bid energy.

B. <u>Project Description</u>

Bidders must: (1) identify the specific type of generation technology to be used, (2) identify any associated control equipment potentially required to satisfy environmental consideration, (3) demonstrate that the proposed generation technology and environmental control equipment is commercially available, and (4) identify the cooling and make-up water supply requirements and availability. Preliminary design and engineering studies must be completed which include at a minimum: (1) major equipment to be utilized, (2) a site layout plan, and (3) heat balances.

C. <u>Project Management Plan</u>

Bidders must have developed a project management plan that at a minimum identifies: (1) principals, (2) expected construction management lines of authority and responsibility, and (3) expected or actual operational staffing levels including contractor utilization. When available, bidders shall provide a list of firms which will participate in the design, construction, operation, and maintenance of the project.

D. Permits, Licenses, and Environmental Questionnaire

Bidders must identify any and all required site-specific permits and licenses and all data requirements of the applicable permitting/licensing agency, and prepare a schedule and plan for obtaining all permits and licenses. Bidders will be solely responsible for applicable environmental regulations.

Bidders must provide a complete environmental licensing assessment which:

1. identifies all required environmental permits and licenses,
2. identifies key environmental issues in the siting of the facility and the key environmental permits likely to be most critical to the licensing process,
3. identifies all environmental control technologies and mitigation measures to be employed in designing the facility: (1) to comply with applicable regulations and any anticipated permit limitations, (2) to carry out any anticipated mitigative measures that might be required as a result of a State Environmental Quality Review Act environmental review, and (3) for any other particular environmental considerations associated with the project,
4. identifies all environmental data sources to be employed in the assessment of environmental impacts as required by the State Environmental Quality Review Act (SEQR),
5. identifies all resources to be used in the environmental licensing process,
6. provides a proposed licensing schedule with identification of all significant milestones,
7. identifies efforts proposed which will provide for public access to and use of the site or its environs for recreational or other public benefit purposes.

E. Cost Estimates

Bidders must base the bid price on project-specific cost estimates derived: (a) from generic capital costs and operation and maintenance expenses (including any alternative fuels) from facilities similar to the project, or (b) from project-specific engineering and design studies developed by a licensed engineer. In addition, bidders must have estimated all relevant costs required to meet the interconnection and operating requirements. Bidders must be prepared to provide full documentation of all data sources and major assumptions used to develop cost estimates.

If RG&E is the host utility, the interconnection costs included in the project cost estimates must be calculated as described in the RFP. If RG&E is not the host utility, an estimate of interconnection costs must be obtained from the host utility in writing and provided with the project proposal.

F. Fuel Plan

Bidders must provide satisfactory evidence of (a) market access (supply and transportation) to the preferred and secondary fuel alternatives, or (b) availability of the preferred and secondary energy sources, as appropriate, of the contract term. Bidders must have developed a fuel procurement and transportation plan for the contract term.

RG&E expects bidders to maintain at least the following inventory levels of their primary fuel: (a) 45 days' supply of coal onsite or in the sole control of the bidder; (b) 20 days' supply of oil onsite or in the sole control of the bidder; (c) 20 days' supply of natural gas, contractual arrangements equivalent to a maximum 50 percent curtailment in the event of a region-wide curtailment of natural gas, or the equivalent of 20 days' supply of an alternate fuel; or (d) 2 days' supply of refuse or waste plus the equivalent of 20 days' supply of an alternate fuel.

G. Basis for Compensation

Payments will be made by RG&E to the successful bidder periodically over the contract term based on capacity and energy received. Bidders must specify a measurable basis on which those payments will be calculated and rendered.

H. Performance Standards and Guarantees

Bidders must stipulate the design and operating performance standards that the project will be guaranteed to achieve (e.g., minimum on-peak and off-peak capacity, minimum on-peak and off-peak energy, unit availability characteristics, unit dispatchability characteristics, minimum equivalent availability factors). Bidders may propose penalty provisions for failure to perform at guaranteed levels.

I. Milestone Schedule

Bidders must prepare a detailed project milestone schedule indicating critical path requirements, including a schedule for equipment procurement and project construction. Bidders must identify both the expected and outer limit dates for key milestones.

J. Financing Plan

Bidders must provide a written statement from a recognized and reputable financial institution verifying that such an institution could reasonably be expected to finance the project.

Bidders must be prepared to provide more detailed financial information if it is selected for the final award group, including: (1) the project's financing plan, including expected levels and costs of equity and debt, and potential sources of funds over the construction period; and (2) bidders' pro-forma income statements, balance sheets, and after-tax cash flow statements with applicable debt coverage ratios consistent with cost estimates and the bid price forecast on an annual basis for the portion of the contract term during which the debt will be amortized. Bidders' financing plan must demonstrate ability to maintain debt coverage each year over the term of the debt equal to or greater than 1.1, and after the term of the debt, operating coverage each year equal to or greater than 1.0.

If the energy price portion of bidders' bid price is not indexed to the cost of fuel used by the project, bidders must demonstrate adequate capital to guarantee its ability to continue to supply energy to RG&E at the bid price in the face of adverse market conditions for project's fuel supply.

K. Interconnection Plan

Bidders must have developed a plan that will comply with the system interconnection agreement. If RG&E is not the host utility, the plan must identify the host utility, bidders must provide copies of documents provided by the host utility describing the terms and conditions of the interconnection, and the plan must comply with those terms and conditions. Whether or not RG&E is the host utility, bidders must identify: (1) the specific interconnection point at which the project will be physically connected to the existing electric network and through which all on-peak and off-peak bid energy from the project will be made available to RG&E, and (2) the route the interconnection facilities have been assumed to follow when calculating the interconnection costs.

L. Operation and Maintenance Plan

Bidders must have developed an operation and maintenance plan that will comply with the minimum requirements and performance guarantees in the sample operating agreement.

M. Waste Disposal Plan

Bidders must have identified any waste materials and developed a plan for their sale, use, or disposal.

N. Thermal Energy

For cogeneration facilities that seek to be considered as PURPA-qualifying facilities (QFs), bidders must have identified a use and user for any thermal output of the project and must: (a) provide evidence that the bidder is actively negotiating a long-term sale of the thermal output, or (b) provide satisfactory evidence of an established market for the project's thermal output for the contract term. Bidders must demonstrate that thermal output, utilization, and facility efficiency meet current industry and applicable government requirements, and that the project is qualified in all respects to be certified by FERC.

If a bidder of a cogeneration project is selected for the final award group, that bidder must, within 60 days thereafter, provide to RG&E a copy of the contract with (or letter of intent from) the project's thermal output user.

RG&E will waive this threshold requirement only if the bidder guarantees the performance of the project and its bid price even if no use is found for the thermal output or no thermal output sales can be made.

Step I -- Self-Scoring Section

The initial award groups will be comprised of the bidders of the highest-scoring eligible project proposals with a cumulative on-peak bid capacity approximately equal to the initial award block. If necessary, the initial award groups will be enlarged to include bidders of the highest-scoring project proposals whose total on-peak bid capacity is equal to (or greater than) the minimum initial award block. In addition, bidders of any project proposal that scores more than 90 percent of the lowest-scoring project proposal selected on the basis of the initial award block and/or the minimum initial award block may be included in the initial award group.

Project proposals selected for the initial award group will be those that best balance value to RG&E's customers with project viability and RG&E's operational needs. The scoring system recognizes the tradeoffs among five factors (summarized below) which are used to find the project score. Bidders can develop project proposals that maximize the project score and potential for selection to the initial award group. The five factors that form the basis of the scoring system are summarized in the schematic diagram of figure A-1. The diagram illustrates the relationship and relative weight of each factor to the project score. A varying number of component scores are summed to produce the remaining factor scores, and the factor scores are then multiplied to produce the project score. The following outline summarizes RG&E's the self-scoring process for supply-side projects.

I. <u>Project Score</u>

Project Score =

Price Factor Score x System Optimization Factor Score x Success Factor Score x Longevity Factor Score x Economic Risk Factor Score

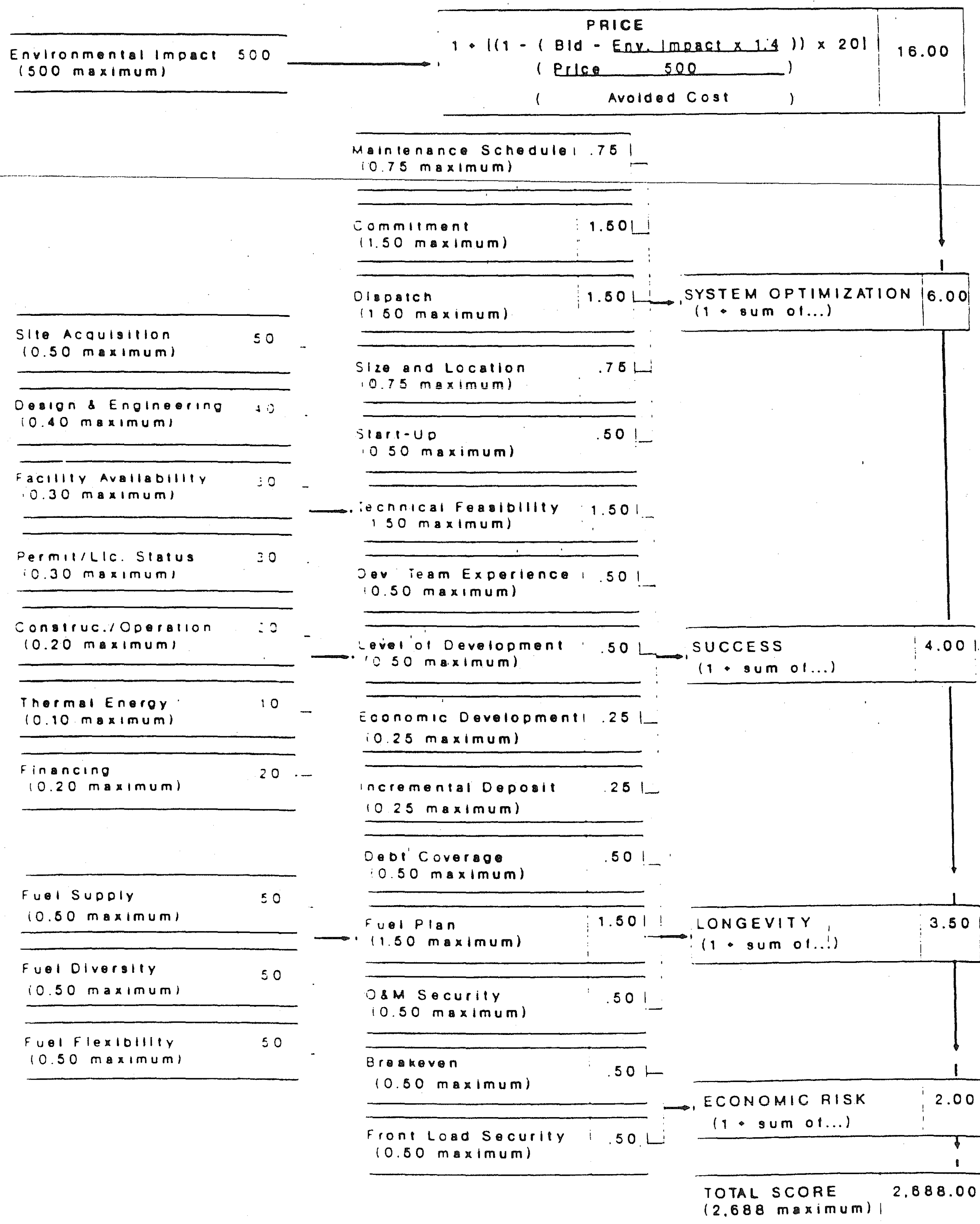

Fig. A-1. Schematic summary of supply scoring factors for RG&E.

II. Price Factor

Price Factor Score =

$$1 + \left[\left(1 - \left[\frac{\text{Bid Price} - (e \times 1.4/500)}{\text{Avoided Cost}}\right]\right) \times 20\right]$$

where:

Bid Price = sum of the present value total annual payments to project divided by the annual minimum bid energy over the contract term times the on-peak bid capacity of the project,

Avoided Cost = sum of the present value total annual avoided costs over the contract term divided by the annual minimum bid energy over the contract term (cents/kWh), and

e = environmental impact, defined as the potential for the project to cause environmental impacts in the areas of air emissions (sulfur oxides, nitrogen oxides, particulates, carbon dioxide), water effects (cooling water volume as a proportion of source water body volume, fish protection, water quality), and land effects (acreage, terrestrial, visual aesthetics, transmission, noise, solid waste disposal, solid waste as fuel, fuel delivery, and sensitive receptor areas).

III. System Optimization Factor (consistent with the planning and operational needs of RG&E).

A. Maintenance schedule: the extent to which planned maintenance of the project can be specified and/or modified by RG&E with advanced notice.

B. Unit commitment: the extent to which the project can be committed or decommitted on a daily and weekly basis by RG&E.

C. Dispatch: the extent that the project will vary output levels and provide automatic generation control at RG&E's direction.

D. Unit size and location: the desirability of the amount of on-peak bid capacity offered by the project and whether it is located in a preferred geographic area.

E. Start-up ability: whether the project will provide black start or quick start capability, that is, the ability to start up without an off-site power source or to start up quickly from a cold (not operating) condition.

IV. Success Factor (likelihood that the project will be completed).

A. Technical feasibility: the technical feasibility of the project based on

1. the status of site acquisition, design and engineering, and permits and licenses, and
2. the performance history of similar facilities.

B. Level of development: the status of milestones of development, specifically, facility construction or operation, an agreement with a thermal host to enable the facility to achieve QF status, and committed capital.

C. Development team experience: bidder's experience in developing facilities that are similar to the project.

D. Economic development: the potential impact on jobs within RG&E's service territory which can be directly attributed to the project or to other bidder facilities.

E. Additional contract deposit: bidder's willingness to increase the required contract deposit.

V. <u>Longevity Factor</u> (likelihood the project will operate throughout the contract term in a reliable and economic manner).

A. Fuel plan: the project's contribution to RG&E's desired generation mix diversity, bidder's access to fuel supplies and fuel transportation for the contract term, and the project's ability to burn more than one fuel.

B. Debt coverage: the extent to which debt coverage ratios exceed the required amount.

C. Operations and maintenance security: the extent to which the bidder is willing to provide protection to RG&E, in the form of power plant operating and maintenance experience or "comprehensive powerplant performance insurance," to secure bidder's obligation to provide the contracted capacity and energy over the contact term.

VI. <u>Economic Risk Factor</u> (compare project proposals based on project-specific attributes which are indicative of the relative economic risk to RG&E's customers over the contract term).

A. Breakeven: the number of years for the project to break even, that is, the number of years in the contract term before the present value of the total payments by RG&E to the project will equal the present value of RG&E's total avoided costs.

B. Front-load security: the type and amount of front load security offered by bidder to mitigate the effects of front loading.

VII. Project Score

A. Project score = price factor score
x system optimization factor score
x success factor score
x longevity factor score
x economic risk factor score

Step II -- Determination of the Final Award Group

In step II of the evaluation process, RG&E will use the detailed project data supplied by bidders to conduct an in-depth evaluation of the project proposals in the initial award groups. This evaluation process will assess the benefits and costs of the projects under different scenarios about future load growth, fuel prices, and so on. This process will enable RG&E to quantify the benefits associated with specific project attributes.

In addition, the results of project assessments across different future scenarios will allow RG&E to select the combination of projects that provides high-quality energy services at lowest cost while minimizing financial risks and negative environmental impacts. RG&E will determine the final award groups by selecting the group of proposals that, in the company's judgment, best satisfies these multiple planning objectives.

Bidders should be aware that adjustments will be made to take into account unequal project scales and unequal project lifetimes. In addition, if RG&E receives either two or more project proposals for the same generating unit or thermal load, or multiple project proposals identified by the bidders as mutually exclusive, this will be taken into account during the evaluation. Finally, bidders should be aware that the ranking of project proposals will be influenced by any wheeling costs that will be incurred by RG&E between the interconnection point and the delivery point for projects outside RG&E's service territory. The following outline summarizes the procedure RG&E uses to determine the final award group.

I. Ranking Projects of Unequal Scale

The purpose of the step II evaluation process is to determine the mix of projects that in combination provides the total resource block in the most cost-effective manner overall. Bidders proposing to supply resources in quantities smaller than the resource block will be evaluated in combination with other proposals. This step is necessary to define mutually exclusive investment options.

If, for example, RG&E has specified a resource block of 50 MW and it receives two project proposals with an on-peak bid capacity of 50 MW each, and two other project proposals of 20 MW and 30 MW, respectively, then the first two project proposals would be evaluated separately since they provide on-peak bid capacity equal to the entire resource block. The second two project proposals would be evaluated together because neither one alone can supply the entire block.

II. Ranking Projects with Unequal Lifetimes

RG&E prefers contract terms ending 15 years after the required in-service date but recognizes that other contract lengths might be necessary. If proposals received have varying contract terms, adjustments will be made in the step II evaluation process to ensure that all project proposals are comparable. For example, the benefits and costs of two projects cannot be compared directly if one has a contract term of 10 years and the other a contract term of 25 years.

The adjustment required will depend upon the types of project proposals that are received. In some cases it will be appropriate to assume that a project with a shorter contract term can be replaced in kind at the end of its contract term. In other cases, it will be appropriate to examine benefits and costs over the shortest common analytical period of the projects. In still others, it may be necessary to examine other means of providing interim resources so that common analytical periods can be developed. For example, if two projects are being compared, one with a 10-year and the other with a 25-year contract term, it may be necessary to determine other means of obtaining interim resources during years 11 through 25 of the shorter project in order to determine which of the two projects is preferable.

III. Ranking Projects with the Same Generating Unit or Thermal Load

Project proposals may be found to be mutually exclusive, particularly those that offer different contractual terms or pricing arrangements for the same generating unit, or multiple cogeneration that rely on the same thermal load. Such projects will not be combined when ranking projects of unequal scale, since it would be impossible to implement both projects simultaneously.

IV. Ranking Projects with Wheeling Costs

If projects for which the interconnection point and the delivery point are not identical and will cause RG&E to incur wheeling costs attributable to the project in addition to the bid price (and if those costs will be sufficient to influence the ranking of the project proposals in the initial award group or the selection of project proposals for the final award group) the bidder of those project proposals will be notified during this step of the evaluation process. Bidders should be aware that reranking due to this factor may remove bidders from the initial award group.

V. Environmental Review

RG&E will evaluate the environmental compatibility of proposed projects in light of environmental standards. However, RG&E has no authority to issue permits, licenses, or approvals, or to judge the ultimate environmental acceptability of bidders' proposals. Such judgments and approvals must be made by the appropriate governmental authorities that have responsibility for licensing and approving such projects. The proposed procedure will be used as an environmental evaluation tool to ensure that a successful bidder's proposal appears to be environmentally sound and licensable and to determine if the costs associated with the environmental control measures identified have been adequately factored into the bid price.

VI. Postbidding Negotiation

In discussing the selection of a final award group from an initial award group, PSC opinion 88-15 explicitly states ". . .other approaches, including postbidding negotiation, would also be permissible." While RG&E will not permit postbidding negotiation to affect the initial ranking procedure, RG&E believes that the use of negotiation to select the final award group from the initial award group may yield significant customer benefits. These negotiations will be used when appropriate to determine mutually agreeable changes to a project that will enable it to better fit into the final award group. The flexibility of allowing for negotiations prior to final selection will aid both bidders and the company's customers. RG&E reserves the right to negotiate with any member of the initial award group prior to selection of the final award group.

Where appropriate, postbidding negotiations will be conducted according to the following guidelines:

A. Negotiation will be limited to changes that, in the opinion of RG&E, are reasonably obtainable and which would be required to address attributes which would cause the project as proposed to be unacceptable to the company;

B. RG&E will notify bidders that it will be selected to the final award group subject to specific conditions that are to be negotiated;

C. The conditions to be negotiated and the reasons for the request will be fully identified to bidders;

D. RG&E will not seek concessions in bid price terms except in unusual circumstances and where nonprice concessions would be offered to bidders;

E. RG&E will negotiate in good faith with bidders to finalize a contract that substantially fulfills RG&E's stated requirements and is mutually acceptable to both parties;

F. A contract will be made with a bidder if the bidder agrees to comply with RG&E's conditions of acceptance; and

G. RG&E will not conduct simultaneous negotiations with bidders of projects that are competing for a contract. Good faith efforts to finalize negotiations for contracts will be completed with bidders of higher-scoring project proposals before negotiations with competing bidders are initiated.

VII. Finalization of Award Group and Contract

RG&E will determine the composition of the final award group and notify all bidders of their rank within 60 days following receipt of the last notice of acceptance required to determine the final composition of the initial award group.

All bidders selected to the final award group will be required to submit complete financial information within seven business days following receipt of notification.

Within 90 days after determining the composition of the final award group, RG&E shall enter into a project contract with each final award group member.

If changes to a sample contract or any documents referenced therein are requested by bidders, those requested changes will be negotiated. If, after 30 days, the parties cannot reach an agreement, the parties may mutually agree to extend the contract finalization period.

If any final award group member changes any representations made in its project proposal during contract negotiations, RG&E shall immediately suspend the contract negotiations with that bidder and rerank the project proposal according to the new representations. If such reranking does not affect the project's standing in the final award group, then the contract finalization process will be resumed. If the reranking evaluation results in a conclusion that the bidder is no longer eligible to be included in the final award group, then the bidder of the reranked project proposal will be disqualified and replaced with the bidder of the next-highest scoring eligible project proposal in the initial award group that was not selected for the final award group.

Certain performance guarantees of bidders are required as outlined in the sample contract.

APPENDIX B

THE 1990 NRRI SURVEY RESULTS ON COMPETITIVE BIDDING PRACTICES BY STATE PSCs AND IOUs

Introduction

The NRRI in February, 1990, issued a survey on competitive bidding to all state Public Service Commissions (PSCs), including the District of Columbia, and to most Investor-Owned Electric Utilities (IOUs). The survey was to be completed by April, 1990. The purpose was to collect information about the various methods and current usage of competitive bidding in securing the power supply needs of electric utilities. A total of forty-nine state PSCs and eighty-six IOUs from forty-eight states responded to the survey. All states have at least one respondent, and in forty-six states, both parties responded.

The Survey's Contents

The survey combines five areas of interest. Initial questions concern the rulemaking and solicitation activities of PSCs and IOUs both past, present, and future. Those with rules or drafts of rules are further queried on their solicitation, evaluation and selection, and negotiation and contractual practices. Those developing rules are asked to describe their program's progress while those not currently active are asked to explain their present lack of interest. Questions about solicitation practices concern their timing, RFP responsibilities, participant eligibility, the disclosure of information, and entry fees. Questions about evaluation and selection practices concern the relative importance of price and nonprice factors, the inclusion of demand-side offers, the evaluation and selection responsibilities, and the subsequent disclosure of details. Questions on negotiation practices cover the approval process for final purchase contracts. Questions on contractual practices cover security and payment provisions, operation and maintenance standards, and legal rights of the purchasing utility. The survey ends by asking all respondents to discuss the perceived strengths and weaknesses of competitive bidding as a viable way to achieve desired ends.

Organization of the Appendix

The appendix includes a copy of the survey and cover letter, a summary table, and the survey responses. The summary table enables a comparison between PSC and IOU responses for most questions. Raw responses are grouped first by origin--PSC or IOU--and then by the current progress in rulemaking activities. The responses of PSCs with rules or drafts of rules are combined and presented together. The responses of those developing rules or not currently active are likewise combined. The responses of IOUs are grouped and presented in similar fashion.

The National Regulatory Research Institute

OHIO STATE UNIVERSITY

1080 Carmack Road
Columbus, Ohio 43210-1002

Phone: 614/292-9404
FAX: 614/292-7196

14 February 1990

Name
Address

Dear ____________:

Enclosed is a survey that is being conducted by the National Regulatory Research Institute (NRRI). The NRRI was established by the National Association of Regulatory Utility Commissioners (NARUC) at The Ohio State University in 1976 to perform research on the regulation of public utilities and related public policy. The survey is an integral component of a research project undertaken as part of NRRI's 1990 research agenda.

The survey is being sent to state utility commissions and investor-owned electric utilities. The purpose is to determine the procedures and practices that states and utilities use or plan to use when employing competitive bidding to secure future power supply needs.

The results of the survey will be presented in an Institute report to all state utility commissions. The quality and usefulness of the report will be greatly enhanced by your cooperation. While the length of the survey may appear daunting, most of the questions are yes/no or multiple choice.

Please return the survey with your responses by March 23. Your participation is greatly appreciated.

Sincerely,

Kenneth Rose, Ph.D.
Senior Institute Economist

THE NATIONAL REGULATORY RESEARCH INSTITUTE

SURVEY OF PUBLIC UTILITY COMMISSIONS AND INVESTOR-OWNED ELECTRIC UTILITIES ON COMPETITIVE BIDDING PROCEDURES

This survey is being conducted by the National Regulatory Research Institute (NRRI). The NRRI was established by the National Association of Regulatory Utility Commissioners (NARUC) at The Ohio State University in 1976 to perform research on the regulation of public utilities and related public policy.

The results of this survey will be reported in an NRRI report to all state utility commissions. The purpose of the study is to examine the practical issues that electric utilities and state commissions face when implementing a competitive bidding program for electric power supply. Obviously, the usefulness of the report is dependent on the quantity and quality of the responses. Your participation is important to the success of this project.

The individual responses from utilities to this survey will not be presented in the report; the results of the survey will only be reported in aggregate form. Survey respondents will receive a complimentary copy of a summary of the survey results when completed.

Please mail responses to:

Kenneth Rose
The National Regulatory Research Institute
1080 Carmack Road
Columbus, OH 43210-1002

If you have any questions concerning the survey, please contact Dr. Kenneth Rose or Mr. Mark Eifert by mail at the above address, by telephone at 614-292-9404, or by FAX at 614-292-7196.

Respondent Information:

Name: ____________________________

Title ____________________________

Organization: ____________________________

Address: ____________________________

____

City, State Zip Code: ____________________________

Telephone Number: ____________________________

Respondent Name: ____________________

Organization: ____________________

____

NRRI SURVEY OF PUBLIC UTILITY COMMISSIONS AND INVESTOR-OWNED ELECTRIC UTILITIES ON COMPETITIVE BIDDING PROCEDURES

Please check the statement below that best describes your current situation with regard to competitive bidding for electric power supply and proceed to the indicated section of the survey.

____ Rules and/or procedures in place -- proceed to Part I.

____ Currently developing a competitive bidding process <u>with a draft</u> of the rules and/or procedures -- proceed to Part I.

____ Currently developing a competitive bidding process <u>with no draft</u> of the rules and/or procedures -- proceed to Part II.

____ No rules and/or procedures in place and not currently developing any -- proceed to Part II.

<u>Part I</u>

1) How many competitive bidding solicitations for electric power supply have you conducted in the past?

____

2) Are you currently conducting a competitive bid solicitation for electric power supply?

____ Yes ____ No

3) If 2 is no, do you plan to conduct a bid solicitation soon?

____ Yes ____ No

4) If 3 is yes, when? (month/year)

____

5) How do you determine when to conduct a competitive bid solicitation? (For example, annually, biennially, utility's need for capacity.)

____

6) What is the Public Utility Commission's involvement with the request for proposals (RFP)? Please state below who writes the RFP and what role the Commission plays in the RFP stage of the bidding process (approval only, rules and approval, etc.)

____

____

____

7) Does your bidding program have open or sealed bidding? (Open bidding is when the bidders are informed of the prices offered by other bidders during the bidding process; with sealed bidding they are not.)

____ Open ____ Sealed

8) Are the bidders informed of the electric utility's avoided cost before the bidding process begins?

____ Yes ____ No

9) Is the host electric utility allowed to submit a bid?

____ Yes ____ No

10) Can other electric utilities, outside the service area, submit a bid?

____ Yes ____ No

11) Is there any type(s) of electric generation precluded from bidding? (e.g., fuel type, ownership, etc.)

____ Yes ____ No

12) If 11 is yes, please specify.

____

13) Can a bidder submit more than one bid in a solicitation?

____ Yes ____ No

14) Are the following details of a bid available to the public <u>before</u> the winners are selected? (Check all that apply.)

____ selection criteria for evaluation

____ price

____ participant identities

____ all information is available

____ no information -- all information is kept confidential.

15) How long is the solicitation period?

____

16) Is an entry fee or bond required?

____ Yes ____ No

17) If 16 is yes, how much is it?

$__________ Entry Fee

$__________ Bond

---

18) Are the following details of a bid available to the public <u>after</u> the winners are selected? (Check all that apply.)

____ selection criteria for evaluation

____ price

____ participant identities

____ all information is available

____ no information -- all information is kept confidential.

19) Is there a public hearing to review successful bidders, their bids, and the process used to select them?

____ Yes ____ No

20) If 19 is yes, can the PUC (check all that apply):

____ select alternative bidder(s)?

____ amend the successful bid(s)?

____ change the selection criteria used to evaluate the bids?

____ other changes ______________________________

21) Are demand-side management options allowed in the bidding?

____ Yes ____ No

22) Who selects the successful bids? (i.e., utility, commission, other.)

____

23) Please check the term that best describes the relative importance of each factor when evaluating power supply proposals.

Factor	Extremely Important	Important	Somewhat Important	Not Important or Not Considered
Price	____	____	____	____
Prospects for successful project development	____	____	____	____
Financial viability of project	____	____	____	____
Longevity of project	____	____	____	____
Management quality and experience	____	____	____	____
Bidder guarantees for system performance	____	____	____	____
Bidder guarantees for in-service date	____	____	____	____
Progress toward acquiring location	____	____	____	____
Flexible system planning	____	____	____	____
Maintenance scheduling by utility	____	____	____	____
Affect on system reliability	____	____	____	____
Maturity of technology	____	____	____	____
Impact on power quality	____	____	____	____
Fuel type	____	____	____	____
Fuel flexibility	____	____	____	____
Fuel supply security	____	____	____	____

Compatibility with fuel diversity goals	____	____	____	____
Environmental impact	____	____	____	____
Dispatchability	____	____	____	____
Contract length	____	____	____	____
Other (please specify) ______________	____	____	____	____
Other (please specify) ______________	____	____	____	____

24) Do you allow "front-loading" of payments to bidders in the terms of the contract? (i.e., setting the price relatively high in the beginning years of the project, then reducing the price over time.)

____ Yes ____ No

25) What is the maximum bidding size allowed? (Please specify MW, percent of block, no maximum, etc.)

____

26) What is the minimum bidding size allowed? (Please specify MW, percent of block, no minimum, etc.)

____

27) Is first-price or second-price bidding used in the evaluation? (First-price is when the winning bidders' price is used; second-price is when the winning bidders are selected based on their price, but the winning price is set at the best price of the unsuccessful bidders.)

____ First Price ____ Second Price

28) Are the final purchase contracts approved by the PUC?

____ Yes ____ No

29) If 28 is yes, when?

_____ Preapproved before going into effect.

_____ During a fuel adjustment clause hearing.

_____ During a rate case.

_____ During a prudence review.

_____ Other (please specify).

30) Please check Yes if the contract provision below is included in the contract with successful bidders, or No if it is not included.

Factor	Yes	No
A secured lien on the property	_____	_____
An unsecured lien on the property	_____	_____
Any other secured property interest	_____	_____
The right to enter and take possession and control of the generating facility in case of default	_____	_____
The right to enter and inspect operation	_____	_____
Specific maintenance standards	_____	_____
Specific operation standards	_____	_____
A liquidated damages provision	_____	_____
A security bond to insure performance	_____	_____
A definition of force majeure	_____	_____

31) Please specify other nonprice contract provisions that ate included inn contracts with successful bidders. If feasible, please send a standard form contract with your response.

____

____

Please proceed to Part III.

PART II

32) Are you considering or developing a competitive bidding program for generation capacity?

____ Yes ____ No

If yes, please explain your current stage in the development of a program (continue on back if necessary).

If no, please explain the reason (if any) why you are not developing a program (continue on back if necessary).

Please proceed to Part III.

PART III

33) What do you consider to be the strengths of competitive bidding? (Continue on back if necessary.)

____

____

____

34) What do you consider to be the weaknesses of competitive bidding? (Continue on back if necessary.)

____

____

____

35) What kind of changes, either to your program or in general, would you recommend to improve competitive bidding? (Continue on back if necessary.)

____

____

____

36) Do you have any additional comments or suggestions about competitive bidding? (Please provide any studies, analysis, or commission orders pertaining to bidding in your state.)

____

____

____

____

TABLE B-1

SUMMARY OF PSC AND IOU RESPONSES TO MOST SURVEY QUESTIONS

Question and Number	State PSCs (Percent Yes)	IOUs (Percent Yes)
0. Current situation		
Rules in place	16[1]	33[1]
Draft in place	4	5
Developing draft	12	15
No rules	67	47
1. Have held solicitation	14	20
2. Are conducting solicitation	6	18
3. Plan to conduct solicitation	10	11
6. Role of PSC in RFP		
Sets guidelines for RFP	60[2]	36[2]
Reviews and makes changes	20	25
Approves before issuance	50	57
No role	0	7
7. Sealed solicitations	100	100
8. Bidders know avoided cost	70	79
9. Host utility can bid[3]	20	54
10. Other utilities can bid	60	82
11. No generation precluded	80	61
13. Bidder can offer multiple bids[4]	80	93
14. Details available before selection		
Selection criteria	100	64
Price	60	7
Participants identity	50	18
No information	0	25
16. Entry fee required	40	46

TABLE B-1--Continued

Question and Number	State PSCs (Percent Yes)	IOUs (Percent Yes)
18. Details available after selection		
Selection criteria	100	68
Price	60	36
Participants	100	57
No information	0	21
19. Public review of selections	10	18
21. DSM bids allowed	50	50
22. Front loading allowed	80	81
25. No maximum bid size	60	41
26. No minimum bid size	90	52
27. First-price bidding	90	93
28. PSC approves final contracts	60	60
30. Contract provisions		
Secured property lien	63[5]	60[5]
Unsecured property lien	38	9
Other secured prop. interest	50	22
Right to take over in default	63	43
Right to inspect operation	88	83
Specific maintenance standards	88	65
Specific operation standards	100	78
Liquidated damage provision	75	83
Performance security bond	75	70
Force majeure clause	88	83

Source: 1990 NRRI survey on competitive bidding.

1 Percentages for questions 0-3 are based on forty-nine PSCs and eighty-six IOUs.
2 Percentages for questions 6-28 are based on ten PSCs and twenty-eight IOUs.
3 Many IOUs consider their avoided cost as a bid.
4 In most instances, bidders can submit only one offer per solicitation; however, they can participate in multiple solicitations at any one time.
5 Percentages for question 30 are based on eight PSCs and twenty-three IOUs.

Current Competitive Bidding Situation For State Public Service Commissions

A. State Commissions with Rules in Place.

(CO PUC)	Colorado Public Utilities Commission
(CT PUC)	Connecticut Department of Utility Control
(ME PUC)	Maine Public Utilities Commission
(MA PUC)	Massachusetts Department of Public Utilities
(NJ PUC)	New Jersey Board of Public Utilities
(NY PSC)	New York State Department of Public Service
(VA SCC)	Virginia State Corporation Commission
(WA UTC)	Washington Utilities & Transportation Commission

B. State Commissions Developing Rules with Draft in Place.

(CA PUC)	California Public Utilities Commission
(MD PSC)	Maryland Public Service Commission

C. State Commissions Developing Rules with no Draft in Place.

(DE PSC)	Delaware Public Service Commission
(KS CC)	Kansas Corporation Commission
(MI PSC)	Michigan Public Service Commission
(OH PUC)	Public Utilities Commission of Ohio
(OR PUC)	Oregon Public Utility Commission
(PA PUC)	Pennsylvania Public Utility Commission

D. State Commissions Not Currently Developing Rules.

(AK PUC)	Alaska Public Utilities Commission
~~(AL PSC)~~	~~Alabama Public Service Commission~~
(AZ PSC)	Arizona Corporation Commission
(AR PSC)	Arkansas Public Service Commission
(DC PSC)	District of Columbia Public Service Commission
(FL PSC)	Florida Public Service Commission
(GA PSC)	Georgia Public Service Commission
(ID PUC)	Idaho Public Utility Commission
(IL CC)	Illinois Commerce Commission
(IN URC)	Indiana Utility Regulatory Commission
(IA SUB)	Iowa State Utilities Board
(KY PSC)	Kentucky Public Service Commission
(LA PSC)	Louisiana Public Service Commission
(MN DPS)	Minnesota Department of Public Service
(MS PSC)	Mississippi Public Service Commission
(MO PSC)	Missouri Public Service Commission
(MT PSC)	Montana Public Service Commission
(NE PSC)	Nebraska Public Service Commission
(NV PSC)	Nevada Public Service Commission
(NH PUC)	New Hampshire Public Utilities Commission
(NM PSC)	New Mexico Public Service Commission
(NC PUC)	North Carolina Utilities Commission
(ND PSC)	North Dakota Public Service Commission
(OK CC)	Oklahoma Corporation Commission

(SC PSC)	South Carolina Public Service Commission
(WV PSC)	West Virginia Public Service Commission
(WI PSC)	Wisconsin Public Service Commission
(WY PSC)	Wyoming Public Service Commission
(TX PUC)	Texas Public Utility Commission
(RI PUC)	Rhode Island Public Utilities Commission
(SD PUC)	South Dakota Public Utilities Commission
(TN PSC)	Tennessee Public Service Commission
(VT PSB)	Vermont Public Service Board

Responses of State PSCs with Final or Drafted Rules: Groups A and B

1) How many competitive bidding solicitations for electric power supply have you conducted in the past?

Commission	Response	Comment
CA PUC	0	
CO PUC	0	
CT PUC	0	
MA DPU	12	
MD PSC	1	
ME PUC	5	Maine utilities have conducted five (5) solicitations: CMP(4); BHE(1).
NJ BPU	1	The Board of Public Utilities is overseeing a bid solicitation being implemented by New Jersey electric utilities.
NY PSC	4	One company has received bids but has yet to choose winners. Three Companies have RFPs out with

		responses due between May and September 1990. Also, three companies will have RFPs out soon.
VA SCC	5	Four solicitations by Virginia Power and one by Delmarva Power.
WA UTC	1	

2) Are you currently conducting a competitive bid solicitation for electric power supply?

Commission	Response
CA PUC	No
CO PUC	No
CT PUC	No
MA DPU	No
MD PSC	No
ME PUC	No
NJ BPU	Yes
NY PSC	Yes
VA SCC	No
WA UTC	Yes

3) If 2 is no, do you plan to conduct a bid solicitation soon?

Commission	Response	Comment
CA PUC	Yes	
CO PUC	Yes	
CT PUC	---	To be determined in May, 1990. No supply solicitations anticipated but possibly demand.

MA DPU	Yes	Commonwealth Electric will solicit when the RFP is issued.
MD PSC	Yes	
ME PUC	Yes	
VA SCC	No	However, Virginia Power will need combustion power within the next few years.

4) If 3 is yes, when? (month/year)

Commission	Response
CO PUC	Unknown - Depends on the growth rate on firm demand, our experience with existing QFs, and whether QFs can come on line as promised.
MA DPU	Approximately July 1990.
MD PSC	December 1990.
ME PUC	We anticipate CMP will conduct another solicitation within 12 months (by May 1991).

5) How do you determine when to conduct a competitive bid solicitation? (For example, annually, biennially, utility's need for capacity.)

Commission	Response
CA PUC	Biennially.
CO PUC	A utility's need for capacity. The CO PUC in 1988 placed a 20% cap on power that a utility can receive from QF's without recourse to competitive bidding. Additional amounts must be secured through competitive bidding.
CT PUC	A biennial review but based on capacity needs.
MA DPU	Annually. According to 220 CMR, RFPs should be filed one year after the DPU's approval of the previous RFP.

MD PSC	A utility's need for capacity.
ME PUC	A utility's need for capacity.
NJ BPU	Annually.
NY PSC	A utility's need for capacity.
VA SCC	A utility's need for capacity.
WA UTC	At least biennially.

6) What is the Public Utility Commission's involvement with the request for proposals (RFP)? Please state below who writes the RFP and what role the Commission plays in the RFP stage of the bidding process (approval only, rules and approval, etc.)

Commission	Response
CA PUC	The Commission determines when there is a need for additional QF capacity and when utilities should solicit bids. The commission has established guidelines to govern both the solicitation and selection of winning bids.
CO PUC	The utility writes the RFP but must receive PUC approval before issuing. The PUC does not get involved beyond this point unless there is an appeal by participants.
CT PUC	If the Commission's decision finds a need for capacity the decision shall include the factors to be included in each RFP.
MA DPU	The utility company submits an RFP to the DPU. The DPU reviews to see if the proposed RFP is consistent with 26 CMR 8.00. Avoided costs, ranking procedure and long-run standard contracts are reviewed. An RFP order is then issued by the DPU outlining what changes the company should make in its Compliance Filing.
MD PSC	The PSC will have input on what elements (i.e., block size, avoided cost) are included in the RFP and <u>may</u> reserve the right to review the utility's choices ex post.

ME PUC	The ME PUC has rules governing the process, however, it does not approve contracts or involve ourselves with negotiations unless one or both parties request intervention.
NJ BPU	The RFPs are drafted by utilities in accordance with guidelines established by the Commission. The Commission must approve the RFP prior to release.
NY PSC	The utility writes the RFP under guidelines issued by the Commission. The Commission must approve before bidding occurs.
VA SCC	The utility writes the RFP. The RFP does not need Commission approval but it must be submitted to the staff for comments.
WA UTC	The utility writes the RFP and then submits it to the Commission for approval.

7) Does your bidding program have open or sealed bidding? (Open bidding is when the bidders are informed of the prices offered by other bidders during the bidding process; with sealed bidding they are not.)

Commission	Response
CA PUC	Sealed
CO PUC	Sealed
CT PUC	Sealed
MA DPU	Sealed
MD PSC	Sealed
ME PUC	Sealed
NJ BPU	Sealed
NY PSC	Sealed
VA SCC	Sealed
WA UTC	Sealed

8) Are the bidders informed of the electric utility's avoided cost before the bidding process begins?

Commission	Response
CA PUC	Yes
CO PUC	No
CT PUC	Yes
MA DPU	Yes
MD PSC	Yes
ME PUC	No
NJ BPU	Yes
NY PSC	Varies by utility
VA SCC	No
WA UTC	Yes

9) Is the host electric utility allowed to submit a bid?

Commission	Response
CA PUC	No
CO PUC	No
CT PUC	No
MA DPU	No
MD PSC	Unresolved
ME PUC	No
NJ BPU	No
NY PSC	Yes
VA SCC	No
WA UTC	Yes

10) Can other electric utilities, outside the service area, submit a bid?

Commission	Response
CA PUC	No
CO PUC	No
CT PUC	Yes
MA DPU	No
MD PSC	Yes
ME PUC	Yes
NJ BPU	No
NY PSC	Yes
VA SCC	Yes
WA UTC	Yes

11) Is there any type(s) of electric generation precluded from bidding? (e.g., fuel type, ownership, etc.)

Commission	Response	Comment
CA PUC	Yes	
CO PUC	No	
CT PUC	No	
MA DPU	No	As long as it qualifies as a qualifying facility.
MD PSC	No	However, a company has proposed excluding combustion turbine offers.
ME PUC	No	
NJ BPU	Yes	
NY PSC	No	

VA SCC	No
WA UTC	No

12) If 11 is yes, please specify.

Commission	Response
CA PUC	Solicitations are for QFs only, IPPs and utilities are excluded.
NJ BPU	Utility affiliates cannot place a bid.

13) Can a bidder submit more than one bid in a solicitation?

Commission	Response
CA PUC	No
CO PUC	Yes
CT PUC	Yes
MA DPU	No
MD PSC	Yes
ME PUC	Yes
NJ BPU	Yes
NY PSC	Yes
VA SCC	Yes
WA UTC	Yes

14) Are the following details of a bid available to the public before the winners are selected? (Options: Selection criteria for evaluation; Price; Participant identities; All information; No information.)

Commission	Response
CA PUC	* Selection criteria for evaluation * Price
CO PUC	* Selection criteria for evaluation * Participant identities
CT PUC	* Selection criteria for evaluation * Price * Participant identities * All information is available
MA DPU	* Selection criteria for evaluation
MD PSC	* Selection criteria for evaluation * Price
ME PUC	* Selection criteria for evaluation
NJ BPU	* Selection criteria for evaluation * Price * Participant identities
NY PSC	* Selection criteria for evaluation
VA SCC	* Selection criteria for evaluation
WA UTC	* Selection criteria for evaluation * Price * Participant identities

15) How long is the solicitation period?

Commission	Response
CA PUC	Unresolved
CO PUC	3 months
CT PUC	4 months
MD PSC	6 months
ME PUC	2 months

NJ BPU	12 months
NY PSC	2 to 6 months
VA SCC	4 to 5 months
WA UTC	Varies in length

16) Is an entry fee or bond required?

Commission	Response
CA PUC	Unresolved
CO PUC	Yes
CT PUC	No
MA DPU	No
MD PSC	Yes
ME PUC	No
NJ BPU	Yes
NY PSC	No
VA SCC	Yes
WA UTC	No

17) If 16 is yes, how much is it?

Commission	Response
CO PUC	There is a $10,000 entry fee to be paid by all bidders and a $25/kW bond to be paid by successful bidders.
MD PSC	Unresolved
NJ BPU	There is a $5,000 entry fee

VA SCC	There is a $2,500 entry fee for projects 10 MW and less, a $5,000 entry fee for projects between 10 MW and 75 MW, and a $7,500 entry fee for projects above 75 MW.

---

18) Are the following details of a bid available to the public after the winners are selected? (Options: Selection criteria for evaluation; Price; Participant identities; All information; No information.)

Commission	Response
CA PUC	* Selection criteria for evaluation * Price * Participant identities
CO PUC	* Selection criteria for evaluation * Price * Participant identities * All information is available
CT PUC	* Selection criteria for evaluation * Price * Participant identities * All information is available
MA DPU	* Selection criteria for evaluation * Participant identities (winners only)
MD PSC	* Selection criteria for evaluation * Price * Participant identities (probably)
ME PUC	* Selection criteria for evaluation * Participant identities
NJ BPU	* Selection criteria for evaluation * Price * Participant identities
NY PSC	* Selection criteria for evaluation * Participant identities
VA SCC	* Selection criteria for evaluation
WA UTC	* Selection criteria for evaluation * Participant identities

19) Is there a public hearing to review successful bidders, their bids, and the process used to select them?

Commission	Response	Comment
CA PUC	No	
CO PUC	No	Unless there is an appeal.
CT PUC	Yes	
MA DPU	No	Only in the case of a dispute between the bidder and utility company.
MD PSC	No	But the PSC can decide to hold such a hearing.
ME PUC	No	
NJ BPU	No	
NY PSC	No	
VA SCC	No	
WA UTC	No	

20) If 19 is yes, can the PUC: select alternative bidder(s); amend the successful bid(s); change the selection criteria; other.

Commission	Response
CT PUC	* Select alternative bidder(s) * Amend the successful bid(s) * Change the selection criteria
MA DPU	* Select alternative bidder(s)
MD PSC	* Select alternative bidder(s) * Change the selection criteria

21) Are demand-side management options allowed in the bidding?

Commission	Response
CA PUC	Unresolved

CO PUC	No
CT PUC	Yes
MA DPU	No
MD PSC	No
ME PUC	Yes
NJ BPU	Yes
NY PSC	Yes
VA SCC	No
WA UTC	Yes

22) Who selects the successful bids (i.e., utility, commission, other)?

Commission	Response	Comment
CA PUC	Utility	
CO PUC	Third party	Under utility direction.
CT PUC	Utility	Requires Commission approval.
MA DPU	Utility	
MD PSC	Utility	
ME PUC	Utility	
NJ BPU	Utility	Requires Commission approval.
NY PSC	Utility	
VA SCC	Utility	
WA UTC	Utility	

23) Please check the term that best describes the relative importance of each factor when evaluating power supply proposals.

General Comments

CT PUC	All the items will be considered but relative importance has not been determined or fixed. The utility's RFP will include weighting factors. The Commission will decide the actual weighting criteria in its decision.
NY PSC	This varies from utility to utility. I have filled in generalizations.

A. Extremely Important

Commission	Response
CA PUC	* Price * Environmental impact
CO PUC	* Price
MA DPU	* Price * Prospects for successful development of project * Financial viability of project * Bidder guarantees for system performance * Progress toward acquiring location * Effect on system reliability * Fuel type * Environmental impact * Dispatchability
MD PSC	* Price * Prospects for successful development of project
NY PSC	* Price * Environmental impact * Dispatchability
VA SCC	* Price
WA UTC	* Price

B. Important

Commission	Response
CO PUC	* Prospects for successful development of project. * Maintenance scheduling by utility * Fuel type * Security of fuel supply * Dispatchability * Contract length
MA DPU	* Longevity of project * Management quality and experience * Bidder guarantees for in-service date * Flexible system planning * Maintenance scheduling by utility * Maturity of technology * Impact on power quality * Fuel flexibility * Security of fuel supply * Compatibility with fuel diversity goals * Contract length
MD PSC	* Financial viability of project * Longevity of project * Management quality and experience * Bidder guarantees for system performance * Progress toward acquiring location * Effect on system reliability * Maturity of technology * Impact on power quality * Security of fuel supply * Environmental impact
ME PUC	* Price * Prospects for successful development of project * Financial viability of project * Management quality and experience * Bidder guarantees for system performance * Bidder guarantees for in-service date * Effect on system reliability * Fuel type * Fuel flexibility * Security of fuel supply * Compatibility with fuel diversity goals * Dispatchability * Contract length
NJ BPU	* Price * Prospects for successful development of project * Financial viability of project

	* Management quality and experience * Bidder guarantees for system performance * Bidder guarantees for in-service date * Progress toward acquiring location * Flexible system planning * Maintenance scheduling by utility * Effect on system reliability * Maturity of technology * Impact on power quality * Fuel type * Fuel flexibility * Security of fuel supply * Compatibility with fuel diversity goals * Environmental impact * Dispatchability * Project location * Fuel efficiency
NY PSC	* Prospects for successful development of project * Financial viability of project * Management quality and experience * Bidder guarantees for in-service date * Progress toward acquiring location * Maintenance scheduling by utility * Effect on system reliability * Security of fuel supply
VA SCC	* Prospects for successful development of project * Financial viability of project * Longevity of project * Bidder guarantees for system performance * Bidder guarantees for in-service date * Progress toward acquiring location * Flexible system planning * Maintenance scheduling by utility * Effect on system reliability * Maturity of technology * Impact on power quality * Fuel type * Fuel flexibility * Compatibility with fuel diversity goals * Dispatchability * Contract length
WA UTC	* Prospects for successful development of project * Financial viability of project * Longevity of project * Management quality and experience * Security of fuel supply * Environmental impact * Dispatchability * Contract length

C. <u>Somewhat Important</u>

Commission	Response
CO PUC	* Financial viability of project * Longevity of project * Management quality and experience
MD PSC	* Bidder guarantees for in-service date * Flexible system planning * Maintenance scheduling by utility * Fuel type * Fuel flexibility * Compatibility with fuel diversity goals * Dispatchability * Contract length
ME PUC	* Longevity of project * Progress toward acquiring location * Flexible system planning * Maintenance scheduling by utility * Maturity of technology * Impact on power quality * Environmental impact
NJ BPU	* Contract length
NY PSC	* Longevity of project * Bidder guarantees for system performance * Maturity of technology * Fuel type * Compatibility with fuel diversity goals * Contract length * Additional contract deposit * Front-loading of payments * Uncertainty of bid price * Progress towards acquiring location * Unit size * Automatic generation control * Black start ability * Response time
VA SCC	* Management quality and experience * Security of fuel supply * Environmental impact
WA UTC	* Bidder guarantees for system performance * Bidder guarantees for in-service date * Progress toward acquiring location * Flexible system planning

* Maintenance scheduling by utility
* Effect on system reliability
* Maturity of technology
* Impact on power quality
* Fuel type
* Fuel flexibility
* Compatibility with fuel diversity goals

D. <u>Not Important or Not Considered</u>

Commission	Response
CA PUC	* Prospects for successful development of project * Financial viability of project * Longevity of project * Management quality and experience * Bidder guarantees for system performance * Bidder guarantees for in-service date * Progress toward acquiring location * Flexible system planning * Maintenance scheduling by utility * Effect on system reliability * Maturity of technology * Impact on power quality * Fuel type * Fuel flexibility * Security of fuel supply * Compatibility with fuel diversity goals * Dispatchability * Contact length
CO PUC	* Bidder guarantees for system performance * Bidder guarantees for in-service date * Progress toward acquiring location * Flexible system planning * Effect on system reliability * Maturity of technology * Impact on power quality * Fuel flexibility * Compatibility with fuel diversity goals * Environmental impact
NJ BPU	* Longevity or project
NY PSC	* Flexible system planning * Impact on power quality * Fuel flexibility * Thermal loss

24) Do you allow "front-loading" of payments to bidders in the terms of the contract? (i.e., setting the price relatively high in the beginning years of the project, then reducing the price over time.)

Commission	Response
CA PUC	No
CO PUC	No
CT PUC	Yes
MA DPU	Yes
MD PSC	Yes
ME PUC	Yes
NJ BPU	Yes
NY PSC	Yes
VA SCC	Yes
WA UTC	Yes

25) What is the maximum bidding size allowed? (Please specify MW, percent of block, no maximum, etc.)

Commission	Response
CA PUC	No maximum
CO PUC	Block size
CT PUC	No maximum
MA DPU	Block size
MD PSC	No maximum
ME PUC	No maximum
NJ BPU	No maximum
NY PSC	Varies across utilities
VA SCC	Block size
WA UTC	No maximum

26) What is the minimum bidding size allowed? (Please specify MW, percent of block, no minimum, etc.)

Commission	Response
CA PUC	No minimum
CO PUC	100 kW
CT PUC	No minimum
MA DPU	No minimum
MD PSC	No minimum
ME PUC	No minimum
NJ BPU	No minimum
NY PSC	No minimum
VA SCC	No minimum
WA UTC	No minimum

27) Is first-price or second-price bidding used in the evaluation? (First-price is when the winning bidders' price is used; second-price is when the winning bidders are selected based on their price, but the winning price is set at the best price of the unsuccessful bidders.)

Commission	Response
CA PUC	Second price
CO PUC	First price
CT PUC	First price
MA DPU	First price
MD PSC	First price
ME PUC	First price
NJ BPU	First price
NY PSC	First price

VA SCC	First price
WA UTC	First price

28) Are the final-purchase contracts approved by the PUC?

Commission	Response
CA PUC	Yes
CO PUC	No
CT PUC	Yes
MA DPU	Yes
MD PSC	Yes
ME PUC	No
NJ BPU	Yes
NY PSC	No
VA SCC	No
WA UTC	Yes

29) If 28 is yes, when?

Commission	Response
CA PUC	Preapproved
CT PUC	Preapproved
MA PUC	Preapproved
MD PUC	Preapproved
NJ BPU	Preapproved
WA UTC	Prudence review and rate case.

30) Please check yes if the contract provision below is included in the contract with successful bidders, or no if it is not included.

General Comments

NY PSC	Varies from utility to utility.

A. A secured lien on the property.

Commission	Response
CA PUC	No
CO PUC	No
CT PUC	No
MA DPU	Yes
MD PSC	Yes
ME PUC	Sometimes
NJ BPU	Sometimes
VA SCC	Yes

B. An unsecured lien on the property.

Commission	Response
CA PUC	No
CO PUC	No
CT PUC	No
MA DPU	No
MD PSC	No
ME PUC	Sometimes
NJ BPU	Sometimes
VA SCC	Yes

C. Any other secured property interest.

Commission	Response
CA PUC	No
CO PUC	No
CT PUC	Yes
MA DPU	No
MD PSC	Yes
ME PUC	Sometimes
NJ BPU	Sometimes

D. The right to enter and take possession and control of the generating facility in case of default.

Commission	Response
CA PUC	No
CO PUC	No
CT PUC	Yes
MA DPU	No
MD PSC	Yes
ME PUC	Sometimes
NJ BPU	Sometimes
VA SCC	Yes

E. The right to enter and inspect the operation.

Commission	Response
CA PUC	Yes

CO PUC	No
CT PUC	Yes
MA DPU	Yes
MD PSC	Yes
ME PUC	Yes
NJ BPU	Yes
VA SCC	Yes

F. Specific maintenance standards.

Commission	Response
CA PUC	Yes
CO PUC	Yes
CT PUC	Yes
MA DPU	Yes
MD PSC	Yes
ME PUC	Yes
NJ BPU	No
VA SCC	Yes

G. Specific operation standards.

Commission	Response
CA PUC	Yes
CO PUC	Yes
CT PUC	Yes
MD PSC	Yes

MA DPU	Yes
ME PUC	Yes
NJ BPU	Yes
VA SCC	Yes

H. A liquidated damages provision.

Commission	Response
CA PUC	Yes
CO PUC	Yes
CT PUC	Yes
MA DPU	No
MD PSC	Not sure
ME PUC	Yes
NJ BPU	Yes
VA SCC	Yes

I. A security bond to insure performance.

Commission	Response
CA PUC	No
CO PUC	Yes
CT PUC	No
MA DPU	Yes
MD PSC	Yes
ME PUC	Yes

NJ BPU	Yes
VA SCC	Yes

J. A definition of force majeure.

Commission	Response
CA PUC	Yes
CO PUC	No
CT PUC	Yes
MA DPU	Yes
MD PSC	Yes
ME PUC	Yes
NJ BPU	Yes
VA SCC	Yes

33) What do you consider to be the strengths of competitive bidding?

Commission	Response
CA PUC	The acquisition of least-cost, nonutility generation.
CO PUC	The use of market forces to acquire least-cost power.
CT PUC	Competitive bidding provides for the lowest price source of power by encouraging price competition from independent power producers. This can lessen the operational and construction risk to utilities and increase fuel mix diversification.
MA DPU	Our proposed regulations will discuss advantages.
MD PSC	1) Market-based avoided cost. 2) Broader range of offers and technologies. 3) Risks shift to developers. 4) Fixed-price offers. 5) Less risk from cost overruns.

ME PUC	Competitive bidding helps the most viable and low cost QF, IPP, and DSM projects to get on line.
NJ BPU	Competitive bidding will aid in the development of a competitive marketplace, if implemented properly, and will provide utilities with a system for acquiring capacity from the best projects based both on price and nonprice factors.
NY PSC	It is better than PURPA because: 1) Allows explicit consideration of nonprice factors. 2) Enables control over the number of APP contracts signed. 3) Compares utility construction options to nonutility options. 4) Promotes the development of a competitive market in electric generation.
VA SCC	Lower prices for capacity. Offers an organized and methodical approach to select among multiple suppliers.
WA UTC	Produces lower prices for ratepayers.

34) What do you consider to be the weaknesses of competitive bidding?

Commission	Response
CA PUC	The Commission's approach is currently limited to QFs only.
CO PUC	Risk of nonperformance by selected winners.
CT PUC	May cause price factors to be overemphasized.
MA DPU	Our proposed regulations will discuss weaknesses.
MD PSC	1) Difficult to choose viable projects. 2) Requires new policy methods to review selected winners. 3) Difficult to determine "block size" and avoided cost cap.
NJ BPU	Since a competitive marketplace does not yet exist, utilities may wield considerable market power.
NY PSC	1) Unless carefully monitored by the PSC, utilities may manipulate auctions to reduce or eliminate APPs from entering the generation business. 2) Self dealing between a utility and its subsidiaries.

	3) Requires better ways to ensure project viability. 4) Dispatchability is often evaluated poorly.
VA SCC	Requires the extensive use of resources to evaluate bids.
WA UTC	No apparent weaknesses.

35) What kind of changes, either to your program or in general, would you recommend to improve competitive bidding?

Commission	Response
CA PUC	An all-source bidding approach could be more favorable.
CO PUC	Unknown at this time because a competitive bid has yet to take place.
CT PUC	Price competition can be enhanced if certain "nonprice" considerations are factored into the selection process. This includes fuel choice, financial and security provisions, environmental concerns, performance guarantees, etc. Competitive bidding can narrow the number of competing projects. Commission and utility review is required to determine the overall best project.
MA DPU	Our proposed regulations will introduce improvements.
MD PSC	In general, it would be useful to require utilities to bid at least a portion of their future resource needs to ensure that the least-cost suppliers are chosen.
NJ BPU	Coordinate regional bidding systems and establish regional wheeling policies.
NY PSC	The exclusion of utility subsidiaries from their own auctions and a requirement that the buying utility pays the wheeling costs.
VA SCC	Better methods to estimate the costs of utility construction.
WA UTC	Our rule permits no utility/developer negotiation on the price submitted by the developer in the RFP. The wisdom of this is not yet clear.

36) Do you have any additional comments or suggestions about competitive bidding?

Commission	Response
CA PUC	A number of issues remain open for consideration in 1990, including the mechanics of issuing and administering the bids.
CO PUC	No further comments or suggestions.
MA DPU	The Department's views on competitive bidding are found in D.P.U. 86-36-G.

32) Are you considering or developing a competitive bidding program for generation capacity?

Commission	Response	Comment
AL PSC	No	Our commission regulates only Alabama Power Company which is part of the Southern Company. No base-load additions will be needed until after 2010.
AK PUC	No	We have excess capacity and have no need to add capacity.
AZ CC	No	We currently have a least-cost planning process in place. We anticipate that utilities will not be planning to add any significant amounts of capacity in the next ten years. However, competitive bidding may be considered in the future.
AR PSC	No	The major investor-owned utility servicing Arkansas customers, Arkansas Power & Light Company, possesses enough excess capacity at this time to meet its forecast load growth for the next 10-15 years. Arkansas Electric Cooperative Corporation, the generation and transmission cooperative, is similarly situated.
DC PSC	No	The Commission feels it would be premature at this time to add competitive bidding to current least-cost planning regulations.
DE PSC	Yes	On October 13, 1988, Delmarva Power & Light Company filed an application with the Delaware Public Service Commission seeking approval of an RFP. The Company's application also asked the Commission to find if the RFP fulfilled the requirements of section 210 of the Public Utility Regulatory Practices Act of 1978. The Cost Recovery phase of this proceeding was decided on January 16, 1990. Delmarva is amending its Request for Proposals.
FL PSC	No	However, two utilities in Florida have undertaken bidding on their own volition.

GA PSC	Yes	Competitive bidding will be factored into the Commission's analysis of least-cost/integrated resource planning.
ID PUC	Yes	There is a hearing scheduled for June 6, 1990, Docket No. GNR-E-89-5, to discuss competitive bidding.
IL CC	Yes	The statewide electric plan instructs parties to develop workshops on this issue. Currently, another agency--Department of Energy & Natural Resources--is developing this agenda.
IN URC	No	The Commission has not developed a competitive bidding program nor guidelines. However, Public Service of Indiana (PSI) has issued RFPs for both supply and demand-side resources.
IA SUB	No	The need to develop competitive bidding program has been considered a nonpriority item due to minimal cogeneration and other nonutility generation. As multiple efficiency projects begin to require evaluation a bidding may become useful.
KS CC	Yes	The Commission is taking a look at the competitive bidding procedures of other states to see what could work best here. The need for procedures is not expected until 1992 or 1993. The next plant will be needed around 1995 to 1996.
KY PSC	No	Competitive bidding for generation capacity is not being considered at this time because of excess capacity. Adequate capacity is expected by the state's electric utilities until around 1995. Competitive bidding is likely to become important when major capacity additions are needed.
LA PSC	No	The IOUs all have excess capacity. Also, Cajun Electric Power Cooperative, Inc. has excess capacity.
MI PSC	Yes	On March 29, 1990, on its own motion in Case No. U-9586, the Michigan Commission directed Consumers Power to formulate a competitive bidding system that effectively eliminates the risk of adverse effects from self-dealing and to propose methodologies and procedures for addressing the need for capacity. Presently,

		the staff is formulating testimony to be filed supporting the development of a bidding system for use in Consumers Power's service territory. Actions have not been initiated to prompt development of bidding procedures for other utilities in Michigan.
MN DPS	No	The Commission favors a more administrative approach to assuring a least-cost combination of supply and demand-side resources. Another reason why competitive bidding hasn't been actively pursued is that there is little short-term need for additional generating capacity.
MO PSC	No	
MS PSC	No	The next additions to capacity are not expected until 1996.
MT PSC	No	The Montana Commission is waiting for the results of our Industry/ Interest Group Task Force which is studying competitive bidding for Montana Power Co. But PP&L is responding to competitive bid offers in other jurisdictions. It is likely that the commission will look into competitive bidding more in the next several years.
NE PSC	No	The Nebraska Public Service Commission does not regulate utilities.
NH PUC	No	The commission has not directed utilities in this direction, leaving how they contract new generation to their discretion. Utilities, however, must demonstrate in biennial least-cost planning filings that they are using consistent criteria for evaluating demand and supply options.
NM PSC	Yes	We are currently monitoring development in other states to determine if competitive bidding is appropriate for New Mexico and if so which competitive bidding process is most appropriate.
NC PUC	No	
ND PSC	No	The region currently has excess generating capacity and slow growth rates.
OK CC	No	The Commissioners previously considered, but did not adopt competitive bidding. Presently generation is adequate.

OH PUC	Yes	The Commission will review the comments from respondents to a commission-ordered inquiry on competitive bidding. The inquiry will be set forth in an entry to be issued in the near future. A draft entry has been prepared by the staff, and is currently under review.
OR PUC	Yes	<u>Schedule Action Item Completion Date</u> 1) Announce investigation (7/19/89) 2) Conduct literature review (9/1/89) 3) Publish issues and concerns paper(10/6/89) 4) Hold public workshop (11/13/89) 5) Publish draft report for comment (Spring 1990) 6) Publish final report (Summer 1990) 7) Begin process requirements (Summer 1990) 8) Conclude investigation (Late 1990)
PA PUC	Yes	Metropolitan Edison Company ("Met Ed") filed a petition in June 1989 requesting authorization to initiate a bidding process. The Commission authorized Met Ed to utilize bidding to obtain the needed capacity as an experimental program. However, the Commission referred Met Ed's RFP to the Office of Administrative Law Judges.
RI PUC	No	The two major electric utilities in Rhode Island, Narragansett Electric and Blackstone Valley Electric, are retail subsidiaries of multistate holding companies, New England Electric System and Eastern Utilities Associates. Both utilities have extensive C&LM programs that we are satisfied with.
SC PUC	No	This Commission is presently involved in the development of least-cost planning, which may develop a bidding program as a part of that process. Presently, the bidding programs of other states, such as in Virginia, are being monitored.
SD PUC	No	
TN PSC	No	The Tennessee PSC regulates only Kingsport Power Company, a subsidiary of American Electric Power. Kingsport purchases 100 percent of its power from AEP.

TX PUC	No	Utilities in Texas rely on competitive negotiation to secure a contract for firm power with a QF. The Public Utility Commission of Texas is not involved in the negotiation process. The utility may request the PUCT to review the contract for approval. If approved, all payments stated in the contract will be prudent and can be recovered in full.
VT PSB	No	Guidelines for bidding (however detailed) will be set out in the Board's forthcoming LCIP order (Docket 5270), the majority of which is dedicated to DSM. In Vermont, DSM is acknowledged by many to be the lowest-cost resource currently available.
WV PSC	No	We are not currently developing a competitive bidding program in West Virginia. The reason is that we currently have excess capacity. The passage of acid rain legislation will likely move forward the time period in which we will consider developing a competitive bidding program.
WI PSC	No	Wisconsin has an advance plan process to continually review the utilities' plans for construction of generating facilities. In the most recent Advance Plan Order (issued 4/89) utilities were ordered to study and prepare reports on the advisability of implementing a bidding system for new demand- and supply side resources for Wisconsin. Staff is in agreement with the utilities that bidding is not an approach we should order at this time. The commission decision is expected in late March or April.
WY PSC	No	

33) What do you consider to be the strengths of competitive bidding?

Commission	Response
AL PUC	Measures cost on a competitive basis which can create savings to ratepayers.
AZ CC	Competitive bidding may force utilities to consider sources of capacity and energy outside the usual universe and thereby identify technologies or sources that are less costly to society.

Competitive bidding may also lower risks faced by ratepayers or utilities by increasing the options; however, this strength may be negligible.

AR PSC

1) Less expensive
2) More competitive pricing structure for electricity.
3) Greater flexibility in size of generating units particularly for short-term needs.
4) Greater flexibility in choosing fuels and controlling air quality.

DE PSC

Bidding is an equitable way to select projects. Bidding is administratively simpler and should produce costs which are equal to or lower than those administratively determined.

FL PSC

No comment. Issue has not been addressed.

GA PSC

Free market enhancement.

ID PUC

May result in less expensive capacity and energy.

IL CC

Unknown--to be determined in workshop.

IN URC

Commission staff perceives three primary advantages from competitive bidding for resources. First, it is a way of promoting competition among multiple suppliers which should help keep costs down. Second, information obtained through a bidding process is useful for evaluating the reasonableness of an electric utility's resource plan and construction cost estimates. Third, a bidding process allows avoided cost to be estimated using a market mechanism rather than an administrative one.

IA SUB

1) Openness of process.
2) Comparability where proposals are comparable.
3) Encouragement of prior needs assessment.
4) Tends toward lowest cost.
5) Attempts to equate noncomparable proposals.
6) Provides record of decision.

KS CC

1) It is the best way to arrive at a market price for electricity.
2) It can be part of a least-cost energy plan.

KY PSC

The obvious benefit of a competitive bidding process is improved economic efficiency of electric utility systems since all resources (utility and nonutility alike) are considered.

LA PSC

No opinion.

MI PSC

1) Can provide less expensive power to a utility.
2) Can diversify utilities' supply options.

MN DPS	1) Greater reliance on market forces thereby reducing the number of mistakes that inevitably results from central planning. 2) Allows utilities to pay independent generators less than the cost they would incur to build their own plants or purchase power from other utilities.
MO PSC	For existing plants, the bidding process provides information on what is available.
MT PSC	The tendency to achieve a lower-cost resource mix to meet future demand.
NH PSC	It provides a means of ensuring that various options are evaluated consistently and fairly.
NM PSC	Competitive bidding has the potential to place downward pressure on electricity costs and to encourage a more efficient electric utility environment.
NC UC	1) Potential cost effectiveness. 2) Establishment of avoided cost.
ND PSC	Enables a utility to acquire capacity additions at least cost.
OH PUC	1) Encourages cost control in utility power plant construction particularly when utilities can bid and their bids are binding. 2) Stimulates the submittal of more proposals to supply electricity than would be submitted without bidding. 3) Provides a competitive market check on the validity of a Commission's administratively determined avoided cost. 4) Assists in assuring that the best choices in meeting supply/demand needs are chosen by broadening the means considered.
OR PUC	Potential to augment least-cost planning through identification and acquisition of economically efficient supply side and demand-side resources.
PA PUC	An RFP would elicit proposals from all potential suppliers and would enable a utility to select the best projects from those available.
SC PSC	Competitive bidding allows options to be evaluated which are outside the direct control of the utility and provide a competitive stimulation to the utility to work toward the best product at the lowest cost with its own construction programs.

VT PSB	Competition, naturally. If we accept the axiom that competition will result in the appropriate allocation of resources at the lowest costs, then bidding will be useful.
WV PSC	Should have a positive effect on keeping costs down.
WY PSC	When there are reliable and adequate large power alternatives and adequate large power transmission alternatives, then competitive bids would be productive. Bidding is also useful in times of limited capacity availability.

34) What do you consider to be the weaknesses of competitive bidding?

Commission	Response
AL PUC	If limited to economic bids only then projects that are perhaps environmentally inferior or are less efficient may win out.
AZ CC	None.
AR PSC	1) Potential reliability problems. 2) Financing and/or feasibility problems with IPP projects.
DE PSC	1) There may not be a clear defined statement of the product or service to be provided. 2) There may not be a clearly stated, easily understood, and nondiscriminatory basis for evaluating proposals. 3) Finding an adequate number of bidders who are both technically qualified and financially capable of fulfilling their obligations.
FL PSC	Issue has not been addressed.
GA PSC	1) Inability to limit unqualified participants. 2) Inability to ensure that participants can fulfill their obligation to provide power.
ID PUC	1) Diverts attention from resource planning and least-cost resources. 2) Puts uncontrollable monopoly power back into utility hands. 3) Typically results in oligopoly of qualified bidders at high prices because gamesmanship and manipulation are difficult to detect.
IL CC	To be determined in upcoming workshop.

IN URC	Commission staff sees problems regarding the evaluation of nonprice factors.
IA SUB	1) Comparative evaluation of proposals that are not directly comparable (this is a difficulty of implementation, not an inherent weakness). 2) Integration of multiple goals and objectives..
KS CC	1) Less control over on-time deliverability. 2) More supply uncertainty over the long-run. 3) If not run properly, it will not deliver reliability or lowest cost.
KY PSC	The increased reliance on nonutility generation could negatively effect service reliability.
LA PSC	No opinion.
MI PSC	1) Potential for self-dealing if the utility or its subsidiaries are allowed to participate in the bid. 2) Small but worthwhile projects may not participate.
MN DPS	1) Difficult to assess relative importance of price and nonprice factors when evaluating bids. (But this is also true with an administrative approach.) 2) In Minnesota, the number of participants would be limited due to our low avoided costs and relatively small industrial base. 3) Difficult to devise system that allows demand- and supply side options to be compared on an equal basis.
MO PSC	For proposed plants, the cost for supplying future power is subject to high levels of uncertainty. It is inappropriate to use a process that treats these costs as if they were certain.
MT PSC	1) Apparent lack of bidding competitors in Montana. 2) Integration of demand-side resources into bidding process.
NH PUC	The process can be administratively burdensome.
NM PSC	The legal status of Independent Power Producers would need to be clearly defined. There could be reliability problems.
NC UC	1) Too little experience with. 2) The reliability of service is at risk until participants climb the learning curve.
ND PSC	1) Caps on emissions may seriously impair the building of new plants. 2) Transmission access problems for IPPs.

OH PUC	1) Can involve higher administrative costs. 2) Can stimulate overinvestment by the private sector. 3) Can undercut the utility's obligation to serve. Utilities may overly rely on bidding to supply low cost power.
OR PUC	Difficulty in accurately accounting for nonprice factors.
PA PUC	If price is weighted too heavily, bidding would tend to favor projects that are not capital intensive, and perhaps, less reliable.
SC PSC	The lack of long-term supply assurance because there is no obligation to serve. The lack of complete control over system availability and dispatch.
VT PSB	The failure to account for all external/environmental impacts.
WV PSC	May add pressure to select bids which are not really least cost.
WY PSC	1) Insufficient amounts of reliable, adequate power sources and transmission alternatives, 2) Purchase of power from sources without continuity. 3) Absence of effective competition. 4) Possible loss of service, steep rate increases, loss of reliable service, inadequate service especially at system peak.

35) What kind of changes, either to your program or in general, would you recommend to improve competitive bidding?

Commission	Response
AL PUC	I would frame the bid process so that environmental and efficiency issues are more fully addressed.
AZ CC	Since we have no experience with competitive bidding, I cannot provide any first-hand information.
AR PSC	A competitive bidding program should encompass reliability, air quality, and fuel type in addition to the major consideration of cost.
DE PSC	Since we do not have a final Commission decision on competitive bidding, I cannot suggest any changes to our program.
FL PSC	No opinion. The issue has not been addressed.

GA PSC	No further suggestions.
ID PUC	Bidding should be limited to QFs. RFPs should be always available with a carefully set price cap equal to the utility's avoided cost. The price cap should be reduced to represent the lower value of capacity after energy acquisition.
IL CC	No opinion.
IN URC	No changes are recommended at this time given Indiana's limited experience with competitive bidding.
KY PSC	The future of competitive bidding in Kentucky is directly related to the adequacy of generating capacity. As excess capacity dwindles, competitive bidding will become more viable.
LA PSC	No opinion.
MN DPS	I suspect that the cost of soliciting independent power should reflect the additional financial risk the utility incurs when it signs long-term contracts with independents. Depending on how the contract is constructed, a utility's long-term commitment to purchase power may be tantamount to the utility building a similar project itself and financing it with 100 percent debt.
NH PUC	No opinion.
NM PSC	No opinion.
NC UC	No opinion.
ND PSC	Make environmental effects a mandatory criteria for bid evaluations in order to provide maximum encouragement for low polluting technologies.
OH PUC	In general, a more rigid process is required than is currently employed in many bidding programs so that qualitative, nonprice related bidding criteria are assessed as objectively as possible.
OR PUC	No opinion. Oregon has not yet determined if it will pursue competitive bidding.
PA PUC	No opinion.
SC PSC	No opinion.
VT PSB	No opinion.
WV PSC	No opinion.

36) Do you have any additional comments or suggestions about competitive bidding?

Commission	Response
AZ CC	No
AR PSC	No
DE PSC	No
FL PSC	No
GA PSC	No
ID PUC	We'll know more shortly.
IL CC	No
IN URC	No
LA PSC	No
MI PSC	No
MN DPS	No
NM PSC	No
NC UC	Competitive bidding will not be met with much enthusiasm if it is seen as just another argument to force open access to transmission lines.
ND PSC	No
OH PUC	No
OR PUC	Additional comments are in the "Issues and Concerns" paper which the staff published on October 6, 1989.
PA PUC	Additional comments are in the Commission's Order for Met Ed's proposal.
SC PSC	We have watched the developments at the national level, but find no real comfort in the process. No studies, analysis, or commission orders pertaining to bidding are available in this state.
WV PSC	No

WI PSC	A Commission decision is forthcoming. Staff is recommending that it not be pursued at this time. The staff sees bidding as a potential way to capture more demand-side potential but there are no current plans to pursue such bidding.
WY PSC	No

Current Competitive Bidding Situation For Investor-Owned Utilities

A. Investor-Owned Utilities with Rules in Place

State	Company	
California	(PGE) (SDE)	Pacific Gas and Electric Company San Diego Gas & Electric Company
Colorado	(PSC)	Public Service Company of Colorado
Connecticut	(CLP)	The Connecticut Light and Power Company
Florida	(FPL)	Florida Power & Light Company
Indiana	(IPL) (PSI)	Indianapolis Power & Light Company Public Service Indiana
Iowa	(IEP)	Iowa Electric Light & Power Company
Maine	(BHE) (CMP)	Bangor Hydro-Electric Company Central Maine Power Company
Massachusetts	(BEC) (WME)	Boston Edison Company Western Massachusetts Electric Company
Minnesota	(NSP)	Northern States Power Company
Nevada	(SPP)	Sierra Pacific Power Company
New Hampshire	(PNH)	Public Service Company of New Hampshire
New Jersey	(JCP) (PSE)	Jersey Central Power & Light Company Public Service Electric and Gas Company
New York	(OAR)	Orange and Rockland Utilities
Oregon	(PEO) (PEO)	PacifiCorp Electric Operations[1] Pacific Power & Light Company[1]
Pennsylvania	(MET)	Metropolitan Edison Company

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1 PacifiCorp Electric Operations (PEO) operates in six states: ID, MT, OR, UT, WA, and WY. They have rules in place for Washington only. In the remaining states, rules are being considered. Responses for Pacific Power & Light, a subsidiary, appear under the state "Washington." The responses for other divisions appear under the state "Oregon."

Vermont	(GMP)	Green Mountain Power Corporation
Virginia	(VEP)	Virginia Electric Power Company
Washington	(PPC) (WPC)	Puget Power Company Washington Water Power Company

B. **Investor-Owned Utilities Developing Rules with Draft in Place**

State	**Company**	
Maine	(MPS)	Maine Public Service Company
New York	(CEH) (RGE) (NYE)	Central Hudson Company Rochester Gas & Electric Corporation New York State Electric & Gas Corporation

C. **Investor-Owned Utilities Developing Rules but No Draft in Place**

State	**Company**	
Florida	(FPC)	Florida Power Corporation
Idaho	(IPC)	Idaho Power Company
Illinois	(CWE) (ILP)	Commonwealth Edison Illinois Power
Iowa	(IPR)	Iowa Power
Maryland	(APS)	The Potomac Edison Company[2]
Montana	(MPC)	Montana Power Company
North Carolina	(DPC)	Duke Power Company
Oregon	(PEC)	Portland General Electric Company
Pennsylvania	(APS) (APS)	Allegheny Power Service Corporation[2] West Penn Power[2]

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2 Allegheny Power Service Corporation (APS) controls the Potomac Edison Company--MY, West Penn Power--PA, and Monongahela Power Company--WVA. The responses of APS and its subsidiaries appear under the state "Pennsylvania."

West Virginia	(APS)	Monongahela Power Company[2]

D. **Investor-Owned Utilities Not Currently Developing Rules**

State	Company	
Alabama	(TSC)	Alabama Power Company[3]
Arizona	(ASC)	Arizona Public Service Company
Colorado	(CTL)	Centel Electric
Florida	(TSC)	Gulf Power Company[3]
Georgia	(TSC)	The Southern Company[3]
	(TSC)	Georgia Power Company[3]
	(TSC)	Savannah Electric & Power Company[3]
Hawaii	(HEC)	Hawaiian Electric Company
Illinois	(CIP)	Central Illinois Public Service Company
Indiana	(NIP)	Northern Indiana Public Service Company
	(AEP)	Indiana Michigan Power Company[4]
Iowa	(IRC)	Interstate Power Company
	(IPS)	Iowa Public Service Company
	(IGE)	Iowa-Illinois Gas and Electric Company
	(ISU)	Iowa Southern Utilities Company
Kansas	(KGE)	Kansas Gas and Electric Company
Kentucky	(AEP)	Kentucky Power Company[4]
Louisiana	(CLE)	Central Louisiana Electric Company

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3 The Southern Company (TSC), located in Georgia, controls Alabama Power Company--AL, Georgia Power Company--GA, Gulf Power Company--FL, Mississippi Power Company--MS, and the Savannah Electric & Power Company--GA. The responses of TSC and its subsidiaries appear under the state "Georgia."

4 American Electric Power (AEP), based in Ohio, controls Indiana Michigan Power Company--IN/MI, Columbus Southern Power Company--OH, AppalachianPower Company--VA, Kentucky Power Company--KY, Kingsport Power Company--TN, Michigan Power Company--MI, and Wheeling Electric Company--WVA. The responses of AEP and its subsidiaries appear under the state "Ohio."

Michigan	(AEP)	Michigan Power Company[4]
Minnesota	(MPO)	Minnesota Power
Mississippi	(TSC)	Mississippi Power Company[3]
Missouri	(SJP) (UEC)	St. Joseph Light & Power Union Electric Company
Montana	(MDU)	Montana Dakota Utilities Company
North Carolina	(CPL)	Carolina Power & Light Company
Ohio	(AEP) (AEP) (AEP) (CGE) (OEC)	American Electric Power[4] Columbus Southern Power Company[4] Ohio Power Company[4] The Cincinnati Gas & Electric Company Ohio Edison Company
Pennsylvania	(PPL)	Pennsylvania Power & Light Company
South Dakota	(BHC)	Black Hills Corporation
Texas	(CSW) (GSU) (HLP) (TPC)	Central Southwest Corporation Gulf States Utilities Company Houston Lighting & Power Texas-New Mexico Power Company
Utah	(PEO)	Utah Power & Light Company
Wisconsin	(WEP) (WPL)	Wisconsin Electric Power Company Wisconsin Power & Light Company

Responses for IOUs with Rules or Draft in Place: Groups A and B

1) How many competitive bidding solicitations for electric power supply have you conducted in the past?

State	Company	Response	Comment
California			
	PGE	0	

	SDE	1	Solicitation was for qualifying facilities (QFs) only on a first come, first served basis.
Colorado			
	PSC	1	An RFP was issued March 1989 but solicited for 0 MW capacity.
Connecticut			
	CLP	0	
Florida			
	FPL	1	
Indiana			
	IPL	1	We requested offers from other utilities in 1985. Since then, we have received offers from others, and have evaluated them.
	PSI	0	
Iowa			
	IEP	1	
Maine			
	BHE	1	
	MPS	0	
	CMP	5	
Massachusetts			
	BEC	2	
	WME	1	
Minnesota			
	NSP	1	One formal and several informal.
Nevada			
	SPP	1	
New Hampshire			
	PNH	1	Ongoing.
New Jersey			
	JCP	1	
	PSE	0	

New York		
	CEH	0
	OAR	1
	RGE	0
	NYE	0
Pennsylvania		
	MET	0
Vermont		
	GMP	1
Virginia		
	VEP	3
Washington		
	PEO	0
	PPC	0
	WPC	0

2) Are you currently conducting a competitive bid solicitation for electric power supply?

State	Company	Response	Comment
California			
	PGE	No	
	SDE	No	
Colorado			
	PSC	No	
Connecticut			
	CLP	Yes	
Florida			
	FPL	Yes	
Indiana			
	IPL	Yes	Ongoing.
	PSI	Yes	

Iowa			
	IEP	No	
Maine			
	BHE	Yes	
	MPS	No	
	CMP	Yes	
Massachusetts			
	BEC	Yes	
	WME	Yes	WME is currently completing verification and contract negotiations for projects in the award group.
Minnesota			
	NSP	Yes	Selected solicitation
Nevada			
	SPP	Yes	
New Hampshire			
	PNH	Yes	
New Jersey			
	JCP	No	
	PSE	Yes	
New York			
	CEH	No	
	OAR	No	
	RGE	No	
	NYE	No	
Pennsylvania			
	MET	No	
Vermont			
	GMP	Yes	
Virginia			
	VEP	Yes	

Washington		
	PEO	No
	PPC	Yes
	WPC	No

3) If 2 is no, do you plan to conduct a bid solicitation soon?

State	Company	Response	Comment
California			
	PGE	No	Not unless directed to do so by the CA PUC.
	SDE	Yes	
Colorado			
	PSC	Yes	
Connecticut			
	CLP	Unk	Northeast Utilities' year of capacity need is 2002.
Iowa			
	IEP	No	
Maine			
	MPS	Yes	
Massachusetts			
	WME	Unk	Northeast Utilities (NU) year of capacity need is 2002 and therefore NU has requested the MA PUC to defer future RFPs until the proposed all-resource regulations have been finalized which is expected to be this summer (1990).
New Jersey			
	JCP	Yes	
New York			
	CEH	Yes	
	OAR	No	
	RGE	Yes	
	NYE	Yes	

Pennsylvania		
	MET	Yes
Virginia		
	VEP	No
Washington		
	PEO	No
	WPC	Yes

4) If 3 is yes, when? (month/year)

State	Company	Response
California		
	SDE	Depends on outcome of the current SDE/SCE merger.
Colorado		
	PSC	March 1991. The amount of capacity to be solicited is unknown at this time.
Florida		
	FPL	Issued July 1989.
Indiana		
	IPL	Ongoing
Maine		
	MPS	Issued June 1990.
	CMP	Issued May 1989.
Nevada		
	SPP	Bids due by 1/15/90.
New Hampshire		
	PNH	Issued July 1989. Selections to be made by May 1990.
New Jersey		
	JCP	To be issued September 1990.
	PSE	Issued August 1989.
New York		
	CEH	June or July 1990.

	RGE	July 1990.
	NYE	Up to ninety days after receipt of NY State Public Service Commission approval of draft guidelines.
Pennsylvania		
	MET	To be issued March 1991.
Vermont		
	GMP	Currently negotiating the May 1988 solicitation.
Virginia		
	VEP	Next solicitation has not been scheduled.
Washington		
	WPC	Unknown at this time.

5) **How do you determine when to conduct a competitive bid solicitation? (For example, annually, biennially, utility's need for capacity.)**

State	Company	Response
California		
	PGE	Biennial Resource Update.
	SDE	Determined in the Biennial Resource Update Proceeding before the California Public Utilities Commission.
Colorado		
	PSC	The company is required by order to issue an RFP every two years. The amount solicited is based on having the QFs serve 20 percent of the Company's firm load obligation.
Connecticut		
	CLP	An RFP is required to be issued when the year of capacity need falls within a ten year planning horizon.
Florida		
	FPL	The utility's need for capacity.
Indiana		
	PSI	Based on need for capacity.
Iowa		
	IEP	When capacity is needed.

Maine		
	BHE	The need for capacity.
	MPS	We maintain a 20 percent reserve margin based on an econometric load forecast coupled with actual data.
	CMP	The need for capacity.
Massachusetts		
	BEC	By regulations, annually, regardless of capacity needs.
	WME	In MA existing regulations require annual solicitations, however, new regulations would establish a ten year planning window.
Minnesota		
	NSP	Utility's need for capacity (annual).
Nevada		
	SPP	Utility's needs capacity.
New Hampshire		
	PNH	Utility's need for capacity.
New Jersey		
	JCP	Annually.
	PSE	Annually.
New York		
	CEH	Utility's need for capacity.
	OAR	Utility's need for capacity.
	RGE	When provided sufficient regulatory incentive.
	NYE	Utility's need for capacity.
Pennsylvania		
	MET	Utility's need for capacity.
Vermont		
	GMP	Utility's need for capacity.
Virginia		
	VEP	Utility's need for capacity.
Washington		
	PEO	Biennially.

	PPC	The utility's need for capacity in conjunction with Commission rule.
	WPC	Biennially if Least Cost Planning (LCP) shows a need.

6) What is the Public Utility Commission's involvement with the request for proposals (RFP)? Please state below who writes the RFP and what role the Commission plays in the RFP stage of the bidding process (approval only, rules and approval, etc.)

State	Company	Response
California		
	PGE	The CA PUC has adopted a complete set of rules.
	SDE	The CA PUC sets the amount of MWs required, when they are required, and the type of contract available to QFs. The utility prepares, issues, and evaluates the RFPs and awards contracts.
Colorado		
	PSC	Public Service Company writes the RFP incorporating PUC rules and orders concerning issues within the RFP. The PUC must approve all RFPs.
Connecticut		
	CLP	The utility is responsible for development of the RFP, however the CT PUC must approve both the RFP and its weighting criteria before it can be issued. The CT PUC is intricately involved in the RFP process, holding hearings on the utility recommended award group. The CT PUC determines final eligibility in the award group.
Florida		
	FPL	The utility writes the RFP but the Commission must approve the outcome.
Indiana		
	IPL	No RFP issued. The IN URC finding of prudence was requested and is expected.
	PSI	The utility develops the RFP. The only contact with the IN URC was an informational meeting with Commission staff.

Iowa		
	IEP	The IA PUC approves results during the cost recovery process.
Maine		
	BHE	The ME PUC has no involvement in the RFP process.
	MPS	The utility writes the RFP and analyzes bids. The ME PUC approves avoided costs and the ultimate purchases.
	CMP	The utility writes the RFP under guidelines set by ME PUC. The commission does not approve final RFP.
Massachusetts		
	BEC	The MA PUC has bidding regulations based on inputs from all interested parties. The MA PUC approves the RFPs written by the requesting utility.
	WME	The utility is responsible for development of the RFP, however, the MA PUC must approve the RFP and its weighting criteria before it is issued. The Commission maintains an oversight role in the RFP process to ensure it is conducted in a fair and equitable manner.
Minnesota		
	NSP	No regulatory involvement. No RFP. Selected utilities submit bids to meet NSP's capacity need.
Nevada		
	SPP	The NV PSC has requested to be informed of the process. The utility writes the RFP. The Commission then reviews contracts submitted as part of the Utility Resource Plan filing for approval as prudent resource acquisitions.
New Hampshire		
	PNH	The NH PUC requires utilities to negotiate long-term arrangements with NUGs for future capacity needs. They review our progress during their proceedings which occur in even-numbered years. PNH writes its own RFP, incorporating NH PUC guidelines. PNH performs its own evaluations and negotiates its own contracts with selected projects. But, we must prove to the NH PUC that our selections were "least cost."

New Jersey		
	JCP	In August 1988 the New Jersey Board of Public Utilities (NJ BPU) approved a "Stipulation of Settlement" which established procedures by which electric utilities will solicit and purchase capacity and energy from qualifying cogenerators, small power producers, independent power production facilities, and conservation/load reduction projects over a five year period. The RFP is written in accordance with this stipulation. The NJ BPU approves the size of block (capacity), avoided cost, and the fully executed power purchase agreements.
	PSE	The utility writes the RFP. The Board of Public Utilities approves RFP. The Board approves contracts.
New York		
	CEH	The PSC must approve the RFP but not the final contracts.
	OAR	OAR operates in both New York and New Jersey. In New York, the utility develops the RFP according to guidelines established by the NY PUC. The Commission must approve the RFP before its issuance. In New Jersey, a similar process occurs.
	RGE	Utility written. The review is by multiple parties. The Commission can revise.
	NYE	The PSC approves guidelines, RFP, and sample contracts prior to issuance of RFP.
Pennsylvania		
	MET	MET's competitive procurement process was proposed under existing rules. MET writes the RFP and the PUC approves RFP before release.
Vermont		
	GMP	Vermont Public Service Board will review and act on contracts resulting from the RFP process.
Virginia		
	VEP	Virginia Power's Capacity Acquisition Department prepares the RFP with input from regulatory commission staff and other departments within the utility.

Washington		
	PEO	The utility must submit its RFP to the WA UTC ninety days before the issuance date. Interested parties have sixty days to submit written comments. The Commission then takes action on the proposed RFP within thirty days after the comment period. The Commission can suspend a RFP filing to determine whether the issuance is in the public interest.
	PPC	The utility prepares and submits its RFPs to the Commission for approval.
	WPC	The RFP is written by the company with input from the Commission staff. Then a ninety-day review period is required for public input and to receive final Commission approval.

7) Does your bidding program have open or sealed bidding? (Open bidding is when the bidders are informed of the prices offered by other bidders during the bidding process; with sealed bidding they are not.)

State	Company	Response
California		
	PGE	Sealed
	SDE	Sealed
Colorado		
	PSC	Sealed
Connecticut		
	CLP	Sealed
Florida		
	FPL	Sealed
Indiana		
	IPL	Sealed
	PSI	Sealed
Iowa		
	IEP	Sealed
Maine		
	BHE	Sealed