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COMPETITIVE BIDDING FOR ELECTRIC GENERATING CAPACITY: APPLICATION AND IMPLEMENTATION

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EXECUTIVE SUMMARY

The purpose of this study is to address two related issues. One is whether competitive bidding is a viable alternative to traditional regulation in securing new generation capacity. The second is how best to design a bidding program to achieve economic efficiency in electricity generation. An examination of institutional arrangements, economic reasoning, and empirical evidence indicates that competitive bidding may be superior to traditional regulation in providing stronger incentives for cost control, expanded supply options, and additional protections for ratepayers. We find that second-price sealed bidding (under which all winning bidders are paid a uniform price equal to the best non-winning bid) with a fixed-price power purchase contract containing certain cost sharing arrangements is the preferred bidding procedure. This finding is based on economic efficiency grounds and the likely market and institutional environment for securing new generation capacity.

Existing State Regulations

Currently, six states (California, Colorado, Connecticut, Maine, Massachusetts, and New York) have adopted bidding programs and seven states (Florida, Hawaii, Nevada, New Hampshire, North Carolina, Vermont, and Virginia) have allowed utilities to solicit bids without formal bidding rules in place. The bidding activities at the state level are expected to intensify with the advent of federal regulations and increasing knowledge about bidding implementations.

The state bidding programs have both similarities and differences. All six states adopted sealed bidding. With the exception of California, they all use a first-price bidding procedure under which each winning bidder is paid its own bid price. Wheeling is required only in Maine and Massachusetts. In Colorado, Maine, and New York, conservation and load management programs are allowed to bid with supply options. The states grant voluntary exemption from the bidding process to some small power producers. Qualifying facilities are generally granted the right to sell electricity to utilities at avoided energy cost if they choose not to participate in the bidding programs. The utilities are permitted to secure supplies of electric power outside the bidding process.

Proposed FERC Regulations

The current position of the Federal Energy Regulatory Commission (FERC)--as of September 1988--on competitive bidding is best exemplified in its Notice of Proposed Rulemaking: Regulations Governing Bidding Programs (RM88-5-000) issued on March 16, 1988. As envisioned by the FERC, the state bidding programs would be flexible in design and, at the discretion of the states, open to all independent power producers, qualifying facilities, and utility subsidiaries subject to certain restrictions.

The FERC also emphasizes that all bidding programs are prohibited from altering existing purchase agreements between electric utilities and qualifying facilities, and that the states still retain the authority to certify capacity needs, to enforce compliance with environmental and siting regulations, and to hold prudence reviews of power purchases when necessary. The proposed FERC regulations support the use of screening criteria to ensure that all participants are bona fide, legitimate businesses and encourage the use of both price and nonprice factors in selecting winning bids. The FERC acknowledges the importance of transmission access and suggests two possible approaches to deal with the transmission issue on an interim basis.

Legal Issues

This study concludes that competitive bidding is consistent with the avoided-cost pricing rules of the Public Utilities Regulatory Policies Act of 1978 (PURPA). It is shown that bidding does not affect the utility's obligation to serve its retail customers. For a qualifying facility, rates set under competitive bidding can be just and reasonable. But it is less certain for other nonQF entities that a market-based rate determined through bidding can be found just and reasonable under the Federal Power Act. The application of bidding could lead to a major shifting of jurisdiction from the states to the FERC over sales from entities owning generation facilities. The inclusion of nonQF entities in the bidding process may create numerous legal problems for both the FERC and the states.

Benefits and Pitfalls of Bidding

The main benefits of bidding are economic efficiency improvement and additional protection for ratepayers. As for service reliability to ratepayers, the results are less clear, but there is no definite indication that it needs to be adversely affected by competitive bidding. Bidding is a more comprehensive approach than individual negotiations or administrative procedures currently applied in selecting and pricing nonutility generation capacity. Bidding also introduces market discipline into electricity generation so utilities and nonutility power producers have stronger incentives to control costs. Furthermore, bidding allows ratepayers to share benefits gained in substituting nonutility generation for utility generation. Some of the take-or-pay risk imposed on ratepayers by cost-based regulation is reduced under a bidding scheme.

But bidding is not without its pitfalls. A review of the history of the use of bidding in government procurement indicates a number of pitfalls to be guarded against in implementing bidding in the electric industry. These include, among other things, price fixing, market share rotation schemes, and the "hungry-firm phenomenon" where a bidder submits an artificially low bid to win, hoping that it can receive extra payments later to make itself whole. As a result, the general attractiveness of the theory of bidding must be juxtaposed with the reality of how imperfectly the process can work out. On balance, the potential benefits of bidding appear to outweigh pitfalls. In most instances, the pitfalls of bidding can be overcome by a properly designed bidding program and rigorous enforcement of antitrust laws.

Design of an Optimal Bidding Program

Extensive surveys of bidding literature indicate that no bidding procedure is superior to another under all circumstances. The selection of a specific procedure depends on the subject of bidding and the market conditions under which bidding is conducted. In bidding for the right to supply electricity generation capacity, at least in some regions, a diverse and competitive environment can be assumed. Specifically, the number of nonutility power producers is great, and they use diverse generation technologies with different cost expectations. Bidders are fully aware of the avoided cost of the host utility and can freely choose the price and the capacity to bid. Based on the characteristics of the bidders as well as the host utility, the elements of a preferred bidding procedure can be identified.

Sealed bidding (bids not revealed to other bidders) is preferred to open bidding because it allows an orderly presentation and evaluation of many complex and complicated bids. Furthermore, open bidding is more susceptible to collusion because it is easier for bidders to monitor one another and retaliate against those who would break the collusion. Second-price bidding is preferred for its strong efficiency advantages. As it is never to a bidder's advantage to submit a bid that deviates from its true cost under a second-price bidding procedure, the selection of the most efficient power producers is more likely. This cost-revelation feature also eliminates the expenses related to the analysis of the costs and bidding strategies of other potential bidders. The third advantage is that the more efficient power producers would have a stronger incentive to expand. As they expand, less efficient power producers are driven from the market resulting in a decline in the cost of electricity for the host utility and ratepayers.

The format of the post-bidding power purchase contract needs to reflect a proper balance of three interrelated goals: encouraging bidding competition, reducing moral hazard, and allocating risk. Moral hazard, here, refers to the lack of efforts in controlling costs after the bid is won. A fixed-price contract provides a strong incentive for the winning bidders to maximize their efforts after bid selection. An adjustable-price contract has the advantages of allocating risk to the party who can best bear risk, and of encouraging bidding competition by reducing the importance of a bidder's cost estimation. The diverse and competitive market conditions of bidding seem to indicate that the dominant consideration in choosing the contract format is the control of moral-hazard behavior. This suggests a preference for a fixed-price power purchase contract. Nevertheless, some cost sharing and cost escalation arrangements are warranted because the uncertainty associated with some cost components, such as fuel, may pose a risk too great for a nonutility power producer to bear.

Since the generation capacity investments are generally immobile, a short-term contract would require the nonutility producer to demand either a higher risk premium or a higher depreciation rate to compensate for the possibility of losing a current buyer after only a few years. On examining the typical contract length of a power purchase agreement between two utilities, and the depreciation practice of utility-owned generation facilities, there is no basis to expect a nonutility power producer to recover its investment within a short time period and be competitive with the host utility. Based on these considerations, a minimum contract length of ten to fifteen years is suggested unless both parties agree to a different arrangement.

Frequency of Bidding

Bidding should occur only when there is a need to add new generation capacity within the planning horizon. There are four factors to be considered in setting the frequency of bidding. The first is to maintain a fair and equitable environment for different generation technologies of various sizes to compete with one another. Frequent bidding is likely to generate a smaller supply block and put large-sized technologies at a disadvantage. Second is the possibility of collusion among bidders. Frequent bidding inevitably involves the same group of bidders, making collusion more likely. Third is the coordination of utility solicitation with the expansion of local industrial plants as cogenerators. The fourth consideration is the transaction costs associated with bid solicitation and evaluation.

Evaluation and Selection of Bids

The basic principle of bid evaluation is that all price and nonprice factors should be given proper consideration based on their respective effects on the host utility. An adjusted-price evaluation method based on the bid price and price adjustments reflecting differences in nonprice factors is favored. This adjusted-price evaluation method starts with the specifications of the nonprice factors and their respective desirable levels based on the host utility's own best supply options and system demand conditions. If certain nonprice factors cannot be substituted or compensated for by other factors, minimum requirements should be set. For those factors where adjustments and substitutions are possible, costs reflecting adjustments to satisfy specific conditions are calculated and added to the original bid price.

Capacity cost and energy cost are the most important factors in a bid to supply electric generating capacity since they affect the cost of purchased power directly. They are probably the most straightforward aspects of a bid evaluation. Because it is difficult to adjust the bid price to reflect differences in quality of power and dispatchability, minimum requirements for power quality may be specified, and separate solicitations for dispatchable and nondispatchable power sources may be conducted. The costs reflecting different reliability and transmission requirements can be measured and the bid price adjusted accordingly. The assessment of project risk includes both the technical viability and the financing and management expertise of the nonutility power producers.

Once all bids are evaluated and ranked, the next step is to select winning bidders based on the ranking of bids. If the amounts of capacity offered are perfectly divisible, all bids are accepted in the order of increasing adjusted unit price until the supply block is filled completely. Due to the lumpiness of the capacity offered, an alternative bid acceptance procedure is suggested. This acceptance procedure is based on the principle of accepting bids beyond the predetermined supply block if the bid price is less than the utility's incremental cost, and benefits exceed costs.

Some Policy Issues

The success of a bidding program depends not only on the bidding procedure itself, but also on the environment for bidding. There are three policy goals in maintaining a fair bidding environment: it does not provide preferential treatments to a specific bidder or a group of bidders, it does not inhibit the maximum participation of nonutility power producers and host utilities, but it does assure an equitable relationship between bidder and host utility. Based on these three policy goals, several policy suggestions are provided in this study.

Due to the inherent differences between demand-side and supply-side options, it is best to conduct separate solicitations and apply different evaluation criteria to them. Any set-aside capacity for renewable and indigenous resources is justified only under specific conditions where the public interest is demonstrated and where the inadequacies of existing regulations and market mechanisms in accounting for the social externalities of using such resources are identified.

There is no need to allow the host utility to bid in its own solicitation since it is already bidding through the publication of its avoided cost. If the host utility's avoided cost is lower than all bids submitted, it can choose to construct new generation facilities. The bidding by a subsidiary in its parent utility's solicitations creates special problems. Significant conflicts of interest and preferential treatment issues are unavoidable if such subsidiaries are allowed to bid. However, a subsidiary may provide some financial advantages and reduce regulatory risk to the host utility under certain circumstances. If such advantages are substantiated and preferential treatment can be avoided, bidding by subsidiaries in the host utility's solicitation may be desirable. Competition is better served, however, if subsidiaries are free to participate in solicitations outside their parent company's service territory.

It is advisable to make the avoided cost provided by the host utility binding on its own power supply options. A binding avoided cost provides an incentive for the utility to do a comprehensive and unbiased analysis in preparing its demand forecast and resource plan. Otherwise, the utility can simply submit an artificially low avoided cost to discourage bidding by nonutility power producers, and later build its own generation facilities at a much higher cost. Since some cost escalations for energy and operating cost may be warranted in the power purchase contract for nonutility power producers, a symmetrical treatment for the host utility is required to ensure efficiency and fairness.

More open access to utility transmission facilities can encourage more participation by nonutility power producers and host utilities, and improve the economic efficiency of bidding results. But such efficiency improvements may be limited given that current solicitations are already highly competitive, and the capacity offered is typically several times greater than the capacity solicited. It is believed that the implementation of bidding need not necessarily be delayed until the transmission access issue is fully resolved.

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FOREWORD

Where economic efficiency is the criterion, the use of competitive bidding for securing additional generating capacity for electric utilities is increasingly looked upon favorably. Benefits and pitfalls are identified in this report. Emphasis is on the design of an effective bidding program.

As with most controversial public policy questions in regulation, it cannot be expected that all readers will agree with the results of the study nor, in fact, that all analysts would arrive at identical conclusions. Its merit is its contribution to the discussion and debate about the efficacy of competitive bidding in electric power supply.

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CHAPTER 1

INTRODUCTION

The purpose of this study is to address two related issues. One is whether competitive bidding is a viable alternative to traditional regulation in securing new generation capacity. The second is how best to design a bidding program to achieve economic efficiency in electricity generation.

In this study, an examination of institutional arrangements, economic reasoning, and empirical evidence indicates that competitive bidding may be superior to traditional regulation in providing stronger incentives for cost control, expanded supply options, and additional protections for ratepayers. But bidding is not without its pitfalls. Price fixing, market share rotation schemes, and other strategic behavior can prevent the full benefits of bidding from being realized. Great care must be exercised in instituting a bidding program that guards against potential pitfalls on the one hand and provides a true competitive bidding environment on the other hand to allow the most economic choice to be made. In the subsequent chapters, we find that second-price sealed bidding[1] with a fixed-price power purchase contract containing certain cost sharing arrangements is the preferred bidding procedure given the market and institutional environment for securing new electric generating capacity.

Background

Competitive bidding, a process where participants submit bids to compete for the right to sell or to buy, has been used extensively in the procurement and allocation of many goods and services. The federal government, for example, periodically auctions Treasury notes, bonds, and

[1] Under second-price sealed bidding, all winning bidders are paid a uniform price that equals the best non-winning bid. The definition of this and other bidding terms is further discussed in chapter 5.

offshore oil leases. The Department of Defense uses bidding to select contractors for weapon systems production. A gamut of private transactions, ranging from construction projects to antique furniture, are also completed though competitive bidding.

Bidding is not totally new to the electric industry. Several state and federal regulatory agencies require electric utilities to use bidding for the issuance of mortgage bonds, debentures, notes, and the purchase of goods and services.[2] There are also proposals for awarding monopoly franchises through a competitive bidding process.[3] But the idea of using bidding to secure new generation capacity began receiving serious attention only recently.

The alleged "bias" associated with the Public Utility Regulatory Policies Act of 1978 (PURPA) and government regulations implementing PURPA is the direct and probably the most obvious motivation for using competitive bidding in selecting and pricing nonutility generation capacity. The nation's electric utilities have complained vigorously about, among other things, overpayments to qualifying facilities, lack of merit-selection in allocating capacity credit, and inflexibility in long-term contracts to reflect changes in avoided cost.[4] Although most of these problems cannot be attributed to PURPA or its related regulations, federal and state regulators perceive some need for certain regulatory reforms in furthering the goals of PURPA.

It is perceived that competitive bidding has several advantages over existing PURPA regulations concerning avoided cost determination and

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[2] National Association of Regulatory Utility Commissioners, 1985 Annual Report on Utility and Carrier Regulation (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1987), pp. 525-529.

[3] Michael H. Riordan and David E. M. Sappington, "Awarding Monopoly Franchises," American Economic Review 77 (June 1987): 375-387. A critical analysis of the efficacy of franchise bidding as an alternative to regulation in the provision of public utility services is provided in Oliver E. Williamson, "Franchise Bidding for Natural Monopoly--In General and with Respect to CATV," Bell Journal of Economics 7 (Spring 1976): 73-104.

[4] U.S. Congress, House, Committee on Energy and Commerce, Oversight Hearing on Cogeneration and the Public Utility Regulatory Policies Act of 1978 (PURPA), 100th Cong., 1st sess., 1987, testimony of William McCollam, Jr. President, Edison Electric Institute.

selection of qualifying facilities. First, it provides a market-based avoided cost that is more likely to be the true incremental cost of electricity than an administratively determined avoided cost. Second, bidding eliminates the possibility of selecting a less efficient project over other more economic alternatives under the first-come, first-served rule currently applied.[5] Third, bidding allows ratepayers to benefit directly from the cost savings gained in substituting nonutility generation for utility generation while full avoided-cost pricing provides no such benefit sharing.

The second source of current interest in competitive bidding is the recognition that new approaches are needed to overcome the many costly predicaments experienced by the nation's electric utilities in building new power plants during the past two decades. Traditional regulation might not have created all the problems, many believe, but it probably exacerbated the problems of construction cost overruns and delays, considerable excess capacity, and the weakened financial condition facing many utilities.[6] Competitive bidding allows nonutility producers to compete directly with utilities and substitutes a fixed-price contract for an after-the-fact prudence review.[7] It can provide stronger incentives for cost control, more flexibility in capacity adjustment, and a better match of risk and reward to utilities and ratepayers.

The third source of current interest in bidding is the possibility of deregulation in the electric industry. The technical changes in generation and transmission have called into question the regulatory doctrine of allowing a vertically integrated monopoly to supply all electricity demand within a franchised service area. Major macroeconomic changes such as

[5] Renee Haman-Guild and Jerry L. Pfeffer, "Competitive Bidding for New Electric Power Supplies: Deregulation or Regulation?" Public Utilities Fortnightly, 17 September 1987, p. 11.

[6] Federal Energy Regulatory Commission, Office of Economic Policy, Regulating Independent Power Producers: A Policy Analysis (Washington, D.C.: Federal Energy Regulatory Commission, 1987), pp. 13-21.

[7] The format of a power purchase contract is to be negotiated between the nonutility power producer and the host utility. In general, a fixed-price contract is preferred. More discussion on this subject can be found in chapter 6.

intensifying business cycles and growing interdependence of world economies also have rendered utility forecasting and supply planning difficult, and revealed inherent defects in the traditional regulatory framework in a changed environment.[8] With the advances in decentralized generation technologies and the "leveling off" of technical progress in central power plants, a utility may no longer enjoy the economies of scale traditionally associated with large power plants.[9] An independent power producer or a qualifying facility can produce electricity as efficiently as most utility companies. Through extended interconnections, a power producer a thousand miles away can "compete" with the local utility in providing electric service.

Several deregulation scenarios have been discussed in the past.[10] The use of bidding in the generation sector is viewed by some as a starting point. The results of bidding may give insight about the viability of and potential for total deregulation.[11] But competitive bidding injects more market forces only into the selection of new electricity generation capacity. It does not change the ownership of existing generation, transmission, and distribution facilities. It does not affect the boundaries of franchised service areas, either. The emergence of a totally deregulated environment would require additional legislative and regulatory actions.

Facing a call for PURPA reforms and new alternatives in securing future electricity generation capacity, a number of state public service commissions (PSCs)--starting with the Maine Public Utility Commission in 1984--have adopted or discussed various bidding programs. On March 16, 1988

[8] U.S. Congress, House, Committee on Energy and Commerce, Oversight Hearing on Cogeneration and PURPA, 100th Cong., 1st sess., 1987, testimony of Charles G. Stalon, FERC Commissioner.

[9] Federal Energy Regulatory Commission, Office of Economic Policy, Regulating Independent Power Producers: A Policy Analysis, pp. 7-8.

[10] Paul L. Joskow and Richard Schmalensee, Market for Power: An Analysis of Electrical Utility Deregulation (Cambridge: The MIT Press, 1983), pp. 93-107.

[11] "FERC Issues Statement on Its Electric Power Initiatives," NARUC Bulletin, NARUC No. 11-1988, 14 March 1988, pp. 13-16.

the Federal Energy Regulatory Commission (FERC) issued its proposed rules governing the implementation of state bidding programs.

There are many similarities and differences among existing state bidding programs. The proposed rules of the FERC accord state PSCs considerable flexibility in instituting bidding programs. As currently envisioned, bidding would be voluntary and state PSCs could use bidding to provide some, all, or none of a utility's capacity needs.[12] Diversity and flexibility in state bidding programs are desirable given each state's unique electricity demand and supply situation, and the state PSCs' pivotal role in carrying out PURPA-related regulations as well as in overseeing new power plant construction.

Organization of the Report

This report has nine chapters. Chapter 2 reviews the current status of competitive bidding at the state and federal levels, and the experience of several utilities in bid solicitations. The legal issues involved in competitive bidding are discussed in chapter 3. It analyzes the legality of bidding under the avoided-cost pricing rules of PURPA, the effects of bidding on the utility's obligation to serve, and other legal issues. The benefits and pitfalls of competitive bidding are discussed in chapter 4.

A literature review on the theory and application of bidding is the subject of chapter 5. The emphasis is on the criteria for selecting a bidding procedure and on the implications of various bidding models in the design of a bidding program for securing new electricity generation capacity. Chapter 6 presents the elements of an optimal bidding procedure, and discusses the frequency of bidding based on industry structure, information distribution, and risk characteristics prevailing in the market for new electricity generation capacity.

Chapter 7 details the evaluation of bids and the development of a bid acceptance procedure. Several policy recommendations to ensure a fair and competitive environment for bidding to supply new electricity generation

[12] Ibid.

capacity are presented in chapter 8. Chapter 9 summarizes the findings of this study.

This study has two appendices. Appendix A provides a summary of the ranking formula used by Central Maine Power Company in its latest bid solicitation. A synopsis of the bidder qualifications and power supply requirements between Central Maine Power and its outside suppliers is contained in appendix B. Central Maine Power is selected here for its extensive experience in bid solicitation and evaluation.

CHAPTER 2

CURRENT STATUS OF COMPETITIVE BIDDING IN THE ELECTRIC INDUSTRY

The development of bidding regulations in the electric industry has entered a critical stage. This chapter provides an overview of the current status of bidding and highlights the practical issues involved. The state regulators took the lead, starting with the actions by the Maine Public Utilities Commission in 1984, in using bidding to select qualifying facilities (QFs) and to determine the avoided cost applicable to power purchases from QFs.[1] Six states (California, Colorado, Connecticut, Maine, Massachusetts, and New York) have adopted bidding programs, seven states (Florida, Hawaii, Nevada, New Hampshire, North Carolina, Vermont, and Virginia) have allowed utilities to solicit bids without formal bidding rules in place, and several other states have regulations proposed or pending.[2]

The Federal Energy Regulatory Commission, though a later participant in the bidding debate, is presently the focus of the debate on bidding regulations. This is partly because of its preemptive power over state regulations and partly because of its own heightened interest in promoting more competition in the electric industry. The authority of the FERC in regulating wholesale power transactions and interstate transmission also gives it a strong voice in the development of state bidding programs. Many states, with limited experience in dealing with competitive bidding, are waiting for further FERC actions before embarking on a specific approach

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[1] Maine Public Utility Commission, Proposed Amendments to Chapter 36, Docket No. 86-215, (1987).

[2] Based on a telephone survey of fifty states and District of Columbia conducted by NRRI staff from May 23 to June 18, 1988 and information available as of August 1988. A comprehensive, though slightly outdated, survey of state regulations is available in appendix I of Pricing New Generation of Electric Power: A Report on Bidding (Washington, D.C.: National Independent Energy Producers, September 1987).

toward bidding. The current position of the FERC (as of September 1988) is best exemplified in its Notice of Proposed Rulemaking: Regulations Governing Bidding Programs (RM88-5-000), issued on March 16, 1988.

Several utilities are soliciting or have secured generation capacity through bidding. For example, Boston Edison and Central Maine Power have contracted for generation capacity totaling about 1,000 megawatts (MW) from 100 nonutility generation facilities through bidding from 1985 to 1987.[3] The payments average 70 percent of projected avoided costs for Boston Edison and 90 percent for Central Maine Power.[4] The capacity acquired through bidding is a relatively small portion of installed capacity for those utilities engaged in bidding, but it may well increase substantially as state PSCs and utilities gain more confidence and experience with bid solicitations.[5]

Five Steps in a Bid Solicitation

Before reviewing the bidding regulations of individual states and the FERC, we provide an overview of a common bidding process. There is no typical way of soliciting bids to supply new electricity generation capacity. Five steps are usually involved: specification of the supply block, calculation of avoided cost, preparation of a Request for Proposal (RFP), evaluation and selection of bids, and negotiation and contracting after bid selection.

Competitive bidding to secure new capacity is an extension, rather than a replacement, of a utility's resource planning process. In some sense, a utility's bid solicitation is no different from its negotiation of a power purchase agreement with another utility. As a result, a utility's bidding

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[3] Based on communications with the staffs of Central Maine Power Company and Boston Edison Company, June 1988.

[4] Ibid.

[5] For example, the total installed capacity for Boston Edison and Central Maine Power are around 3,000 MW and 1,700 MW, respectively. The total capacity secured through bidding is more than 20 percent of the combined system capacity.

process should start with the preparation of its demand forecast and resource plan. The resource plan determines the amount of capacity needed and the utility's cost of supplying this block of capacity.

Based on a utility's supply block, avoided cost, and other factors, an RFP specifying the conditions of solicitation is prepared and publicized. The host utility, the regulators, or both evaluate the bids submitted and select the best bids. These may be either the lowest-cost bids or those with the highest scores based on specific merit selection criteria. The negotiation and signing of a power purchase contract finalize the obligations and responsibilities of the host utility and winning bidders.

Specification of Supply Block

The supply block is the amount of capacity, usually expressed in megawatts, that the host utility wants to secure during the planning horizon to meet its projected demand and reliability requirements. The planning horizon is the time period over which a resource plan is developed. For an electric utility, a planning horizon of eight to fifteen years in adding new generation capacity is usually reasonable given the time needed to design and construct new generation facilities and the degree of uncertainty associated with future demand and supply conditions.

The determination of the size of the supply block depends on many factors. These include characteristics of existing power plants, plants under construction, planned capacity reduction, planned supplemental power, conservation and load management programs, economies of scale, and advancements in generation technology. For example, if rapid technical advances are foreseen, a short planning horizon may be warranted and the supply block reduced accordingly, other things being equal. On the other hand, if the regulators and the host utility are concerned with the scale economies of large-sized technologies, it may be advisable to lengthen the planning horizon, which, in turn, results in a larger supply block. The utility may also choose to fill the supply block over time through several solicitations instead of just one.

Even though the supply block specifies in advance the amount of capacity needs subject to bidding, the capacity secured from bidding may not always match the predetermined supply block. It could be more or less than the supply block due to technical lumpiness and the economies of scale associated with different generation technologies. Therefore, the supply block itself should not be viewed as an absolute limit in accepting or rejecting a marginal bid.[6]

Calculation of Avoided Cost

The calculation of avoided cost is a controversial area in PURPA regulations. There are various methods used for calculating avoided cost; they vary by state and by utility. This study does not evaluate the various methodologies. In most states with bidding, utilities are required to use either PSC-approved costing models or to file findings for commission approval before a bid solicitation. Since the supply block may not always match the total capacity of selected bids, it is worthwhile to calculate the avoided cost beyond the predetermined supply block so that cost information is available in deciding whether to accept or reject a marginal bid.

Preparation of Request For Proposal

The request for proposal specifies the conditions of bidding such as the supply block, avoided cost schedule, ranking formula, pricing formula, and bidder qualification questionnaire. When completed, the qualification questionnaire becomes the bid proposal on which the evaluation and selection process is based. A ranking formula, reflecting the specific merit selection criteria of the host utility or the regulators, assigns a composite score to each bid proposal. The pricing formula determines the payments to winning bidders. Such payments may not necessarily equal the

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[6] The marginal bid refers to the last bid to be accepted that may exceed the predetermined supply block. A detailed discussion of bid acceptance can be found in chapter 7.

bid prices submitted.[7] The state PSCs generally do not impose strict conditions on the preparation of the RFP assuming that the host utility probably knows best how to assess conditions beneficial for its operation.

Evaluation and Selection of Bids

Electric utilities are required by state commissions to publicize the advent of a bid solicitation. Typically, it must be advertised in at least one state newspaper with general circulation and in one widely circulated trade journal. The solicitation periods vary in duration among the states, generally from 90 to 120 days.

After the solicitation period, the sealed bids are opened, examined, and ranked according to the ranking formula and selection guidelines contained in the RFP. Bid evaluation is based on the cost, reliability, dispatchability, transmission requirements, project risk, performance warranty, and any other factors peculiar to the host utility. All bids are ranked according to the bid prices or composite scores derived from the ranking formula. Then a bid acceptance procedure is used to select the winning bidders and the amount of capacity accepted. In some instances, a portion of the supply block may be set aside for bidders with specific characteristics of size, ownership, technology, or fuel.

The utilities usually have the primary responsibility in bid evaluation and selection. Most state PSCs are not involved in the evaluation and selection process unless irreconcilable differences arise among the parties. In certain states, the PSCs may conduct public hearings after the evaluation and selection process to ensure that commission rules and guidelines are followed by the utilities and bidders.

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[7] Here, the pricing formula is broadly defined to specify the relationship between the payments received by winning bidders and their own bid prices. Since most states adopt a first-price bidding procedure, the meaning of the pricing formula becomes more restricted. It refers mainly to the price discount in the event the bidders fail to deliver power at a particular time or in a particular amount to the host utility.

Negotiation and Contracting

After the winning bidders are selected, the host utility negotiates a power purchase contract with each winning bidder to make the agreed-upon conditions legally binding on both parties. Ideally, the RFP should contain all the conditions of a power purchase arrangement so that post-bidding negotiations serve only to formalize the terms of winning bids. A post-bidding negotiation is not always a routine exercise, however, given the complexity of a typical utility system and numerous requirements for integrating nonutility power producers with the host utility. Some post-bidding adjustments are likely and probably desirable, considering that even the most detailed RFP cannot contain all possible contingencies or fine details unique to a power purchase arrangement.[8] The negotiation process serves to fine-tune the details of purchase arrangements and to reduce the amount of uncertainty and ambiguity associated with a long-term supply relationship. But post-bidding negotiations should not alter the basic economic terms presented in the original bid proposal. In particular, energy and capacity costs, or the conditions for price adjustments are generally not negotiable.[9]

Existing State Bidding Regulations

Only a few states have bidding programs in place. There are several reasons why this is so. First, many states do not have significant cogeneration or self-generation activities within the state.[10] Second, states are concerned about the legality of competitive bidding under the

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[8] For a discussion on the difficulties of preparing and executing a complete contingent claims contract see Oliver E. Williamson, Market and Hierarchies: Analysis and Antitrust Implications (New York: The Free Press, 1975), pp. 64-67.

[9] According to staff members of Boston Edison and Central Maine Power, the negotiations center mostly on security provisions and penalties for unsatisfactory performance.

[10] National Independent Energy Producers, Pricing New Generation of Electric Power: A Report on Bidding, pp. 2-12, 2-13.

avoided cost pricing rule of PURPA.[11] Third, some states are satisfied with the existing administrative procedures and the individual negotiation approach for determining avoided cost and selecting QFs.[12] In this section, we highlight the essential aspects of the bidding programs in six states. We start with some common aspects and move to the unique features of individual states' programs.

Similarities in State Regulations

The six states with bidding programs in place (California, Colorado, Connecticut, Maine, Massachusetts, and New York) have all adopted sealed bidding procedures. The supply block and avoided cost are usually determined jointly by the regulators and the host utility. The host utility is required to submit a resource plan with projected capacity needs and planned capacity additions. The state PSCs then hold hearings to evaluate the utility's resource plan and make adjustments if necessary. Each bidder can submit only one bid per power source per solicitation. A bidder may, however, participate in more than one solicitation at a time. Once a bid is submitted, its contents cannot be modified before the completion of the evaluation and selection process.

The state PSCs permit small power producers--generally those under one megawatt--to enter into long-term supply agreements with the electric utilities under commission-approved standard contracts without bidding. The qualified facilities generally can sell electricity to the utilities at avoided energy cost if they choose not to participate in a bidding program. The electric utilities are permitted to secure supplies of electric power outside the bidding programs. Such purchases must undergo close scrutiny with a resource plan review or a purchased power prudence review by state

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[11] See, for example, Joint Special Committee on Cogeneration, Final Report and Recommendations to the 70th Legislature, Austin, Texas, p. 29.
[12] Nevada Public Service Commission, Comments of the Public Service Commission of Nevada to FERC, Dockets No. RM88-6-000, RM88-5-000, RM88-4-000 (1988).

PSCs to ensure that the electric utilities are not attempting to evade a competitive bidding process.

California[13]

The California Public Utilities Commission requires the states' three large investor-owned utilities to prepare a resource plan to determine the capacity additions needed to meet demand during the next eight years.[14] The resource plan, updated every two years, is composed of several scenarios sketching out the probable capacity needs of the utility. When capacity additions are warranted, the Commission defines the avoidable plant; that is the most cost-effective means of adding capacity to the utility system. The size of the avoidable plant determines the supply block.

The Commission adopts a second-price bidding procedure where all winning bidders are paid a uniform price that equals the price quoted in the best non-winning bid. If the total amount of capacity offered through bidding is less than the supply block, the winning bidders are paid the host utility's full avoided cost. Price is the sole criterion in bid evaluation. All nonprice factors are expressed as a set of standard requirements. Bids that do not meet those standard conditions are excluded from further evaluation.

An entry fee, currently five dollars per kilowatt bid, is collected from each bidder. It is returned in full to losing bidders and partially refunded to winning bidders. The money not refunded is used to reimburse

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[13] California Public Utilities Commission, Compliance Phase, Final Standard Offer 4: Bidding Protocol, Derivation of Prices from Avoidable Resources, and Associated Issues, Decision 87-05-060 (1987); and id., Second Application of Pacific Gas and Electric Company for Approval of Certain Standards Offers Pursuant to Decision 82-01-103 in Order Instituting Rulemaking No. 2, Decision 86-07-004 (1986).

[14] The three utilities are Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company.

the host utility for performing a study of interconnection costs. The frequency of bidding is decided by the Commission based on the projected discrepancy between the host utility's current supply capability and likely load growth. Electric utilities are not required to prepare a bid solicitation as long as their current capacity is sufficient to accommodate all anticipated load growth over the planning horizon.

Colorado[15]

In Colorado, bidding regulations are currently in place, but actual utility solicitations will not start until 1989. The bidding process is a first-price sealed bid auction under which each winning bidder is paid a price equal to its own bid. Target purchase (supply block) amounts to 20 percent of system-wide native peak load.[16] The winning bidders are each required to post a security deposit as performance warranty.

An independent third party, selected by the host utility subject to commission approval, is responsible for evaluating bids and conducting the bid solicitation. All potential bidders can be categorized into one of five different energy supply groups. These five groups are unscheduled energy only, scheduled energy, unscheduled energy and capacity, scheduled energy and capacity, and economic dispatch of energy and capacity. Both demand-side and supply-side options are allowed to bid. Each energy supply group has a maximum payable price (avoided cost) that is not revealed until all bids are received.

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[15] Colorado Public Utility Commission, The Application of the Public Service Company of Colorado Regarding Cogeneration and Small Power Production, Commission Initial Decision and Order, Decision No. C88-726 (1988).
[16] The Commission may change this 20 percent figure depending upon future experience with the reliability and cost of power supplied by nonutility power producers.

Connecticut[17]

The Connecticut Department of Public Utility Control (DPUC) requires electric utilities to file a yearly report outlining potential capacity needs for the next ten years. The report must include a demand forecast reflecting the host utility's current conservation and load management efforts, projected power purchases, and life extensions plans, as well as more traditional supply options such as building new power plants. The DPUC then holds a public hearing to review the report and determine the supply block.

The DPUC also uses a first-price bidding procedure. After bid evaluation and selection by an electric utility, it holds a public hearing to review the host utility's selections and to ensure compliance with state guidelines. Following this, the DPUC contacts all winning bidders, informing them of their eligibility to enter into long-term power purchase contracts with the host utility. The bids are ranked based on the following factors: the criteria established by the DPUC; the effects on the utility's revenue requirements; the effect on the safety, reliability, and capability of the utility system; and other information specified by the DPUC. As long as current capacity is sufficient to meet future demand within a certain period, no bidding is required.

Maine[18]

In Maine, the electric utilities are required to spend a fixed amount of money (the total avoided cost of the supply block) on power purchased through competitive bidding. If the bid prices of the winning bids are less than the avoided cost, the host utility purchases more capacity than the

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[17] Connecticut Department of Public Utility Control, Regulations Regarding Contract Procedures for Private Power Producers, Docket No. 87-04-02 (1987).
[18] Maine Public Utility Commission, Proposed Amendments to Chapter 36.

predetermined supply block.[19] As a result, the host utility knows in advance approximately how much money will be spent in securing power from nonutility producers but not the actual amount of power to be secured through bidding.

The host utility's supply block is determined solely by its peak demand. The supply block is either 10 percent of its peak demand or fifty megawatts, whichever is less. Since the supply block is tied to peak demand, subsequent bidding is required in spite of the presence of excess capacity or anticipated low load growth in the future. The commission delegates full authority to the host utility in preparing the RFP, in evaluating bids, and in selecting the winning bidders. No public hearings are held either before or after bid selection. The commission intervenes only when disputes arise among parties.

Currently, the Central Maine Power Company is using an elaborate ranking system in bid evaluation.[20] The ranking system is comprised of five indexes: a capacity index, an endurance index, a security index, a price index, and an operation index. A bid's overall rating is the product of individual index scores, and it can range from a low of 1.2 to a high of 330 (assuming the bidder bids a price of zero).[21] A more detailed description of the CMP ranking system is in appendix A. The bidder qualification and power supply performance requirements are summarized in appendix B.

The Commission has adopted procedures to allow the bidders with conservation and other load management projects to participate in the bidding process. An industrial customer, for example, can recover conservation costs at a rate equal to Central Maine Power's avoided cost.

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[19] Ibid. Such an arrangement appears intended to increase the amounts of capacity and energy secured through bidding and, thus, be more beneficial to the development of cogeneration and small power producers.

[20] In addition to the ranking of bids, all bids are subject to certain qualification and power supply performance requirements before they are selected as winning bids.

[21] Central Maine Power Company, Cogeneration/Small Power Production Request for Proposals (Augusta, Maine: Central Maine Power Company, 21 December 1987).

In other words, if the industrial customer can demonstrate and quantify the reduction in load that results from its conservation efforts, it can be reimbursed at the host utility's avoided cost even if this may exceed the actual cost of conservation efforts.

Mandatory wheeling access is required. Any person may petition the Commission to obtain wheeling service. Such service includes the wheeling of energy and capacity from any utilities, qualifying facilities, or other power producers to any utility. An industrial enterprise can also request transmission of self-generated energy to an affiliated industrial enterprise provided that both enterprises are located in Maine. The Commission orders wheeling on a case-by-case basis if the proposed transmission is in the public interest and meets particular reliability conditions.

Massachusetts[22]

In Massachusetts, a utility's supply block is either the capacity additions projected over the next twenty years or 5 percent of its present peak demand, whichever is larger.[23] Consequently, the frequency of bidding may be determined by the host utility's peak demand. The host utility may be required to start a bid solicitation even with excess capacity or projected low load growth. A utility is allowed to wait a year before the next solicitation. Massachusetts' bidding rules require mandatory wheeling. Each utility must provide wheeling service for QFs located within the state to transmit QF power to the transmission and distribution facilities of any other interconnected utility or nonregulated utilities. The Massachusetts

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[22] Massachusetts Department of Public Utilities, Rules Governing Sales of Electricity by Small Power Producers and Cogenerators, Docket No. 84-276-13 (1986).

[23] The following utilities are covered under the bidding rules in Massachusetts: Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, Eastern Edison Company (and Montaup Electric Company where it sells at retail in Massachusetts), Fitchburg Gas and Electric Light Company, Massachusetts Electric Company (and New England Power Company where it sells at retail in Massachusetts), Nantucket Electric Company, and Western Massachusetts Electric Company.

Department of Public Utilities may order a utility to provide wheeling service on its own motion or following a complaint by a qualifying facility. A utility is also required to provide access upon request to its current transmission-related rules and practices and any FERC-approved wheeling tariffs.

New York[24]

The bidding rules in New York are only guidelines to the bid solicitations by individual utilities. A utility, subject to approval of the Public Service Commission, may choose to use a bidding procedure with different features than discussed here. In New York, the initial supply block for bidding is determined by the utility's capacity needs over the next seven years. A two-year bidding cycle is preferred if capacity additions are needed. A utility must state its justifications explicitly if bidding is not held two years after the prior solicitation.

The bid evaluation is a two-stage process. An explicit ranking formula is used as a "first cut" to select an initial set of projects with a combined capacity of 150 percent of the supply block. The host utility, based on its own judgment, selects the bids that can best supply the needed capacity. The explicit ranking formula includes both price (overall price level, payment schedule, and price risk) and nonprice factors (dispatchability, fuel diversity, location, environmental impacts, and likelihood of project completion).

In addition to QFs, independent power producers (IPPs) and utility subsidiaries are allowed to bid. Load management programs can be included in the bidding provided that the costs borne by customers are included, and that no reduction in industrial and commercial production occurs as a result of the load management programs. Small power producers, two megawatts or less, are allowed to bypass the bidding program and contract with the

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[24] New York Public Service Commission, Opinion and Order Concerning Bidding, Avoided-Cost Pricing, and Wheeling Issues, Opinion No. 88-15 (1988).

utility at a price equal to the average of winning bids in the most recently completed solicitation.

Proposed FERC Regulations

In June 1986, the United States Senate and House of Representatives held separate hearings on the implementation of PURPA. During these hearings, utilities, qualifying facilities, independent power producers, and state regulators provided extensive testimony concerning the determination of avoided cost, rates for back-up power, transmission and wheeling of QF power, avoided cost determination for multi-state utilities, and related issues.[25] The FERC, responding to the concerns raised in the hearings, held four regional conferences on PURPA and related topics in March and April 1987.[26]

FERC Chairman Martha O. Hesse, in a speech to the annual meeting of the Edison Electric Institute on June 10, 1987, proposed an all-source competitive bidding scheme. She argued that a properly structured bidding program could provide least-cost and reliable electricity and serve as an alternative to administratively determined avoided costs. She expressed the belief that bidding programs could be made to comply legally with an avoided cost concept and that the FERC would have the authority to declare rates determined through bidding as "just and reasonable" under the Federal Power Act.

On March 16, 1988, the FERC issued three interrelated Notices of Proposed Rulemaking (NOPRs): Regulations Governing Independent Power Producers (RM88-4-000), Regulations Governing Bidding Programs (RM88-5-000), and Administrative Determination of Full Avoided Costs, Sales of Power to

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[25] U.S. Congress, Senate, Committee on Energy and Natural Resources, Implementation of the Public Utility Regulatory Policies Act of 1978, 99th Cong., 2nd sess., 1986; and U.S. Congress, House, Committee on Energy and Commerce, Independent Power Producers, 99th Cong., 2nd sess., 1986.
[26] Federal Energy Regulatory Commission, Cogeneration; Small Power Production--Notice of Public Conference and Request for Comments, FERC Stat. & Reg. para. 35,011, Docket No. RM87-12-000.

Qualifying Facilities and Interconnecting Facilities (RM88-6-000). The three NOPRs represent the current position of the FERC on PURPA-related reforms.

As envisioned by the FERC, the state bidding programs would be flexible in design and, at the discretion of state PSCs, open to all IPPs, QFs, and subsidiaries of electric utilities. The proposed FERC regulations, as stated in the bidding NOPR (RM88-5-000), are not intended to impose any particular bidding approach on state PSCs and nonregulated electric utilities.[27]

According to the bidding NOPR, the implementation of bidding does not represent the abolition of PURPA regulations. The bidding NOPR also emphasizes that bidding programs are prohibited from altering existing purchase agreements between electric utilities and qualifying facilities and that the proposed regulation would not change the traditional responsibilities of state regulatory authorities. The bidding NOPR indicates that the state PSCs still retain the authority to certify the capacity needs of electric utilities, to enforce compliance with environmental and siting regulations, and to hold prudence reviews of utility power purchases when necessary.[28]

Requirements for a State Bidding Program[29]

The bidding NOPR does specify some requirements a state bidding program must meet.[30] Specifically, the proposed regulations require that a state bidding program be explicit about the following: (1) the procedure for determining the quantity, type, and timing of the generation capacity needed; (2) the rules for participation in the bidding process and the

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[27] Federal Energy Regulatory Commission, Notice of Proposed Rulemaking: Regulations Governing Bidding Programs, Docket No. RM88-5-000, p. 17.
[28] Ibid., p. 17.
[29] Ibid., pp. 36-90.
[30] In our view, these requirements deal mainly with the information available in implementing a bidding program. State PSCs still maintain a high degree of freedom in defining the substance of state bidding programs.

avoidable plant and avoided costs; (3) the qualifications of participating bidders; (4) the bid ranking criteria; (5) the selection process; (6) the determination of prices based on bidding results; (7) the contract format including negotiable and non-negotiable contract terms and conditions; (8) the post-bidding conditions on all bidders and on winning bidders; and (9) the conditions under which a solicitation would be considered unsuccessful and cancelled.

Substantial Issues

On the substance issues of a state bidding program, the bidding NOPR has some requirements and suggestions about bidding procedures, bid evaluation and selection criteria, exemptions of nonbidding alternatives, and the approach to transmission access. They are summarized here.

Bidding Procedure[31]

To ensure fairness in a bid solicitation, the bidding NOPR requires that all bidders submit their bids simultaneously. No particular group of bidders is permitted to examine the submitted bids of others until after the solicitation period. Following a solicitation, state PSCs and nonregulated electric utilities are required to publicize the results of the bid solicitation.

The proposed FERC regulations specify that the winning bidders should be held to the prices contained in their bids. A first-price bidding procedure is preferred.[32] No adjustments to bid prices are allowed during the life of the contract. This approach discourages bidders from advancing

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[31] Federal Energy Regulatory Commission, Notice of Proposed Rulemaking: Regulations Governing Bidding Programs, Docket No. RM88-5-000, p. 60.
[32] However, the FERC specifically indicates that the proposed regulations do not preclude the use of other pricing formulas such as the second-price bidding used in California. Ibid., p. 20.

artificially low bids, which may have to be adjusted in the future. In case a winning bidder fails to meet the terms of a power purchase contract, the host utility is allowed to acquire ownership interest and continue the operation of the facility. The ownership interest can be allowed into the utility's rate base. The host utility also has the option to re-bid any unfulfilled capacity.

Bid Evaluation and Selection[33]

The proposed FERC regulations support the use of screening criteria to ensure that all participants are bona fide, legitimate businesses. The criteria include the possession of requisite operating and environmental permits, licenses, or variances as well as certified or documented proof of financial and technical capabilities.

The proposed FERC regulations encourage the use of both price and nonprice factors in selecting winning bids. The weighting criteria used in the ranking formula should be clearly communicated to all participants, and the information provided must enable participants to calculate their bid's composite score and to identify separately the relative importance of each criterion.

The bidding NOPR suggests that the intricate details of designing a ranking formula are best left to the electric utilities and state commissions. As a safeguard against possible abuse, the FERC would require state PSCs and nonregulated electric utilities to submit written evaluations fully describing the selection process and weighting criteria. The written evaluations must explain the rationale behind the ranking formula as well as the supply sources excluded from the benchmark avoided cost, if any. The proposed FERC regulations suggest that utilities should have primary responsibility for selecting winning bids. But state PSCs must certify both the bid selection criteria as well as the final selection of bids.

[33] Ibid., p. 66.

Exemption and Nonbidding Alternatives[34]

The proposed FERC regulations permit the exemption of small QFs with a capacity of one megawatt or less from the state bidding programs. Exempted projects would receive capacity payments based on the results of previous solicitations. State commissions and nonregulated electric utilities are accorded the option of using standard-offer contracts to facilitate post-bidding negotiations.

Transmission Access[35]

The proposed FERC regulations acknowledge the importance of transmission issues and state that FERC intends to review expeditiously its transmission pricing policies on a generic basis. FERC requests comments on two possible approaches: wheeling-in and wheeling-out. Under the wheeling-in approach, a utility wishing to compete with other bidders in supplying another utility's capacity needs is required to provide firm transmission service (subject to reliability and economic dispatch considerations) to the purchasing utility for successful bidders that are located within the bidding utility's own service territory, or are capable of reaching one of its interconnection points. Under the "wheeling-out" approach, a utility bidding to supply its own capacity needs would have to agree to wheel power (subject to reliability and economic dispatch considerations) from any unsuccessful bidder that wishes to sell to another wholesale buyer to other utilities that border its service area.

Selected Utility Experience

Competitive bidding programs have received support from some electric utilities that have solicited and entered into formal power supply agreements with QFs and IPPs through bidding. Thirteen utilities from eight states have used bidding to purchase firm power supplies from nonutility

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[34] Ibid., p. 94.
[35] Ibid., p. 79.

producers since 1984.[36] Since January 1987, more than 3,200 MW of electric generation capacity has been contracted from nonutility power producers resulting from 450 bids submitted with a total capacity of 37,000 MW. Most bidding activity has occurred in East Coast states including Maine, Massachusetts, Vermont, Virginia, and Florida. Utilities in California, Nevada, and Hawaii have used bidding too. Massachusetts has five utilities with bidding experience, the most of any state. Since the information provided here is based on available information of selected utility experience, it is not represented as a complete description of the bidding experience up to now.

The fuel sources of selected projects are usually coal and natural gas. Other fuel sources include oil, refuse, water, wind, wood, and geothermal energy. The amounts of capacity solicited by utilities have ranged widely from 30 MW solicited by Eastern Edison to 1,750 MW solicited by Virginia Power.[37] The amounts of capacity offered in bids also vary from less than 1 MW to 1,300 MW by Pacific Gas and Electric Company responding to a 1987 solicitation from the Sacramento Municipal Utility District.[38]

Central Maine Power Company has successfully solicited eight decrements (fifty MW each) of power and has held more solicitations by far than any other utility, most of which have held only one solicitation to date. Central Maine Power now has contracts for 90 projects with over 600 MW of firm, dispatchable power at rates averaging 90 percent of its full avoided costs. About 70 percent of these projects are wood burning facilities, and about 20 percent are small hydroelectric facilities. About 40 percent of the contracted capacity is with local paper mill cogenerators. Central Maine Power also has contracts with waste-to-energy facilities, stand-alone

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[36] These utilities are Central Maine Power, Green Mountain Power, Boston Edison, Western Massachusetts Electric, Eastern Edison, Cambridge Electric Light, Commonwealth Electric, Connecticut Light and Power, Virginia Electric and Power, Sacramento Municipal Utility District, Seminole Electric Cooperatives, Hawaii Electric, and Sierra Pacific Power.

[37] "Eastern Ed Solicitation Attracts 11 Independents Totaling 180 MW," Electric Utility Week, 1 February 1988, pp. 11-12; and "Virginia Power to Seek 1,750 MW More Through Competitive Bidding," Electric Utility Week, 14 March 1988, pp. 15-16.

[38] "SMUD Power Request Attracts 45 Bids Including Major PG&E, BPA Proposals," Electric Utility Week, 28 September 1987, pp. 1, 4.

wood burners, and cogenerators burning wood, coal, and oil. In its June 1987 solicitation for 100 MW of capacity, Central Maine Power received fifty-one bids offering approximately 1,400 MW of capacity. It ultimately selected three bidders with a total capacity of 123 MW; ninety-two MW came from six wood burning facilities, thirty MW came from a waste-to-energy facility, and one MW came from a hydro facility.[39]

In a 1987 solicitation for 200 MW of firm capacity, Boston Edison Company agreed to purchase 344 MW of capacity from nine projects at rates averaging 70 percent of its full avoided cost. Winning bids varied considerably in size from a 2.5 MW waste-to-energy facility to a 200 MW coal-fired cogeneration facility. The other seven projects, supplying 144.5 MW of capacity, burned natural gas, oil, and wood.[40]

The largest single solicitation to date is a Virginia Power Company solicitation of 1,750 MW of firm capacity in 1988.[41] The company received ninety-six bids for firm capacity totalling 14,000 MW. Of the bids submitted, forty-nine were from cogenerators, thirty-one were from IPPs, fourteen were from small power producers, and two were from other utilities. In terms of fuels, 60 percent came from coal burning facilities, 31 percent came from natural gas facilities, and the remaining 9 percent came from waste-to-energy, peat-fueled, and wood-burning facilities. Around 26 percent (3,584 MW) of the offers were for projects that would be located outside Virginia Power's service territory.

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[39] Based on communications with the staff of Central Maine Power Company, June 1988.

[40] Based on communications with the staff of Boston Edison Company, June 1988.

[41] "Follow-up Bids Cut Va. Power's 27,000 MW Draw to 14,000 MW," Electric Utility Week, 20 June 1988, pp. 19-20.

CHAPTER 3

LEGAL ISSUES IN COMPETITIVE BIDDING

In this chapter, several of the legal issues associated with competitive bidding are addressed. The issues covered are not exhaustive of those that are associated with competitive bidding; however, they do represent some of the more important ones. These include whether competitive bidding is consistent with the PURPA, whether a competitive bidding scheme would necessarily result in an exemption from regulation under the Federal Power Act (FPA) and the Public Utility Holding Company Act (PUHCA), whether the rates set by competitive bid are necessarily just and reasonable, whether and how competitive bidding would affect a utility's obligation to serve, and where the appropriate bounds of federal and state jurisdiction are under a competitive bidding scheme. Each of these topics is discussed in a section of this chapter.

Competitive Bidding and PURPA

One of the principal concerns about the legality of competitive bidding programs is whether state implementation of competitive bidding is inconsistent with either PURPA section 210 or the FERC regulations implementing PURPA section 210. For example, when the Virginia State Corporation Commission investigated a proposed competitive bidding program, a developer of QFs filed a legal challenge to the proposed scheme. The developer argued that competitive bidding offers QFs something below the utility's full avoided cost (the federally-mandated standard) and that competitive bidding ignores the federal requirement that utilities must purchase power made available from QFs.[1] The Virginia Commission, in an

[1] "Developer Challenges Legality of Virginia Competitive Bidding Scheme," Electric Utility Week, 30 November 1987, pp. 8-9.

order adopting nonbinding guidelines for competitive bidding, rejected this challenge. The Commission held that nothing in PURPA or its regulations required utilities to pay rates equal to full avoided costs. Instead, the law forbids only those payments that exceed the incremental costs of alternative supplies. The Commission concluded that a competitive bidding procedure for new power suppliers is a permissible response to PURPA and its regulations.[2] The legality of competitive bidding has remained a concern of state commissions.

PURPA Section 210

The best way to begin an analysis of whether competitive bidding is consistent with PURPA section 210 and its associated regulations is to go to the statute, its legislative history, the regulations promulgated to implement the statute, and the relevant case law. PURPA section 210 states that the FERC must prescribe, and from time to time revise, rules to encourage cogeneration and small power production. The rules must require electric utilities to offer to purchase electric power from QFs.[3] In addition, the rules must ensure that the rates offered by an electric utility to a QF for the purchase of electric energy are just and reasonable to the consumers served by the electric utility, are in the public interest, and do not discriminate against the QFs. The rate for purchase must not exceed the incremental cost to the utility of alternative electric energy.[4] The term "incremental cost of alternative electric energy", with respect to electric energy purchased from _a_ QF, means the cost that the utility would have incurred either by generation or purchase from another source _but for_ the purchase from the QF.[5] Finally, PURPA states that each state PSC will,

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[2] Re Purchase of Electricity by Public Utilities from Qualifying Facilities, 89 PUR4th 185 (VaSCC 1988).
[3] PURPA, section 210(a)(2).
[4] PURPA, section 210(b).
[5] PURPA, section 210(d).

after notice and an opportunity for public hearing, implement the FERC's rule or revised rule for each electric utility for which it has ratemaking authority.[6] This is all that PURPA itself states concerning the purchase of power by electric utilities from QFs.

PURPA itself is silent as to whether a competitive bidding process is permitted to determine the incremental cost of alternative electric energy for a particular utility. However, the incremental cost of an alternative electric energy supply is defined as a "but for" test with the relevant cost being the cost to the utility of generation or a purchase from another source. The "but for" test applies to the purchase of electric energy from the individual QF. Nothing in the statutory language would prevent the purchase from another source from being a purchase from another QF that had negotiated a lower purchase price with the utility. In other words, the statute leaves open the possibility of QF-on-QF competition through competitive bidding or otherwise.

The 1980 Avoided Cost Regulations

The FERC issued final rules implementing PURPA section 210 in February 1980.[7] In these final rules, which are still in effect, the FERC sets forth an electric utility obligation to purchase from QFs any energy and capacity made available by them at the right price. The obligation to purchase extends to power made available to the utility either directly or indirectly through the transmission facilities of another utility.[8] The obligation to purchase energy or capacity is not absolute, but is nearly so. The only instance in which an electric utility may refuse to purchase power from a QF is when, due to operational circumstances, purchases from QFs would result in costs greater than those the utility would incur if it did

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[6] PURPA, section 210(f).
[7] Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 18 CFR Part 292, FERC Order No. 69, 45 Fed. Reg. 12214-12237 (February 25, 1980).
[8] 18 CFR Part 292, sec. 292.303(a),(d), at 45 Fed. Reg. 12235.

not make the purchase, but rather generated the equivalent amount of energy itself.[9] This is most likely to occur during light loading periods when a utility is operating only base load units. It might be uneconomical then to cut back on output from base load units in favor of purchases from QFs. In such situations the avoided cost of power is negative, and there is no obligation to purchase from QFs.[10]

Under the FERC rules, the price paid for purchases of QF power from new QF capacity is the utility's full avoided cost.[11] New QF capacity is defined as capacity from a QF, construction of which began on or after November 9, 1978. The FERC rejected other alternatives that were suggested such as split-the-difference pricing or setting the purchase price at the QF's cost of service (rather than at the utility's avoided cost). Instead, the FERC noted that, in most instances a purchase of power or capacity from a QF only occurs when the QF's own costs are lower than the utility's avoided costs. In particular, a QF only produces if its marginal cost of production is less than the price it receives for its output. If a utility were to pay less than its own avoided costs, a QF may stop producing and a utility may operate less efficient generating units or purchase more expensive power than would have been made available from the QF.[12] Thus, the full avoided cost standard in FERC's rules is equivalent to the incremental cost requirement under PURPA section 210.

The regulations give little guidance on how to measure avoided costs. Instead, they merely define avoided costs as the incremental costs to an electric utility of electric energy or capacity or both, which, but for the purchase from the qualifying facility or facilities, the utility would produce itself or purchase from another source.[13] The definition provides for a comparison with the utility's purchase of power from another source, and the "but for" part of the definition provides for purchases from QFs. The regulations allow QFs to be grouped together in determining the size of

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[9] 18 CFR Part 292, sec. 292.304(f), at 45 Fed. Reg. 12236.
[10] 45 Fed. Reg. 12227-8.
[11] 18 CFR 292, sec. 292.304(b)(1),(4) at 45 Fed. Reg. 12234.
[12] 45 Fed. Reg. 12222-12223.
[13] 18 CFR Part 292, sec. 292.101(b)(6) at 45 Fed. Reg. 12234.

the increment for measuring avoided cost. This implicitly works against competitive bidding plans with possible QF-on-QF competition. Further, in the commentary on its rules, the FERC said that "if, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs 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)"[14] No mention is made of the possibility of a utility buying power from a QF as another source. Thus, the use of competitive bidding among QFs to determine the avoided cost, while not explicitly prohibited, was not contemplated under the 1980 regulations. Indeed, it was against this legal back-drop that the Pennsylvania Public Utility Commission and the Illinois Commerce Commission questioned whether competitive bidding was inconsistent with the concept of full avoided cost.[15]

However, the FERC did not require the use of any particular method of calculating avoided costs.[16] Indeed, the FERC required state public service commissions only to implement the avoided cost regulations noted above. The regulations specifically authorize state commissions to issue their own regulations, or to undertake any other action to fulfill the full avoided cost rules. State commissions implemented these full avoided cost rules in a variety of ways. One of the methods was a purchased power approach, in which the full avoided costs were set at the cost of purchased power from

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[14] 45 Fed. Reg. 12216.

[15] Comments of the Pennsylvania Public Utility Commission in FERC Docket No. RM87-12-000, March 6, 1987, and Comments of the Illinois Commerce Commission in FERC Docket No.RM-87-12-000, April 29, 1987, which are abstracted in Mary Nagelhout, "Competitive Bidding in Electric Power Procurement: A Survey of State Action," Public Utilities Fortnightly, 17 March 1988, pp. 44-45.

[16] However, the FERC did note that one way of determining avoided costs is to calculate the total costs that would be incurred by a utility to meet a specific demand both before and after QFs are included in the system. The method would utilize an optimal capacity expansion planning model to reoptimize the system after including QFs. The total avoided costs (both capacity and energy) would be the difference between the two figures, the total costs without QFs and the total cost with QFs. See 45 Fed. Reg. 12216.

other utilities.[17] In many respects, a competitive bidding process merely sets the avoided cost for power from a QF at the cost of purchased power, whether that power is from a utility or a QF. Next, the judicial review of PURPA Section 210 and the FERC rules are discussed.

American Paper Institute v. American Electric Power

Some utilities were not pleased with the full avoided cost requirement of the 1980 regulations that implemented PURPA section 210(a). Indeed, several electric utility companies sought judicial review of the regulation requiring the utilities to purchase power from QFs at a rate equal to the purchasing utility's full avoided costs. A utility's full avoided costs, as explained, is defined as the cost the utility would have incurred had it generated electricity itself or purchased the electricity from another source.

In the first appeal, the Court of Appeals for the District of Columbia vacated the rule, holding that the FERC had not adequately explained its adoption of a full avoided cost rule.[18] In particular, the Court of Appeals faulted the FERC for not giving additional consideration to a percentage-of-avoided cost approach for determining the purchase price from QFs. The Court of Appeals held that the FERC had, by adopting the full avoided cost approach, failed to consider adequately whether the resulting rates were just and reasonable to the customers of the utility and in the public interest.[19] That decision was brought before the United States Supreme Court on a writ of certiorari.

In a unanimous decision, eight Justices of the Supreme Court reversed and remanded, holding that the FERC did not act arbitrarily or capriciously in promulgating the full avoided cost rule.[20] Justice Marshall, writing on

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[17] Robert E. Burns et al., The Appropriateness and Feasibility of Various Methods of Calculating Avoided Costs (Columbus, Ohio: The National Regulatory Research Institute, 1982), pp. 15-16, 91-92.
[18] 675 F.2d 1226 (1982).
[19] Ibid., pp. 1232-3.
[20] American Paper Institute v. American Electric Power Service Corp., 461 U.S. 402, 76 L.Ed.2d 22 (1983).

behalf of the Court, noted that section 210 of PURPA was designed to encourage the development of cogeneration and small power production.

The Court examined whether the FERC adoption of a full avoided cost rule was arbitrary, capricious, or an abuse of discretion. The Court noted that it could not answer this question merely by observing that a full avoided cost rule was within the range of rates that Congress had made permissible under PURPA section 210(b). (Indeed, the Court noted that full avoided cost was the maximum rate Congress had made permissible.) Instead, the Court decided that it must determine whether the FERC adequately considered the factors relevant to choosing a rate that would best serve the purposes of the statute and whether the FERC committed a clear error in judgment in its decision. In particular, the justices examined whether the FERC had explained its reasons for issuing a full avoided cost rule in light of the criteria set forth in PURPA section 210(b), which provides that the purchase rate must (1) be just and reasonable to the customers of the utility and in the public interest, and (2) not discriminate against QFs.[21]

The justices observed that the full avoided cost rule by definition satisfied the nondiscrimination requirement.[22] This left the more difficult issue of whether a full avoided cost rate was just and reasonable to consumers and whether it was in the public interest.

The Court rejected the respondent-utilities' contention that a just and reasonable rate must be one that is the lowest possible rate consistent with maintaining adequate service in the public interest. Instead, the legislative history of PURPA section 210 makes clear that Congress did not intend for purchases of electricity from QFs to be subject to cost-of-service regulation with its traditional ratemaking concepts. The just-and-reasonable language of PURPA section 210(b) requires consideration of potential rate savings for electric utility customers.[23]

The Court noted that the FERC recognized that its full avoided cost rule would not provide any direct savings to consumers because, when a

[21] Ibid., pp. 412-413.
[22] Ibid., p. 413.
[23] Ibid., pp. 414-415.

utility purchases energy from a QF at its own full avoided cost, the rates the utility charges its customers do not decrease or increase, but remain the same. A full avoided cost rule provides a significant incentive for a high growth rate of cogeneration and small power production, however. Ratepayers and the nation as a whole would benefit both from the decreased reliance on scarce fossil fuels, such as oil and gas, and from the more efficient use of energy.[24] The Court recognized that such a decreased reliance on fossil fuels might result in a reduction of fuel prices. Electric customers would share in the savings to the utilities from lower fuel prices, since they would be passed through to the customers and result in lower rates.[25] Therefore, FERC's explanation of its rationale for adoption of the full avoided cost rule met the criterion of being a just and reasonable rate for electric utility consumers.

The Court also observed that the public interest criterion would be met if the regulation served the purposes of the legislation. Since the basic purpose of PURPA section 210 is to increase cogeneration and small power production and to reduce the reliance on fossil fuels, the full avoided cost rule met the public interest criterion.[26]

Because the full avoided cost rule adopted in the 1980 regulations meets the three criteria of PURPA section 210(b) (namely, it is not discriminatory, it results in just and reasonable rates for electric utility customers, and it is in the public interest), the Court upheld the rule as being consistent with PURPA. The Court held that "<u>at this early stage</u> in the implementation of PURPA, it was reasonable for the Commission to prescribe the <u>maximum</u> rate authorized by Congress and thereby provide the maximum incentive for the development of cogeneration and small power production. (emphasis added)"[27] The Court also noted that the full avoided cost rule adopted by the FERC is subject to revision as the FERC obtains more experience with the effects of the rule.[28]

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[24] Ibid., p. 415.
[25] Ibid., at ftnt. 10.
[26] Ibid., p. 417.
[27] Ibid., p. 417.
[28] Ibid., p. 416.

The significance of the Supreme Court's decision in American Paper Institute v. American Electric Power is that the Court, while upholding FERC's full avoided cost rule, made clear that the rule is not sacrosanct. The FERC is quite free to promulgate another set of regulations that requires or allows something less than full avoided cost. The key requirement for adopting another set of regulations is that the FERC must explain how the regulations meet the criteria of PURPA section 210(b) enumerated above. Recall also, PURPA section 210(a) mandates that regulations must require the electric utility to offer to purchase electricity produced by QFs if the price is right. Within these broad requirements the FERC is free to adopt new regulations concerning purchases from QFs.

The FERC NOPRs Concerning Competitive Bidding

State public service commissions implemented with some difficulty the FERC 1980 regulations requiring the use of full avoided costs as the purchase price for cogenerated power. The rates that were administratively determined using some methods for calculating avoided cost resulted in an oversubscription of cogeneration and small power production. This has been the case particularly when avoided capacity costs have been included in the purchase rates or when the avoided cost-based rates were levelized by significantly loading the front-end of the contract period with a rate higher than the then-current avoided cost.

State commission reactions to these problems varied. Some states imposed a temporary moratorium on new purchase contracts between QFs and the utilities. In other states, the commissions instituted a system of competitive bidding to provide market ordering of QF supplies according to the QFs' own marginal costs of production. However, some of these competitive bidding programs have been challenged as being contrary to the FERC full avoided cost regulations implementing PURPA section 210. Because of the uncertainty involved with this issue, several state public service commissions requested that the FERC explicitly state whether competitive bidding is authorized under PURPA. Several utilities asked that the FERC provide guidance on how bidding procedures could be implemented in a manner consistent with PURPA.[29]

The FERC responded by issuing three NOPRs, described as a "PURPA reform" package. One of the NOPRs focuses on technical considerations for calculating avoided costs if a state public utility commission chooses to determine administratively the avoided costs paid for purchases of QF power. It is intended to correct problems created by the state implementation of the 1980 FERC full avoided cost rules. The NOPR reaffirms the existing 1980 FERC rules and sets out several new requirements for administratively determining these full avoided costs. The proposed rule provides that capacity payments need not be included in avoided cost-based rates if a purchasing utility's capacity needs have been met. If the amount of capacity offered by QFs exceeds a utility's capacity needs, a state commission should consider redetermining the utility's avoided capacity cost rate. Such a redetermined avoided capacity cost rate would not affect existing QF-utility contracts unless the contract specifically provides otherwise. The proposed rule also requires that avoided costs take into account the availability of purchases from other wholesale sources. It provides that wholesale sources of power can be excluded from the consideration of avoided costs only if a state commission gives a written explanation.

The proposed rule would require state commissions to state explicitly in writing how they consider certain factors in setting standard avoided cost rates. These factors include: (1) the quantity and characteristics of a utility's energy or capacity needs and the QF's ability to meet those needs; (2) the costs or savings resulting from variations in line losses from what would have existed without purchases from the QF, if the purchasing utility had generated an equivalent amount of power itself or purchased an equivalent amount of electric energy and capacity; and (3) the value to the utility of a diversity of fuel sources. Concerning levelized

[29] FERC, <u>NOPR: Regulations Governing Bidding Programs</u>, p. 11.

rates, the FERC would require that any front-end loading of avoided costs (1) be based on estimates of avoided costs over the term of the contract, (2) not result in payments in excess of the total avoided costs as calculated at the time the obligation is incurred, and (3) take into account the time value of money, the QF's financing needs, and the inequities that may result from the difference between the rate paid to the QF and the avoided cost at the time of delivery.[30]

The proposed rule would have little substantive affect on those states using one of the more complex methods of calculating avoided costs. However, states using more simplified methods may need to use a different approach in the future to comply with FERC's proposed regulation.[31] Procedurally, the proposed rule would require states to set out explicitly their methodology for determining avoided cost. Further, because the proposed role is a revision of FERC's existing 1980 regulation, each state commission will be required to provide notice and an opportunity for a public hearing within one year of the rule's issuance, concerning implementation of the revised rule.[32]

The most significant NOPR for our purposes concerns competitive bidding programs. The NOPR, if issued as a final rule as proposed, clarifies that competitive bidding is consistent with PURPA if done in accordance with the NOPR. Competitive bidding is one option that a state may adopt voluntarily. If state regulators choose not to do so, they may continue to use administratively determined full avoided cost rates instead. States also have the discretion to extend the competitive bidding process to all sources, including bids from the utility itself.

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[30] Federal Energy Regulatory Commission, Notice of Proposed Rulemaking: Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, Docket No. RM88-6-000 (1988).

[31] See Robert E. Burns et al., The Appropriateness and Feasibility of Various Methods of Calculating Avoided Costs, for a fuller discussion of the various methods of calculating avoided costs available under the 1980 regulations.

[32] PURPA, section 210(f).

Consistency with PURPA

Some key observations can be made about the FERC proposed bidding rule. First, the proposal does not affect the utility's obligation to purchase energy made available by QFs. If a QF were to make power available to a utility outside a bidding process, the utility would still be required to buy the power. However, the utility would not be obligated to make any capacity payment for that power, but would only be required to make avoided energy cost payments, which would be determined administratively. In other words, the proposed rule merely provides an alternative means of determining avoided (incremental) costs. It is therefore consistent with the requirement of PURPA section 210(a)(2). Further, it provides that in the case of a tie in bidding between a QF and a nonQF, the QF is given preference to the capacity payment.

Second, the FERC demonstrates in its NOPR that bidding is consistent with the full avoided cost standard, because bidding identifies a utility's lowest cost opportunity for purchasing power from another source, even if that other source is a QF. The proposed bidding rule is not inconsistent with the language of PURPA section 210(d), which provides that the price paid to a QF should not exceed a utility's incremental costs, with the costs of purchased power from another source being one measure of incremental costs.

Third, and most importantly, the proposed bidding rule is consistent with the United States Supreme Court decision in American Paper Institute v. American Electric Power. As was stated in that case, a FERC rule on avoided costs will be upheld as long as the FERC explains its reasons for issuing the rule in light of the criteria set forth in PURPA section 210(b). The FERC must explain why the proposed rule is just and reasonable to the customers of the electric utility and in the public interest, and why the rule does not discriminate against QFs.

In its NOPR, the FERC notes that its proposed rule would continue to encourage the development of cogeneration and renewable energy technologies, even though a bidding process might result in a lower rate. The Commission notes that under properly structured bidding procedures successful bidders would receive no more than the utility's marginal cost. (Recall that the benchmark avoided cost rate acts as a ceiling.) Such a bidding process would result in just and reasonable rates to the customers by assuring that the utility ratepayers do not subsidize QF producers. This is so because the utilities and the state PSCs would be better able to discover the lowest price at which utilities could purchase power from another source.[33]

The FERC contends that bidding promotes both equitable rates for consumers and efficient use of electric resources and facilities. By improving incentives for efficient QFs, bidding lowers the utility's production costs.[34] This is in the public interest because it promotes the purposes of PURPA.[35]

The FERC also contends that its proposed rule would not discriminate against QFs. While the proposed rule, like the current rule, may result in different rates for different QFs, each QF is given an equal opportunity to compete under a bidding process. Each QF has an equal opportunity to show that it is the most efficient source of capacity for the utility.[36]

Thus, one can conclude that competitive bidding can be consistent with PURPA section 210. However, no judgment is made thus far as to whether bidding is consistent with other federal legislation, namely the Federal Power Act (FPA) and the Public Utility Holding Company Act of 1935 (PUHCA). That question is discussed in the next section.

Bidding and the FPA and PUHCA

As long as a bidding process is otherwise consistent with PURPA and involves only QFs, there should be few problems in making competitive bidding consistent with the FPA and the PUHCA. PURPA subsections 210(d)(1) and (2) provide that the FERC may exempt most QFs in whole or in part from the provisions of the FPA and the PUHCA if the Commission determines that the exemption is necessary to encourage cogeneration and small power production. The only QFs not covered by this provision are qualifying small

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[33] FERC, NOPR: Regulations Governing Bidding Programs, pp. 21-22.
[34] Ibid., p. 23.
[35] Ibid., at footnote 47.
[36] Ibid., p. 24.

power production facilities that do not use biomass as a primary energy source, and that have over 30 megawatts of capacity at the same site.

IPPs and the FPA

When nonQFs win in the bidding process, the legal situation becomes more complex. A nonQF that is successful in bidding is subject to both the rate and the nonrate provisions of the Federal Power Act because of its wholesale electricity sales in interstate commerce.[37] With only a few exceptions, all of the sales of a nonQF to a utility would be sales for resale in interstate commerce. 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. Section 205(e) imposes the burden of proving that a proposed rate is just and reasonable on the selling entity.

The FERC recognizes that the rates for successful nonQF bidders would be subject to its review under section 205 of the FPA.[38] The Commission proposes to streamline the regulation of certain wholesale power producers, called independent power producers (IPPs). An IPP's rates would be deemed just and reasonable if the rates were at or below the purchasing utility's avoided cost, whether determined administratively or by a bidding process.[39] 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.[40] The issue of whether this FERC proposal is sufficient to meet the criterion of just and reasonable rates is discussed in the next section.

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[37] This would not include electricity sales for resale in Alaska, Hawaii, and the ERCOT portion of Texas.
[38] FERC NOPR: Regulations Governing Bidding Programs, pp. 29-34.
[39] Federal Energy Regulatory Commission, Notice of Proposed Rulemaking: Regulations Governing Independent Power Producers, Docket No. RM88-4-000 (1988), pp. 131-132.
[40] See for example, Electricity Consumers Resource Council v. Federal Energy Regulatory Commission, 747 F.2d 1511 (D.C. Cir. 1984).

The FERC also explicitly recognizes that IPPs would be subject to the nonrate regulatory provisions of the FPA. The Commission has proposed that, except for some utilities that sell power as IPPs from facilities outside their service area, it is inappropriate to subject IPPs to the FPA's nonrate regulation. The FERC would like to streamline these regulations for IPPs, other than those owned by utilities. IPPs would be partially exempt from the provisions of section 203 of the FPA, which provides for Commission review of (1) selling, leasing, or otherwise disposing of facilities that are under FERC jurisdiction; (2) mergers or consolidations of those facilities; and (3) acquisition of the securities of any other public utility. IPPs would still be required to file an application with the Commission for these types of transactions. However, the application would be abbreviated and automatically approved unless intervenors filed motions in opposition, in which case the FERC might ask for additional information, or set the matter for a hearing.[41]

The FERC also proposes to exempt nonutility IPPs partially from the provisions of FPA section 204. This section requires FERC approval for any securities issuance after notice and an opportunity for a hearing. The Commission proposes a reduced filing requirement from these IPPs, who could then take advantage of FERC's shelf regulation policy so that they could issue securities in an expedited manner. The FERC would exempt the nonutility IPPs from the requirement that securities can only be issued after a public invitation and acceptance of bids for the securities.[42] The FERC also proposes to exempt nonutility IPPs from procedures for enforcing compliance with its accounting and reporting regulations, from reporting on their procurement policies and procedures, from complying with the FERC Uniform System of Accounts, and from filing the statements and records that are required from utilities.[43] The Commission's justification for these exemptions is that nonrate regulation is inappropriate for IPPs that are not utilities with retail service franchise areas because the nonrate regulation

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[41] FERC NOPR: Regulations Governing Independent Power Producers, pp. 106-108, 136-139.
[42] Ibid., pp. 108-110, 140-142.
[43] Ibid., pp. 111-115, 142-144.

is intended to protect the quality and reliability of service provided by franchised utilities to customers with no supply alternatives. No useful purpose would be served by extending the regulation to nonutility IPPs.[44]

IPPs and the PUHCA

Successful nonQF bidders could be subject to the provisions of the Public Utility Holding Company Act of 1935, particularly if the successful bidder were a utility outside of its franchise territory. The PUHCA can be triggered by acquisition of a utility and applies to holding companies, as defined in the Act.[45] An entity can become a holding company under the PUHCA without owning a traditional utility company. A utility as defined under the PUHCA need not have a governmental franchise or an obligation to serve. An electric utility is one that owns or operates facilities used for the generation, transmission, or distribution of electricity for sale. An IPP could be such a utility.

To become a holding company, a person, corporation, or other legal entity only need own 10 percent or more of, or exercise a controlling influence over, an electric or gas utility.[46] 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. Section 9 requires approval by the Securities and Exchange Commission before certain acquisitions of utility assets or securities can take place. This prior approval requirement applies to all registered (nonexempt) holding companies and their subsidiaries,[47] and to any person (including exempt holding companies) if

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[44] Ibid., pp. 104- 106. It is worth noting that the FERC allows for similar exemptions and streamlined nonrate regulation on a case-by-case transaction-specific basis for IPPs owned by utilities with retail franchise areas.

[45] 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?" 1 The Electricity J. 40, 47-49 (July 1988).

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

[47] Ibid., section 9(a)(1).

the acquisition results in the person being an affiliate (the owner of 5 percent or more) of two or more utilities.[48]

If SEC approval were required, this Commission must apply six criteria set out in section 10 of the PUHCA to determine whether to approve the acquisition. The most significant of the six criteria for our analysis is that the acquisition must serve the public interest by tending toward the economical and efficient development of an integrated public utility system.[49] An integrated public utility system under the PUHCA is a system consisting of one or more generating plants, transmission lines, or distribution facilities, having utility assets that are physically interconnected or capable of physical interconnection. Under normal conditions, an integrated public utility system is capable of being economically operated as a single interconnected and coordinated system confined in its operations to a single area or region. It should not, however, be so large as to impair (considering the state of the art and the affected area or region) the advantages of localized management, efficient operation, and the effectiveness of regulation.[50] If a utility were to attempt to set up an IPP outside its own service area, it would fail to meet the criterion 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.

An entity that is a registered holding company under the PUHCA must comply with comprehensive, ongoing regulation by the SEC. This ongoing regulation entails advance approval by the SEC of certain issuances and sales of securities,[51] Commission review of interaffiliate transactions,[52] Commission review of service, sales, and construction contracts,[53] and detailed financial reporting requirements. The only way a holding company

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[48] Ibid., section 9(a)(2).
[49] Ibid., section 10(c)(2).
[50] Ibid., section 2(a)(29)(A).
[51] Ibid., sections 6 and 7.
[52] Ibid., section 12.
[53] Ibid., section 13.

under the PUHCA can avoid this comprehensive, ongoing regulation is to qualify as an exempt holding company.

There are five categories of exempt holding companies under section 3 of the PUHCA, three of which concern our analysis.[54] 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.) These so-called intrastate holding companies can have nonutility subsidiaries that are located out-of-state or are engaged in out-of-state nonutility activities. To qualify for this exemption, a holding company would need to locate all its utility activities (IPPs) in one state.[55]

The second exemption, known as the "predominately a utility" exemption, would be available to a utility setting up IPPs that are outside of its own franchise service territory. To qualify for this exemption, a holding company itself would have to be primarily a utility operating only in the state in which it was organized and in adjoining states. Thus, any IPPs the utility set up would have to be in the same or adjoining states, outside of the utility's own franchised service territory, and would have to be operated as a part of a single interconnected and coordinated system. This might be possible under certain tight power pooling agreements.[56]

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. An example of this exemption would be an aluminum company which sets up a subsidiary to generate its own electricity. This exemption might be available under certain limited circumstances.[57] While one can imagine

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[54] The two exemptions not covered here are the section 3(a)(4) and 3(a)(5) exemptions. Section 3(a)(4) provides a "temporary holding company" exemption that deals with bankruptcies, reorganizations, and defaults where an investor only temporarily holds the company. Section 3(a)(5) provides an exemption for holding companies over foreign utilities.
[55] Ibid., section 3(a)(1).
[56] Ibid., section 3(a)(2).
[57] Ibid., section 3(a)(3).

individual special circumstances under which each of these exemptions would be available, in the great majority of cases they would not apply.[58]

Most utilities and other corporations that might be interested in setting up IPPs wish to avoid becoming registered holding companies under the PUHCA. Indeed, former FERC Chairman Charles Curtis observed that the criteria set forth in the NOPR on independent power producers for a utility's ownership of facilities outside of its own franchise area directly conflict with the PUHCA's prohibition of utility ownership of nonintegrated facilities. As a result, the FERC is presenting utilities with opportunities that they are legally obligated to refuse. While most QFs would be exempt from the PUHCA, most IPPs would not be exempt. This is likely to discourage many IPPs from entering the market as new capacity suppliers. According to Mr. Curtis, given the obstacle of the PUHCA, it would seem unwise for the FERC to press forward with its initiative to substitute bidding for regulation in the development of new generating capacity.[59]

However, the PUHCA might be sidestepped by taking advantage of a recognized exception to the Act. Enterprises wishing to set up IPPs might set up non-holding company entities, where each utility is a division of the parent company and where the only subsidiaries are those not jurisdictional to the PUHCA.[60] Such a strategy might be unavailable in some states because of a requirement that companies providing utility services must be incorporated in that state. Also, nonutility companies interested in

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[58] Even when a section 3(a) exemption does apply, all such exemptions are subject to one very important clause, commonly known as the "unless and except" clause. This provides the SEC with the power to withhold, revoke, or condition an exemption insofar as it finds the exemption to be detrimental to the public interest or the interest of investors or consumers. However, this clause has only been successfully invoked once by the SEC in the last twenty-eight years. For the most part it is used as a threat to prevent imprudent capitalization, distortions of debt to equity, and other historical excesses of holding companies. See Hawes, at 3-20 - 3-21.

[59] "Without PUHCA Changes, Electric Initiatives Are Flawed, Curtis Says," Inside F.E.R.C., 13 June 1988, pp. 4a-4b.

[60] See Hawes, Utility Holding Companies, pp. 3-9, where he suggests this strategy. This strategy has been used by Pacific Corp., Utilicorp, Citizens Utilities, and Allegheny Energy Companies.

setting up IPPs might be disinclined to set up utility divisions because of the possibility of being regulated by the FERC or the state PUCs. Finally, a major individual or institutional owner of stock in such a company may inadvertently become a holding company subject to the PUHCA.

Just and Reasonable Rates

There are two statutory provisions that determine whether rates arrived at by a bidding process are just and reasonable. The first applies to successful QFs and is contained in PURPA section 210(b). The second applies to nonQFs and is the rate regulation provision found in FPA section 205, which is referred to above. Each is discussed below.

Just and Reasonable Rates for QFs

Recall that the United States Supreme Court in American Paper Institute v. American Electric Power Service Corp. held that the term "just and reasonable" as used in PURPA section 210(b) means something different from the traditional cost-of-service approach with which the term is normally associated. Congress did not intend for QFs to be subject to the type of examination that is traditionally given to electric utility rate applications. Instead, Congress intended that recognition be given to the difference between QFs and electric utilities: namely, QFs are not being guaranteed a rate of return on their sale of power to the utility. QFs bear the risk in proceeding forward with cogeneration and small power production and that risk is not guaranteed recovery.[61]

Instead, the Court held that the "just and reasonable" language of PURPA section 210(b) requires a consideration of potential rate savings for an electric utility's customers that could result by setting a power purchase price at a level lower than the statutory ceiling, that is, lower than full avoided cost.[62] However, the Court also noted that Congress

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[61] American Paper Institute, Inc. v. American Electric Power Service Corp., 461 U.S. 402, 414 (1983).
[62] Ibid., p. 415.

intended that cogeneration be encouraged. Therefore, the examination of the level of prices that would apply to purchases of QF power should be less burdensome than that under cost-of-service regulation.[63] Although the Court upheld the 1980 full avoided cost rule for the statutory maximum rate, it left the door open for downward revisions as the FERC obtained more experience with the effects of the rule.[64]

The FERC has proposed such a downward revision in its competitive bidding NOPR.[65] Although the competitive bidding rule is presented as an alternative way of determining full avoided costs,[66] it is implicitly different from previous full avoided cost calculations. A bidding process furthers the interests of the ratepayers in receiving a just and reasonable rate by enabling the utilities to better discover the lowest price at which they could purchase power from an alternative source. Further, bidding allows the alternative source to be another QF, thus allowing for QF-on-QF competition. Bidding among QFs is likely to generate savings for ratepayers by encouraging production by the most efficient QFs.[67] The 1980 regulations were intended to assure only that ratepayers would be indifferent as to the source of power. Thus, the bidding process as proposed by FERC results in a different balancing of interests than was found in the 1980 regulations.

The proposed bidding regulations do a better job of considering the potential rate savings for customers of electric utilities and better fulfill the "just and reasonable" requirement than the 1980 regulations. In addition, the proposed FERC regulations provide a means for examining the

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[63] Ibid., p. 414.
[64] Ibid., p. 416.
[65] Avoided cost rates reached by competitive bidding can only result in a downward adjustment from previous full avoided cost rate calculations. This is so because in bidding systems that exclude some alternative wholesale sources of capacity from the bidding process, the FERC has required that a benchmark avoided cost rate be set as a ceiling above which a successful bid cannot be accepted.
[66] The FERC states that it believes that bidding is consistent with full avoided costs and therefore should not be interpreted as a departure from the implicit balancing of the objectives of PURPA reflected in the 1980 regulations. See FERC NOPR: Regulations Governing Bidding Programs, pp. 20-21.
[67] Ibid., pp. 22-23.

level of QF rates that is less burdensome than the typical utility cost-of-service regulation. Therefore, it is likely that rates set by the proposed bidding process would be consistent with the just and reasonable standard of PURPA section 210(b), as explained by the United States Supreme Court.

Just and Reasonable Rates for IPPs

For nonQFs involved in a bidding process, the issue of whether a rate determined by a bidding process is a just and reasonable rate is more troublesome. This is because wholesale sales by nonQFs are subject to the rate regulation provisions of section 205 of the FPA. Section 205(a) requires that all rates subject to FERC jurisdiction be "just and reasonable" and declares rates that do not meet this standard to be unlawful. Section 205(b) requires that the rates not be unduly preferential or prejudicial. Section 205(e) imposes on the regulated entity the burden of proving that any proposed rate is just and reasonable.

Traditionally, the FERC and the courts have interpreted the "just and reasonable" standard to mean that rates must be cost based. Indeed, traditionally, the FERC and the courts have interpreted "just and reasonable" rates to be embedded cost based.[68] However, the FERC has not strictly followed this standard in setting rates for coordination sales. There the Commission has allowed the seller to split-the-savings or to recover its incremental costs plus an adder.[69] Indeed, in one circumstance the FERC has allowed a utility to sell the unutilized share of its transmission capability on the basis of a telephone auction, thus replacing embedded-cost based rates with market-based rates.[70]

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[68] See generally, Electricity Consumers Resource Council v. Federal Energy Regulatory Commission, 747 F.2d 1511 (D.C. Cir. 1984).

[69] See Public Service Co. of New Mexico, 25 FERC para. 61,469 (1983); Portland General Electric Co., 33 FERC para. 61,459 (1985); Pacific Gas & Electric Co., 38 FERC para. 61,242 (1987); and Orange and Rockland Utilities, Inc., 42 FERC para. 61,012 (1988).

[70] Baltimore Gas and Electric Company, 40 FERC para. 61,170 (1987). However, Commissioner Trabandt's concurring opinion should be noted. He stated that, essentially, the FERC approved the proposal because there was no objection raised and because approval was likely to result in greater economic efficiencies and customer savings.

The Circuit Court of Appeals for the District of Columbia made clear in Electric Consumers Resource Council v. F.E.R.C., (Elcon)--a case that rejected the use of marginal cost based rates--that the courts were willing to examine whether rates based on some method other than embedded costing are "just and reasonable" and nonpreferential if the FERC can submit a substantial record of evidence and an articulation of a rational basis for its decision to use another cost based pricing scheme. The Court rejected a rate design based on marginal cost pricing, emphasizing that the FERC cannot rely exclusively on economic theory for the adoption of a new ratemaking methodology.[71]

The FERC proposed in its NOPR on independent power producers that a rate tariff filed by an IPP is just and reasonable under section 205 of the FPA if the rate is at or below the purchasing utility's avoided costs. The purchasing utility's avoided cost may be determined either administratively or by a bidding program that meets the Commission's requirements.[72] The FERC based its rationale for its proposed rule mainly on economic theory, noting that the economic rationale for cost-of-service regulation is to obtain the efficiency of natural monopoly supply while protecting the public from the exercise of monopoly power.

The Commission reasoned that because the nature and magnitude of coordinated transactions among utilities have changed dramatically, with substantial quantities of bulk power being moved between regions, the assumption that the generation sector of the electric industry is still a natural monopoly is called into question. Next the FERC noted that traditional cost-based regulation creates certain inefficiencies, namely: (1) it often encourages inefficient supply and consumption decisions, (2) it blunts the profit incentive for utilities to minimize costs by tying prices to costs, and (3) it does not adequately compensate for risk taking. The Commission contended that because IPPs by definition have no market power,

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[71] Electricity Consumers Resource Council v. Federal Energy Regulatory Commission, 747 F.2d 1511, 1513, 1518 (D.C. Cir. 1984).
[72] FERC NOPR: Regulations Governing Independent Power Producers, pp. 131-132.

and hence no monopoly power, cost-based regulation is inappropriate. Furthermore, the FERC argued that the development of IPPs would be beneficial and in the public interest.[73]

After finding that traditional cost-of-service regulation was not appropriate for IPPs, the FERC examined other alternative forms of establishing a cost-based cap for IPPs. Based on its evaluation, the Commission concluded that rates paid to IPPs should be based on the purchasing utility's avoided cost. This is the same avoided cost standard found in the proposed regulations for determining avoided cost administratively or by competitive bidding. Hence, the FERC has proposed, by means of regulation and without any supporting legislation, to equate the just and reasonable standard for IPPs under FPA section 205 with the avoided cost standard for QFs under PURPA section 210. Whether the economic rationale used to justify this proposed rule would withstand judicial review is a subject for conjecture.

The Elcon case, which would appear to provide a precedent, might be distinguishable from the current FERC rulemaking because it deals with a rate design question in the context of a judicial review of a rate tariff proceeding. The current FERC proceeding is a rulemaking that normally would be reviewed by the courts using an "arbitrary and capricious" or an "abuse of discretion" standard rather than the "substantial evidence" standard. However, the D.C. Circuit Court appears reluctant, if not loath, to allow the adoption of new costing methodologies based solely on economic theory. The courts also tend not to allow an administrative agency from using a rulemaking procedure to make an "end run" around its statutory obligations.[74] Whether the courts would uphold the FERC proposed rule on

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[73] Ibid., pp. 22-64.
[74] The leading case for this proposition is Motor Vehicle Manufacturers Association v. State Farm Mutual Automobile Insurance Company, 462 U.S. 919 (1983). For a comprehensive discussion of the scope and standards of judicial review of administrative actions see "Scope-of-Review Doctrine: Restatement and Commentary," 38 Ad. L. Rev. 235 (1986); Levin, "Scope-of-Review Doctrine Restated: An Administrative Law Section Report," 38 Ad. L. Rev. 239 (1986); and Breyer, "Judicial Review of Questions of Law and Policy," 38 Ad. L. Rev. 363 (1986).

the issue of a competitively bid or administratively determined avoided cost rate being a just and reasonable rate under FPA section 205 is of course not known. The matter might well be decided based on the commentary and rationale that would be published with a final rule. What is certain, however, is that if a final rule is issued containing "just and reasonable" provisions similar to those contained with the proposed rule, it will be tested in the courts.

Obligation to Serve

The use of competitive bidding to determine a utility's supply sources would in no way affect a utility's obligation to serve its retail customers. As has been observed by others, all states have either encouraged or required electric utilities to provide retail electric service in an identifiable service area. With only a few exceptions of limited significance, state law, whether by statute, case law, or commission decision, imposes on the utility an obligation to serve all existing and future customers within its service area, and to plan for and to acquire the facilities necessary to serve those customers adequately and reliably in the future.[75] Nothing in the competitive bidding process as proposed by the FERC would necessarily affect the utility's obligation to serve its retail customers.[76] That is a matter of state law.

However, the ability of a utility to fulfill its obligation to serve its retail customers is affected by its ability to be certain of its supply sources. When a utility does not own and operate its own generation facilities, its supplies would be acquired in wholesale sales under FERC regulation. Some would contend that the FERC has plenary authority (except for certain statutory limitations not applicable here) under FPA section

[75] Bouknight and Raskin, "Planning for Wholesale Customer Loads in a Competitive Environment: The Obligation to Provide Wholesale Service under the Federal Power Act," 8 Energy L.J. 237, 238 (1987).
[76] This is recognized by the FERC at NOPR: Regulations Governing Independent Power Producers, p. 68.

202(b) to enforce an obligation to serve for wholesale sales.[77] Also, the Commission can require that the obligation to serve once undertaken exists apart from the underlying terms of the service agreement and that the supplier must satisfy the public interest requirement under FPA sections 205 and 206 before terminating service.[78]

The FERC, on the other hand, has recently decided that there is no express obligation to serve wholesale customers. However, where a utility has contractually agreed to provide such service, the Commission will not allow termination of the service without a showing that the termination would be in the public interest.[79]

Under the current FERC regulations, when a utility's supplier is a QF that is either a cogenerator or a non-biomass small power producer having capacity not exceeding 30 megawatts, that QF is exempt from sections 202(b), 205, and 206 of the FPA. Hence, it is exempt from FERC's authority (if any) to enforce an obligation to serve.[80] Nothing in the proposed regulations on competitive bidding would change that.

Currently, utilities require a variety of means, such as performance bonds, acquiring a security interest in the plant, and penalty clauses, to assure that QFs will fulfill their contracts and to protect themselves in case of default. Thus far, these contractual means of assuring QF performance have proven to be satisfactory. However, the possibility that a QF might declare bankruptcy remains a concern. Bankruptcy would be

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[77] Federal Power Act, section 202(b), as interpreted in New England Power Co. v. FPC, 349 F.2d 258 (1st Cir. 1965). This obligation to serve is not an obligation to provide common carriage. It extends to wholesale sales of power relied on by the buying-utility to serve its own retail customers. It does not apply to coordination or opportunity transactions between self-sufficient utilities. See generally, Bouknight and Raskin, supra.

[78] Federal Power Act, sections 205 and 206, as interpreted in Pennsylvania Water & Power Co. v. FPC, 343 U.S. 414 (1952).

[79] FERC NOPR: Regulations Governing Independent Power Producers, p. 68 at footnote 122, citing FERC Order 474 and 474-A.

[80] See 18 CFR section 292.601 in 45 Fed. Reg. 12237 (March 20, 1980). It is interesting to note that QFs are not exempt from FPA section 202(c), which could require a QF to provide energy if the Economic Regulatory Administration of the U.S. Department of Energy determines that an energy emergency situation exists.

particularly troublesome if caused by high fuel costs and if the spot market price for fuel or replacement power were high. In such a situation, the variable costs of running the QF plant might not be fully recoverable and the trustee in bankruptcy might be disinclined to operate the plant.

The FERC has made it clear in its commentary in the NOPR that it does not intend to place an obligation to serve on IPPs. According to the Commission, the problems caused by attempting to integrate an increased reliance on wholesale sources of power with a utility's obligation to serve its retail customers is a matter appropriate for state and utility resolution. The FERC suggests that appropriate pricing, performance bonds, dispatchability requirements, appropriate selection criteria, and acquisition of a security interest in the plant in case of a default are all means that can be used to reach this resolution.[81] Although the various means of assuring that a utility can meet its obligation to serve its retail customers add to the complexity of planning for adequate and reliable sources of power for future needs, it is believed that they can work. For example, see appendix B.

A more relevant question may be whether the costs of employing these legal mechanisms outweigh the benefits. While a utility has an obligation to purchase from a QF, it does not have an obligation to purchase from an IPP. If the costs of assuring performance outweigh the comparative advantage of purchasing from an IPP, a utility would be better off simply generating its needed power itself.

Preemption and the Appropriate Bounds of State and Federal Jurisdiction

The problems that state commissions face concerning competitive bidding and the potential for federal preemption differ according to whether the bidding process allows QF-only bidding or whether IPPs are allowed. QF-only bidding and bidding involving IPPs are examined each in their turn.

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[81] FERC NOPR: Regulations Governing Independent Power Producers, pp. 68-71.

QF-Only Bidding

If competitive bidding between QFs were available as an option for state public service commissions under the FERC proposed regulations, it would be up to the state commissions to decide whether to implement the regulation for those utilities over which they have ratemaking authority. State PSC implementation of QF rules is specifically provided for in PURPA section 210(f),[82] and the FERC in its NOPR makes competitive bidding an option, not a requirement.[83] PURPA Section 210(f) would apply when a state commission implemented QF-only bidding.

The FERC proposed rules have a number of requirements that a state commission must follow for its competitive bidding process to be considered consistent with PURPA section 210. These requirements, which deal principally with bid solicitation and bid evaluation reporting, have been discussed earlier. They are needed so the FERC can accurately track state experiences with the bidding process, in order to fine tune its bidding regulations in the future in light of state experiences.

The FERC also requires a state commission to certify the results of its bid solicitation process by notifying the FERC of the winning bidders. The FERC states that its reasons for requiring state certification are to ensure state commission involvement in the implementation of the bidding programs, to lessen the need for prudence review of the purchased power costs of winning bids, to allow the FERC to better monitor the outcomes of competitive bidding, and to provide the utilities with a "state action" exemption from the antitrust laws.[84]

While state involvement in competitive bidding and FERC monitoring of bidding programs are appropriate goals, one might question the other two FERC goals of state certification. Lessening the likelihood of an after-the-fact prudence review would seem to be an appropriate goal only if state

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[82] Public Utility Regulatory Policies Act, section 210(f).
[83] FERC NOPR: Regulations Governing Bidding Programs, pp. 16, 101.
[84] Ibid., pp. 53-55. See also, Robert E. Burns, "Legal Impediments to Power Transfers," Non-Technical Impediments to Power Transfers ed. Kevin A. Kelly (Columbus, Ohio: The National Regulatory Research Institute, 1987), pp. 88-89.

regulatory commissions were involved not only in the bidding process design, but in the selection process itself. If the actual bid selection was done by the utility, as suggested by the FERC,[85] there would be no other effective regulatory mechanism for state commission review of the reasonableness of the bid selection. Also, the FERC has suggested that state certification should provide "state action" antitrust immunity to the utilities. If there were bid rigging (a form of price fixing) or leveraging of monopoly power (a form of monopolization), however, there would then be no antitrust remedy to protect the public interest if the FERC suggestion were taken. This would be particularly troublesome if the state commission were not directly involved in the bid selection process and could not protect the ratepayers from these potential abuses.[86] The potential abuse of bid rigging is addressed further in chapter 4.

The FERC has made it clear that, beyond compliance with its proposed regulations, the implementation of the bidding program is left entirely with the state public service commissions.[87] State commissions are free to experiment with different bidding designs and approaches, such as first-price and second-price bidding. Allowing the states to experiment with different approaches is appropriate because state PSCs can act as regulatory laboratories to find the bidding process that works best. Also, state commissions can react better to local conditions than the FERC. The proposed rules would not foreclose states from considering demand-side alternatives in the bidding process; the FERC, however, has requested comments on this.[88] Unless some type of grandfathering provision is included in the final rules, the proposed rules as currently written would require those states with existing bidding programs to reexamine those programs in light of the FERC regulations.

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[85] Ibid., pp. 66-68. However, this is not required in the proposed regulations themselves.
[86] Bid rigging is discussed elsewhere in this report. Also, see "Attorney Says Bidding Likely to Create 'Classic' Antitrust Conflicts," Electric Utility Week, 21 December 1987, pp. 12-13.
[87] FERC NOPR: Regulations Governing Competitive Bidding, p. 17.
[88] Ibid., p. 57.

The proposed rules do not alter states' traditional responsibilities concerning certification of need, siting, and environmental regulations.[89] Indeed, state agencies, together with the utilities they regulate, would continue to be responsible principally for making certain that there is adequate and properly sited capacity available to provide adequate and reliable service to the customers in the utility's franchise area. Thus, federal preemption of state prerogatives is not as threatening with QF-only bidding.

Bidding with IPPs

The possibility of federal preemption becomes more troublesome when IPPs are allowed in the bidding process. When IPPs become involved, PURPA section 210(f) no longer applies, at least not for those bids submitted by the IPPs and other nonQFs. There is simply no statutory provision that assigns the implementation of a competitive bidding process involving nonQFs to the states. Without such a statutory provision, the FERC could, if it so chooses, regulate the selection of bids of nonQFs.[90] This could lead to a major shift of jurisdiction over sales by entities owning generation facilities from the states to the FERC.[91] The FERC could effectively preempt state regulation of these nonQF sources of power.

Indeed, depending on the ultimate reach of the recent U.S. Supreme Court decision in Mississippi Power & Light Co. v. Mississippi Ex Rel. Moore, state commissions might even find themselves foreclosed from conducting prudence reviews on whether a less expensive source of power were available to the purchasing utility.[92] The majority opinion in that case

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[89] Ibid., p. 17.
[90] This is assuming that a just and reasonable rate can be market-based as it would be under a competitive bidding scheme rather than cost based as is traditionally the case under FPA section 205.
[91] It is quite possible that such jurisdictional transfers would occur in any event. Generally, see William Lindsay and Jerry Pfeffer, Deregulation of the Electric Power Industry: Perspective of State Regulation, (Columbus: The National Regulatory Research Institute, 1983).
[92] Mississippi Power & Light Company v. Mississippi Ex Rel. Moore, Docket No. 86-1970, U.S. Supreme Court (June 24, 1988).

uses broad, sweeping language to reestablish the bright-line distinction between state and federal authority over the setting of wholesale rates and over agreements affecting wholesale rates, and concludes that states cannot prevent their regulated utilities from passing through to retail customers FERC-mandated wholesale rates. Such "trapping" of rates, as the Court calls it, is impermissible.[93]

However, the concurring opinion of Justice Scalia would limit the Court's holding to a finding that the FERC has exclusive jurisdiction to determine the prudence of a particular utility's participation in a power pool.[94] Such a narrow holding would still allow state commissions to determine that a state regulated utility should have bought wholesale power from another source at a lower cost.[95]

Some Implications

Throughout this chapter, it is shown that FERC and state implementation of competitive bidding poses few legal problems when the bidding is limited to QFs. A QF-only bidding process would be consistent with PURPA section 210, would have few FPA and PUHCA problems, would result in just and reasonable rates as defined by PURPA, would not cause any additional problems concerning a utility's obligation to serve, and would cause few federal-state jurisdictional problems. However, it has also been shown that inclusion of nonQFs (that is, IPPs) in the bidding process creates numerous legal problems for both the FERC and the states. Although all-source competitive bidding may be desirable from the point of view of economic theory, there are significant legal impediments to the inclusion of nonQFs in bidding. These problems need to be addressed by the FERC or the courts or remedied by Congress before the inclusion of IPPs in a bidding process is attractive to state PSCs from a legal standpoint.

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[93] Ibid., pp. 17, 19-21.
[94] Ibid., concurring opinion.
[95] See the <u>dicta</u> in Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 992 (1986).

CHAPTER 4

BENEFITS AND PITFALLS OF COMPETITIVE BIDDING

In this chapter, the benefits and pitfalls for using competitive bidding as an alternative to traditional regulation in securing new electric generating capacity are examined. Also analyzed are the benefits of bidding in replacing existing PURPA regulations such as avoided-cost pricing and administrative procedures or negotiations in selecting nonutility generation capacity. The idea of using competitive bidding is to substitute market forces for regulatory oversight in resource allocation. The potential benefits and pitfalls of bidding relate to how closely the characteristics of the bidding environment and the bidding participants approach those of an ideal competitive marketplace. Before the benefits and pitfalls of bidding are discussed, it is important to recognize that our conclusions reflect the general conditions associated with competitive bidding and traditional regulations. They may not always reflect the many differences among state utility regulations concerning the construction and operation of new power plants, purchased power prudence reviews, PURPA regulations, and the specifics of power purchase contracts entered into by a host utility and the selected nonutility producers.

In the following sections, we find that the primary benefits of competitive bidding are economic efficiency improvement in electricity generation and additional protection for ratepayers. The effect of bidding on the reliability of service to ratepayers is less clear, but there are reasons to believe that bidding is unlikely to have an adverse affect. In terms of economic efficiency, bidding is a more comprehensive approach than individual negotiations or administrative procedures currently applied in selecting and pricing nonutility generating capacity. Bidding also introduces market discipline into the electricity generation sector so that electric utilities as well as nonutility power producers have stronger incentives to control costs. In terms of ratepayer impact, bidding allows ratepayers to benefit directly from cost savings gained in replacing utility generation with lower cost nonutility generation and reduces the take-or-pay risk associated with poor performance by the power producers.

But bidding is not without its pitfalls. A review of the history of the use of competitive bidding in four areas of government procurement indicates that the results of bidding can be far from the efficiency and fairness hoped for. The pitfalls of competitive bidding include, among other things, unlawful practices such as price fixing and market share rotation schemes, as well as lawful (but detrimental) activities such as the "hungry-firm phenomenon," in which a bidder submits an artificially low bid to win, hoping to recoup more revenue later.

On balance, the potential benefits of bidding appear to outweigh the potential pitfalls. In most instances, the pitfalls are related to the absence of a large number of rivalrous bidders with even technological and information conditions. The pitfalls can be eliminated or mitigated through a properly designed bidding program and rigorous enforcement of antitrust laws. The design of such a bidding program and the assurance of a competitive bidding environment are discussed further in chapter 6 and chapter 8, respectively.

Economic Efficiency

Improvement in economic efficiency is the primary goal of using competitive bidding in securing new electric generating capacity.[1] Bidding can achieve efficiency improvements because the changes in the technological and economic conditions in electricity generation have made competitively-determined pricing a viable alternative to traditional regulation. In this

[1] Competitive bidding can also be applied in other aspects of the electric industry. For example, a discussion on the use of bidding in pricing transmission capacity can be found in Kevin Kelly et al., Some Economic Principles for Pricing Wheeled Power (Columbus, Ohio: The National Regulatory Research Institute, 1987), pp. 214-216.

section, we first compare bidding with existing PURPA-related regulations in selecting and pricing nonutility power producers such as QFs and IPPs. Then we compare competitive bidding with traditional regulation in securing new generation capacity.

Bidding is a more comprehensive search mechanism for the host utility to identify potential nonutility power producers than existing PURPA-related regulation such as individual negotiation or administratively-determined pricing. The use of bidding instead of individual negotiations can save a significant amount of time and effort for the host utility in sorting out the offers from many potential nonutility power producers and their technical and financial capability. Furthermore, existing regulations concerning utility power purchases generally do not provide strong incentives for the host utilities to search for and secure the most economical sources of electricity supply. The total cost of purchased power generally "flow through" directly to the ratepayers. As a result, many potential nonutility power producers may not be selected through individual negotiations or administrative procedures.

Bidding is also more flexible than the administrative procedures currently applied in setting the price of electricity provided by nonutility power producers. Market demand and supply conditions determine the proper price level in a bidding process. As market conditions change, the results of bidding can reflect these changes quickly. An administratively determined pricing rule, on the other hand, has to go through an extensive and prolonged process before being modified to reflect new economic and technical conditions.

Under a bidding program, the host utility is more likely to select the least-cost options in meeting future demand for electricity. The host utility is directly competing with many nonutility power producers and only the most economical options are selected. As for the competition among nonutility power producers, bidding affords them the opportunity to compete with each other fairly. Other ways of selecting nonutility suppliers do not assure the selection of the least-cost suppliers. For example, under a first-come first-served rule or a lottery selection process, the consideration of cost advantages and service reliability may be overshadowed by negotiation skills or some chance factors. The cost of electric service to the ratepayers may be higher than if the least-cost options were chosen.

It can also be argued that bidding provides stronger incentives for cost control in building and operating new generation facilities than traditional regulation. Since a fixed-price contract is most likely to be used in post-bidding power purchase agreements[2], the selected nonutility producers bear the full consequences of cost overruns in building and operating their own generation facilities. A nonutility power producer can receive higher profits as a result of cost savings derived from superior performance. On the other hand, profits may be reduced when poor performance leads to higher than expected costs. For the host utility, traditional regulation provides weak incentives to control cost because the host utility is normally allowed to pass along all cost increases or savings to the ratepayers. The host utility's profit may not directly relate to its superior or poor performance. As discussed before, individual states may have different cost recovery regulations such as prudence reviews, "used and useful" disallowances, or fuel cost adjustment clauses. These regulations can mitigate the effects of the lack of cost-control incentives associated with traditional regulation.

A competitive bidding process expands supply options in meeting future electricity demand. The bidding process opens up a larger market for nonutility power producers and provides more equitable conditions for nonutility producers to compete with electric utilities in supplying generation capacity. The expansion of alternative supply options may have the additional benefit of creating a better match between the demand and

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[2] The FERC and several states suggest the use of a fixed-price contract. As discussed further in chapter 6, certain fuel cost escalation clauses may be included in a long-term power purchase contract between the host utility and a nonutility power producer. Under this circumstance, the incentive for controlling fuel cost is reduced.

supply of electricity. Nonutility power producers are more likely to adopt small-sized, alternative power production technologies than utilities because these alternative technologies are less appealing to the host utility for its size and technical characteristics.[3]

Ratepayer Impact

In addition to the effects of economic efficiency, which ultimately are shared by ratepayers, additional protection can be provided to ratepayers from the institutional arrangements of bidding. First, ratepayers can directly benefit from any cost savings achieved in replacing utility generation with nonutility generation. Such savings to the ratepayers are unavailable under avoided-cost pricing, and may be reduced under other existing PURPA regulations such as individual negotiations or an administratively determined pricing rule. Under a bidding process, the host utility secures new generation capacity from the most economical sources (including the host utility itself) at a price no higher than its own avoided cost. The difference between the bid price and avoided cost goes directly to the ratepayers. If avoided-cost pricing is used, ratepayers are indifferent to the sources of new electric generating capacity since they are paying the same price no matter which options are selected. All cost savings in substituting nonutility generation for utility generation goes to the selected nonutility power producer. If negotiations or administrative procedures are used, the payment received by the selected nonutility power producer may be less than the host utility's avoided cost. There is no assurance, however, that this is the lowest-cost alternative available.

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[3] The bidding process itself does not provide preferential treatment to small-sized facilities. In fact, economies of scale may dictate the choice of large-sized facilities. But such cost advantages are probably already reflected in the bid price so no preferential treatment for large-sized facilities is required.

A portion of the cost savings is captured by the selected nonutility producer rather than passed through to the ratepayers.

Second, a bidding process shifts the risk of construction cost overruns and poor operating performance from the ratepayers to the nonutility producers.[4] Under a bidding process, the ratepayers do not have to pay if the generation facilities are not completed, electricity is not delivered to the host utility as promised, or if there are cost overruns incurred by the nonutility producer when a fixed-price power purchase contract is used.[5] On the other hand, under traditional regulation, ratepayers are generally responsible for the total cost of building a power plant unless the state PSCs make specific disallowances such as a "prudence disallowance" or a "used and useful" adjustment. Once a power plant is completed and enters into the utility's rate base, ratepayers often end up paying the carrying costs (interest payment and depreciation) even if the plant becomes inoperable or generates far less electricity than the design capacity due to poor operating performance. As a result, the risk of "take or pay" obligations on ratepayers can be lessened considerably under a bidding process even with explicit "take or pay" provisions included in the power purchase contract between the nonutility producer and the host utility. If the "take or pay" provisions are included in a power purchase contract, ratepayers are still responsible for the cost of contracted capacity when future demand for electricity does not materialize. Consequently, there is no difference between bidding and traditional regulation in dealing with the "take or pay" risk associated with insufficient demand. However, under a bidding process ratepayers are still protected from poor operation

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[4] Since there are significant differences among state regulations concerning the treatment of power plant construction costs and operating expenses, the conclusions provided here should be viewed as a comparison of bidding and traditional regulations in general. Some exceptions can be expected.

[5] Power purchase contracts with front-loaded pricing and fuel escalation clauses are two exceptions.

performance and unexpected forced outages. Such protection is simply not available under traditional regulation.

Service Reliability

It is commonly argued that competitive bidding can lead to a decline in electric service reliability since part of the generation facilities are no longer controlled by the host utility and capacity may not be available when needed. However, the actual experience of the nonutility power producers up to now and the institutional arrangements governing the bidding process do not support these arguments. It is important to recognize that a proper yardstick for evaluating the service reliability of nonutility power producers is the comparable performance of the utility-owned generation facilities rather than a 100 percent reliability level. Failures (cost overruns, delays, and project cancellation) and poor performances (frequent forced outages, and higher than expected fuel consumption) on the part of nonutility power producers can occur. Failures and poor performance also can occur on the part of electric utilities. With this understanding, the following analysis suggests that competitive bidding is unlikely to reduce, and perhaps can enhance in certain instances, electric service reliability.

The ownership of generation facilities in itself has no bearing on the reliability and availability of electric service. Qualifying facilities, independent power producers, and utility subsidiaries are legitimate enterprises. They must obtain the necessary expertise, financing, and specific regulatory approvals to build and manage new generation facilities; otherwise, they cannot compete with other power providers and will suffer economic losses and perhaps even go out of business. Poor performance and failures of nonutility power producers are possible, and they can affect the service reliability the same way poor utility performance does. However, we are not aware of any empirical evidence showing any systematic differences between utility-owned facilities and those secured through competitive bidding in terms of the construction and operation of an individual generation facility.[6]

As for the integration of nonutility power resources with the utility system, it need not pose overall reliability problems. Two opposing considerations are involved. On the negative side, the large number of facilities and their diversity in size and technology require greater coordination and cooperation among the host utility, the nonutility producers, and possibly other utilities. In this regard, service reliability may be adversely affected if such coordination and cooperation are lacking or insufficient. The state PSCs, under FERC regulations implementing PURPA, have promulgated clear technical requirements and regulatory oversights on interconnections between nonutility power producers and utilities. The initial experience has been satisfactory.[7] The host utility and the nonutility power producers also have strong incentives to cooperate and to coordinate with one another for smooth integration to achieve a high level of service reliability. Furthermore, transmission requirements and system integrity issues can be dealt with in the bid evaluation process.[8] Bids with a substantial detrimental effect on service reliability can be excluded in bid evaluation. Nevertheless, it is important to recognize potential adverse effects on service reliability can occur due to the increasing requirements on transmission capability as a result of bidding. For example, some argue that as the generation networks grow larger (the number of generators and load centers increase) the difficulties of synchronization (coordination of frequency and phase of

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[6] Even the utilities generally agree that nonutility facilities can achieve high capacity factors on an individual plant basis, but the utilities emphasize that individual plant reliability is not the key issue. See "Transmission, Reliability Key Issues as Electric NOPR Debate Widens," Inside F.E.R.C., 26 September 1988, pp. 3-5.

[7] Michael D. Devine et al., Public Policy Issues of Decentralized Electricity Production (Norman, Oklahoma: Science and Public Policy Program, University of Oklahoma, 1984), pp. 3-32 to 3-38.

[8] See chapter 7.

alternating voltage variations) grow correspondingly large.[9]

On the positive side, the large number of facilities, and the technical and size diversity actually could enhance the generation reliability of the utility system.[10] The argument goes that a generation system composed of many small-sized generation facilities is more "reliable" in the sense that the outage of an individual plant affects the system capacity less severely than a system with few large-sized facilities even if the expected system capacity factors of both systems are the same.

There are discussions that service reliability to ratepayers would be adversely affected if most electricity were supplied by nonutility producers with no "obligation to serve" and the contract relationship governing power purchase transactions in competitive bidding is weaker than the "obligation to serve" inherent in traditional regulation. Others contend the utility's "obligation to serve" is incompatible with increased competition in the electric industry.[11] These arguments are questionable, and the inference that the lack of "obligation to serve" on the part of nonutility power producers in a bidding context leads to a decline in service reliability needs closer scrutiny.[12] The power purchase contract entered into between the nonutility power producers and the host utility is a wholesale power transaction. In such a wholesale power transaction between two utilities (also governed by a contractual relationship) the selling utility has no so-called "obligation to serve" to the purchasing utility except when the purchasing utility is a full-requirements customer such as a municipal

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[9] See Kelly et al., Some Economic Principles for Pricing Wheeled Power, p. 26.

[10] The more generating units in a utility system, the larger a sudden load change it can absorb, and the system is likely to be more stable. See ibid., p. 28.

[11] Joe D. Pace, "Increased Competitiveness and the Obligation to Serve: An Oxymoron?" Public Utilities Fortnightly, 7 January 1988, pp. 36-38.

[12] The concept of "obligation to serve" may need to be reexamined closely in a totally deregulated electric industry. But the use of bidding in securing new generation capacity will not necessarily lead to total deregulation by itself.

electric utility with no generation capacity.[13] In the past, there were few complaints that such inter-utility power purchase transactions would affect service reliability. There is no reason to believe that power purchases from nonutility power producers would now affect service reliability adversely. Therefore, the lack of "obligation to serve" on the part of nonutility producers, at most, would affect service reliability the same way as the inter-utility power purchases made by the utilities have all these years.

Pitfalls of Competitive Bidding

Few economic propositions are as widely shared by the Congress, economists, and the public at large as the idea that "competition is a good thing." Interest in the competitive bidding of new electric power supplies is but one more manifestation of this uncritically held belief. But it is important to have a non-idealogical, steely-eyed examination of the usefulness and workability of competitive bidding to the provision of supplemental power supplies. In other words, the general attractiveness of the theory of competitive bidding must be juxtaposed with the reality of how imperfectly the process can work.

This section, then, identifies some of the darker sides of competitive bidding outcomes as experienced (primarily) by government. It does so by citing the mixed histories of the use of competitive bidding arrangements in

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[13] Some argue that from the perspective of a utility planner, a de facto obligation to serve at the wholesale level currently exists. See Bouknight and Raskin "Planning for Wholesale Customer Loads in a Competitive Environment: The Obligation to Provide Wholesale Service under the Federal Power Act", p. 264. However, FERC has recently decided that there is no expressed obligation to serve wholesale customers. FERC also indicated that it would not allow termination of service where a utility has contractually agreed to provide that service, absent a showing that the termination would be in the public interest. See chapter 3. It is doubtful that FERC would treat the contract between the utility and the nonutility power producer differently. In other words, the power purchase contract is unlikely to be terminated unilaterally by the nonutility power producers without FERC approval.

four disparate activities--timber auctions on national forest lands, road construction for states, weapon system procurement for the armed services, and electric equipment purchases by public and investor-owned power companies. For our purposes here, little distinction is made between those practices cited that are outright unlawful (e.g., bid-rigging or price fixing) and those that may be lawful but clearly frustrate in one way or another (e.g., "buying-in low" and "getting well later") the competitive ideal. Whenever possible, a harmful practice found in any of the four selected cases is highlighted as a pitfall to be guarded against in implementing competitive bidding programs for securing new electricity generation capacity.

Four Downside Experiences

The legal mandate for competitive procurement of defense supplies was the Armed Services Procurement Act of 1947. More recently, renewed emphasis for more effective use of competition at the Department of Defense (DOD) has come from the Competition in Contracting Act of 1984, which, among other things, gave "open competition" and "negotiated competition" equal status in satisfying the act.[14] As to how this has gone, perhaps the worst cases come to public view as major scandals in weapon system acquisition. Celebrated scandals occur periodically, with the procurement scandal involving Navy and Air Force contract awards the most current ones. Less anecdotal evidence comes from an article that appeared in the National Contract Management Journal (Winter 1984) entitled "Competition in Weapon System Procurement: A Summary and Evaluation of Research."[15] Here the authors found that despite

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[14] Louis A. Kratz and Jacques S. Gansler, "Effective Competition During Weapon System Acquisition," for The National Contract Management Association, Challenge Monograph Series, Vol. 1, 31 December 1985, pp. 5-6.
[15] William R. Greer, Jr. and Shu S. Liao, "Competitive Weapon System Procurement: A Summary and Evaluation of Recent Research," National Contract Management Journal 17 (Winter 1984): 37-47.

the pervasiveness of the view in DOD procurement circles "that competition is beneficial to the government, (their) research suggests that competition has resulted in added life cycle costs almost as often as it has produced savings."[16] They conclude, however, that the overall results of research on this topic are "disappointingly unreliable"--and this after 40 years of experience with competitive bidding in the defense industries.

Problems with competitive bidding in the sale of U.S. Forest Service timber stands are well illustrated in a 1988 monograph entitled "Deterring Bid Rigging in Forest Service Timber Auctions."[17] Prepared by the Economic Analysis Group of the Antitrust Division of the U.S. Department of Justice, the paper reports that anticompetitive bids (sales) accounted for as much as 30 percent of all sales in some forests: in the most competitive national forest regions the low estimate was 13 percent of sales in the 1980-1983 period.[18] Anticompetitive behavior here involved bid rigging and the allocation of market shares through conspiratorial "winning bid" rotation schemes on successive auctions, potential competitors refraining from bidding in exchange for subcontracted work, or direct cash payoffs to competitors for not bidding. While all these activities are crimes, they are difficult to detect by screening the bid data and even harder to successfully prosecute.[19]

Public highway contracts have a spotty history of illegalities in competitive bidding. In recent years, there have been forty to fifty cases that have come to Justice Department attention.[20] Price fixing and market allocation schemes characterize these cases, most of which never went to trial. While few states have been exempt from anticompetitive behavior in

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[16] Ibid., p. 37.
[17] U.S. Department of Justice, Antitrust Division, Deterring Bid Rigging in Forest Service Timber Auctions, by Luke Froeb and Preston McAfee (Washington, D.C., 5 May 1988).
[18] Ibid., p. 6.
[19] In the 18 years since 1970 the Department of Justice reported only three successful prosecutions for bid rigging in Pacific Northwest forests. Ibid., p. 7.
[20] Telephone conversation with Mr. John Joyce, Economic Analysis Group, Antitrust Division, U.S. Department of Justice, 10 June, 1988.

dealing with the road construction industry, notable cases of interest to the Antitrust Division have occurred in North Carolina, South Carolina, Georgia, Tennessee, and Virginia.[21]

The electrical conspiracy case of 1960 involved phony competitive sealed bidding and elaborate market allocation schemes of enormous sweep and scope. Some nineteen cartels operating for ten years divided up the market in sales of various electrical equipment products--turbine generators, transformers, arrestors, insulators, cutouts, condensers, capacitators, and industrial control equipment.[22]

Virtually the whole country geographically was covered by the conspiracies, and the values amounted to several billion dollars. The unsuspecting parties conducting the "competitive bidding" included investor owned utilities as well as municipal electrics, public power agencies (Tennessee Valley Authority, Bonneville Power Authority, and the Corps of Engineers), and the Departments of Defense, Interior, and Commerce. The conspirators were twenty-nine corporations, including household names like General Electric, Westinghouse, Allis Chalmers, McGraw Edison, and Foster-Wheeler.

The attorney general of the United States said at the time that the "indictments represented the most serious violations of the anti-trust laws since the time of their passage, at the turn of the century . . . "[23] The chief of the antitrust division declared at the trial, "These men and companies have in a true sense mocked the image of that economic system

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[21] Ibid.
[22] For an excellent treatment of this sorry story see Richard A. Smith, "The Incredible Electrical Conspiracy," Fortune Magazine, April 1961, pp. 132-224.
[23] Affidavit of U.S. Attorney General William P. Rogers, submitted to the Court during the Philadelphia Electrical Conspiracy trial in opposition to accepting a plea of "nolo contendere" by the defendants, 22 March 1960. In all, twenty indictments were issued involving twenty-nine corporations and forty-four individuals. All attempted to plead "no contest."

which we profess to the world."[24] Upon conclusion of the case corporate and personal fines totaled $1.925 million, forty-four individuals were sentenced--seven of them to jail.[25]

Cautions and Considerations

What can be gleaned from the downside experiences that accompany competitive bidding in practice? There is a series of cautions and considerations that could helpfully be a part of the decision whether or not to have competitive bidding of new electric power supplies in the first place, or (more likely) about the design and implementation of competitive bidding schemes once the concept is decided upon. The reader should interpret these propositions and observations in that context.

Open and competitive bidding generally assumes that the universe of rivalrous firms is a fairly large number and that bidders operate fully informed and in a frictionless environment. Several or all of these things may not be true. While so far, instances of competitively bidding new electric supply capacity have generally had many respondents, this may not always be the case. There are times when "too much competition" can discourage rather than stimulate participation in a bidding, for example, when the number of potential bidders is so large that the chance of winning is perceived as very small (or the chance of follow-on contracts, once having won, is thought to be slight). Under these conditions, a marginally eager firm might choose not to enter the bidding at all or submit a perfunctory courtesy bid. Moreover, just how willing some companies are to

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[24] James M. Clabault and John F. Burton, Jr., Sherman Act Indictments 1955-1965: A Legal and Economic Analysis, Federal Legal Publications, 1966, appendix B, p. 68. All the while, GE's "General Instruction 2.35" to its executives regarding compliance with antitrust laws read,

> It has been and is the policy of this Company to conform strictly to antitrust laws. . .special care should be taken that any proposed action is in conformity with the law as presently interpreted.

[25] Ibid., appendix D. The government had requested $2.565 million in corporate fines and jail sentences for 31 individuals.

compete vigorously sometimes depends on general business conditions in the economy and how well they are faring.

The unevenness of information and experience makes for a less than smoothly functioning optimal process. There is a learning curve to be climbed by the newcomers that is not faced by the established participants. Knowledge of costs and operating characteristics of power production (if not differences in technology) is not uniformly held by all bidders. And if one of the bidders is the electric utility itself through, say, an IPP in which it has an ownership interest, the asymmetry problem is still worse.

The parity of the competitive bidding model also loses a good bit in the translation to the actual environment in which bidding is carried out and awards are made. There is the problem of when the rewarding of past performance becomes cronyism and favoritism in subsequent contract awards. Success does beget success.

There is, of course, a logic to dealing with companies that have been reliable suppliers in the past, but such a practice can result in less sharp performance over time than with new competition "each time out." Also, the intertwining of the supplier's performance (e.g., IPP or QF) with the performance of the awarding company (the utility) may make for such complementarity that it is unclear which one is responsible for success or failure. Further, it is asking a lot for certain potential new players in the power supply field, who are also old players in terms of, say, equipment vendors to existing electric utilities, to vigorously compete head-to-head. One can imagine the reluctance of members of the latter group to risk their traditional seller/buyer relations with the former by "beating out" a customer utility for the provision of new electric capacity. It is the old problem of cooperating and competing at the same time.

Competitive bidding may be enmeshed in various socioeconomic and political objectives that make the process anything but straightforward. Examples might be considerations of employment, regional development, and "fair distribution" in contract awards. And are foreign sources eligible to bid? And what about small business or minority business set-asides? Finally, not only is competitive bidding not frictionless, it is also not without cost. Frequently neglected in the decision to introduce competitive bidding where it was not practiced before are calculations of the front-end costs, including additional administrative costs associated with many more players, the costs of preparing and distributing RFPs and invitation for bids (IFBs), the cost of evaluating and selecting the winners, and then monitoring and overseeing their performance.

There are also a host of concerns of the institutional variety about the nature of the bid procedure and bidder response to it. It is generally thought that selection criteria in contract letting should include performance and quality factors and not price alone. This might be especially important in the electric power case where reliability, the avoidance of cost overruns in plant construction,[26] and timely completion of the plant may be important considerations. On the other hand, multiple criteria and the weighting thereof make the selection process a good deal more judgmental and qualitative--hence more subject to both mischief and challenge.

There is the question of "winner-take-all" or "multiple sourcing" in procurement. Evidence exists that the former type of award results in stiffer competitive bidding than the latter, and it avoids both the quarrels about the size of the allocated shares and the extra costs of dealing with more companies than split awards entail.[27] Relatedly, it appears that larger sized auctions (e.g., purchases of capacity), done infrequently, tend to discourage cartel behavior by participants. But the other side is that smaller, rather frequent auctions keep the bidder pool lively and provide a kind of continuous interfirm rivalry.

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[26] Just how state PSCs would ultimately handle major cost overruns and even bankruptcy in power plant construction by IPPs and QFs that were successful winners in competitive bidding for additional electric capacity is, it appears, an open question. In all events, in those states where the competitive bidding process explicitly involved the PSC itself in evaluating and selecting bids (as opposed to only the regulated utility making the selection) one would expect the commissions to be faced with very awkward situations.

[27] Greer and Liao, "Competitive Weapon System Procurement: A Summary and Evaluation of Recent Research," p. 38.

Several other dilemmas deserve mention. Knowing which companies are likely to be good performers is desirable in selecting new power suppliers. The idea of being "fit, willing, and able to serve" has long been a hallmark proposition in the transport and utility fields. Adopting the DOD approach of "qualifying bid procedures" followed by the bidding itself as a second step is attractive in this light, but has the downside of revealing the identity of all the potential bidders to each other. After a few bidding experiences of this sort, there can develop what several authors have called "natural focal points for collusion."[28] The choice between disclosed and concealed bids in the wake of the process presents similar problems. Where the avoided cost to the regulated electric utility becomes the general counterpart to a "reserve price" in the auction concept, a special difficulty can arise. That is, bids <u>somewhat</u> <u>below</u> the known avoided cost "look more competitive" than ones right <u>at</u> the avoided cost, even though they may be higher than they should be. Detection of explicit or implicit collusion in these cases is hard.

An important form of implicit collusion that would seem to be a potential danger for competitive bidding in new electric power supply is what might be called "territorial forbearance." The practice itself has several facets. At its worst, bidders might act as a cartel, and either take turns submitting the eventual winning bid in a given geographic area (say, a utility's service area) or abstain altogether in one territory in exchange for reciprocal abstention by other cartel members in another territory.[29] Open bid procedures would allow cartel members to police each other; undisclosed bids permit cheating among members, and in both cases the PSCs and/or the regulated utilities might never be the wiser.

Lastly, competitive bidding arrangements must cope with the "hungry firm" phenomenon. In crass terms, this describes the optimistic bidding

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[28] U.S. Department of Justice, "Deterring Bid Rigging in Forest Service Timber Auctions," p. 5.
[29] One could imagine, for example, existing utilities taking the latter course where each had the opportunity to "compete" through IPPs in which they had an interest.

strategy of discounts now and counting on being made whole later. It presumes (often correctly) that the penalties for underestimation of costs are seldom severe. The tactic also presumes that actual cost increases, if disclosed gradually and only after substantial sunk costs have accumulated, will not induce cancellation of the project--especially if a wide array of subcontracts has been deployed. So-called "extra scope" add-ons and "change orders" become the vehicles for higher cost recovery and perhaps even higher profits. Thus, bidder optimism, by design or otherwise, can become a problem.

As mentioned, the purpose of this section is not the relating of real or imagined horror stories for their own sake, but rather to identify some of the pitfalls of competitive bidding. It is, of course, at least arguable that the experiences of the four industries from which downside examples were drawn (defense, timber lands, road construction, and electrical equipment) are not very transferrable to the application of competitive bidding in electric power supply. But our purpose is served if this review and recollection alerts the policymaker and the program implementer to the need for safeguards and surveillance after the beauties of auction theory are accepted. In any event, care must be taken that a move to competitive bidding in the electric industry does not merely swap one form of regulation (traditional utility oversight) for another (competitive bidding oversight). Said starkly, it would not be an advance to have to add to the Public Service Commission model a "Public Utility Competitive Bidding Board" for each of the states and the FERC.

CHAPTER 5

LITERATURE REVIEW OF BIDDING MODELS

The study of competitive bidding has important practical and theoretical value. Bidding has been used in many private transactions and government procurements over a long period of time. The analysis of bidding also provides a systematic approach to understanding transactions under asymmetric information and price-making without explicit bargaining.[1] Several comprehensive literature surveys on bidding are available elsewhere.[2] This chapter generally follows the outline of the McAfee and McMillan 1987 survey article on bidding[3], focuses on the theory of bidding, and discusses the implications of various bidding models in designing an optimal bidding procedure for securing new generation capacity from qualifying facilities, independent power producers, and utility subsidiaries.

Extensive surveys of bidding models indicate that no single bidding procedure is superior to other procedures under all circumstances. The selection of a specific bidding procedure depends upon the item being auctioned, the characteristics of participants, and the market environment under which bidding is conducted. In this study, from the perspective of a public policy analyst, the economic efficiency of electricity generation (with proper consideration of service reliability) for the society as a whole is the criterion in selecting a bidding procedure. One bidding procedure is preferred over another if it is more likely to minimize the cost of electricity generation, to induce the bidders to reveal their true

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[1] R. Preston McAfee and John McMillan, "Auctions and Bidding," Journal of Economic Literature 25 (June 1987):700.

[2] Richard Engelbrecht-Wiggans, "Auctions and Bidding Models: A Survey," Management Science 26 (February 1980): 119-142; and McAfee and McMillan, "Auctions and Bidding," pp. 699-738.

[3] Ibid.

costs, to reduce moral hazard[4] on the part of all bidders, and to allocate risk optimally between the host utility and the bidders.[5] The empirical analyses of treasury note and bond auctions and timber land bidding provide additional insights into the advantages and limitations of various bidding procedures.

Definitions and Assumptions

Most bidding models, following the format of a typical property auction, are specified in a one-seller, many-buyer, high-bid-wins context. The bidders' strategies, bidding equilibrium, and efficiency implications are presented accordingly. However, in the case of supplying electric generating capacity, many sellers (utility subsidiaries, IPPs, and QFs) are competing for the right to provide generation capacity to a single buyer (host utility) and the lowest bid is selected. The specification of a one-buyer, many seller low-bid-win context is more appropriate for our purpose since the conclusions drawn from this context can be applied directly in the design of an optimal bidding procedure for securing new electric generating capacity.

In a one-buyer, many-seller context, a bidder is an individual or a business that submits a bid for the right to supply a particular item. A bid-taker is an individual or an enterprise that wants to secure a particular item through bidding. A bidding procedure is a set of rules that

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[4] Moral hazard refers to the adverse effects, from the bid-taker's point of view, derived from the inability of a bid-taker to observe and control the winning bidders' actions after the bid selection. In the case of bidding to supply electric generating capacity, the moral-hazard behavior of a bidder includes, but is not limited to, slack in controlling construction cost or cost misallocation from unrelated projects.

[5] In the bidding literature, the term "optimal auction" refers to a bidding procedure that minimizes the expected cost (or maximizes the expected revenue) of the bid-taker. See Roger B. Myerson, "Optimal Auction Design," Mathematics of Operations Research 6 (February 1981): 58-73; John G. Riley and William F. Samuelson, "Optimal Auctions," American Economic Review 71 (June 1981): 381-392; and McAfee and McMillan, "Auctions and Bidding", pp. 711-714.

specify the conditions of participation, select the winning bids, determine the payment to the winning bidders, and define other relevant bidding arrangements.[6]

Four Types of Bidding Procedures

There are four basic types of bidding procedures: English bidding, Dutch bidding, first-price sealed bidding, and second-price sealed bidding (Vickrey bidding).[7] In English bidding, applied in the low-bid-win context, the bid is successively lowered and bidders drop out as the bid price ceases to cover their costs. Eventually, only one bidder remains as the bid price falls below the cost of the last bidder to drop out of bidding. In other words, the winning bidder is the only one willing to supply the item at the current bid. English bidding can be either a descending or an ascending process. The common characterization of English bidding as an ascending-quote bidding process only is incorrect.[8] The key point is that bidding remains open until only one bidder remains.

In Dutch bidding, the bid-taker announces an extremely low initial bid, which has practically no chance of being accepted by the bidders. The bid-taker then increases the bid gradually until the first (also the last) bidder, who concludes that all of its costs (including profits) can be covered at that bid price, accepts the bid. Dutch bidding is not an open

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[6] A bidding procedure is broadly defined here. It not only includes the process of selecting the winning bids, it also specifies the general format of a contract to be entered into between the bidders and bid-taker after bid selection. Obviously, the contract format affects the bidding strategies of the bidders and the bidding results. As a result, the choice of a bidding procedure and a post-bidding contract format should be analyzed jointly.

[7] Second-price sealed bidding is referred to as "Dutch auction" in financial publications. This is a misnomer as Dutch auctions commonly known in the bidding literature refer to a discriminatory pricing procedure rather than the uniform pricing procedure that characterizes the second-price sealed bidding. See Charles C. Baker, "Auctioning Coupon-bearing Securities: A Review of Treasury Experience," in Bidding and Auctioning for Procurement and Allocation, ed. Yakov Amihud (New York: New York University Press, 1976) pp. 146-147.

[8] McAfee and McMillan, "Auctions and Bidding," p. 702.

bidding process since only one bid is tendered before bidding ends. Dutch bidding has the distinctive advantage of the speedy completion of an auction.[9]

In first-price sealed bidding, potential bidders submit sealed bids with the lowest-price bidder awarded the right to supply an item at the bid price. All bids submitted remain sealed until the evaluation and selection stage. A bidder does not have the opportunity to adjust its bid after observing bids from others. An example is provided here to illustrate how first-price sealed bidding works in the context of a utility solicitation. Assume that three bidders all submitted similar bids except for price. Say bidder A submitted a bid of 25 mills per kilowatt-hour, bidder B, 30 mills, and bidder C, 35 mills. Bidder A is selected and the host utility pays bidder A 25 mills--its bid price. First-price sealed bidding is the most common bidding procedure. Dutch bidding yields the same outcome as first-price sealed bidding since the situation facing a bidder is essentially the same under both bidding procedures. A bidder must decide whether to accept the current bid knowing that once tendered no changes can be made and he will be paid its own bid as in the case of first-price sealed bidding.[10]

In second-price sealed bidding, bidders submit sealed bids knowing that the lowest bid wins, but that the payment received does not equal their own bid, but rather the lowest non-winning bid. This bidding procedure has some desirable efficiency implications, but is not widely used. Assume that three bidders submit similar bids except for price. As discussed in later sections, second-price bidding provides incentive for a bidder to reveal its true cost. Therefore, the bids submitted tend not to include economic rent contained in bids submitted under first-price bidding. The bids are lower. Say bidder A submitted a bid of 20 mills per kilowatt-hour, bidder B, 25 mills, and bidder C, 30 mills. Bidder A is selected, but the host utility

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[9] William Vickrey, "Counterspeculation, Auctions, and Competitive Sealed Tenders," <u>The Journal of Finance</u> 16 (March 1961):14.

[10] Ibid., pp. 14-16; and McAfee and McMillan, "Auctions and Bidding," p. 707.

does not pay bidder A its own bid (20 mills). Instead the host utility pays 25 mills which is the bid price of the best non-winning bid.

There are many variations to the four basic types of bidding procedures. In bidding to supply new electricity generation capacity, the imposition of a reserve price (avoided cost of the host utility) and the inclusion of royalties (cost sharing and escalation arrangements) in the pricing formula are the two most relevant variations.[11]

Basic Assumptions

All bidding models have four common assumptions.[12] These assumptions serve to define a bidding environment in which each participant's strategy is well defined. These assumptions have no normative connotations. First, each participant in the bidding process behaves rationally and expects others to behave rationally as well. All participants choose strategies to further their own objectives. The bidders and the bid-taker may have different objectives, but each individual's objectives are assumed to be internally consistent and unchanged during the bid solicitation process.

Second, the bidding procedure is fully and truthfully disclosed to the participants prior to the solicitation, and all participants are fully committed to the bidding procedure and bids submitted. Specific conditions can be set in advance concerning the cancellation of bidding results, but these conditions must be clearly set out so that credible commitments by both the bidders and bid-taker are maintained. It may be advantageous for

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[11] Other possible variations include the collection of entry fees and payments from non-winning bidders.

[12] Some of these assumptions may be implicit in certain bidding models. Additional conditions may also be added as basic assumptions. For example, the number of bidders may be assumed to be fixed and known to all bidders and there is no collusions among bidders. See Michael H. Rothkopf et al., Designing PURPA Power Purchase Auctions: Theory and Practice (Berkeley, California: Energy Analysis Program, Lawrence Berkeley Laboratory, 1987), pp. 4-5. The Rothkopf report, funded by the U.S. Department of Energy, provides an extensive analysis on the use of competitive bidding in allocating PURPA power purchase. Some of the issues discussed there may be duplicated with the discussion in this study.

the bid-taker to renege on a prior commitment after observing all bids. But such a commitment is essential to conducting a successful solicitation and can actually reduce the expected cost to the bid-taker.[13]

Third, each auction is a one-time event, and the results from previous auctions do not affect current or subsequent solicitations. In reality, it is possible that winners in previous auctions have some information and cost advantages over non-winning bidders.[14] This may create an incentive for the bidder to submit an extremely low bid to win the initial bidding and thereby obtain advantages for subsequent solicitations. Such consideration is excluded in most bidding models, making each participant's goal the maximization of the expected return of the current solicitation rather than maximization of the total return over several sequential auctions.

Fourth, the bidders and the bid-taker alike are concerned with their own interest only; that is, they are principals instead of agents for the third parties. Bidding analysis can concentrate on the bidding strategies and procedures embodied in the typical profit-maximization or cost-minimization behavior without the complications of additional principal agent considerations.

Desirable Properties of a Bidding Procedure

For regulators and policy analysts, the most important concern in selecting one bidding procedure over another is which procedure can lead to the most economically efficient bidding results given the participants' self-interests. To put this definition of economic efficiency into operational terms, four desirable properties of bidding can be specified: incentive compatibility, Pareto efficiency, reduction of moral hazard, and optimal allocation of risk. These criteria reflect the more important

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13 McAfee and McMillan, "Auctions and Bidding", pp. 703-704.

14 Williamson, "Franchise Bidding for Natural Monopoly--In General and Respect to CATV," p. 83; and Richard Luton and R. Preston McAfee, "Sequential Procurement Auctions," Journal of Public Economics 31 (November 1986): 181-182.

efficiency considerations in securing new generation capacity, and other criteria may be added as the goals in selecting a bidding procedure.[15]

Incentive Compatibility

A bidding procedure is incentive compatible if it causes a bidder, in its own interest, to reveal its own true cost in its bid under the specific bidding procedure.[16] Incentive compatibility is desirable since it has significant efficiency implications. With a non-adverse selection rule (a lower bid is always selected over a higher bid), incentive compatibility assures that the lowest-cost bidder is selected and the total cost of supplying the auctioned item is minimized. Aside from the production efficiency consideration, an incentive-compatible procedure reduces the "non-productive expenditure" incurred by bidders to evaluate and investigate the costs and bidding strategies of other bidders.[17] In other words, a bidder does not have the need to guess the opponents' costs and bids and then slightly under-bid them.

Pareto Efficiency

A bidding procedure in this application is said to be Pareto efficient when the most efficient (lowest-cost) bidder is selected to supply the particular item.[18] An incentive-compatible bidding procedure is Pareto efficient, but incentive compatibility is not required for Pareto efficiency. Pareto efficiency can be achieved as long as a lower-cost

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[15] For example, the tendency to prevent collusive behavior of the bidders, the fairness of the bidding procedure, and the general workability of the auction design are also important considerations.. See Rothkopf et al., Designing PURPA Power Purchase Auctions: Theory and Practice, p. 20.
[16] McAfee and McMillan, "Auctions and Bidding", p. 712.
[17] Vickrey, "Counterspeculation, Auctions, and Competitive Sealed Tenders," pp. 21, 28.
[18] McAfee and McMillan, "Auctions, and Bidding", p. 711.

bidder always submits a bid lower than that of a higher-cost bidder even though the bids may not equal true costs. It should be noted that the minimization of the expected cost of the bid-taker does not necessarily lead to Pareto efficiency. As shown later in the case of asymmetric bidders, a lower-cost bidder may bid higher than a higher-cost bidder if the bidders possess different assessments of cost distribution and probability of winning.[19] Under this circumstance, a winning bidder might have a higher cost than a non-winning bidder, and Pareto efficiency no longer holds.[20]

Reduction of Moral Hazard

Moral hazard in bidding refers to the tendency on the part of a winning bidder to behave opportunistically in its performance, such as slack in cost control or asset relocations, to benefit itself at the expense of the bid-taker after receiving a contract.[21] Moral hazard in competitive bidding is derived from the inability of the bid-taker to correctly observe and control a bidder's efforts after bid selection.[22] In the presence of moral hazard behavior, the format of a post-bidding contract matters. For example, a fixed-price contract has the advantage of reducing moral hazard. Since the total payment is fixed, it is in the bidder's own interest to put the best effort into supplying the item being bid.[23] Moral hazard behavior is more likely to occur under a cost-plus or a cost-sharing contract because the bidder does not bear the full consequences of its effort.

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[19] Ibid., p. 715.
[20] Ibid.
[21] Williamson, Markets and Hierarchies, p. 84.
[22] R. Preston McAfee and John McMillan, "Bidding for Contracts: A Principal-Agent Analysis," Rand Journal of Economics 17 (Autumn 1986): 326.
[23] A fixed-payment contract may impose a higher risk on the bidder since he does not have perfect information about future events, and the realized cost may turn out to be higher than expected. See the next section for a more detailed discussion.

Optimal Risk Allocation

Different bidding procedures allocate risk differently between the bidders and the bid-taker. A cost-plus contract shifts all risk to the bid-taker while a fixed-price contract places all risk on the bidder.[24] When asked to take on a larger share of risk, a bidder either demands a higher risk premium, which increases the expected cost to the bid-taker, or simply chooses not to bid at all. A reduction in the number of bidders also tends to increase the expected cost to the bid-taker.[25]

If the bid-taker is to shoulder a larger portion of risk, the bid price submitted may be lowered since a bidder would require a smaller risk premium. But a higher risk exposure can lead to higher financing cost for the bid-taker. So the overall impact of assuming a larger share of risk on the bid-taker is less certain.

The Benchmark Model

Different bidding models reflect the various assumptions about the bidding environment in which a solicitation is conducted. A benchmark model is one that has restrictive assumptions, but is easy to analyze. The most interesting conclusion about the benchmark model is that the four different bidding procedures yield basically the same results even though the bidders choose vastly different bidding strategies.[26] In the benchmark model, it is assumed that:[27] (1) all bidders are risk neutral, (2) all bidders' cost functions are independently determined, (3) all bidders have identical information about their own and other bidders' cost functions, (4) all bids are specified as a lump-sum payment, (5) the bidding is an all-or-

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[24] Williamson, Market and Hierarchies, p. 84.
[25] McAfee and McMillan, "Auctions and Bidding," p. 711.
[26] Ibid., pp. 707-710.
[27] Ibid., p. 706. The assumption of an all-or-nothing bidding is not explicitly specified but implicitly assumed.

nothing solicitation; that is, there is only one winning bid and the winning bidder alone supplies the item.

These assumptions bear close resemblance to conditions prevailing in a typical property auction where bidders have independent valuations about a particular item, their valuations are drawn from an identical distribution, they have the same expectation about such valuation distribution, only one bidder wins the bid, and the winning bidder pays a lump-sum payment. But in the following discussion of the benchmark model, a one-buyer, many-seller low-bid-wins context is applied.

Bidding Strategies

In English bidding, a bidder with full knowledge of the current bid continues to bid as long as the current bid is above its own cost estimation. The bidder drops out of the bidding as soon as the current bid falls below that cost estimation. At that bid price, the bidder earns no profit in supplying the particular item. All bidders (except the lowest-cost bidder) are essentially bidding their own costs independent of what other bidders bid or the estimation of other bidders' costs.[28]

In second-price sealed bidding, the bidder's strategy is similar to that under English bidding. All bidders, including the lowest-cost bidder, submit bids equal to their own cost estimations.[29] A bidder's bid only determines whether it wins the bid or not; the amount paid, if the bidder wins, is determined by the second-lowest bid. The best strategy for a bidder is to bid its own cost.[30] If a bidder considers lowering the bid below that, it will either remain the lowest bidder and receive the same payment it would have received without lowering its bid or it will become the lowest bidder and be paid a price below cost and be worse off. A bidder

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[28] Ibid., p. 708.
[29] Ibid.
[30] Ibid.; and Vickrey, "Counterspeculation, Auctions, and Competitive Sealed Tenders," pp. 10-12.

has no incentive to lower its bid below its own cost. Similarly, a bidder will be the same or worse off if it increases the bid above cost.

In a first-price sealed bid auction, a bidder's bid depends on its estimations of the costs and bidding strategies of other bidders. A bidder typically submits a bid above its own cost with the difference (economic rent) decided by its estimation of the probability distribution of the second-lowest bid assuming that the bidder itself is the lowest cost producer.[31] The bid submitted represents a trade-off between a higher probability of winning the auction and a lower profit if it does win. The bidder who submits the lowest bid is selected and paid an amount equal to its own bid. As discussed before, the bidding strategy under Dutch bidding is similar to that of first-price sealed bidding because the situations facing a bidders are the same under both bidding procedures.

Bidding Equilibrium

Obviously, the lowest-cost bidder wins under both English and second-price sealed bidding procedures since all bidders bid their true costs. The properties of incentive compatibility and Pareto efficiency are satisfied under both bidding procedures. In both Dutch bidding and first-price sealed bidding, the lowest-cost bidder submits the lowest bid since all bidders have identical information about the distribution of bidders' costs.[32] The difference between the bid price and a bidder's true cost is decided solely on its own cost.[33] As a result, the lowest-cost bidder is selected and the condition of Pareto efficiency is satisfied. The property of incentive compatibility is violated since a bidder does not bid its own cost.

The winning bidder is paid an amount that equals the second-lowest cost under both English and second-price sealed bidding in every bid

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[31] McAfee and McMillan, "Auctions and Bidding," p. 708-710.
[32] Ibid., p. 710.
[33] Vickrey, "Counterspeculation, Auctions, and Competitive Sealed Tenders," p. 16.

solicitation, assuming there is only one winner. Under Dutch and first-price sealed bidding, the expected economic rent for the winning bidder is determined by the average difference between the lowest cost and the second-lowest cost. So the bid-taker may pay more or less than the second-lowest cost in a specific solicitation but on average the bid-taker's payment equals the second-lowest cost. The expected payment of the bid-taker is the same under the four different bidding procedures, but the variance of the bid-taker's expected cost is smaller in English or second-price sealed bidding than in Dutch or first-price sealed bidding.[34]

The four bidding procedures deal with the issue of moral hazard similarly since they all specify the bid as a lump-sum payment. The winning bidder has an incentive to maximize its effort in supplying the particular item since any savings that result from its increased effort generates a higher profit for itself.

The issue of optimal risk allocation does not arise in the benchmark model. The winning bidder, by accepting a fixed payment, has assumed all risk and reward derived from future uncertainties. This does not mean that a fixed-price contract is the best contract format in dealing with the issues of moral hazard and risk allocation. It only indicates that the four bidding procedures are indifferent with respect to moral hazard and risk allocation due to the specification of the bid as a lump-sum payment.

Relevant Bidding Models for Generation Capacity Auctions

In this section, we examine some variations of the benchmark model which can provide additional insights into the design of a bidding procedure for securing new electric generating capacity. These include different technologies and cost estimates associated with various bidders, all bidders are allowed to supply part of the item being bid, a post-bidding contract

[34] Ibid., p. 28; and McAfee and McMillan, "Auctions and Bidding," p.710.

with cost sharing and escalation provisions, and bidders with correlated costs.

Asymmetric Information and Technologies

The possibility that the distributions of cost information and production technologies are not symmetric is probably the most important consideration in analyzing the solicitation to supply new electricity generation capacity. If asymmetric bidders were assumed, English bidding and second-price sealed bidding still would yield the same results as those in the benchmark model. The bidding strategy of an individual bidder does not change from that of a symmetric bidder. Each bidder still bids its own cost and the lowest-cost bidder wins. The properties of incentive compatibility and Pareto efficiency still hold under these two bidding procedures.

If bidders are assumed to be asymmetric, first-price sealed bidding and Dutch bidding yield different results from those of the benchmark model. Since the bidders use diverse technologies and possess different cost estimations, they can be divided into groups each composed of bidders with similar technologies and cost estimates. The bidding strategy of an individual bidder remains unchanged. A bidder still submits a bid above its own cost based on the trade-off between a higher probability of winning and a lower profit from winning. Thus, a lower-cost bidder submits a lower bid than a higher-cost bidder within a group of symmetric bidders. But the bidders in different groups perceive different degrees of competition and cost distributions, the lower-cost bidder in one group does not always submit a lower bid than a higher-cost bidder in another group.[35] The linkage between the ranking of the bidders' costs and the bids submitted is broken. Among all bidders, the lowest-cost bidder does not always submit

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[35] Vickrey, "Counterspeculation, Auctions, and Competitive Sealed Tenders," pp. 17-20; and Eric S. Maskin and John G. Riley, "Auction Theory with Private Values," American Economic Review 75 (May 1985): 153-154.

the lowest bid. Since the lowest-cost producer is not always selected, the condition of Pareto efficiency is no longer satisfied.

As for the bid-taker, the expected cost under first-price sealed bidding can be either higher or lower than that under second-price sealed bidding under the assumption of asymmetric information and technologies.[36] One recent study suggests that second-price sealed bidding is likely to lower the average cost to the bid-taker if the item being bid has a fixed intrinsic value, that is, a common cost estimation that applies to all bidders.[37]

If the bid-taker wants to minimize the expected cost, discriminatory treatment of different groups of bidders may be justified with asymmetric bidders.[38] For example, if the distributions of cost are identical except that the average costs differ among groups of bidders, the bid-taker should favor the higher-cost bidders. Such discrimination forces the low-cost bidders to bid more aggressively and submit lower bids than they otherwise would, thus reducing the expected cost to the bid-taker. On the other hand, such discrimination may increase the probability of selecting a higher-cost bidder and the expected cost becomes higher instead.[39]

As for the issues of the reduction of moral hazard and risk allocation, the assumption of asymmetric bidders does not introduce additional concerns. Since the bids are still specified as lump sum payments, the four bidding procedures do not produce different results in terms of controlling moral hazard and allocating risk.

Variable Capacity Bidding

Up to now, the bidding process is modeled in an all-or-nothing context where only one bidder is selected to supply the item being bid. But there

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[36] Ibid.
[37] Donald B. Hausch, "An Asymmetric Common-Value Auction Model," Rand Journal of Economics 18 (Winter 1987): 611-621.
[38] McAfee and McMillan, "Auctions and Bidding", pp. 715-716.
[39] Ibid.

are many situations where more than one bidder is selected and each bidder supplies only a portion of the item being bid.[40] With variable capacity bidding, the bidder must specify both a bid price and the quantity supplied at that price. In first-price sealed bidding, the winning bidders are paid at their own bid. In second-price sealed bidding, all winning bidders are paid a uniform price equal to the best non-winning bid.

If each bidder has a constant cost function or a fixed production output, the assumption of variable unit bidding does not change the nature of bidding from that of an all-or-nothing bidding. The fixed production output of each bidder determines the bid quantity, and a bidder needs only to decide the bid price to be submitted. Results that are similar to those in the unit bidding (all or nothing bidding) model can be derived.[41] The expected costs to the bid-taker under the four bidding procedures are the same. Both Pareto efficiency and incentive compatibility are satisfied under English and second-price sealed bidding procedures. Incentive compatibility is lost in Dutch bidding or first-price sealed bidding.

If each bidder does not have a constant cost function or a fixed production output, the bidding strategies become more complicated. The bidder must decide simultaneously both the bid price and bid quantity. The bid price affects the probability of winning while the bid quantity affects the bidder's average cost and expected profit. In first-price sealed bidding, the bidder can determine the unit price it receives but remains uncertain about winning. In second-price sealed bidding, the bidder knows neither the price it will be paid nor whether it will be selected.

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[40] The variable capacity bidding model is similar to, but not exactly the same as, the multiple units bidding model discussed in the bidding literature. The bidder is allowed to bid for more than one unit at a single price. The bidder's valuations (or costs) of different units are related. See Milton Harris and Artur Raviv, "A Theory of Monopoly Pricing Schemes with Demand Uncertainty," American Economic Review 71 (June 1981): 347-349.

[41] The assumption of constant cost function and fixed capacity essentially reduce the bidder's strategy to the choice of price alone, which is exactly the same as the case of single unit bidding. See McAfee and McMillan, "Auctions and Bidding," pp. 723-724.

The bidding strategy of an individual bidder under first-price sealed bidding is analogous to that of the unit capacity bidding model. The optimal bid price corresponding to a specific bid quantity is the unit cost plus a premium, which is decided by the bidder's estimated probability of winning at different price levels. The optimal bid quantity is selected by equating marginal cost to bid price.[42] In second-price sealed bidding, a bidder still bids its own true cost but selects a bid quantity that can maximize expected profits.[43]

Cost-Sharing and Cost-Escalation Contracts

In this section, we examine the results of relaxing the assumption of specifying the bid as a lump-sum payment. The royalties based on the amount of oil actually produced in an oil field and the number of books actually sold are two typical examples. In this circumstance, all bids submitted consist of two parts: a fixed payment and a cost-sharing or escalation rate. The bid-taker can ask the bidders to submit both parts or just one. The common practice is for the bid-taker to set the cost-sharing rate and ask for bids on the fixed payment.[44] The fixed payment can be determined as in the case of bidding with a lump-sum payment only. The task facing the bid-taker is to set a cost-sharing rate or a cost-escalating formula that represents the best trade-off among stimulating competition in initial bidding (bidding-competition effect), sharing risk between the bidders and the bid-taker (risk-allocation effect), and giving the winning bidders incentives to limit their total costs (moral-hazard effect).[45] A linear

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[42] Rothkopf et al., Designing PURPA Power Purchase Auctions: Theory and Practice, appendix D.
[43] To the best of our knowledge, there is no formal model explaining the selection of a specific bid quantity under a second-price sealed bidding. But the truth-revealing property of second-price bidding still holds. See for example, Vickrey, "Counterspeculation, Auctions, and Competitive Sealed Tenders", pp. 10-12, 26-27.
[44] McAfee and McMillan, "Auctions and Bidding," p. 717.
[45] Ibid., p. 327.

cost-sharing contract between the bidders and the bid-taker can be specified as:[46]

$$P = B + r*(C - B)$$

where

P : total payment

B : initial bid

C : realized cost

r : cost-sharing rate.

If the bidder's effort has no effect on the realized cost, a higher cost sharing rate tends to lower the expected total payment of the bid-taker for two reasons. First, a higher cost-sharing rate reduces the importance of the differences of bidders' cost estimations and reduces the variance in the cost estimations of all bidders. Since a bidder shares only a small portion of any cost overrun above its own estimation, the cost estimation becomes less of a constraint on the total payment a bidder expects to receive. This in turn induces more aggressive bidding that lowers the expected cost to the bid-taker.[47] Second, a higher cost-sharing rate lowers the risk exposure of a bidder and a lower risk premium is needed. In the case where the bid-taker is a better risk-taker than the bidders, the total risk premium combined is lowered with a high cost-sharing rate.[48]

In general, the bidder's effort does affect the realized cost so the bid-taker must address the moral hazard issue. A high cost-sharing rate is likely to enhance the tendency of moral-hazard behavior since the bidder only assumes a small portion of any cost increase resulting from its

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[46] It has been shown that an optimal incentive contract is indeed linear in cost overruns, i.e., the difference between the ex post cost and bid. See Jean-Jacques Laffont and Jean Tirole, "Using Cost Observation to Regulate Firms," Journal of Political Economy 94 (June 1986): 614-641; and id., "Auctioning Incentive Contracts," Journal Of Political Economy 95 (October 1987): 921-937.

[47] McAfee and McMillan, "Bidding for Contracts: A Principal-Agent Analysis," p. 331.

[48] Ibid.

actions. A lower cost-sharing rate has the advantage of reducing moral hazard, but it introduces additional concerns of high risk premiums required by the bidders and the reduction in the number of bids submitted. The decision on an optimal cost-sharing rate depends on the balance between increasing competition and lowering risk premium of bidders through a higher cost-sharing rate on the one hand, and decreasing the tendency of moral-hazard behavior with a lower cost sharing factor on the other.[49]

A cost-plus contract (r = 1) can never be optimal if there is more than one bidder. With a cost-plus contract, a higher-cost bidder has no incentive to submit a higher bid than a lower-cost bidder. All potential bidders would submit bids that give the appearance that they are the lowest-cost bidder. Afterwards, they can fully recover their actual higher costs through the cost-plus provision in their contracts. The bid-taker cannot identify the most efficient bidder through the bids submitted and is unlikely to select the bidder with the lowest realized cost.[50]

A fixed price contract (r = 0) is optimal if there are many bidders and they are all risk neutral. This is true because the concern about the bidding-competition effect is small if the number of bidders is large, and the risk-allocation effect can be ignored when all bidders are risk neutral. Otherwise, some cost-sharing arrangements are preferred.[51] The more risk-averse the bidders are relative to the bid-taker, the higher the optimal cost-sharing rate should be.[52]

Bidders with Correlated Costs

In certain bidding circumstances, bidders share a common technology but do not know with certainty the eventual costs. The bidders' cost estimations are correlated due to an underlying common technology. As a result, a low bid reflects more of the bidder's own low cost estimation

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[49] Ibid.
[50] Ibid., p. 328.
[51] Ibid., p. 332.
[52] Ibid., p. 335.

rather than the real differences in production technologies and cost structures. The lowest bid wins, but this is likely to represent the most optimistic estimation and may turn out to be too difficult to meet. Since all bidders are aware of this "winner's curse" they are likely to raise their cost estimations,[53] which, in turn, increases the expected cost to the bid-taker under both the first-price sealed bidding and second-price sealed bidding.

Under this circumstance, English bidding can partially reveal the cost estimations of bidders and can somewhat alleviate the effects of "winner's curse". The bidders are therefore more inclined to bid aggressively, lowering the bid-taker's expected cost.[54] In general, English bidding results in the lowest expected cost to the bid-taker, second-price sealed bidding the second-lowest expected cost, and first-price sealed bidding and Dutch bidding the highest expected cost.[55] With the assumption of correlated costs, it is to the bid-taker's advantage to publicize the best information available about the estimated cost of the solicited project because this reduces the effects of "winner's curse" and induces bidders to submit lower bids.[56]

Some Empirical Studies

The literature on the empirical evidence about bidding is rather sketchy, covering current bidding practices more than modern bidding theory and its verification.[57] The conclusions drawn from most empirical studies are valid in limited circumstances and should be treated with caution.

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[53] The term "winner's curse" refers to the fact that the bidder who wins is the one who makes the lowest cost estimate. Winning, in a sense, may convey bad news to the winner because everyone else estimated the costs to be higher. See McAfee and McMillan, "Auctions and Bidding", p. 721.
[54] Ibid., p. 722.
[55] Paul R. Milgrom and Robert T. Weber, "A Theory of Auctions and Competitive Bidding," Econometrica 50 (September 1982): 1095.
[56] Ibid., p. 1096.
[57] McAfee and McMillan, "Auctions and Bidding," p. 726.

The results of federal timber land auctions have been used to empirically compare the advantages and disadvantages of sealed bidding and opening bidding. The U.S. Forest Service has used both first-price sealed bidding and English bidding to sell timber land harvest contracts. Some studies suggest that sealed-bid auctions can yield significantly higher revenues for the bid-taker (U.S. Government) than English bidding, while others argue that no statistically significant difference is detected.[58] There are indications that the difference in government revenue is not a good indication of the inherent differences between the English and sealed bidding procedures. The theoretical conclusion is ambiguous since bidders for timber land may possess asymmetric cost information.[59] The lower revenue from English bidding is likely to result from a stronger tendency for bidder collusion and a reduction in the number of bidders involved in an open bidding for timber land. For example, in an oral bidding the bidders with distant mills are reluctant to compete for timber land near another bidder's mill, and the bidders can react to unexpected competition quickly in enforcing and maintaining collusions.[60]

In the early 1970s, the U.S. Treasury used first-price sealed bidding for selling short-term Treasury bills and second-price sealed bidding for selling long-term Treasury bonds.[61] It has been argued that bidding risk (receiving a lower yield) and immediate post-bidding market risk (changes in market interest rate) can be reduced by second-price sealed bidding, which in turn encourages more participation and quicker sales of Treasury notes

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[58] Walter J. Mead, "Natural Resource Disposal Policy: Oral Auction Versus Sealed Bids," Natural Resource Journal 7 (April 1967): 195-224; Robert G. Hansen, "Empirical Testing of Auction Theory," American Economic Review 75 (May 1985): 156-159; and id., "Sealed-Bid Versus Open Auctions: The Evidence," Economic Inquiry 24 (January 1986): 125-142.

[59] Hansen, "Sealed-Bid Versus Open Auctions: The Evidence," pp. 134-136.

[60] Mead, "Natural Resource Disposal Policy: Oral Auction Versus Sealed Bids," pp. 219-223; and Marc S. Robinson, "Collusion and the Choice of Auction," Rand Journal of Economics 16 (Spring 1985): 141-145.

[61] For a review of the Treasury experience see Charles C. Baker, "Auctioning Coupon-Bearing Securities: A Review of Treasury Experience", in Bidding and Auctioning For Procurement and Auction, ed. Yakov Amihud (New York: New York University Press, 1976), pp. 146-151.

and bonds.[62] Existing data indicate that second-price sealed bidding generally yields more revenue to the government than first-price sealed bidding.[63] This result is not unexpected, given that Treasury obligations have roughly the same value in the financial market. The correlated-cost model already suggests similar conclusions.[64] However, due to the deficiency in actual data, it is difficult to ascertain empirically whether the observed difference in auction results can be attributed fully to the different bidding procedures used.[65]

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[62] Ibid., pp. 146-147.
[63] Ibid.
[64] Hausch, "An Asymmetric Common-Value Auction Model," pp. 611-621.
[65] Baker, "Auctioning Coupon-Bearing Securities: A Review of Treasury Experience," p. 149.

CHAPTER 6

DESIGN OF AN OPTIMAL BIDDING PROGRAM

In this chapter, the design of an optimal bidding program for a host utility to secure new electric generating capacity from QFs, IPPs, and utility subsidiaries is discussed. A bidding program includes the procedure of soliciting bids and selecting winning bidders, the frequency of bidding, and the format of power purchase contracts entered into after the bid selection.

In the following sections, the competitiveness of the market for supplying electric generating capacity is examined.[1] There are many potential nonutility power producers that are willing to submit bids. They offer comparable electric generating capacity to the host utilities, and the prices are determined by competitive forces. Furthermore, based on the limited data available, it appears that nonutility power producers use diverse generation technologies, choose different-sized facilities, and possess asymmetric and independent cost expectations. The nonutility power producers, acting as typical entrepreneurs, seek to maximize expected profits from bidding. The host utility, as the bid-taker, evaluates the bids submitted in a manner similar to the evaluation of other internal and outside supply options.

Matching this market environment of bidding to supply electric generating capacity with the results of bidding models discussed in chapter 5 indicates that a second-price sealed bidding procedure with a

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[1] A proposed criterion in determining the competitiveness of an electric utility bulk power market has suggested that each buyer should have three or more viable suppliers for a comparable electric service to establish a workably competitive bulk power market. See James V. Barker, Jr., "A Workable Test of a Workably Competitive Bulk Power Market", Public Utilities Fortnightly, 14 April 1988, pp. 13-17. A more extensive discussion on the structural norms, conduct criteria, and performance criteria of workable competition can be found in F. M. Scherer, Industrial Market Structure and Economic Performance (Boston: Houghton Mifflin Company, 1980), pp. 41-44.

fixed-price post-bidding power purchase contract containing cost-sharing arrangements is the most desirable bidding procedure.

The Bidders: QFs, IPPs, and Utility Subsidiaries

In this section, the characteristics of the potential bidders in an electric utility solicitation for new generation capacity are examined. The limited data available in this early phase of competitive bidding indicate that the market environment for bidding is likely to be competitive, although additional empirical verification may be needed.

Current data show that the number of bidders is many, and they exhibit great diversity in facility size, technologies, fuels, and ownership arrangements. According to information provided by the FERC, there are 3,378 QFs nationwide through June 30, 1987 with a total capacity of 57,332 megawatts.[2] Among them, there are 1,502 cogeneration facilities with initial capacity of 41,985 MW and 1,876 small power production facilities with initial capacity of 15,347 MW.[3] These figures may not indicate precisely the status of current nonutility power sources for various reasons,[4] but they represent a significant part of the nation's nonutility

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[2] Federal Energy Regulatory Commission, Office of Electric Power Regulation, The Qualifying Facilities Report (Washington, D.C.: Federal Energy Regulation Commission, 1987). This report lists all of the filings made with the FERC for qualifying small power production and cogeneration facilities since 1980.

[3] The term "initial capacity" is used by FERC since the filing requirements on qualifying facilities do not specify at what stage of completion a filing must be made. Some are submitted after the facilities begin operation, others are made for facilities that are proposed and which may never be constructed.

[4] See Federal Energy Regulatory Commission, The Qualifying Facilities Report, p. i. First, only qualifying facilities under PURPA regulations are included in the report. Second, the data provided in filing are not verified by FERC inspection of facilities. Third, the FERC has not completed review of all listed applications for certification. Fourth, the FERC has not verified whether all proposed facilities are actually constructed or completed.

power sources. They are potential bidders as well in a utility solicitation for electric generating capacity. The addition of independent power producers and utility subsidiaries is unlikely to diminish the number and diversity of potential bidders capable of supplying new generation capacity.

The Qualifying Facilities Report published by the FERC is probably the most comprehensive and current data available on nonutility power producers. It is used here to illustrate the diversity among qualifying facilities. In table 6-1, we categorize the qualifying facilities by the types of primary fuel used.

In table 6-2, we list the major technologies (prime mover) of the qualifying facilities.[5] Since aggregate national data are not readily available, we examine only those facilities in the New England Census Region (Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut). It should be noted that QFs may use different energy sources even if they have the same prime mover technologies. So the actual technologies used are probably more diversified than those indicated here. The size distribution of QFs in the New England Region is shown in table 6-3.

In addition to the qualifying facilities, it is useful to examine the characteristics of other potential bidders such as independent power producers and utility subsidiaries. Although no comparable data are available, some cursory observations suggest that the addition of independent power producers and utility subsidiaries would tend to increase the number and diversity of potential bidders. Specifically, IPP and utility subsidiaries are more likely to be better financed, more involved in large-scale generation projects, and probably more experienced with advanced

[5] A review of major technologies is provided elsewhere. See Edison Electric Institute, Economics Division, Strategic Implications of Alternative Electric Generation Technologies (Washington, D.C.: Edison Electric Institute, 1984), pp. 5-12.

TABLE 6-1

QUALIFYING FACILITIES BY ENERGY SOURCE

Fuel	Facilities		Capacity	
	Number	Percentage	MW	Percentage
Coal	161	4.8	9719	17.0
Natural Gas	1076	31.9	25492	44.5
Biomass	560	16.6	8216	14.3
Waste	149	4.4	4857	8.5
F06/F02	55	1.6	652	1.1
Hydro	624	18.5	3115	5.4
Wind	614	18.2	1822	3.2
Geothermal	64	1.9	2001	3.5
Solar	35	1.0	290	0.5
Other	40	1.2	1168	2.0
Total	3378	100.0*	57332	100.0

*Does not add up to 100% due to rounding.

Source: The Qualifying Facilities Report, Federal Energy Regulatory Commission, 1987.

technologies, than the typical qualifying facility.[6]

A word of caution should be provided here. Since the generation facilities of some bidders such as hydro or industrial plants are site-specific and no universal access to the transmission grid is available at the present time, the number and diversity of potential bidders in a specific utility solicitation are probably more restricted than national or regional data suggest.

[6] After all, the qualifying facilities are subject to more strict size limitations, energy efficiency requirements, and ownership restrictions. An anecdotal description of current nonutility power producers (including IPPs) can be found in Richard Munson, The Power Makers (Emmaus, Pennsylvania: Rodale Press, 1985), pp. 144-180.

TABLE 6-2

QUALIFYING FACILITIES BY PRIME MOVER
IN NEW ENGLAND REGION

Prime Mover	Facilities		Capacity	
	Number	Percentage	MW	Percentage
Steam Turbine	79	57.2	2099	49.1
Combustion/gas Turbine	10	7.2	1084	25.4
Combined Cycle	26	18.9	1008	23.6
Duel Fuel Engine	1	0.7	2	0.0
Spark Ignition	5	3.6	14	0.3
Diesel Engine	4	2.9	17	0.4
Other	13	9.4	51	1.2
Total	138	100.0*	4275	100.0

*Does not add to 100% due to rounding.

Source: Authors' calculation based on data of individual facilities provided in The Qualifying Facilities Report, Federal Energy Regulatory Commission, 1987.

TABLE 6-3

SIZE DISTRIBUTION OF QUALIFYING FACILITIES
IN NEW ENGLAND REGION

Size	Number of Facilities	Percentage
No more than 1 MW	48	17.0
1.01 - 10 MW	95	33.7
10.01 - 30 MW	93	33.0
30.01 - 50 MW	22	7.8
50.01 MW or more	24	8.5
Total	282	100.0

Source: Authors' calculation based on data of individual facilities provided in The Qualifying Facilities Report, Federal Energy Regulatory Commission, 1987.

In summary, current data on nonutility power producers and the actual experience of utility solicitations, as discussed in chapter 2, tend to support the notion that a bidding process can be competitive. The number of bidders is large and total capacity offered far exceeds the amount solicited. Furthermore, there is also great diversity in terms of fuel, size, and technology in bids. Bidders can choose the capacity offered as well as the bid price.

As for the possible collusion among nonutility power producers, the market environment of bidding to supply electricity generation capacity does not appear conducive to collusion for several reasons. First, the number of bidders is large making it difficult to enter into and enforce a collusive agreement. Second, the ownership and financial arrangements of nonutility power producers are diversified, and a collusive agreement may not uniformly benefit every party involved compelling some profit redistribution scheme. Third, the existence of a reserve price (the host utility's avoided cost) can mitigate the effects of collusion making it less profitable to potential colluders.[7] This is because potential colluders cannot conspire to rig a bid price higher than the host utility's avoided cost. The discussion here does not mean that collusion will not happen or that nonutility producers have no incentive to collude to increase the payments they receive. It only indicates that it is not easy to create or sustain collusive activities given the diversity and number of potential bidders.

The Bid-Taker: Host Utility

In this section, the role of a host utility in soliciting new generation capacity is examined. The host utility has the primary responsibility of preparing and conducting a bid solicitation. As previously discussed, bid solicitation is an extension of a utility's resource planning process. There is no inherent difference between securing generation capacity through a bidding process and purchasing capacity from

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[7] R. Preston McAfee and John McMillan, "Auctions and Bidding," Journal of Economic Literature 25 (June 1987): 725.

another utility through negotiation. With this basic understanding, the characteristics of the host utility in a bidding context are quite clear.

First, the host utility, subject to the review and approval of the state PSCs (in most instances) is responsible for calculating and publicizing its avoided cost. The avoided cost is the upper limit that the host utility can pay for power provided by nonutility producers. The avoided cost acts like the reserve price in a high-bid-wins auction. It can prevent unrealistic bidding and can reduce the expected cost to the host utility.[8] The avoided cost of the host utility is known in advance with certainty to all bidders. The revelation of the avoided cost may create an incentive to under-bid by nonutility power producers if a cost-plus power purchase contract is used after bid selection. A potential bidder can submit a low bid to win and hope to recover full cost through cost escalation clauses. Presumably, the tendency of under-bidding can be eliminated if a fixed-price contract is used.

Second, the host utility uses the same evaluation criteria in selecting the nonutility power producers as those used in its consideration of other supply options such as purchasing power from other utilities or building its own power plants. It seeks to minimize the expected cost of purchased power subject to maintaining reliable electric service.

Third, the capacity offered by a nonutility power producer does not affect the ranking of its bid or the probability of being selected. In other words, the bid capacity is relevant to bid selection only when its acceptance causes the total capacity accepted to exceed the prespecified supply block.[9]

Elements of an Optimal Bidding Procedure

Based on the above analysis of the characteristics of potential nonutility power producers and the host utility, bidding to supply new generation capacity is best described as having an independent choice of

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[8] Ibid., pp. 712-714.

[9] A detailed discussion of a bid acceptance procedure is provided in chapter 7.

generation technologies, asymmetric information, variable capacity bidding, and an explicit avoided cost. The elements of an optimal bidding procedure follow from this specification and the results of bidding models discussed before.

Sealed Versus Open Bidding

The choice of a sealed or an open (oral) bidding procedure depends on the feasibility and difficulty of conducting complicated transactions and on reducing the tendency of bidder collusion. The nature of a power purchase arrangement favors the use of a sealed bidding procedure. A power purchase agreement over an extended period of time is a complicated business arrangement involving extensive transaction-specific information and significant amounts of money. A bid to supply power needs to define a broad range of factors, including capacity charge, energy cost, expected effects on system reliability, dispatchability, financing, management experience, and cost-sharing clauses. It is difficult or even impossible for a bidder to present so many complex arrangements in an oral bid. It is even more difficult for the host utility to evaluate them. Only a sealed bidding procedure can afford an orderly presentation and evaluation of many complex bids.

An open bidding procedure is also more susceptible to collusion among bidders because it is easier for bidders to monitor one another and take immediate retaliatory actions against those bidders who break the collusion.[10]

Second-Price Versus First-Price Bidding

The selection of a first-price or a second-price bidding procedure has significant economic efficiency implications. It could well be the most

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[10] Marc S. Robinson, "Collusion and the Choice of Auction," Rand Journal of Economics 16 (Spring 1985): 141-145; and Michael H. Rothkopf et al., Designing PURPA Power Purchase Auctions: Theory and Practice (Berkeley, California: Energy Analysis Program, Lawrence Berkeley Laboratory, 1987), p. 18.

critical element in the design of a bidding procedure. First-price sealed bidding is widely used in government and private procurements. It is familiar and easily understood. Second-price sealed bidding, despite several theoretical advantages, is used only in a limited number of situations. An obvious reason for the lack of popularity of second-price bidding is its deviation from the notion of "you pay what you bid" associated with the more common progressive oral bidding (English bidding).[11] Some studies suggest that the appearance of fairness is also a concern in second-price bidding. Some argue that "the public is likely to think a second-price procedure is giving something away to the winning bidders. First-price auctions do not create such an impression."[12]

Another commonly-cited shortcoming of second-price bidding is that it is susceptible to multiple bids by a single bidder aiming at manipulating the best non-winning bid. Since winning bidders are paid a price equal to the best non-winning bid, a bidder can submit several bogus bids to increase the bid price of the best non-winning bid and increase the payment it stands to receive.[13]

A fourth reason for not using second-price sealed bidding is that its truth-revelation property can be lost under certain circumstances. It is argued that third parties can take advantage of the cost information revealed in a second-price bidding procedure and thereby extract some part of the economic rent from the winning bidders.[14] Since the winning bidders must negotiate with others for permits, construction financing, and labor contracts, these third parties might have substantial market power and could take advantage of the revealed minimum price that a winning bidder would have accepted. Since a bidder is fully aware of this possibility, he adjusts his bidding strategy so that the amount of economic rent captured by the third parties comes from the host utility only. The truth-revelation

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[11] However, English bidding is strategically equivalent to the second-price sealed bidding.

[12] See Rothkopf et al., Designing PURPA Power Purchase Auctions: Theory and Practice, p. 21.

[13] Ibid., p.20.

[14] Ibid., p. 16-17, and appendix A infra.

property of a second-price bidding is lost, and the expected cost to the host utility increases.

These arguments favoring the use of first-price bidding are questionable in the context of bidding to supply electric generating capacity. Most nonutility power producers, as business entrepreneurs, are not so naive as not to fully comprehend a second-price bidding procedure. As for fairness and the appearance of fairness, it can be argued that to pay all winning bidders a uniform price representing the host utility's avoided cost is a more equitable arrangement than the discriminatory prices associated with first-price bidding. After all, in the eyes of the host utility, the capacity supplied by a high-bid bidder is identical to that provided by a low-bid bidder providing the nonprice factors are the same for both. There is no reason to pay them differently. To eliminate the cost advantages of the more efficient nonutility power producers for the appearance of fairness is itself grossly unfair. At the same time, it should be noted that paying a uniform price provides an incentive for bidders to submit bids that are lower (without inclusion of economic rent) than they would have been under first-price sealed bidding. As a result, the total cost to the host utility may decrease.

In terms of the strategic use of multiple bids, it is generally not in a bidder's own interest to submit multiple bids. Nor can multiple bids improve efficiency except in cases with restrictive assumptions. Allowing multiple bids only adds additional complexity.[15]

As for the increase of expected cost to the host utility as a result of the economic rent captured by third parties, the key question is not how much information the third parties obtain but rather how much market power the third parties have with or without cost revelation by the selected nonutility power producers. The revelation of true cost does not increase the economic rent captured by the third parties. Actually, the situation facing a selected nonutility producer in obtaining services and goods from third parties is similar to that of a host utility soliciting bids from nonutility power producers. The true cost revealed by the winning bidder is

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[15] See the next section on the choice of single bid versus multiple bids.

functionally similar to the avoided cost publicized by the host utility. The winning bidder can use competitive solicitations to obtain services and goods from third parties. The revelation of true cost, similar to the revelation of avoided cost, does not affect the expected cost to the winning bidders in obtaining goods and services from third parties.

In first-price bidding, third parties are aware that the nonutility power producers have included premiums in their bids and that economic rents are available as well. Comparing this situation with the revelation of true cost in second-price bidding, minimal qualitative differences exist in terms of the informational advantage available to the third parties in subsequent negotiations with winning bidders under either bidding procedure. The best conclusion we can draw here is that second-price bidding does not lose its truth-revelation property unless the nonutility power producers are convinced that the third parties have significant market power. Furthermore, a bidder will adjust its bidding strategies to counter the market power of third parties only if it expects other bidders to make similar adjustments. Otherwise, any unilateral adjustment may cause the bidder to lose. Paying part of the rents to third parties is probably preferred to losing the bid altogether.

A second-price sealed bidding procedure has strong efficiency advantages unavailable in a first-price bidding procedure.[16] Since it is never to the nonutility producer's advantage to submit a bid that deviates from true cost provided that there are no pervasive non-competitive third parties, the conditions of incentive compatibility and Pareto efficiency are always satisfied under a second-price bidding procedure. A second-price

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[16] It is argued that the inefficiency of first-price sealed bidding results primarily from the inability of bidders to estimate the cutoff (winning) price. As more bidding is conducted, the bidders can estimate the cutoff price more accurately, reducing the inefficiency of first-price bidding. See Rothkopf et al., Designing PURPA Power Auctions: Theory and Practice, p. 23. But this observation is likely to hold only in the case where the number of participants of the bidding are fairly stable over a long period of time. If there are constantly new bidders, it is difficult to predict the new bidders' strategies and how to improve the estimation of the cutoff price.

bidding procedure assures the selection of the most efficient power producers.

The truth-revelation property of the second-price bidding provides an additional advantage by eliminating the expenses related to the evaluation of the cost distributions and bidding strategies of other possible nonutility power producers.[17] Eventually, a part of these costs is passed through to the host utility and ratepayers. The third advantage of second-price bidding procedure is the encouragement of business expansion from the more efficient nonutility power producers.[18] Since a uniform price is paid to all selected nonutility power producers, a lower-cost producer receives higher profits than a higher-cost producer. This dynamic long-term consideration can further improve economic efficiency in electricity generation. In other words, in the long run, it makes more sense to encourage more efficient producers to expand by allowing them a higher profit. As the more efficient producers expand, they drive less efficient producers from the market resulting in a decline in the cost of electricity for the utility and its customers.

Single Bid Versus Multiple Bids

Before discussing the advantages and disadvantages of multiple bids, a clear definition of multiple bids is required. Multiple bids refer to two or more bids submitted for a single power source in a utility solicitation. An example may illustrate this point more clearly. If an independent power producer has two hydro sites under development, it can submit two bids (one for each site) in a utility solicitation. Because only one bid is submitted for a single power source, the two bids are not

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[17] William Vickrey, "Counterspeculation, Auctions and Competitive Sealed Tenders," The Journal of Finance 16 (March, 1961): 21, 28.

[18] Ronald L. Lehr and Robert Touslee, "What Are We Bid? Stimulating Electric Generation Resources Through the Auction Method," Public Utilities Fortnightly, 12 November 1987, p. 15.

considered to be multiple bids.[19] If the developer submits two or more bids for one of the sites, he is using multiple bids in the solicitation.

Advocates of multiple bids argue that allowing multiple bids may have the advantage of reducing the lumpiness of capacity offered and improving efficiency of the bidding results.[20] As argued by some, the lumpiness of capacity can be reduced if more bids involving small capacity are submitted instead of few bids with large capacity size. But the lumpiness of capacity is not a real concern because the supply block specified in an RFP should not be viewed as an absolute limit on the amount of capacity eventually accepted. Several measures can alleviate the problems associated with capacity lumpiness. These measures include post-bidding negotiation to downsize the bid capacity and the acceptance of capacity that exceeds the initial supply block if the avoided cost is higher than the bid price.

The efficiency improvement associated with multiple bids occurs only in restrictive situations considering the sizes of the supply block in typical utility solicitations and the range of capacity sizes with decreasing average cost for most generation technologies. If a nonutility power producer has a constant average cost function, it does not submit multiple bids because the quantity of a bid does not affect its average cost or the bid price. The efficiency improvement of multiple bids depends on specific assumptions about the cost functions. Specifically, multiple bids can generate higher efficiency only when the capacity offered is perfectly divisible and strictly increasing as a function of the capacity size. In all other situations, the submission of multiple bids may not result in a lower bid price that can increase a bidder's chance of winning the bid or increase the amount of profit if it is selected.

On the other hand, the submission of multiple bids does lead to strategic behavior in second-price sealed bidding. A nonutility power producer seeking to maximize profits can submit several bids; none of which

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[19] The bidder may have some cost advantages, however, in bundling the two hydro projects together and submitting a single bid.

[20] Rothkopf et al., Designing PURPA Power Purchase Auctions: Theory and Practice, pp. 37-38.

may be serious, with the sole purpose of manipulating the price of the best non-winning bid to increase the payment received.

Fixed-Price Versus Adjustable-Price Contracts

This consideration on the format of a post-bidding contract deals primarily with the desire of the host utility to achieve three interrelated goals in securing new electricity generation capacity: encourage competition, reduce moral hazard, and allocate risk.[21] A fixed-price contract discourages moral hazard on the part of nonutility power producers because the amount of payment is not affected by post-bidding actions. A nonutility power producer has the strongest incentive to minimize realized (<u>ex post</u>) costs. But a fixed-price contract also tends either to increase the amount of risk premium required or reduce the number of bids submitted since some nonutility producers may simply refuse to accept the higher risk associated with a fixed-price contract. In both instances, the expected cost to the host utilities increases. A fixed-price contract is more risky to the nonutility power producers due to substantial uncertainties involved in a long-term contract. A nonutility producer usually does not have the capability to ascertain all possible variations over an extended period of time and to estimate costs accurately. As a result, it charges a higher premium to protect itself from the risk of unexpected drastic cost increases.

An adjustable-price contract allows a nonutility power producer to pass along a portion of the cost difference between realized cost and the initial bid. The advantages of such a contract in a bidding context are the possibility of allocating risk to the party that can best bear it, and the encouragement of bidding competition by reducing the risk associated with the bidders' cost estimations.

An extreme form of the adjustable-price contract is a cost-plus contract in which the host utility assumes the responsibility of all future cost increases. A cost-plus contract has the advantages of minimizing the

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[21] R. Preston McAfee and John McMillan, "Bidding for Contract: A Principal-Agent Analysis," <u>Rand Journal of Economics</u> 17 (Autumn 1986): 326-338.

risk premiums charged by the nonutility power producers and of encouraging intensive competition among them. But a cost-plus contract is never an optimal contract format for competitive bidding.[22] It eliminates the linkage between the bid prices and the costs of nonutility power producers. A high-cost nonutility power producer can submit an artificially low bid initially to win, knowing that all cost overruns can be recovered from the host utility later. Since the lowest-cost producer is not always selected, the cost of electricity generation is not minimized. Furthermore, a cost-plus contract is susceptible to moral-hazard behavior on the part of selected nonutility power producers. Once selected, the nonutility power producers have no incentive to control costs because all cost increases will be passed directly to the host utility and ultimately to the ratepayers.

Clearly, the best contract format for supplying generation capacity depends on the emphasis on controlling these three related factors: bidding competition, moral hazard, and risk allocation. Since there are many nonutility power producers in a typical utility solicitation, the bidding-competition effect is probably of less concern. In the absence of specific information about the risk-taking attitude of the bidders and the host utility, the risk-allocation effect may not be a critical consideration. There is no special reason to transfer risk from the nonutility producers to the host utility or vice versa.

Then the dominant consideration in bidding to supply new generation capacity is the control of moral-hazard behavior. Specifically, the key question in designing a post-bidding contract is how to enhance the possibility that the bidders' bids are closer to their true costs and that the winning bidders provide their best efforts in constructing and operating new power generating facilities. Here, a fixed-price contract is preferred. Another reason favoring the fixed-price contract is that it is easier to evaluate two fixed-price contracts than two contracts with various cost sharing and escalation clauses.

Nevertheless, the bidding-competition effect should not be entirely ignored since the total number of bidders is not infinite. The host utility

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[22] Ibid., pp. 330-333.

might have a lower financing cost than the nonutility producers. Some cost-sharing and cost-escalating arrangements may be warranted. The principle of cost sharing and cost escalating is to impose fixed-price arrangements on the tasks where a nonutility power producer has a higher degree of control, and to share costs on those tasks that are less controllable. In a long-term power purchase contract, for example, the energy cost component is probably less predictable, and the nonutility producers have only limited control over its fluctuation. A cost-sharing arrangement here may be beneficial for both ratepayers and nonutility power producers. On the other hand, the capacity cost is more attributable to the efforts and expertise of a nonutility power producer, so a fixed-price approach is desirable. This is especially true with the mature and short lead-time technologies commonly used by nonutility power producers.

Short-Term Versus Long-Term Contracts

For the host utility, the decision on the length of a power purchase contract is a trade-off between having more flexibility in selecting new alternatives to meet future demand and having more predictable prices and supplies of electricity. A short-term contract allows the host utility to solicit new bids after a short period of time. New technologies are afforded a greater opportunity to compete. Future favorable economic conditions such as lower capital costs and declining fuel prices are more likely to be incorporated into new power purchase arrangements.

The benefits of a long-term contract to the host utility are its assurances of power supply and predictable cost as well as protection from unexpected economic changes, such as an oil embargo or acid rain control legislation, which can drastically increase the price of electricity.

For a nonutility power producer, a short-term contract may require it to recoup a larger share of its capital investment over a shorter contract term than under a long-term contract. Even though a nonutility producer can still participate in a new round of bid solicitation after expiration of its current contract with a host utility, the options available are restricted. The capital investment in facilities built to fulfill the initial power purchase contract are generally immobile and idiosyncratic so the nonutility power producer may have difficulties in finding a new buyer for the capacity already in place. As a result, the bidder requires either a higher risk premium or a higher depreciation rate to compensate for the risk of losing the current contract after only a few years. On the other hand, a short-term contract may be feasible and desirable if there is universal transmission access and a secondary market for purchased power contracts. Under this circumstance, a buyer for the electric generating capacity is easier to find after the expiration of short-term power purchase contracts.

The disadvantages of a long-term power purchase contract to a nonutility producer are the difficulties in correctly estimating costs over a long period of time and the loss of the opportunity to receive higher payments in a changed marketplace. In summary, a short-term power purchase contract is likely to increase the expected cost of generation capacity to be secured by the host utility. A short-term contract also puts the nonutility power producers in a less favorable position compared with the utility-owned generation facilities, which are afforded a longer depreciation period.

One way to determine a proper contract length is to look at the contract length of the power purchase agreements between two utilities and the depreciation rate of a utility's own generation plants. A comparable contract length would allow a fair comparison between the annual capacity costs associated with the utility-owned facilities and those owned by nonutility power producers. For example, because a utility is not allowed to recover its capital investment within a five-year period or calculate its avoided cost on a five-year depreciation schedule, there is no reason to expect a cogenerator to recover its cost within a five-year period. A short-term contract essentially requires the nonutility producer to do just that. Based on these considerations, a minimum contract length of ten to fifteen years would be preferred unless both the nonutility producers and the host utility agree to a different arrangement.

Frequency of Bidding

Since bidding for supplying new generation capacity is an extension of the host utility's resource planning process, the principles used in utility resource planning are still valid in the solicitation of bids to supply generation capacity. Specifically, bidding should occur only when there is a need to add new generation capacity within the planning horizon. The approach adopted in several states that set aside a fixed percentage of peak load for bidding needs to be reconsidered. If the frequency of bidding is tied to the growth in peak demand alone, bidding may exacerbate the problem of excess generation capacity by adding more capacity when there is no need for such capacity. Such an approach also tends to generate a smaller supply block, which puts large-scale technologies at a disadvantage when competing with small-sized technologies.

There are four factors to be considered in setting the frequency of bidding. The first one is to maintain a fair and equitable environment for generation technologies of various sizes to compete with one another. The second consideration is to prevent the possibility of collusive agreements among nonutility power producers. Frequent bidding inevitably involves the same group of bidders, making such strategic behavior by nonutility producers more likely. Bidders are not only concerned with the results of the current solicitation but also about the effect on potential competitors in subsequent auctions.[23] Frequent bidding makes it easier to redistribute the gains obtained from collusion, providing a more favorable environment for collusion among nonutility power producers.

The third consideration is the coordination of utility solicitation with the expansion of local industrial plants. Advocates of such coordination argue that infrequent bidding may reduce the opportunity for incorporating cogeneration by local industrial plants because owners may not be willing to wait for the next solicitation. Although such coordination is desirable, it is unlikely to play a major role in determining the frequency of bidding. There is no guarantee that the bid from an industrial plant will be competitive with other nonutility power producers or acceptable to the host utility. The expansion plans of other potential bidders (IPPs, small power producers, and subsidiaries of utilities) may not match those of the industrial plant, making it difficult for any utility solicitation to match the expansion plans of all potential bidders.

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[23] S. S. Oren and M. H. Rothkopf, "Optimal Bidding in Sequential Auctions," Operations Research 23 (November-December 1975): 1080-1090; and Rothkopf et al., Designing PURPA Power Auctions: Theory and Practice, p. 43.

A fourth factor to be recognized is the transaction costs associated with bid solicitation and evaluation. Bidding is not a free process. The nonutility producers must spend a great deal of time and effort in preparing bids and collecting information. The host utility also incurs substantial expenses in preparing an RFP, publicizing the solicitation, evaluating bids, and negotiating a power purchase agreement.

Current bidding regulations in two states (California and New York) call for a bidding frequency of two or three years. One study also recommends this time period.[24] This appears, in our view, to be a reasonable bidding frequency.

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[24] Rothkopf et al., Designing PURPA Power Auctions, p. 43.

CHAPTER 7

EVALUATION AND ACCEPTANCE OF BIDS

The power purchase arrangements between QFs, IPPs, utility subsidiaries, and the host utility are complex business transactions. The host utility not only faces the task of assessing an array of price and nonprice factors but also needs to ascertain the probability that conditions specified in a bid proposal will be realized.

Utilities have used vastly different bid evaluation methods based on their own system characteristics and planning capability. A uniform bid evaluation method may not always be applicable to all utilities. This study does not propose a particular evaluation paradigm. Instead, in this chapter we only identify and explore the more important factors to be considered in the power purchase transaction between a nonutility power producer and the host utility. Some factors, such as capacity cost and energy cost, are easier to calculate and compare. But other factors, such as dispatchability, reliability, and transmission requirements are more difficult to measure in monetary terms. A merit selection method or a system of binding constraints, which reflect the relative values of various price and nonprice factors to the host utility, can be used to derive a common measurement for comparing different bids.

Due to the technical lumpiness and economies of scale associated with various generation technologies, the capacity offered in a bid is rarely perfectly divisible. In other words, the capacity offered by a nonutility power producer may be subject to certain minimum-size restrictions or may not be adjusted by small increments. The total capacity offered does not necessarily match the predetermined supply block perfectly. A bid acceptance procedure is needed to assure the overall economic efficiency for the host utility in serving its ratepayers.

Evaluation of Bids

The basic principle of bid evaluation is that all price and nonprice factors should be given proper consideration based on their respective effects on the host utility. Two approaches have been proposed to assess the various factors in a bid to supply electric generating capacity. In California, bids are evaluated solely in term of bid price while other nonprice factors are expressed as binding constraints. In Maine, as in most states, a merit selection system assigns different weights to various price and nonprice factors.

There is no fundamental difference between a binding constraint and a weighting system for a particular nonprice factor. A binding constraint is essentially a weighting system consisting only of extreme values. For example, a binding constraint on dispatchability is similar to a weighting system that assigns a weight of one to those bids satisfying the dispatchability requirement, and an extremely large negative number to those bids not meeting the dispatchability constraint. The large negative number makes those bids uncompetitive with other bids, essentially excluding them from further consideration. Neither of these two approaches has any inherent advantage or disadvantage over the other. This study recommends an adjusted-price evaluation approach that represents a compromise of these two evaluation methods. The adjusted-price evaluation method, based on the capacity and energy costs contained in a bid proposal and price adjustments reflecting differences in nonprice factors, derives an adjusted price for each bid. The adjusted price reflects the real cost to the host utility rather than a composite index far removed from the actual cost of generation capacity secured.

The adjusted-price evaluation method starts with the specification of the nonprice factors and their respective desirable levels based on the host utility's best supply options and system demand conditions. If a specific nonprice factor cannot be substituted or compensated for by other nonprice factors, minimum requirements of this factor should be specified. A merit-selection system implicitly assumes that different nonprice factors of a power purchase arrangement can be fully substituted for one another. In some instances, substitution is inappropriate or impossible. For example, the higher reliability of power supply cannot compensate for inferior quality if the quality does not meet the minimum requirements of operating household appliances.

For those factors where adjustments and substitutions are possible, costs reflecting such adjustments to satisfy preferred supply conditions are calculated and added to the original bid price. The adjusted prices can be compared directly with the avoided cost of the host utility, and the final rankings of all bids are determined accordingly. The host utility still faces the task of adjusting the bid price to reflect the differences of nonprice factors. This is similar to the establishment of a weighting system. The adjusted-price approach is a combination of both merit selection and binding constraint approaches.

Capacity and energy costs are probably the most important factors in a bid since they affect the cost of purchased power directly. They are also the most straightforward aspects of a bid evaluation. The methodologies used in calculating production cost for selecting the best supply options in a utility's capacity expansion plan can be applied similarly.[1] Based on the capacity and energy costs contained in a bid proposal, in combination with available data and procedures used by the host utility in calculating its avoided cost, the expected total payment streams of different bids over the contract period can be calculated and compared. For some utility solicitations, bidders are required to bid a single price representing a combination of capacity and energy costs. Under this circumstance, it is even easier to compare different bid prices.

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[1] A detailed discussion of the electric production cost models is available in Allen J. Wood and Bruce F. Wollenberg, Power Generation, Operation, and Control (New York: John Wiley & Sons, 1984), pp. 239-289. Discussions on the selection of generation technologies based on capacity cost and energy cost are also available. See John T. Wenders, "Peak Load Pricing in the Electric Utility Industry," Bell Journal of Economics 7 (Spring 1976): 231-241; and Michael A. Crew and Paul R. Kleindorfer, The Economics of Public Utility Regulation (Cambridge: The MIT Press, 1986).

Consideration of Nonprice Factors

Quality of Power

In addition to price, the quality of power and the compatibility of nonutility power sources with the host utility's generation system are also important considerations in a bid evaluation. The quality of power refers to the physical characteristics of electricity. Since the nonutility power producers are interconnected with the utility grid, safe interconnection and provision of power with acceptable quality are essential.[2] The minimum requirements for new power sources in modern utility grids include unit synchronization, stability, real power control, and reactive power management.[3] Synchronization of generators refers to the coordination of both the frequency and the phase of the alternating voltage variations.[4] Stability is the ability to maintain synchronization despite sudden increases and decreases in load, and despite possible loss of some generation or transmission facility. Real power control refers to the control of the movements of power actually consumed by customers.[5] Better real power control can reduce the system-wide generation cost and increase system stability.[6] In addition to real power production, electric power generating units are usually operated so as to supply reactive power as well.[7] Nonutility power producers are expected to manage their own

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[2] Standards and requirements concerning interconnection are well-developed. State PSCs have jurisdiction in this area, and current information does not indicate that outside suppliers have difficulties in meeting the interconnection requirements. See Michael D. Devine et al., Public Policy Issues of Decentralized Electricity Production (Norman, Oklahoma: Science and Public Policy Program, University of Oklahoma, 1984), pp. 3-32 to 3-38.

[3] Kevin Kelly et al., Some Economic Principles for Pricing Wheeled Power (Columbus, Ohio: The National Regulatory Research Institute, 1987), pp. 25-32.

[4] Ibid., p. 25.

[5] Ibid., p. 26.

[6] Ibid., p. 28.

[7] Ibid., p. 30.

reactive power and provide their own reactive power compensation so as not to impose on the host utility system.[8]

The quality of power represents the necessary requirements in integrating nonutility power with the utility system. Consideration of this factor is best reflected in binding constraints since power with unsatisfactory quality is of little value and may be detrimental in some instances to the host utility and ratepayers.[9]

Reliability

The concept of reliability refers to the ability to supply capacity and energy over an extended period of time. The methodology of determining and evaluating power supply reliability and its application in utility capacity planning are well developed.[10] Incorporating a less reliable outside power producer into the utility system can have three adverse effects. First, it affects the utility's ability to serve its customers if the host utility does not have adequate back-up power available. To meet unexpected demand for back-up power, the host utility may have to purchase outside power, operate peaking units, or choose other expensive supply options. Second, it creates additional operation and maintenance problems for the utility's own generation facilities since the host utility does not know when its own generation facilities may be needed. Third, unreliable power sources make the host utility's capacity expansion planning more difficult.

The utilities typically use some probabilistic indices to define a specific reliability level that they deem desirable and reasonable based on system characteristics, industrial practices, and regulatory policies. This

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[8] Ibid., p. 32.

[9] It should be noted that QFs, IPPs, and other power producers generally supply power with acceptable quality and have no adverse effects on the stability and availability of the utility system. See Devine et al., Public Policy Issues of Decentralized Electricity Production, pp. 3-36 to 3-38.

[10] See Mohan Munasinghe, The Economics of Power System Reliability and Planning (Baltimore: The Johns Hopkins University Press, 1979); and Allen J. Wood and Bruce F. Wollenberg, Power Generation, Operation, and Control.

"equilibrium" reliability serves as a baseline reliability level from which bid-price adjustments can be made. In evaluating a bid to supply electric power, the consideration of reliability should not be limited to the availability of individual generation facilities. The overall effects on system reliability of the host utility and service reliability to the ratepayers are more important considerations. But the determination of the relationship between the reliability of individual supply alternatives and system reliability is a complex matter. Sometimes a proxy for reliability, such as capacity factor, instead of the impact on system reliability, is used in bid evaluation. It is important to recognize that such a proxy is an imperfect representation of the actual reliability effect of the individual supply alternatives. Two generating facilities with the same capacity factor might have quite different effects on the service reliability of the utility system.

Two approaches have been used to evaluate the different reliability levels associated with different bids. A payment discount can be applied for less reliable power sources. For example, the California PUC specifies that QFs must maintain an 80 percent capacity factor during the summer on-peaking period in order to receive the full capacity credit.[11] This capacity factor equals the expected "reliability" of a combustion turbine; that is, the best alternative for the host utility to meet its peak demand. Those generation facilities with lower capacity factors receive only part or none of the full capacity credit.

In addition to price discounts for less reliable power sources, another method is to adjust the capacity cost in the bid price upward for a less reliable generation facility in bid evaluation. By doing this, a less reliable power source is ranked lower than a more reliable power source, assuming other things are equal. The rationale for this approach is that additional capacity is needed for a less reliable facility to maintain its ability to supply electricity at the equilibrium reliability level. The

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[11] Michael H. Rothkopf et al., Designing PURPA Power Purchase Auctions: Theory and Practice (Berkeley, California: Energy Analysis Program, Lawrence Berkeley Laboratory, 1987), p. 29.

additional capacity needed is equivalent to an increase in unit capacity cost.[12] A highly simplified and stylized example is provided here. A two MW windmill with a 40 percent capacity factor is determined to be providing only one MW "equivalent capacity" in maintaining the system-wide 80 percent capacity factor. The unit capacity cost of the windmill should be doubled to reflect the difference in reliability.[13]

Dispatchability

Dispatchability refers to the degree of the host utility's control over electricity supplied by nonutility power producers. For technical and economical reasons, an outside producer may not be able to provide dispatchable capacity to the host utility. For example, the timing and amount of power produced by a cogenerated petroleum refinery is decided largely by the demand for petroleum products and the storage facilities of the refinery rather than the electricity demand of the host utility. As a result, the availability of electric energy from the oil refinery may not coincide with the variable power needs of the host utility. Placing a value on dispatchability is not easy. It depends on the supply and demand conditions of the host utility as well as the location of nonutility power sources within the utility transmission and distribution network. The benefits of a dispatchable power source to the host utility are the reduction of spinning reserve, the improvement of load-following capability, and the decrease of minimum loading of other generation plants.[14] Since it is difficult to measure the exact value of dispatchability among different

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[12] It should be noted that this increase in capacity cost only affects the bid evaluation and has no effect on the payment received by the bidder with less reliable power.

[13] Details on the calculation of "reliability-adjusted" unit capacity cost can be found in Michael A. Crew and Paul R. Kleindorfer, "Electricity Pricing and Plant Mix under Supply and Demand Uncertainty," Conference on Issues in Public Utility Pricing and Regulation, Rutgers University, Newark, New Jersey, 1981.

[14] Rothkopf et al., <u>Designing PURPA Power Purchase Auctions: Theory and Practice</u>, p. 27.

bids, it may be advisable to specify several distinct categories of requirements for dispatchability and to conduct separate solicitations for different categories of projects.[15]

Transmission Requirement

The electric generating facilities located in different areas inside or outside the host utility's service territory can impose different transmission requirements on the host utility. Since a utility generally does not control the transmission facilities outside its service territory, the nonutility power producer is responsible for securing the necessary transmission access outside the host utility's service area. The costs of securing such transmission service are likely to be reflected in the bid price. In this section, the discussion centers on the costs of transmission requirements within the host utility's service area.

The costs of transmission requirements within the host utility's service territory fall into one of three main categories. First, a nonutility power producer's electric output may impose a significant burden on existing transmission facilities so that capital investment must be made to increase transmission capacity. Second, additional transmission line losses are likely to occur. Third, the host utility may face additional constraints such as the foregoing of economy energy exchange and reduction in dispatchability and reliability.[16] The capital cost of needed transmission facilities, transmission line losses, and reduced operational flexibility are real costs to the host utility and have to be taken into consideration in evaluating different bids. The host utility can adopt a scoring system which assigns different bonus points to the bids with projects located in desirable transmission areas.[17]

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[15] Ibid., p. 28.
[16] See Ralph Turvey, Optimal Pricing and Investment in Electricity Supply (Cambridge: The MIT Press, 1968), pp. 21-22.
[17] Rothkopf et al., Designing PURPA Power Purchase Auctions: Theory and Practice, pp. 32-33.

Technical Feasibility

In addition to price and nonprice factors explicitly specified in a bid proposal, the host utility needs to evaluate the likelihood that these conditions will be realized. The host utility needs to make sure that the generation facilities proposed by nonutility power producers will be completed and operated as planned. Such an assessment includes both the technical feasibility of a generation facility and the financing and management expertise of the nonutility power producers.

The technologies commonly used by QFs, IPPs, and utility subsidiaries include steam and gas turbine generators, combined cycle, windmills, geothermal, low head hydro, and solar energy. These technologies exhibit different technical and operational characteristics: many of them are mature technologies with a high degree of commercialization. A few still need additional improvement and are not ready for large-scale application while others are somewhere in between.[18] It is best to separate the assessment of technical feasibility from other considerations in a bid evaluation. Bids with low technical feasibility either should be excluded from bidding or treated in a separate solicitation with different financing arrangements to assure that the project sponsors assume a large portion of financial responsibility in case of technical failure.

Financing and Management Expertise

Financing risk has two aspects. Inadequate financing increases the cost of capital and makes the project less likely to succeed when it encounters unexpected difficulties such as drastic cost overruns and delays, more stringent environmental regulations, or higher interest rates.

Inadequate financing also can lead to front-loaded pricing. A bid proposal with front-loaded pricing requires the host utility to pay more

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[18] Edison Electric Institute, Economics Division, Strategic Implications of Alternative Electric Generation Technologies (Washington, D. C.: Edison Electric Institute, 1984), pp. 5-12.

than its avoided cost at the beginning of the project and to pay less than avoided cost in later years. Front-loaded pricing is not unusual and can be beneficial in cases where a host utility's financing cost is significantly lower than that of a nonutility power producer. Some projects, though economical in the long-run, may not be feasible without front-loaded pricing for a nonutility producer with limited financial resources. Thus, the outright prohibition of front-loaded pricing may reduce the number of potential bidders and increase the expected cost to the host utility. There is no need to reject a bid simply because of its requirement of front-loaded financing. Nevertheless, some minimum financing qualifications need to be set for all bidders. After all, the capital market is more likely to provide the capital required if the bid proposal has sufficient technical and economic merits.

Besides prohibiting front-loaded pricing, several forms of performance warranties guarding against front-loaded pricing and poor operation performance are also available.[19] A cash deposit from the nonutility power producer can be required. The host utility can ask for a lien on the facility so that it can take over the project in the case of default. The host utility also can require a discount in the bid price for bidders with front-loaded pricing.

A nonutility producer's management expertise in constructing and operating generation facilities affects the probability of completing the project on time and within budget. If the nonutility producer is inexperienced or incompetent, cost overruns, unscheduled outages, and default are more likely. Therefore, it is better to have certain minimum requirements concerning the management expertise of all bidders. A synopsis of bidder qualifications and power supply performance requirements of Central Maine Power is provided in appendix B.

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[19] Rothkopf et al., Designing PURPA Power Purchase Auctions: Theory and Practice, pp. 30-31.

Acceptance of Bids

Once all bids are evaluated and ranked, the next step is to select the winning bidders based on the ranking. If the amounts of capacity offered by the nonutility power producers are perfectly divisible and not subject to minimum-size restriction, the acceptance of bids is a routine procedure. All bids are accepted in the order of increasing adjusted unit cost until the supply block is fulfilled completely.

However, the amounts of capacity offered are generally subject to some size limitations, and rarely match perfectly with the host utility's supply block. Two explanations can be provided for this. First, the suitable sites, turbines, boilers, and other equipment associated with certain generation technologies have certain minimum-size requirements. Second, there are economies of scale associated with the planning, design, construction, and operation of generation facilities. The costs of planning, financing, and managing the project are pretty much fixed regardless of the size of capacity offered. Some nonutility power producers, therefore, find it either physically impossible to build smaller-sized generation facilities or possible only at a higher unit cost. For example, a cogenerator may be willing to offer four megawatts of capacity out of his five-megawatt facility if it can recover the total cost of the entire facility. Some may argue that the cogenerator can sell the remaining one megawatt of capacity to another buyer. But there is no guarantee that the cogenerator can do so and recover 20 percent of the total cost from another buyer. The cogenerator is likely to charge a high unit price for the four-megawatt bid if it is willing to submit such a bid.

The problem of matching a fixed supply block with various bids with discrete amounts of capacity offered is similar to the "knapsack problem" referred to in the operations research literature.[20] Several remedies to alleviate this lumpiness problem have been proposed.[21] The utility can

[20] Ibid., appendix C.
[21] Ibid., pp. 34-39.

allow or negotiate with a marginal bidder to reduce its offered capacity without changing its bid price so that total capacity accepted does not exceed the predetermined supply block. Another possibility is to specify a broad range of capacity amounts as the acceptable supply blocks. For example, Southern California Edison accepts bids below its avoided cost as long as the total capacity accepted does not exceed 110 percent of the supply block.[22] The host utility may also consider allowing and encouraging potential bidders to submit multiple bids with smaller capacity from a single power source.[23] Finally, the host utility can develop a demand function for outside power supply beyond the predetermined supply block. These alternatives can alleviate the lumpiness problem to a certain degree. In this study a bid acceptance procedure based on the principle of developing a demand function for outside power supply is suggested.

Though the lumpiness of capacity offered is a real concern and substantial efforts have been devoted to solving it, it is important to put this issue in perspective. The supply block is not an absolute limit to the amount of total capacity accepted in a utility solicitation. A bid acceptance procedure aimed at meeting the supply block exactly is likely to induce inefficiency. There are several reasons why it is unnecessary to treat the supply block as an absolute capacity limit. First, the supply block is derived from a host utility's load forecast and resource plan. Since a load forecast is rarely perfect, some uncertainties exist concerning the exact size of the supply block. Second, the supply block rarely equals the total system demand of the host utility. Any capacity provided beyond the supply block may have incremental value although the value may be less than avoided cost. In other words, the utility has a demand function for nonutility power above and beyond the predetermined supply block. If the bid price is less than the incremental values of capacity (the utility's avoided cost of supplying electricity), it can be economical to accept bids beyond the supply block.

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[22] Ibid., p. 38.
[23] As discussed in chapter 6, the submission of multiple bids based on a single power source is not a desirable approach.

The criterion in selecting a bid acceptance procedure should be the overall efficiency of the utility system rather than simply minimizing the total cost of meeting the supply block. Based on this criterion, the following bid acceptance procedure is suggested. Figure 7-1 is used to illustrate this proposed bid acceptance procedure.

1. The utility derives a demand function for nonutility power supply (avoided cost schedule) based on its own supply resources and demand conditions.

2. All bids are ranked according to the adjusted cost (based on the bid capacity and energy costs and differences in nonprice factors).

3. Bids with an adjusted cost higher than the utility's avoided cost are rejected except for the one with an adjusted price lower than avoided cost for part of its capacity offered. (Bid 5 and Bid 6 are rejected.)

4. The bids are accepted in the order of increasing adjusted cost provided that total capacity accepted does not exceed the supply block. (Bids 1, 2, and 3 are accepted.)

5. For the marginal bid (bid 4), the utility can negotiate to "downsize" the capacity offered up to the level where avoided cost is higher than the bid price. (The capacity of bid 4 becomes CD' instead of CD.)

6. If "downsizing" is unsuccessful, the utility needs to determine the net cost effect of the whole utility system (comparing block WXYZ with the sum of blocks ZST and NQWR.)[24]

7. If block WXYZ is greater than the sum of blocks ZST and NQWR, bid 4 should be accepted. In this case, the cost savings can be obtained in accepting bid 4 outweigh the additional payments to the winning bidders. Otherwise bid 4 should be rejected.

The bid acceptance procedure discussed above is presented in a highly simplified manner. There are certain practical difficulties involved in

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[24] The determination of the net cost effect under a second-price bidding procedure is different from that of a fist-price bidding procedure. Here, a second-price bidding procedure is assumed.

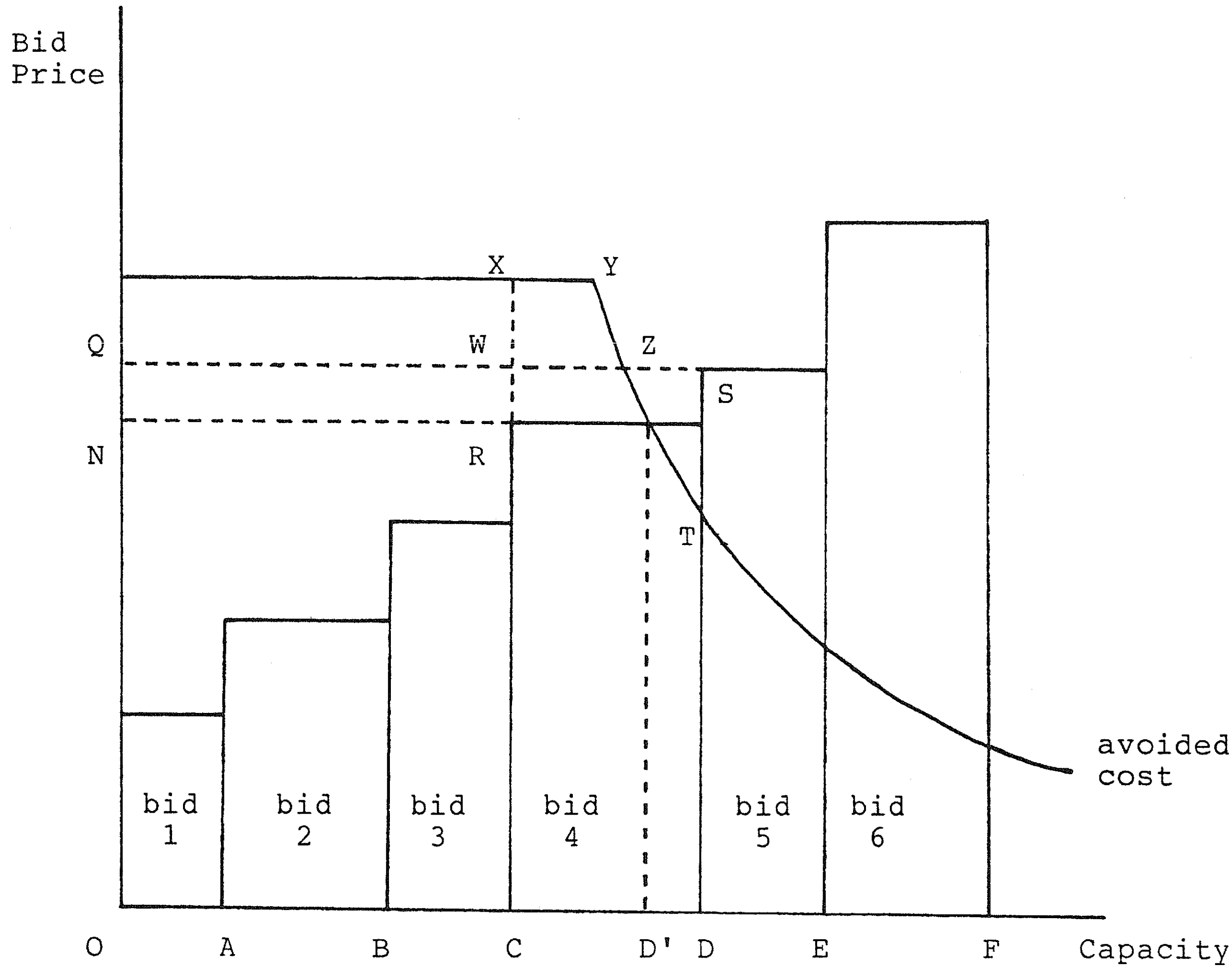

Fig. 7-1 A proposed bid acceptance procedure

applying this bid acceptance procedure. For example, it may not be easy to determine the avoided cost associated with capacityexceeding the supply block. It may also be difficult to measure the net cost effect of accepting capacity beyond the supply block. Regulators and utilities need to consider the costs and feasibility in obtaining more cost-related information before adopting a specific bid acceptance procedure.

CHAPTER 8

SOME POLICY ISSUES

The success of a bidding program depends not only on the design of the bidding procedure, but also on the market environment underlying the bidding process. A utility solicitation cannot achieve the highest economic efficiency improvement unless there is real and fair competition among all potential nonutility power producers and host utilities. There are three policy goals in promoting a fair and competitive bidding environment.

First, a fair and competitive bidding environment would not provide preferential treatment to one or even several nonutility power producers, nor purposely diminish the inherent technical or economic advantages of any power producer. However, the use of competitive bidding to secure new generation capacity cannot be separated from other public policy considerations concerning the electric industry. Some deviations from the ideal competitive environment may be justified. Preferential treatment can be accorded certain nonutility power producers if such preferential treatment is based on clear demonstration of public interest and affirmation of market failures and shortcomings of existing regulatory interventions.

A second policy goal in setting up a bidding program is to maintain an equitable relationship between the host utility and the nonutility power producers. The introduction of competitive bidding need not produce the side effects of promoting the development of nonutility power producers at the expense of the electric utilities, or of allowing the host utility to favor its own subsidiaries in bid preparation and evaluation.[1]

The third policy goal in a bidding program is to encourage maximum participation by the host utilities and the nonutility power producers in

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[1] In this instance, a utility can sidestep the traditional regulatory oversights concerning construction cost recovery and prudent operating expense through the use of competitive bidding.

the solicitation process. As the number of participants increases, the possibility of selecting the least-cost options also increases.

Based on these three policy goals, this chapter provides suggestions on several public policy issues related to the implementation of competitive bidding in securing new electric generating capacity. These policy issues include bidding by conservation and load management programs, set-aside capacity for renewable and indigenous resources, bidding by the host utility, bidding by utility subsidiaries, avoided cost that is binding on the host utility, and the necessity of transmission access for implementing competitive bidding.

Conservation and Load Management Programs

This issue deals with the proper role of conservation and load management programs (LMPs) in a state's competitive bidding programs. It is generally agreed that conservation and LMPs can play a role in meeting this nation's future electricity needs and utility participation in these areas is justified under certain circumstances.[2] However, the inherent differences between the load management programs and the supply-side options may warrant that separate solicitations be conducted and that different evaluation criteria be applied.

We first discuss why it is desirable to allow conservation and LMPs to participate in a bidding process. Ideally, the decision about whether to include conservation and LMPs in a utility solicitation with other supply options should not affect the resource plans of the host utility. The host

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[2] It is argued that "...if the marketplace is providing ratepayers with pecuniary incentives to 'purchase' energy conservation when it is in their self interest and if ratepayers are rational and unobstructed in making decisions by either market or regulatory barriers, the role of utilities in subsidizing and promoting energy conservation should be kept to a minimum." See Kenneth W. Costello, "Ten Myths of Energy Conservation," Public Utilities Fortnightly, 11 March 1987, pp. 19-22.; and id., "Should Electric Utilities Try to 'Unsell' Electricity? and More," presented at the NARUC National Conference on Least Cost Utility Planning, Aspen, Colorado, 11-13 April 1988.

utility can either include conservation and LMPs in its resource planning process in calculating avoided cost, or it can allow conservation and LMPs to participate directly in the bidding process without considering them in determining avoided cost. If conservation and LMPs are included in the internal resource planning process of the host utility and are found to be more economical than the utility's own supply options, they become the best alternatives. The utility's avoided cost then should reflect the cost of conservation and LMPs. Conservation and LMPs, as the host utility's best alternatives, can compete with nonutility power producers in a competitive solicitation. If conservation and LMPs are less economical than the host utility's own supply options, they are excluded in calculating the utility's avoided cost. There is no need to subject conservation and LMPs programs to further competition from nonutility supply options since they already were rejected in the host utility's internal resource planning process. In either case, conservation and LMPs are afforded a fair and equitable competition with the nonutility power producers just as they are afforded such an opportunity in directly participating in a utility solicitation.

But there is likely to be more than one conservation and load management alternative available. The best way to identify all possible demand-side options is to ask all interested parties to submit bids; otherwise, the host utility may not be able to identify the best alternatives or can do so only with substantial time and effort. A better policy is to allow demand-side options to participate in utility solicitations.

The next issue is whether conservation and LMPs can be solicited and evaluated in ways similar to other supply options. There are several reasons why it is best to conduct bidding separately for demand-side and supply-side options. First, the identification and quantification of the effects of conservation and LMPs are more difficult than those of supply-side options. Even though a host utility cannot predict perfectly the capacity factor of a generation facility offered by a nonutility power producer, there is no uncertainty about the realized operational performance of such a facility.

For most demand-side options, both the prediction about future performance and the identification of actual capacity and energy contributions to the host utility are rather speculative. For example, a building insulation program is projected to reduce peak load by thirty megawatts a year over the next ten years. It is difficult to ascertain whether the insulation program has indeed achieved this projected goal. A higher than expected rate of economic growth may cause a faster than expected rate of load growth, making the insulation program appear less effective. Conversely, a prolonged economic downturn may severely depress system demand and make the insulation program appear more effective than it really is.

Second, there is the "free rider" issue where some ratepayers would have made conservation and load-management investments without the proposed conservation and LMPs. Clearly, the effects of these load-management investments on the host utility should not be attributed to the proposed demand-side options. These effects should be explicitly identified, quantified, and excluded from the benefits of conservation and LMPs. There is no "free rider" issue associated with supply-side options.

Third, there are certain implicit costs associated with conservation and load management programs that are more difficult to quantify. For the host utility, capacity and energy payments to the nonutility power producers represent its total cost. But most conservation and load management programs invariably involve some costs from the ratepayers. For example, in a utility-sponsored heat-pump program, ratepayers may have to spend money to purchase a heat-pump to receive the benefits of reduced electricity consumption. Though the host utility does not have to pay this cost out of its own pocket, it still represents the real cost to society as a whole. Thus, such ratepayer costs must be considered part of the cost associated with demand-side options. Without including such costs, the cost of demand-side options may be underestimated.

Fourth, incentives for inefficient resource allocation may be created if demand-side options are paid an amount equal to the host utility's avoided cost. Ratepayers have an inherent incentive--savings in electricity bills--to adopt conservation and load management measures. If the host utility is required to pay an amount equal to the cost of the best supply options, ratepayers may essentially receive double payments. Then a situation might develop in which it may be financially rewarding for a ratepayer to adopt a specific conservation measure at a cost less than the total payment (savings in electric bill plus utility payment) received even if the cost of such a conservation measure is higher than the cost of the best supply-side options. From a broader perspective, a more expensive alternative (conservation) is selected over a less expensive alternative (the best supply-side option).[3] Thus, significant distortion in resource allocation can occur when a host utility is required to pay the same amount for both supply-side capacity and capacity-saved (demand-side options).[4]

Fifth, combining conservation measures and supply-side options in a single utility solicitation can lead to counterproductive conservation and load management programs.[5] For a supply-side option, the money paid to the selected nonutility power producer is generally proportional to the generation capacity and electric energy supplied. If the host utility were required to pay the provider of a conservation program in proportion to the capacity and energy saved, inefficient electricity use can result, creating more "savings" to sell. Obviously, the least energy-efficient ratepayers before the implementation of competitive bidding can get the largest payment.[6]

Based on the above discussion, the combination of demand-side and supply-side options may create numerous measurement and incentive problems. These problems would need to be overcome if the bidding program were to combine both demand-side and supply-side options.

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[3] Larry E. Ruff, "Least-cost Planning and Demand-side Management: Six Common Fallacies and One Simple Truth," Public Utilities Fortnightly, 28 April 1988, pp. 19-26.

[4] Ibid.

[5] Charles G. Stalon, "The Role of Conservation Programs in the Bidding NOPR (RM88-5)," Memorandum to Chairman Hesse and Commissioners Sousa, Trabandt and Naeve, 4 March 1988.

[6] Ibid.

Renewable Resource and Set-Aside Capacity

This section analyzes the desirability of setting aside a fixed amount of capacity to be supplied by renewable or indigenous resources. Some state bidding programs give such preference to renewable resources.[7] In our view, such preference is justified where clear advantages of renewable resources and indigenous resources are demonstrated and where current market and regulatory mechanisms have not reflected such advantages. Otherwise, such preferential treatment may induce economic inefficiency and actually become a subsidy from the ratepayers to the owners of renewable and indigenous resources.

An example can be provided to illustrate this point. A state bidding program may decide to set aside a fixed amount of supply block for generation facilities fueled by municipal solid waste based on the notion that burning solid waste alleviates a municipal waste disposal problem and reduces air pollution by replacing coal-burning power plants. The reduction of municipal waste and air pollution are desirable effects of such a policy. But such social externalities probably have been reflected in existing market and regulatory schemes. Presumably, the fuel cost of the trash-burning plant should have already reflected the benefits of reducing solid waste through a lower fuel cost for using municipal waste, or through a direct payment from the municipal authority for waste disposal. As for the reduction in air pollution, existing air quality control standards have, presumably, already accounted for the proper social value of clean air. Costs incurred by coal-burning power plants to meet such environmental standards are included in the bid prices of those nonutility power producers. Because the social externalities of a trash burning power plant are already included in the costs, and consequently in the bid prices of

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[7] For example, Michigan and New Jersey provide some preferential treatments for renewable resources or technologies. See National Independent Power Producers, Pricing a New Generation of Electric Power: A Report on Bidding (Washington, D. C.: National Independent Energy Producers, September 1987), appendix A.

nonutility power producers, there is no need to set aside an amount of capacity for facilities using municipal waste as fuel.

Bidding by the Host Utility

A separate question is whether a host utility should be allowed to bid in its own solicitation. First, we need to recognize that a host utility is already bidding through the publication of its avoided cost. This avoided cost schedule represents the cost of the host utility's best alternative in meeting the future demand for electricity. If the host utility submits a separate bid priced lower than the avoided cost contained in the RFP, the host utility obviously has not identified its best supply options and has overestimated its avoided cost. A lower avoided cost should be used instead. If the host utility submits a bid higher than its avoided cost, its bid will not be accepted anyway. There is no need to submit a separate bid.[8]

Another reason for not allowing a utility to bid is that the host utility may establish and apply nonprice evaluation criteria to favor its own bid.[9] Even though some regulatory procedures can be adopted to mitigate potential self-dealing problems, they may not prevent all potential abuses.[10] As a result, the issue of allowing the host utility to submit a separate bid boils down to the choice of giving electric utilities great discretion in implementing a bidding program if host utility bidding were prohibited, or of requiring more stringent regulatory oversight by state PSCs in the case host utility bidding were allowed. Clearly, the intricate details of bid evaluation and selection are better left in the hands of utilities than regulators. If the regulators or third parties are totally responsible for the evaluation and selection of all bids submitted, the host

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[8] Renee Haman-Guild and Jerry L. Pfeffer, "Competitive Bidding for New Electric Power Supplies: Deregulation or Reregulation?" Public Utilities Fortnightly, 17 September 1987, p. 17.

[9] Federal Energy Regulatory Commission, Notice of Proposed Rulemaking: Regulations Governing Bidding Programs, Docket No. RM88-5-000, p. 72.

[10] Ibid., pp. 72-74.

utility may be allowed to bid with other potential bidders. Under this circumstance, the host utility has no unfair advantages over other bidders.

It is also important to recognize that the prohibition of bidding by the host utility does not preclude it from building new generation facilities. If no outside bidders submit bids lower than the host utility's avoided cost, the utility is free to proceed with its regular power plant planning and construction activities. It is a questionable argument that the exclusion of bidding by the host utility essentially prevents the participation of the very supplier that is often the most experienced and most knowledgeable about the needs of the electric system and its customers.[11] On the contrary, the exclusion of host utility bidding can promote and assure a comprehensive resource planning effort by the host utility knowing that it can submit only one bid (the avoided cost).

Bidding by Utility Subsidiaries

In this section, we discuss the participation of utility subsidiaries in solicitations inside and outside its parent company's service territory. Since the increase in the number of bidders (nonutility power producers) tends to make the market for electricity generation capacity more competitive (and results in a lower expected cost to the host utility), subsidiaries can be allowed to bid outside their parent company's service territory.

There are some concerns that the market power possessed by the parent company may create certain unfair advantages for the utility subsidiary even in the bidding outside its parent utility's service territory.[12] For example, a parent company may enter into an agreement with another utility to set up each other's generation subsidiary and to purchase power

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[11] This argument is advanced by the FERC in Notice of Proposed Rulemaking: Regulations Governing Bidding Programs, p. 72.
[12] See Federal Energy Regulatory Commission, Office of Economic Policy, Regulating Independent Power Producers: A Policy Analysis (Washington, D. C.: Federal Energy Regulatory Commission, 1987), pp. 57-66.

reciprocally at inflated prices from one another, or to use bid evaluation schemes favoring the selection of affiliated subsidiaries.[13] Similar arrangements with more than two utilities can also be arranged.[14] Another potential problem is cost misallocation and cross subsidy between the regulated business and the power generation subsidiary.[15] Since part of the parent company's business is still cost-regulated while the revenue to the power generation subsidiary is unregulated and determined by market conditions, the parent company can increase the profit of its subsidiary at the expense of ratepayers by allocating costs incurred by the subsidiary to the regulated business.

In our view, these potential abuses generally involve more than one utility, and the common interest to collude and the cooperation needed to allocate extra profits may not materialize considering that the utilities are being regulated by different state PSCs and face diverse supply and demand conditions. Any potential abuses are probably easier to detect than those involving only one utility. At any rate, the cost misallocation problem with utility subsidiaries is not unique to bidding.

Bidding by a utility subsidiary within the service territory of a parent company is another matter. The potential for self-dealing and the efforts needed to overcome such abuses are probably too great to justify a policy allowing a subsidiary to bid in the parent company's service territory. There are no net advantages in allowing a subsidiary to bid in its parent's service territory. A utility subsidiary generally has no real technical or economic advantages over its parent company within the service territory. If a subsidiary can provide generation capacity cheaper than the parent company's avoided cost, the parent (host utility) should be able to supply power at the lower cost. The avoided cost, then, should be reduced accordingly.

Obviously, there are situations where the subsidiary, as an independent power producer, is subject to different regulatory oversight than

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[13] Ibid., p. 58.
[14] Ibid., pp. 58-60.
[15] Ibid., p. 61.

traditional regulation accords to utility-owned power plants. In this regard, the subsidiary arrangement may provide certain financial advantages or reduce regulatory risk to the host utility. The risk to ratepayers may also be reduced if a fixed-price power purchase contract is entered into with the subsidiary. In short, if there are substantial advantages in doing so and potential self-dealing problems can be overcome, it may be desirable to allow the subsidiaries to bid in the host utility's solicitation.

However, if the subsidiary is allowed to bid, conflict of interest and preferential treatment issues become unavoidable. Under this circumstance, the parent company does not need to collude with other utilities to provide unfair advantages to its subsidiary. The incentive for unfair and preferential arrangements is stronger. The parent company can give preferential treatment to its subsidiary in numerous ways. The subsidiary can receive unfair advantages in bid preparation even if the bid evaluation and selection by the host utility are fairly conducted. To prevent such abuses, the regulators either have to undertake additional major responsibilities of bid solicitation and evaluation or they must institute numerous safeguards. Both approaches are costly and therefore probably unattractive.

Binding Avoided-Cost on Host Utility

This issue concerns the implication of avoided cost on the cost recovery of the host utility's own supply options. Avoided cost reflects the cost of the best alternative available to the host utility. Since it constitutes the upper limit for payment to the nonutility power producers, a fair treatment would require that the avoided cost also constitute an upper limit for the cost of adding new supply capacity by the host utility.[16]

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[16] According to FERC Commissioner Charles G. Stalon, "If utilities are to build in direct or indirect competition with other bidders, they should be subject to the same price discipline. . .that the bidding scheme imposes. . ." See "FERC Commissioners Debate Electric Restructuring," Public Utilities Fortnightly, 31 March 1988, p. 41.

The host utility's avoided cost generally includes both capacity cost and energy and operating cost components. As discussed in chapter 6, some cost escalation arrangements may be warranted for the energy and operating cost component in a power purchase contract for nonutility power producers. For efficiency and fairness, it would seem reasonable to require that there be a symmetry between the cost escalation possibilities for the host utility (operating under traditional cost-based regulation) and nonutility bidders (operating under contracts). Alternatively, the nonutility bids could be weighted in such a way as to generally account for any differences in cost escalation provisions.

There are several advantages in making the avoided cost binding on the host utility's own supply options. A binding avoided cost provides an incentive for the host utility to prepare a comprehensive and realistic resource plan in calculating its avoided cost.[17] Without a binding avoided cost, the host utility may post an artificially lower avoided cost to prevent the nonutility power producers from winning the bid and becoming the supplier of new generation capacity.[18] In doing so, the cost of electricity to ratepayers may increase since the actual cost of building a power plant by the host utility can be much higher than the best bid submitted by the nonutility power producers. If the avoided cost schedule were binding, the host utility would have an incentive to reveal its best unbiased estimate of avoided cost. The most efficient providers would be selected regardless of whether they are utilities or nonutility power producers.

A binding avoided cost also serves to control the construction and operating cost of the utility generation plants in the event that the host utility cannot obtain capacity from nonutility producers and has to build the power plant itself. For example, the Massachusetts Executive Office of Energy Resources proposed that a utility's cost recovery of building its own power plant be capped at a predetermined avoided cost. Additional costs

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[17] National Independent Energy Producers, Pricing New Generation of Electric Power: A Report on Bidding, pp. 4-7.
[18] William R. Meade, "Competitive Bidding and the Regulatory Balancing Act," Public Utilities Fortnightly, 17 September 1987, p. 29.

incurred would be borne by the shareholders, while cost savings would be treated "below the line" giving shareholders the opportunity of earning higher returns for the utility's cost control efforts.[19]

Necessity of Transmission Access

The transmission access issue is at the heart of the current debate on the FERC proposed bidding regulation.[20] It is generally agreed that expanding transmission access can increase the number of potential bidders in a solicitation, and the probability of selecting more economic power producers outside the host utility's service territory. On the other hand, increased transmission access also affords the nonutility power producers access to a larger number of potential buyers (other utilities outside the service territory of the host utility) and reduces the monopsonistic power of the host utility.[21] Expanding transmission access and establishing a nondiscriminatory wheeling rate can help to realize the full potential of competitive bidding and improve the economic efficiency of electricity generation.

It is acknowledged this study does not treat the transmission access issue in the context of competitive bidding. This section tries to deal only with a more immediate concern: whether the current development of bidding programs can move forward and not be entirely contingent upon progress in resolving the transmission access issue. In other words, the question at hand is to know whether bidding implementation without federally-mandated transmission access can cause significant distortions to the results of bidding. The experience of bidding in several states so far does not appear to indicate that this is the case, suggesting that bidding

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[19] Ibid.
[20] "Transmission, Reliability Key Issues as Electric NOPR Debate Widens," Inside F.E.R.C., 26 September 1988, pp. 3-5.
[21] National Independent Energy Producers, Pricing New Generation of Electric Power: A Report on Bidding, pp. 4-9.

may not need to be put on hold pending the final resolution of the transmission access issue. Several reasons exist for this conclusion.

First, the state PSCs (for example, Maine and Massachusetts) can require mandatory transmission access for potential bidders within the state boundary.[22] If the states perceive the need for intrastate transmission access to be provided in a utility solicitation, they can choose to do so within their own jurisdiction. Second, the total amount of capacity offered in a typical utility solicitation has been several times greater than the capacity solicited, and the capacity has been offered by a great number of diverse bidders.[23] Under this circumstance, any further increase in the number of bidders might not significantly increase the degree of competition among nonutility power producers. The expected cost to the host utilities may not change much as a result of expanding transmission access.

Third, a losing bidder in a utility solicitation may still have a hard time competing in another utility's service territory except where there are drastic cost differences among nonutility producers in different regions.[24] Fourth, the need for electric generating capacity and the host utility solicitations are not one-time-only events. Those potential bidders, even though currently not viable due to insufficient transmission access, can still compete in future utility solicitations when the constraint on access is reduced.

Additionally, a recent article has argued that regulators and the utility industry should refrain from demanding a complete and final treatment of the transmission issue be a prerequisite to bidding.[25] The argument goes that such a requirement could backfire, prompting the FERC to

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[22] See chapter 2 for more discussions on state bidding programs.
[23] The experience of selected utility solicitations can be found in chapter 2 of this report.
[24] The investigation of regional cost differences among nonutility power producers is outside the scope of this study. No assumptions were made in this regard.
[25] Philip R. O'Connor and Gerald M. Keenan, "The Politics and Policy of Access to the Electric Utility Transmission System," Public Utilities Fortnightly, 7 July 1988, pp. 11-17.

adopt a common carrier oriented transmission policy which may not be beneficial to the utility and ratepayers.

Obviously, then, transmission access is an important element to the success of competitive bidding, and the efforts devoted in resolving this issue should be continued and even expanded. Nevertheless, the development of bidding regulations need not be delayed or unduly impeded by the lack of progress in the transmission access issue.

CHAPTER 9

CONCLUSIONS

This study favorably considers competitive bidding as a viable alternative to traditional regulation in securing new generation capacity. Despite its pitfalls and limitations, the use of bidding can provide significant advantages in remedying some implementation problems of PURPA, in providing an efficient and equitable way of supplying future generation capacity, and, after some years of bidding experience, in affording an empirical and reasoned basis for discussions of deregulation in the electric industry.

The pitfalls of bidding include, among other things, price fixing, market share rotation schemes, and the so-called "hungry-firm phenomenon". These pitfalls can be eliminated or mitigated, in most instances, by a properly designed bidding program and rigorous enforcement of antitrust laws.

The benefits of bidding are many. Bidding is a more comprehensive approach than individual negotiations or administrative procedures currently applied in selecting and pricing nonutility power. Bidding also introduces market discipline into electricity generation so utilities and nonutility power producers have stronger incentives to control costs. Furthermore, bidding allows ratepayers to share directly in cost savings gained in substituting nonutility for utility generation.

Existing state bidding regulations show many similarities and diversities. Given the unique conditions of the electric demand and supply in each state, the diverse approaches adopted by states concerning competitive bidding are expected and even desirable. The proposed FERC regulations on competitive bidding also afford considerable flexibility to state PSCs. The FERC requirements deal primarily with the information availability of a bidding program to all potential bidders rather than the substance of a bidding procedure. The details of implementing bidding is, in essence, up to the state PSCs.

This study has offered a number of suggestions about the design of a state bidding program. These suggestions are not offered as constraints on the implementation of state bidding programs. They serve mainly as illustrations of the important concepts, criteria, and considerations involved in setting up a bidding program.

Economic efficiency is here the main criterion in designing a bidding program. The consideration of economic efficiency in bidding to supply new generation capacity is best reflected in four aspects: incentive compatibility, Pareto efficiency, reduction of moral hazard, and allocation of risk. Based on the characteristics of the potential bidders and the host utility, a second-price sealed bidding procedure with a post-bidding fixed-price power purchase contract with an energy cost sharing arrangement appears to work best to satisfy these four criteria.

The evaluation of bids should consider all price and nonprice factors based on their effects on the host utility with the price factor given predominant considerations. Nonprice factors include, among other things, quality of power, dispatchability, reliability, transmission requirements, and project risk.

One possible impediment to the implementation of competitive bidding is the legal uncertainty involved in the inclusion of nonQF entities in the bidding process. A number of legal problems such as the certification of a market-based rate as just and reasonable under Federal Power Act and the division of federal-state jurisdiction concerning independent power producers need to be resolved.

Several policy suggestions are also provided in this study. Due to the inherent differences between supply-side and demand-side options, bidding by conservation and load management programs is best held separately and evaluated using different sets of criteria. Preferential treatment can be provided for bidders with certain characteristics, such as renewable resources, granted that the social externalities of such resources are demonstrated and current market mechanisms and regulatory interventions are incapable of reflecting them.

The host utility, in general, need not be allowed to bid in its own solicitation since it is already bidding through the published avoided cost schedule. The subsidiaries of a utility can choose to bid freely outside the service territory of their parent company. The avoided cost publicized by the host utility should be binding on its own supply options; otherwise, the host utility may not prepare a comprehensive, unbiased, and realistic resource plan in deriving avoided cost. Even though expanding transmission access can increase the participation of nonutility power producers and host utilities in the bidding process (and may improve the efficiency of bidding results), the development of bidding can move forward and need not be contingent upon the progress or full resolution of transmission-related issues.

Given the continuing development of competitive bidding at the federal and state levels, new issues and different approaches are likely to emerge. As a result, it is more important to develop an objective and analytic framework for solving new problems than to design particular solutions that may become obsolete as the electric industry changes.

APPENDIX A

A SUMMARY OF THE RANKING FORMULA USED BY CENTRAL MAINE POWER

We selected the ranking formula of Central Maine Power (CMP) since CMP is probably the most experienced utility in bid solicitation. Its ranking formula reflects the bid evaluation factors of most utilities. As emphasized by CMP, the ranking formula itself does not determine the selection of winning bids. All bids are still subject to the bidder qualifications and power supply performance requirements established by CMP. These qualifications and requirements are discussed in appendix B.

Five distinct indexes comprised the ranking formula used by CMP for its December 1987 solicitation: a capacity index, an endurance index, a security index, a price index, and an operation index. A bid proposal's overall rating is the product of the individual index scores and can range from a low of 1.2 to a high of 330.0.

A bid proposal has a capacity index of two if the proposed facility has a capacity factor of 80 percent or higher. Otherwise, the capacity index has a value of one. If the bidder is willing to pledge, in an irrevocable letter of credit, sufficient funds to protect CMP and its customers from the project's poor performance, the bid receives an endurance score of two; otherwise, an endurance score of one is awarded.

The security index evaluates the proposal's payment schedule and ranges from a low of 1.2 to a high of 2.5. Bid proposals without levelized pricing receive a security index score of 2.5. Proposals with levelized or front-loading pricing receive a lower score whose value depends on the liquidity of security guarantees posted by the bidders. Since a levelized or front-loaded price means CMP will pay more for power than its avoided cost during the project's early service years, bidders must provide some security guarantees that equal the amount of excess payments. Posting a highly liquid security guarantee can increase the security index up to a maximum value of two. So a bid offering levelized pricing without a liquid security guarantee may receive a score only three-fifths as high as an identical bid with a more liquid security guarantee and only one-half as high as an identical bid without levelized-pricing.

The operating index assesses the dispatchability, maintenance scheduling, and peak/off-peak power production. It ranges from a low value of 1.5 to a high value of 3, with most points apportioned to the peak/off-peak level of power production. A bid proposal receives an extra .3 points if the project is dispatchable and another .2 points if CMP can schedule maintenance. The proposal receives either 1.5, 1.0, or .5 points depending on the proportion of total power production that is delivered during peak hours. In short, CMP prefers on-peak production and therefore awards fewer points to projects that supply power during off-peak periods.

The price index takes the percentage savings between CMP's avoided cost and the bid price, divides the percentage by ten, and then adds one to derive the final score. A bid receives a low value of one if its bid equals the avoided cost and receives the highest value, eleven, if it offers the power for free.

APPENDIX B

A SYNOPSIS OF BIDDER QUALIFICATIONS AND POWER SUPPLY PERFORMANCE REQUIREMENTS OF CENTRAL MAINE POWER

This appendix summarizes the current requirements and conditions of Central Maine Power (CMP) in assuring all bidders are qualified power producers and are providing good performance after being selected. In general, CMP requires written statements from a registered professional engineer, a certified public accountant, and a lawyer all supporting the bidder's ability to construct, operate, and finance the proposed facility properly. CMP also uses financial incentives to guard against poor performance by the chosen bidders. If worse came to worst, CMP may terminate the power supply contract.

Along with the bid proposal, a bidder must submit an engineering-economic feasibility study of the proposed facilities. The study must describe in full detail the facility's design, construction schedule, equipment, and fuel needs, and its potential environmental effects. CMP requires the study to be reviewed by a register professional engineer who must support the study's results in writing. The bidder's legal counsel must prepare a report stating what rights, permits, licenses, and other legal documents are needed and when they should be procured. A certified public accountant must prepare statements explaining the project's financing. This includes letters of commitment from all financial backers and partners or past proof of the bidder's ability to market stock and partnership interests. The experience and expertise of the project manager and architect-engineer must be documented as well. All this information must accompany a bid before it can be considered complete by CMP.

Before accepting any power deliveries, CMP inspects the facility to determine whether it meets the standards of prudent electrical practice. If necessary adjustments are not made in a reasonable period of time, CMP can terminate the contract. To guard against contract termination by the bidder before making any deliveries, CMP imposes a lump-sum damage charge equal to the current New England Power Pool (NEPOOL) capability responsibility adjustment charge multiplied by the facility's design capacity. The bidder must pledge this amount in a manner suitable to CMP shortly after signing the power agreement; otherwise, CMP can terminate the contract.

Once the facility passes inspection and is delivering power, CMP extracts payments for under-performance to protect ratepayers and to promote superior performance by the winning bidder. Since CMP wants most outside power to be delivered during peak hours, the bidder must agree to keep the facility at an on peak capacity factor (OPCF) of 80 percent or better. If the facility fails to meet this condition, CMP allows a "cure period" to upgrade the performance. During this period, CMP pays a rate equal to avoided energy rates for power delivered. Following the cure period, CMP downgrades the facility's capacity rating unless the facility's performance meets the OPCF condition. The utility levies a charge tied to the amount it downgraded the facility's capacity rating and the NEPOOL charge. Should the problem persist and the facility's OPCF drop to 50 percent or less for an extended period. CMP can terminate the contract and levy the damage charge. Besides committing itself to a specific amount of capacity, the bidder must also commit to deliver a minimum amount of energy each year. A charge of one cent a kilowatt-hour is assessed for each kilowatt-hour below the minimum amount promised.

To protect ratepayers from being overcharged for electricity, CMP requires any bidder receiving front-loaded pricing to secure the amount of excess payment in a manner acceptable to CMP. This must be done before any power deliveries are made. The amount of front-loading (excess payment) is revised monthly. If the bidder fails to maintain a proper balance during the agreement, CMP can realize upon any and all security posted for the excess payment. Until the sponsor properly secures the excess payment, CMP accepts power deliveries but pays only short-term avoided energy rates.

CMP has the right to dispatch power from the bidder's facility within agreed technical limits. The bidder is responsible for protecting its own equipment. The bidder must agree to change, at its own expense, the facility, interconnection equipment, and protective relays to meet changes in the CMP system. CMP reserves the right to disconnect the bidder's facility during system emergencies, or if the bidder fails to maintain its equipment according to prudent electrical practice.

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