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BIDDING FOR POWER: THE EMERGENCE OF COMPETITIVE BIDDING IN ELECTRIC GENERATION

March 1990

NATIONAL INDEPENDENT ENERGY PRODUCERS

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The National Independent Energy Producers (NIEP) is an association of leaders in the electric energy industry committed to shaping the long-term future of competitive electric power generation. Member companies generate electricity for sale to utilities and develop cogeneration and alternative energy projects for a variety of users. NIEP membership is comprised of both publicly traded and privately held corporations that develop projects generating electricity from hydro, biomass, geothermal, gas, wood, coal, municipal solid waste, and solar technologies.

BIDDING FOR POWER: THE EMERGENCE OF COMPETITIVE BIDDING IN ELECTRIC GENERATION is the second in a planned series of **NIEP ENERGY FOR THE FUTURE** Working Papers.

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GLOSSARY OF REGULATORY COMMISSION AND UTILITY ABBREVIATIONS

Regulatory Commissions:

BPU	—Board of Public Utilities
DPUC	—Department of Public Utility Control
MDPU	—Massachusetts Department of Public Utilities
PSB	—Public Service Board
PSC	—Public Service Commission
PUC	—Public Utility Commission
VSCC	—Virginia State Corporation Commission
WUTC	—Washington Utilities and Transportation Commission

Utilities:

AMP	—American Municipal Power, OH
Bangor	—Bangor Hydro Company, ME
CMP	—Central Maine Power, ME
CPSC	—Colorado Public Service Company, CO
Delmarva	—Delmarva Power, DE & MD
FP&L	—Florida Power & Light, FL
Green Mountain	—Green Mountain Power Company, VT
HECO	—Hawaiian Electric Company, HI
IMPA	—Indiana Municipal Power Agency, IN
JCP&L	—Jersey Central Power & Light, NJ
LILCO	—Long Island Lighting Company, NY
Met Ed	—Metropolitan Edison, PA
NCPA	—Northern California Power Agency, CA
NEP	—New England Power Company, MA
NIMO	—Niagara-Mohawk Power Company, NY
PSE&G	—Public Service Electric & Gas, NJ
PSNH	—Public Service Company of New Hampshire, NH
Puget Sound	—Puget Sound Power & Light, WA
Sam Rayburn	—Sam Rayburn Electric Cooperative, TX
Seminole	—Seminole Electric Cooperative, FL
Va. Pwr.	—Virginia Power Company, VA
WMECO	—Western Massachusetts Electric Company, MA

EXECUTIVE SUMMARY

In the 1980s, the electric generation industry in the United States made a major transition away from monopoly regulation and toward market competition. For most of the industry's history, the dominant method for pricing electric energy has been cost-of-service ratemaking. Cost-of-service ratemaking is based on the premises that generation is a natural monopoly and the electric energy consumer should underwrite the utility's cost of providing that service. As a result, it was closely regulated by state regulatory commissions. As long as the funds were not imprudently spent, utilities could recover from their ratepayers the costs, including overruns, incurred in the construction and operation of power plants.

Operating within the secure perimeters of franchised retail territories, utilities in the 1950s, 1960s, and early 1970s provided reliable power at declining or stable rates. As a result, they enjoyed, in essence, a truce with state public service commissions that became known as the "regulatory compact."

Beginning with the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978 and accelerating over the last six years, this system, along with the economic assumptions supporting it, has been challenged by new competitive forces. A vast array of new suppliers has come onto the scene prepared to offer power under fixed-price contracts that shift construction and operating risks from ratepayers to third-party investors. In the process, the concept of electric generation as a natural monopoly was discredited.

Since 1984, public service commissions and/or utilities in 27 states have adopted or are developing competitive procurement systems that, together with the access already granted by PURPA, are restructuring the nation's electric power markets. Through the end of 1989, contracts to build power plants capable of generating 5,743 megawatts of power have been awarded to third parties through competitive bidding. And, in the 1990s, the pace of bidding will accelerate. New generation contracts awarded through bidding may account for 50 percent or more of the 100-150,000 MW of new electric power that the U.S. Department of Energy predicts will be needed by the end of the decade. In short, competitive bidding will replace cost-of-service ratemaking in the 1990s as the dominant process for determining the supplier and pricing of new electric generation.

How did this change come about?

In the late 1970s and 1980s, the traditional electric utility industry was shaken by rate shocks, excess capacity, cost overruns, and subsequent prudence reviews, which led to disallowances of expenditures that utilities believed were reasonable at the time they were made. In the decade after the passage of PURPA, utilities cancelled or abandoned more than 75,000 MW of generating capacity the bulk of it nuclear, that was either planned or under construction. Morgan Stanley & Company estimates that disallowances imposed by state regulators over the past five years alone amount to $13 billion, or about 10 percent of all utility capital investment during this period.[1]

As a result, many utilities, cautioned by their investment bankers, have become reluctant to build new cost-of-service plants under the terms of traditional regulation. Utility executives explain that, while the upside from their successes is limited by a profit cap, the downside from their failures may be unlimited, pushing some into bankruptcy.[2] This view is reinforced by bankers who remind these executives that many utilities regained fiscal strength only after they ceased building new generation.

For many utilities, therefore, the prudent strategy has been to buy, rather than build, new capacity. Officials at Virginia Power, for example, which has contracted for more third-party power than any other utility, estimate that the 2,086 MW that the utility purchased in its 1988 solicitation saved the company over $2.3 billion in financing requirements, preventing significant adverse impacts on cash flow and earnings.[3] For some utilities, the capital saved by not building can be more profitably invested in the projects of their unregulated affiliates.[4]

At the same time, developers of qualifying facilities (QFs), unleashed by the passage of PURPA, stepped into the vacuum created by the utility retreat, offering to build power plants on a competitive basis to serve new electricity demand. These non-utility suppliers were aided by a shift in the economies of scale of generation from large, central-station nuclear and coal plants with long lead-times and large capital risks toward more flexible cogeneration and other smaller-sized, less capital-intensive technologies with shorter lead-times.

PURPA required traditional utilities to purchase electric energy from cogeneration and small power production facilities at not more than "avoided cost"[5] and left implementation of this requirement largely to state regulatory bodies. Almost immediately, two problems developed with this system. First, disputes arose regarding the proper methodology for calculating avoided cost. Second, as the independent power industry matured, the supply offered in some states exceeded the capacity needed. Allocating capacity on a first-come, first-served or other arbitrary basis meant that the most efficient producer would be selected only by chance.

In the 1980's, some states and utilities turned to competitive bidding as a convenient and fair method of addressing these two problems. In 1984, Central Maine Power (CMP), the first utility to initiate bidding, did so as a defensive move after the Maine Public Service Commission adopted avoided-cost rates for QFs based on the cost of a nuclear power plant. CMP feared that these rates would unleash a flood of suppliers seeking contracts in excess of CMP's need for capacity.[6] By substituting market pricing for administratively determined pricing, bidding offered a way to reduce purchase prices below the avoided cost levels which would have prevailed in the absence of bidding. By allocating capacity needs to winners of a competition, bidding also offered a more objective, less contentious pricing method and a more rational means of finding the most effective supplier.

Bidding was also compatible with the free market, anti-regulation political ideology of the 1980's. State regulators, perhaps less influenced by this sentiment than the Federal Energy Regulatory Commission (FERC), nevertheless saw the opportunity to use market pricing information as a benchmark for utility plants in cost recovery proceedings. Many state regulators, faced with a proposal for a cost-of-service plant from a regulated utility, began to ask: "Can we get a better deal for the ratepayer and reduce our regulatory burdens by having the utility bid for rather than build capacity?"

In reviewing the development of bidding in the 1980's, three paradoxes stand out:

- While bidding has been the subject of a highly controversial Notice of Proposed Rulemaking (NOPR) by FERC which aimed at establishing guidelines for bidding programs in the states, the focus of bidding initiatives has been on the states. FERC has been forced to play "catch-up" with the states, a situation which will probably continue in the future, since FERC's NOPR has been deferred indefinitely.
- While PURPA opened the door to competition, which in turn spawned bidding, the adoption of "all source" bidding in conjunction with proposed changes in the Public Utility Holding Company Act may render PURPA requirements less relevant as IPPs (non-utility suppliers which do not qualify for rights under PURPA) crowd out QFs in bids for capacity.
- While over 27,000 MW of non-utility capacity was on-line by the end of 1989, only approximately 500 MW of projects selected through bidding have had time to complete development and actually deliver the power requested. It is, therefore, too soon to pass judgment on the success of competitive bidding. In the meantime, however, states are moving forward. The competition genie is out of the bottle and no one—at FERC, in the Congress, or among states—is likely to stop its progress in the short term.

WHY THIS STUDY WAS WRITTEN

Bidding programs for new generating capacity are now being widely adopted, but many growing pains remain. Given the lack of industry experience through the whole cycle—bid, selection, financing, construction, and operation—it is important to carefully track the progress of bidding programs, learn from their successes and mistakes, and seize opportunities to perfect them.

With this goal in mind, the National Independent Energy Producers (NIEP) has prepared this report on competitive bidding in the electric power generation market in the United States. This report was written in response to intense interest in the development of competitive bidding by federal and state regulators, the Congress, electric utilities, and wholesale generation companies. It is based on the results of a telephone survey of the utility regulatory commissions in all 50 states. In addition, a comprehensive questionnaire was sent to all public service commissions and electric utilities that have bidding programs or were actively developing them. The response to the questionnaires was 100 percent. Data from the survey are supplemented by the bidding experiences of NIEP members, available public testimony, interviews with industry sources, state bidding orders, and requests for proposals (RFPs).[7]

ORGANIZATION OF STUDY

This study is organized into six parts:

- The Executive Summary, which includes a summary of the findings and recommendations of the study;
- Results of bidding survey, Chapters I-IV;
- Analysis of policy issues in competitive bidding, Chapters V-XI;
- The Guidelines for Competitive Bidding Programs, which describes in detail the study's recommendations based on lessons learned from bidding programs to date, Chapter XII;
- Appendices, which include discussion of case studies mentioned in the text; and
- Tables, which provide a comprehensive summary of the data discussed in Chapters I-IV.

FINDINGS

This report identifies a number of issues and trends that will shape the structure of competitive bidding in the 1990s:

- *Even in states that have adopted it, bidding has not been the exclusive means of securing new capacity.* This study shows that utilities are continuing to build traditional cost-of-service facilities or make purchases outside of bidding in bid states. Contracting outside bidding for smaller QFs, demand-side management (DSM) projects, waste-to-energy projects, imported power, emergency power, and other exceptions is permitted in most states. In Massachusetts, Maine, and Virginia, regulators have recently approved purchases of power outside bidding. *See* Chapter IX for a detailed discussion of this point.

  Some state commissions have shown a preference for a mixed system of contract and rate-based power. Colorado, for example, limits contracts with QFs to 20% of needed capacity. While some utilities claim that bidding eliminates their opportunity to build to meet their own capacity needs, this has not been true in major bid states to date. For example, in Virginia, the state where the most megawatts have been awarded through bidding, approximately one quarter of the new capacity commissioned since 1987 has been in the form of traditional rate-based facilities.
- *In RFPs held to date, there have been no shortages of wholesale generators willing to provide capacity at market-determined prices.*[8] In the 34 bidding solicitations where the filing period had closed as of December 31, 1989, 1086 projects accounting for approximately 56,000 MW have been bid to fill up to 7310 MW of needed capacity.[9] A typical RFP received proposals for ten times the amount of capacity requested.[10] *See* Chapter III for more detail on this point.

- *The success of bidding, measured by the number of completed plants, cannot yet be determined.* Other than in Connecticut, Maine, and Hawaii, there has not been sufficient time since solicitations were completed for bid projects to come on-line. In Connecticut, no projects have failed or been delayed to date. In Maine, only four projects totaling 5.8 MW have failed; the rest have come on-line or are proceeding on schedule. The 326 MW awarded to developers in Hawaiian Electric Company's (HECO) RFP have not suffered significant delay.

  In all other solicitations where the commercial operations date has not yet arrived, 9 projects totaling 435.7 MW have been canceled as of December 31, 1989. This failure can largely be attributed to the design of RFPs which permitted contracts to be awarded to bidders before they had chosen sites or, in the case of projects outside the service area of the host utility, before bidders had confirmed that they could gain access to another utility's transmission lines to carry the power to the utility's borders. *See* Chapter III for a detailed discussion of these findings.
- *While bidding was originally limited to QFs, most bidding programs now accept proposals from all sources.* IPPs, DSM projects, and utility sales are playing a larger role in bidding. Utility participation in bidding has expanded rapidly in the last two years. Utilities participate directly through bidding system sales, power-from-wholesale facilities, portions of rate-based facilities, and as utility affiliates, usually through joint ventures with QFs. *See* Chapter IV for a detailed discussion.
- *There is no evidence that bidding has made utilities lose control of their fuel mix.* In the RFPs held to date, a wide range of technologies has been represented in the bids submitted, although coal and natural gas fired projects have been awarded the most contracts. Where natural gas projects have been the preferred technology for electric generation, this has been a function of declining gas prices, low capital costs, and improving gas turbine technology, not a result of bidding per se. States and utilities have shown that they can structure bidding to meet a variety of fuel preferences in state or utility resource plans.[11] *See* Chapter III for a detailed discussion.
- *The failure of most bidding systems to take into account environmental externalities is reflected in the poor performance of renewable and demand side management (DSM) projects in terms of megawatts awarded in competitions to date.* Renewable energy projects, including hydro, geothermal, resource recovery, wood and other biomass, account for 20.7% of total MWs awarded to bidders through June 1, 1989. Over the last two years, hydro projects have had a lower rate of bidding success than any other technology. This experience highlights the difficulties faced by hydro projects which must endure the "double jeopardy" of the cost and uncertainty of a multi-year state and federal licensing process and the challenge of competing for capacity credits once regulatory approval is received. While DSM projects have been successful bidders in Maine and New Jersey solicitations, utility acceptance of DSM is retarded by the financial disincentives embedded in utility rate regulation. For example, most utilities, when they buy "negawatts" rather than megawatts, are not compensated for lost revenue resulting from reduction in sales.
- *The majority of bidding programs do not contain any measures to prevent self-dealing or cross-subsidization.* As utility participation in bidding increases, the issue of how to prevent potential abuse of market power becomes more acute. Non-utility suppliers advocate the development of safeguards against the transfer of assets or services from a utility to its affiliate. Such cross-subsidization would give the affiliate an unfair competitive advantage and be unfair to ratepayers.

  Experience in the states covers the spectrum from reliance on traditional state regulatory oversight to adoption of preemptive rules to reduce or eliminate the possibility of anti-competitive practices. Only New Jersey prohibits utility affiliates from selling to their parents; however, this moratorium is only for a three-year period, at which time it will be reviewed.[12] In a number of states, "affiliate" statutes provide safeguards against cross-subsidization. For example, by state order in Virginia, a regulated utility is not permitted to provide any services to its unregulated affiliate.

  With respect to self-dealing, only two bidding programs require a third party to select winning bidders: Colorado and New York.[13] New York, however, requires third-party selection only if the host utility affiliate is participating.[14] The Connecticut D.P.U.C. selects winners after receiving the recommendations of its utility, which evaluates the bid.[15]

  Few state commissions have taken explicit steps to protect proprietary information supplied by bidders from use by utilities or their affiliates when they are competing against bidders in other solicitations. *See* Chapter VII for a detailed discussion.
- *The fairness of "build vs. buy" comparisons by utilities that want to build traditional cost-of-service plants in bid states is an emerging issue.* The integrity of the competitive generation market may depend on a fair and accurate comparison of traditional cost-of-service plants proposed by utilities and the proposals of unrelated suppliers. Utility evaluation methodology, if not filed in advance with the public service commissions and opened to public review, could be subject to manipulation to favor the utility proposal. *See* Chapter X for a detailed discussion.
- *In states that have adopted bidding, few have changed their treatment of the cost of utility-built generation.* In those instances where the RFP requires the utility to establish a benchmark price and the proposed utility facility is selected to build the capacity over other bidders, only Colorado will hold the utility to the benchmark price.[16] At best, the other state commissions will use the price established through bidding as a guideline during subsequent cost-recovery proceedings. The Massachusetts' DPU, however, has recently proposed a bidding program where utilities will be required to submit sealed bids like third party suppliers and be held to

the bid price during cost-recovery.[17] *See* Chapter IX for detailed a discussion.

- *Most bidding programs provide little data about transmission access.* Most bidding programs fail to provide data about transmission access and pricing and leave bidders to negotiate wheeling arrangements on their own. Information about transmission capacity, rates, and terms and conditions is rarely included in RFPs. *See* Chapter VIII for a detailed discussion.

- *IPPs are facing major legislative and regulatory barriers as they attempt to participate in bidding.* It is doubtful that QFs alone can produce enough power to meet the needs of the competitive generation market in the 1990s because of the diminishing number of large steam hosts and the difficulty in curtailing steam loads for peaking plants. An estimated 25 percent of power needed in the 1990's will be in the form of peaking capacity.[18] Non-QF suppliers, such as IPPs, which could supply this power, face major obstacles. These include the Public Utility Holding Company Act of 1935, state regulation of IPPs as utilities, and the largely untested FERC regulation of IPPs under the Federal Power Act.

RECOMMENDATIONS

On the basis of its review of competitive bidding to date, NIEP developed guidelines for competitive bidding programs. These guidelines are summarized below:

- *The public should participate in the development of bidding programs.* Regardless of whether a regulatory commission or a utility initiates a bidding program, the public should have an opportunity to comment on the development of bidding. Commissions should include public participation in all key phases in the development of the bidding program, as has been done in such states as Massachusetts, New York, and New Jersey. Public participation provides an important protection for all participants: the regulatory commission, ratepayers, host utility, and bidders. It permits officials responsible for bidding to learn from the experience of other bidding programs; helps to ensure that bidding remains consistent with the state's electricity resource plan and its efficiency and reliability objectives; and finally, eliminates most grounds for potential claims of unfairness in the bidding process.

- *Utility cost-of-service plants should be held to their "bid" price.* When utilities decide to issue an RFP for new capacity, they should be required to develop a "build" proposal that is consistent with the pricing and other terms and conditions of the RFP and submit it in a sealed package to the public service commission at the same time or before the bidders' responses to the RFP are due. If, when the bids are opened, it is determined that the utility proposal is the best supply option (based on cost and non-price factors), the utility should be required to build and be held to its proposed price when it seeks cost recovery from ratepayers. To provide incentives for maximum efficiency, the utility should receive the benchmark price whether its actual costs are either above or below the proposal.

- *Contracts signed outside of bidding should not undermine bidding program.* One of the important roles of state regulatory commissions is to ensure that contracts signed outside of bidding do not undermine the fairness of the bidding program. During the public review of the bidding program, utilities must justify why they are withholding any capacity from bidding. Should contracts be signed outside of bidding, the price paid for the power should be at or below the price established in the most recent RFP or the avoided cost if no RFP has been held. In addition, these contracts should be subject to the same terms and conditions as contracts awarded through bidding.

- *State commissions should give pre-approval of contracts for new generating facilities.* Under traditional cost-of-service regulation, utility planning and construction of new plants were subject only to after-the-fact review by the regulatory commission. This system has led to two problems: uncertainty for the utility over its ability to recover costs; and a lack of a timely opportunity for losing bidders to challenge the utility's cost proposal. It also leads utilities to include "regulatory out" clauses in power purchase agreements which relieve them of the obligation to make contract payments if pass-through of costs is denied. These clauses may become an obstacle to the financing of power projects. *See* Section II G of the Guidelines.

  If a host utility's facility appears to be the preferred supplier, the commission's review of the utility's cost recovery requests should be conducted at the same time that the commission considers the utility's petition for approval of construction of the plant. This concurrent review will ensure that alternative suppliers have an opportunity before construction begins to test the cost assumptions of the utility. The Massachusetts Department of Public Utilities enacted such a rule on October 28, 1988.[19] Utility-built facilities approved under this system would not be rate-based and therefore not subject to the profit-cap on the utility's regulated rate-of-return.

  When a non-utility supplier wins the bid, preapproval of contracts provides some assurance that the payment stream under the contract has been found to be in the public interest and therefore is not likely to be interrupted by state action after the fact. The Michigan legislature passed legislation requiring that such approvals be binding on future commissions.[20] In New Jersey, contracts do not become operative until approval of the pricing terms by the Board of Public Utilities, and the BPU has issued an order stating its intention that such approval not be subject to reconsideration in rate proceedings.[21]

- *Transmission access should be assured.* For ratepayers to receive the full benefit of a competitive generation market, wholesale suppliers need predictable access to and pricing of the use of transmission facilities controlled by utilities. While application must be tailored to specific conditions in the states, state regulatory commissions, as a general rule, should make transmission access within the state a mandatory condition of bidding programs. The general policies for transmission access within each state should at a minimum require that:

i. Utilities within the same power pool or state should be required to wheel power from winning bidders to the host utility at non-discriminatory rates;
ii. The host utility should be required to wheel power "out" of its service territory for losing bidders;
iii. When a utility or its affiliates are participating in bidding in adjacent service territories, it should be required to wheel power in its service territory to any adjacent service territories regardless of whether or not the adjacent service territory is holding a bid solicitation.

- *Protection should be given against the abuse of market power.* A competitive market is a delicate mechanism. For the maximum number of suppliers to participate, they must be confident that they know the rules of the competition and that the rules will be applied fairly. States should either enact strong cross-subsidy prevention measures and have the ability to enforce them, or the states should prohibit utilities and their affiliates from competing in their own bid solicitations. It may also be necessary to limit utility ownership in wholesale suppliers. In addition, states must be alert to prevent cross-subsidies when utilities or their affiliates participate in bidding *outside* their service territory.

- *Oversight of contracts signed under bidding.* While bidding programs should allow for flexibility in negotiating the exact terms and conditions of contracts signed between the utilities and third party suppliers, too much flexibility can allow for abuse. To insure a fair bidding program, commissions should review final contracts and approve them as is done in Massachusetts and New Jersey.

  For example, commissions should check that final contracts comply with the basic terms and conditions stated in the RFP, allowing for flexibility on specific terms and conditions in the contract which would not affect the evaluation of other proposals.

- *Treatment of renewable energy and demand-side management projects should be addressed.* In many bidding programs, renewable energy and demand-side management projects appear to have difficulty competing on an equal footing with other supply-side projects because of price and other bid evaluation factors. If a state decides that it wants to encourage the development of renewable energy projects and demand-side management, then it must make sure that provisions are made in the design of the bidding program to achieve this goal. For example, it may be necessary to require that the selection criteria be weighted to provide an incentive for these project types or that an RFP will be designed specifically for renewable energy or demand-side management projects. In short, the states and utilities should retain the flexibility to be very explicit about the mix of demand and supply-side projects they want and make sure that these preferences are reflected in the resource plan and the design of the bidding program.

Footnotes

[1] Mr. Jay Beatty, Morgan Stanley & Company, Public Utilities Group.

[2] *See* Comments of Edison Electric Institute, *Notice of Proposed Rulemaking: Regulations Governing Bidding Programs*, 53 Fed. Reg. 9,324 (1988) (to be codified 18 C.F.R. Parts 35 and 293) (Proposed March 16, 1988) *reprinted in* Federal Energy Regulatory Energy Reporter (CCH) Volume IV ¶ 32,455.

[3] Thomas E. Capps, President and Chief Executive Officer, Dominion Resources, Inc., speech given at Ponte Verda Beach, Florida, on May 21, 1989.

[4] *See infra* at Introduction for a discussion of the source of the data used in this study.

[5] Under PURPA, utilities must purchase power from qualifying facilities at the utility's avoided cost which is the "incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility . . . such utility would generate itself or purchase from another source." 18 C.F.R. §§ 292.101(6) 292.304; 16 U.S.C. 824a-3.

[6] Arthur Adelberg, General Counsel, Central Maine Power.

[7] The NIEP Bidding Questionnaire is described more fully in the Introduction. Unless cited to another source, all data in this study came from the NIEP Bidding Questionnaire and subsequent follow-up interviews.

[8] The term wholesale generators as used in this report includes QFs, independent power producers, utilities and utility affiliates.

[9] According to the NIEP Bidding Questionnaire, 56,085.2-56,268.2 MW were bid to fill 6139.7-7309.7 MW of requested capacity. The reason for the range in numbers is that some RFPS could accommodate different levels of capacity depending on the year in which it was offered.

[10] *Id. See also* Table IV.

[11] CMP, for example, did not award contracts to any wood or gas projects in its first four solicitations because of fuel supply concerns. Virginia Power, between its first and second solicitations, successfully shifted the emphasis from gas to coal projects by changing evaluation and pricing criteria.

[12] *See* State of New Jersey Board of Public Utilities, *In the Matter of Consideration and Determination of Cogeneration and Small Power Producer Standards Pursuant to the Public Utility Regulatory Policies Act of 1978: Stipulation of Settlement*, Docket No. 8010-687B, 33 35 (July 1, 1988) (*hereinafter* New Jersey Docket No. 8010-687B).

[13] California gives utilities the option of having a third party select the winning bidder when the utility affiliate is a participant in the RFP. *See* California Public Utilities Commission, *Decision No. 87-0560*, pp. 16-18 (May 28, 1989).

[14] *See* State of New York Public Service Commission, *Proceeding on Motion of the Commission to Examine the Plans for Meeting Future Electricity Needs in New York State: Opinion and Order Concerning Bidding, Avoided Cost Pricing, and Wheeling Issues*, Opinion No. 88-15, 13 17 (June 3, 1988) (*hereinafter* N.Y. Order No. 88-15).

[15] *See* Regulations of Connecticut State Agencies, § 16-243a-6.

[16] *In Re: The Application of the Public Service Company of Colorado Regarding Cogeneration and Small Power Production Projects (Qualifying Facilities or QFs)*, Decision No. C88-736, 15 19 (June 9, 1988) (*hereinafter* Colorado Decision No. C88-736).

[17] *See* Commonwealth of Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities pursuant to Section 76 of Chapter 164 of the General Laws, into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities as defined in 220 C.M.R. 8.02*, D.P.U. 86-36-G (December 6, 1989) (*hereinafter* Mass. D.P.U. 86-36-G).

[18] Remarks by Dr. James Williams, RCG/Hagler, Bailly at NIEP Conference, October 1989.

[19] Under the Massachusetts rule, a utility must obtain approval for cost recovery for all major incremental investment in electric power generation facilities. Major incremental investments include the con-

struction of new generating plants, or capital expenditures made in connection with an existing plant if such expenditures would (a) materially extend the useful life of the plant, (b) materially increase the capacity of the plant, or (c) are expected to exceed $250,000 per megawatt of net maximum capacity to be expended during a single plant outage, or uninterrupted construction project of combination of closely related projects. An electric utility may only recover costs associated with major incremental investment in electric power generating facilities without prior approval if such expenditures are made on an existing plant and emergency conditions mandate the immediate commencement of construction is necessary. *See* Commonwealth of Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities on its own motion, pursuant to Section 76 of Chapter 164 of the General Laws, into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not Qualifying Facilities as defined in 220 C.M.R. 8.02*, D.P.U. 86-36-E, Appendix A, Rule 9.02 (October 28, 1988) (*hereinafter* Mass. D.P.U 86-36-E).

[20] Under the Michigan statute, once the Michigan Public Service Commission has approved a capacity payment in a contract with a QF, that decision shall not be reconsidered during the financing period of the project, which is considered 17.5 years. *See* Mich. Stats. Ann. § 22.13(6j)(13)(b).

[21] *See* New Jersey Docket No. 8010-687B.

I. INTRODUCTION

The National Independent Energy Producers (NIEP) has been active in the development of policies for competitive bidding systems at the federal and state levels since 1986. In 1987, NIEP published *Pricing New Generation of Electric Power: A Report on Bidding*, a comprehensive study analyzing existing state bidding programs and presenting NIEP's position on key bidding policy issues. Since the release of this report, there has been rapid growth of interest in the use of competitive bidding systems for determining the pricing and supplier of new capacity. Subsequently, NIEP's members, state regulators, the Federal Energy Regulatory Commission (FERC), utilities, the Department of Energy, and the Congress have expressed a strong interest in all information about the rapidly changing landscape of bidding activity. Therefore, NIEP prepared this new edition of its study.

The study is based on data collected from every state regulatory commission and utility that has experimented with bidding. As in the previous study, the state regulatory commissions were telephoned to determine what, if any, bidding activity was occurring in that state. The study covers all types of bidding systems: Those initiated by the state public utility commissions through some type of rulemaking, and those initiated by private utilities, rural electric cooperatives and municipal utilities.

Copies of state regulatory commission rules on bidding and all requests for proposals (RFPs) were obtained and reviewed. A detailed questionnaire was sent to utilities and state regulatory commissions that had bidding programs or are developing them. *See* Appendix A for a copy of the NIEP Bidding Questionnaire.

The questionnaire collected information about the basic characteristics of each bidding program, roles of regulatory commissions and utilities in the development and implementation of bidding, policies on participation in bidding, evaluation methods, contracting practices, prevention of market power abuses, and transmission access problems; challenges to bid outcomes by losing bidders; contracting outside bidding; and results of the RFPs held to date.

This report identifies the major trends suggested by the responses to the questionnaire and other sources, discusses problems associated with those trends that have been identified by bidding participants, and suggests recommendations on how to make bidding a more effective instrument of a competitive generation market.

The survey of the status of competitive bidding in each state is current as of December 31, 1989, as are the statistics on the RFPs issued by December 31, 1989. However, data collection for the detailed questionnaire on each RFP issued was completed on June 1, 1989. Therefore, any RFPs that have been issued or completed since June 1, 1989 are not covered.

By June 1, 1989, the regulatory commissions of New York and New Jersey had issued bidding rules to which their utilities were responding.[1] Both states were in the process of approving the individual RFPs submitted by their utilities. Because significant changes were expected in the proposed utility RFPs, the questionnaire was completed using the state regulations rather than the individual utility RFPs.

It was also decided to include Washington State's proposed bidding rule in the study, in spite of the fact that it was in the development phase on June 1, 1989.[2]

Footnotes

[1] *See* State of New Jersey Docket No. 8010-687B; N.Y. Order No. 88-15.

[2] *See* Washington Utilities and Transportation, *In the Matter of Adopting Chapter 480-107 WAC Relating to Electric Companies Purchase of Electricity from Qualifying Facilities and Independent Power Producers and Purchase of Electrical Savings From Conservation Suppliers; and Repealing WAC 480-105-001; WAC 480-105-005 WAC 480-105-010, WAC 480-105-020, WAC 480-105-030, WAC 480-105-040, WAC 480-105-050, WAC 480-105-060, WAC 480-105-070, and WAC 480-105-080. Final Order Adopting Rules Permanently*, Docket No. U-89-2814-R (July 1989).

II.
CURRENT STATUS OF BIDDING PROGRAMS

Since 1984, 34 states, more than two thirds of the states, have adopted, are developing, or are considering using competitive procurement procedures to determine how their future electric generation needs will be met. *See* Table I—Summary of Bidding in the United States. The great majority of this interest has developed since 1987.

Summary of Bidding Activity

There are 27 states that have adopted or allowed bidding; are in the process of developing a bidding program; or have bidding RFPs initiated by utilities.[1] *See* Table II—Summary of Bidding Activity in Every State. A total of 41 RFPs have been issued by 30 utilities and 1 regulatory commission to date. *See* Table III—Status of All Bidding Programs Initiated by State Regulatory Commissions or Utilities.

Bidding Initiated by State Regulatory Commissions

Seven state regulatory commissions have developed and implemented bidding programs (California, Connecticut, Maine, Massachusetts, New Jersey, New York, and Washington). RFPs have been issued under six of the state-initiated programs and have affected 17 investor-owned utilities (IOUs). Seven more utilities are expected to issue RFPs under these state programs. California's bidding rule will affect three utilities when it is used.[2]

Bidding in other states varies. Vermont's first attempt to develop a bidding program failed when its proposed rules were not approved within the required time limit, but the state expects to try again. Two regulatory commissions, Texas and Montana, do not have specific rules regulating bidding. However, these commissions report that existing regulations in their states will allow utilities to initiate bidding if they choose, or in the case of Texas, competitive negotiation. Neither has done so to date.

Table I

SUMMARY OF BIDDING IN THE U.S.[1]

Number of States	Action
19	Have active bidding program initiated by state rule or utility(s)
13	Bidding currently being developed or studied[2]
1	Bidding allowed but no utilities have issued RFPs
9	Expressed an interest or plan to consider bidding in future[3]
16	No interest in bidding at this time
1	Rejected the concept of bidding

[1]See Table II for detailed breakdown. Data collected as of Dec. 31, 1989
[2]Seven of these states already have bidding RFPs initiated by utilities
[3]One of these states already has RFPs issued by two utilities

Even in states with formal bidding programs, utilities are given some latitude to develop RFPs consistent with individual needs. In these instances, the evaluation methodology and RFPs developed by the utility are usually reviewed by the public service commissions before they are used.[3]

Bidding Programs Initiated by Investor-Owned Utilities

Ten investor-owned utilities in 10 states have initiated bidding programs without formal advance approval by their public service commissions. These utilities are Florida Power and Light, Public Service Company of New Hampshire, Virginia Power, Sierra Pacific, Colorado Public Service Company (CPSC), Hawaiian Electric Company (HECO), New England Power Company (NEP), Central Vermont Public Service Company (CVPS), Green Mountain Power Company (GMP), and Delmarva Power in both Maryland and Delaware. *See* Table III.

The state commissions may review the bidding RFPs issued by such utilities after the fact in ratemaking cost recovery proceedings or in hearings on petitions for Certificates of Convenience and Necessity with respect to proposed new facilities by utilities.[4]

Bidding Programs Initiated by Public Power Systems and Rural Electric Cooperatives

Public power utilities and rural electric cooperatives have experienced little bidding activity to date. Only three public power utilities (Northern California Power Agency (NCPA), American Municipal Power (AMP) of Ohio, and Indiana Municipal Power Agency (IMPA)) and two rural electric cooperatives (Seminole and Sam Rayburn) have held bid solicitations. *See* Table III and Table IV. The majority of public power systems have excess capacity at this time and, therefore, have no need to bid for additional supply.

The Future of Bidding Activity

Four states are in the process of developing or approving bidding proposals (Delaware, Maryland, Michigan, and Vermont). Ten states are directing utilities within their jurisdiction to study or develop bidding programs or are reviewing bidding themselves (the District of Columbia, Georgia, Kansas, Michigan, Nevada, New Hampshire, Ohio, Oregon, Pennsylvania and Wisconsin). Of the ten, six require that utilities include bidding as an option in their least-cost planning process. In responses to the NIEP questionnaire, nine other states expressed an interest in taking action on bidding in the next several years (Arizona, Arkansas, Florida, Idaho, Illinois, Kentucky, North Carolina, South Carolina, and Utah). Although Florida has had two RFPs issued in the state, the Commission has not formally adopted a bidding policy to date. *See* Table II.

Table II

SUMMARY OF BIDDING ACTIVITIES IN EVERY STATE

State	No Action By Regulatory Commission	Reason For No Bidding Action Now: Excess Capacity	Prefer PURPA	Awaiting FERC Rule	Other	Consider In Future	Reviewing Idea Either Directly Or In LCP* Proceeding	Developing Program	Adopted Bidding But Not Used	Adopted Bidding & RFP Issued	RFP Issued Without PUC Approval/Rule	Notes
AL	X	X										
AK	X	X										
AZ		X				X*						Will be included in LCP.
AR		X				X*						Informal review.
CA									X*		X*	May review in 1990. NCPA (Public) issued RFP.
CO										X*		Rule in response to IOU submittal of bid RFP. RFP for O capacity.
CT										X*		Added DSM to rule in response to state law.
DC							X*					LCP for supply & demand under development—bidding an option.
DE								X*			X*	Delmarva both issued RFP without approval and submitted 2nd for review.
FL		X				X					X*	Seminole Rural Electric & FP&L issued RFPs— PUC will review results.
GA		X					X*					Also interest from 1 GA Coop/started LCP process. May review bidding.
HI											X*	HECO (IOU) issued 2 RFPs. PUC only approves contracts.
ID		X				X*						Will consider in 1990.
IL						X*						LCP order issued, will hold bidding workshops—Spring 1990.
IN	X	X									X*	IMPA (Public) issued RFP.
IA	X	X										
KS							X					
KY						X*						Will review under state wide planning and LCP process.
LA	X	X										
ME										X*		CMP issued 5 RFPs. Bangor Hydro issued one.
MD								X*			X*	Delmarva both issued a RFP without approval and submitted 2nd for review.
MA										X*	X*	9 RFPs 7 utilities under MDPU rule. 1 multi-state RFP-NEP.
MI								X*				Required Consumers Power to develop bidding program—on hold.
MN	X	X	X									
MS	X	X										
MO	X	X										
MT		X							X*			Montana rules allow bidding but no need yet.
NE	X	X			X*							No IOUs subject to PUC control.
NV							X				X*	Sierra Pacific (IOU) issued 2 RFPs. PUC now reviewing concept.
NH							X*				X*	PSNH (IOU) issued RFP. PUC open to idea but small capacity need.

* = See Notes/LCP = Least Cost Planning

Table II (Continued)

SUMMARY OF BIDDING ACTIVITIES IN EVERY STATE

State	No Action By Regulatory Commission	Reason For No Bidding Action Now: Excess Capacity	Prefer PURPA	Awaiting FERC Rule	Other	Consider In Future	Reviewing Idea Either Directly Or In LCP* Proceeding	Developing Program	Adopted Bidding But Not Used	Adopted Bidding & RFP Issued	RFP Issued Without PUC Approval/Role	Notes
NJ										X*		3 IOUs issued RFPs in 1989 under NJ rule.
NM	X	X		X								
NY										X*		3 IOUs issued RFPs, remaining 4 IOUs expected to issue RFPs in 1990.
NC		X				X						
ND	X	X										
OH		X					X*				X*	Ohio issued resource planning regs—bidding under review. AMP Ohio (Public) issued RFP.
OK	X	X										
OR							X*					LCP process asks utilities to suggest how bidding should be used.
PA				X			X*					Waiting for ALJ decision on cogen, Met Ed. filed RFP to force consideration.
RI	X				X*							Rejected concept of bidding.
SC		X	X	X		X						
SD	X	X										
TN	X	X										
TX									X*		X*	Rules allow bidding, No IOUs tried. Sam Rayburn Coop issued bid in 1989.
UT					X*	X						Will consider after merger rate proceedings.
VT								X*			X*	May reissue bid rule in 1990. 2 IOUs issued RFPs without PUC approval.
VA											X*	Va. Pwr. issued 1 competitive negotiation. 1st RFP without VSCC role, VSCC approved idea but not involved except for contract review. To date, Va. Pwr. issued 3 bids, 1 competitive negotiation.
WA										X*		Puget Sound issued RFP under new rule.
WV	X	X										
WI							X*					LCP required utilities to study bidding. IOUs rejected concept at this time. PUC to issue final decision.
WY	X	X										

* = See Notes/LCP = Least Cost Planning

Footnotes

[1] *See* Glossary of Regulatory and Utility Abbreviations for a listing of abbreviations for state regulatory commissions and utilities.

[2] California Public Utility Commission's answer to NIEP Bidding Questionnaire.

[3] *See, e.g., Proceeding on Motion of the Commission (established in Opinion No. 88-15) as to the guidelines for bidding to meet future electric capacity needs of Orange and Rockland Utilities, Inc.*, Opinion No. 89-7 (April 13, 1989); *Proceeding on Motion of the Commission (established in Opinion No. 88-15) as to the guidelines for bidding to meet future electric capacity needs of Long Island Lighting Company*, Opinion No. 89-18 (June 13, 1989); *Proceeding on Motion of the Commission (established in Opinion No. 88-15) as to the guidelines for bidding to meet future electric capacity needs of Niagara Mohawk Power Corporation*, Opinion No. 89-20 (June 19, 1989).

[4] *See, e.g., Application of Virginia Power for Approval of expenditures for new generation facilities pursuant to Va. Code §56-234.3 and for a Certificate of Public Convenience and Necessity pursuant to Va. Case §56.265.2*, Case No. PUE890007 (*hereinafter* Virginia Case No. PUE890007).

Table III

STATUS OF ALL BIDDING PROGRAMS INITIATED BY STATE REGULATORY COMMISSIONS OR UTILITIES[1]

State	Utility Subject to Bidding	Bidding Initiated By: Regulatory Comm.	Bidding Initiated By: Utility	Issued RFP	Year Issued	Selected Winners
CA	Pacific Gas & Electric	X		NO	-	-
	Southern California Edison	X		NO	-	-
	San Diego Gas & Electric	X		NO	-	-
	Northern California Power Agency		X	YES	1989	NO
CT	Connecticut Light & Power Co.[2]	X		YES	1986	YES
	United Illuminating	X		YES	1986	YES
CO	Colorado Public Service Company[3]		X	YES	1989	N.A.
DE/MD	Delmarva Power[4]		X	YES	1989	YES
FL	Seminole Electric Cooperative		X	YES	1988	YES
	Florida Power & Light		X	YES	1989	NO
HI	Hawaiian Electric Company		X	YES	1987-1st	YES
					1989-2nd	NO
IN	Indiana Municipal Power Agency		X	YES	1989	YES
ME	Central Maine Power	X		YES	1984-1st	YES
					1984-2nd	YES
					1987-3rd	YES
					1987-4th	CANCELLED
					1989-5th	NO
	Bangor Hydro			YES	1989	NO
MA	Boston Edison	X		YES	1987-1st	YES
					1989-2nd	YES
	Cambridge Electric Company	X		YES	1988	YES
	Commonwealth Edison Company	X		YES	1988	YES
	Eastern Edison Company	X		YES	1988-1st	YES
					1989-2nd	YES
	Fitchburg Electric Company	X		YES	1988	YES
	Nantucket Electric Company[5]	X		YES	1988-1st	N.A.
	Western Massachusetts Elec. Co.	X		YES	1988	NO
	New England Power		X	YES	1988	NO
NV	Sierra Pacific Power		X	YES	1988	YES
					1989	NO
NH	Public Service Company of NH		X	YES	1989	NO
NJ	Rockland Electric[6]	X		YES	1989	YES
	Atlantic Electric	X		NO	-	-
	Jersey Central Power & Light	X		YES	1989	YES
	Public Service Gas & Electric	X		YES	1989	NO
NY	Niagara Mohawk Power Company	X		YES	1989	NO
	Orange & Rockland Utilities	X		YES	1989	NO
	Rochester Gas & Electric	X		NO	-	-
	Long Island Lighting Company	X		YES	1989	NO
	Central Hudson Gas & Electric	X		NO	-	-
	Con Edison	X		NO	-	-
	NYS Electric & Gas	X		NO	-	-
OH	American Municipal Power		X	YES	1989	YES
TX	Sam Rayburn Electrical Coop		X	YES	1989	YES
VT	Central Vermont Public Ser. Co.		X	YES	1988	YES
	Green Mountain Power Company		X	YES	1988	YES
VA	Virginia Power Co.		X	YES	1987-1st	YES
					1988-2nd	YES
					1989-3rd	NO
WA	Puget Sound Power & Light	X		YES	1989	NO
	Pacific Power & Light Co.	X		NO	-	-
	Washington Water Power Co.	X		NO	-	-

[1]Bidding Programs Status as of December 31, 1989.
[2]The Connecticut DPUC initiated the competitive solicitation. The utilities were subject to the DPUC selections of winning bidders.
[3]Colorado Public Service issued an RFP under the Co. PSC order but no capacity was solicited.
[4]Delmarva issued an RFP before Commission approved their use of bidding.
[5]Nantucket Electric had no responses to its 4 MW RFP.
[6]Parent of Rockland Electric of NJ and Orange & Rockland of NY put out a joint RFP for operating companies.

Table IV

SUMMARY OF BIDDING SOLICITATIONS ISSUED[1]

State: Utility	MW Requested	Bids Received (# projects/MW)	Bids Awarded (#projects/MW)
CA:			
NCPA	40-330	67/3,580	Not Awarded Yet
CT:	500	34/800	27/552
CO: PSCC	0	-	-
DE/MD:			
Delmarva	100	10/830	1/48
FL:			
Seminole	440	8/1,989	1/440
Florida P&L	800	Filing Open	-
HI:			
HECO-1st	146	9/618	2/326
-2nd	500	6/3,000	Not Awarded Yet
IN:			
IMPA	120-160	5/600-750	Rejected All Bids
ME:			
CMP 1984	100	65/462	27/150
1984	100	26/314	9/153.5
1987	100	50/1,447.2	10/123.2
1987	100	45/907.6	Cancelled
1989	100-700	47/2,179.5	Not Awarded Yet
Bangor Hydro	60	30/936	Not Awarded Yet
MA:			
Boston Edison			
1987	200	61/1,840	9/344.1
1989	200	48/2,827	2/200
Cambridge Elec.	33	6/131	1/33
Commonwealth	76	25/914	4/102.5
Eastern Ed. 1988	30	11/179	2/40
1989	30	14/337	1/30
Fitchburg	11.7	13/455.4	1/13.5
Nantucket	4	0/0	N.A.
WMECO	54	11/382	Not Awarded Yet
NEP	200	73/4,729.4	Not Awarded Yet
NV:			
Sierra Pacific			
1988	125	94/3200	3/238
1989	200	Filing Open	-
NH:			
Public Service Co.	50	15/557.1	Not Awarded Yet
NJ:			
JCP&L	270	19/768	8/287
PSE&G	200	Filing Open	-
Rockland Electric	(See O&R)[2]	(See O&R)	(See O&R)
NY:			
LILCO	150	Filing Open	-
NIMO	350	Filing Open	-
Orange & Rockland	100-150	40/1,425	8/158
OH:			
AMP-Ohio	20-100	13/1,075	3/275
TX: Sam Rayburn Coop	25+	4/103-136	1/60
VT:			
CVPS	50	28/660	3/52.3 (to date)
Green Mountain	105-240	24/806	1/29 (to date)
VA:			
Va. Pwr.[3] 1988	1750	95/14,653	19/2088
1989	300	50/2,139[4]	Rejected all bids
1989	1100	Filing Open	-
WA:			
Puget Sound	100	40/1,241	Not Awarded Yet
TOTAL:	8,939.7-10,109.7	1086/56,085.2-56,268.2[5]	143/5,743

[1]As of December 31, 1989.
[2]Rockland Electric (NJ) and Orange and Rockland (NY) held a joint RFP.
[3]Va. Pwr. also held a solicitation in 1986 however as it is not considered by most people to be true bidding it is not included in this table. That solicitation for 1000 MW resulted in 24 bids/5000 MW and 7 projects/1178 MW were awarded contracts.
[4]Number of projects is approximate.
[5]MW totals rounded off to nearest tenth of a MW for both competing and awarded projects.

III.
SUMMARY OF BIDDING RFP RESULTS

Virtually all state commissions and utilities surveyed agreed that bidding solicitations have been successful in providing a greatly enriched menu of projects to fill capacity needs. In bidding RFPs held to date, there has been no shortage of private suppliers willing to provide capacity at market-determined rates.

As competition among prospective suppliers has increased, many state regulators and utilities have seen the rationale for a competitive bidding shift. Bidding is now being justified not only as a more efficient system for determining avoided costs and allocating capacity credits among "qualifying facilities" (QFs) but also as an essential component in the development of a competitive generation market, in which all sources compete to provide the most reliable, least-cost power.

The following summary of trends in bidding RFPs is derived from responses to the NIEP Bidding Questionnaire and telephone interviews through the end of December 1989.

Capacity Subject to Bidding

The 41 competitive bid solicitations issued as of December 31, 1989, represent a total of from 8,939.7-10,109.7 megawatts of requested capacity. The range in capacity requested reflects that six RFPs included flexible supply blocks, in which the amount of capacity actually awarded will depend on a variety of factors including the on-line date. *See* Table IV.

RFPs Elicit More Capacity Than Requested

The capacity bid in the 34 RFPs ranged from 2 to 53 times the amount of power requested, with the average response being 10 times the capacity sought. In RFPs where the submission of bids has been completed, there have been 1,086 bids for 56,085.2-56,268.2 megawatts to fill 6,139.7-7,309.7 MW of capacity need.[1] *See* Table IV.

More Capacity is Awarded Than Requested

Winners have been selected in 24 of the 34 RFPs where the filing period is closed.[2] In the majority of cases, bidders were awarded contracts for more capacity than was originally asked for in the RFP. In the 24 bidding solicitations where winners have been announced, 143 projects representing 5,743.1 MW were selected to fill 4,931.7-5,211.7 MW of requested capacity.[3] *See* Table IV.

In four RFPs, no capacity was awarded: Nantucket Electric (no bids); CMP's fourth RFP (canceled because of regulatory change); Virginia Power's third RFP and IMPA's first RFP (all bids rejected for being non-responsive or above utility's avoided cost). *See* Table IV.

Most RFPs Are Shifting to All-Source Bidding

Some of the early bidding programs, such as those in Maine and Massachusetts, limited participation to facilities that were QFs under the Public Utility Regulatory Policies Act (PURPA). Recent RFPs have been opened to a variety of sources of supply, including independent power producers (IPPs)—wholesale suppliers that do not qualify as QFs, utility facilities, imported power, and demand-side management (DSM) proposals. *See* Table V.

Bids Reflect a Diversity of Technologies

There has been a wide cross-section of technologies competing in bid solicitations (Table VI-XI). However, the vast majority of the winning bids, measured in megawatts, has been from coal and gas-fired projects, either cogeneration or independent power projects which do not qualify under PURPA. Projects using coal and natural gas technologies account for 3,266.6 MW, or 70.5 percent of megawatts awarded.[4] *See* Table VI. Renewable energy

Table V

PARTICIPATION IN BIDDING SOLICITATIONS[1]

State: Reg. Comm. or Utility	QF	IPP	IOUs	Public	Rural Elec.	DSM	Host/Sub.
CA: PUC	X						
CA: NCPA	X	X	X	X	X		
CO: CPSC	X						
CT: DPUC	X	X[2]				X	
DE/MD: Delmarva	X	X	X				
FL: Seminole	X	X	X	X	X	X[3]	
FL: FP&L	X	X	X	X	X		
HI: HECO	X	X					
IN: IMPA	X	X	X	X	X		
MA: DPU[4]	X[5]						
MA: NEP	X	X	X	X	X		
ME: CMP	X	X				X	
ME: Bangor Hydro	X	X	X	X	X		
NV: Sierra Pacific	X	X	X	X	X		
NH: PS Corp. of NH	X	X	X	X	X		
NJ: BPU[6]	X	X	X			X	X[7]
NY: PSC[8]	X	X	X	X		X	X
OH: AMP	X	X	X	X	X		
TX: Sam Rayburn	X	X	X	X	X		
VA: Va. Pwr.	X	X	X	X	X		
VT: CVPS	X	X	X	X	X		X[9]
VT: GMP	X	X	X	X	X	X	X
WA: UTC	X	X	X			X	X[10]

[1]Covers All RFPs as of December 31, 1989.
[2]Subject to Conn DPUC approval.
[3]DSM bids were not precluded but the RFP was not geared for non-supply side bids.
[4]This policy covers the seven IOUs in Massachusetts subject to the DPU bidding policy.
[5]Massachusetts DPU proposed regulations to expand participation in bidding in December 1989. It is expected that participation will be expanded in 1990.
[6]Applies to all four NJ utilities subject to bidding rule.
[7]NJ BPU has put a 3 year moratorium on the participation of a utility's subsidiary in its parent's RFP.
[8]Applies to all NY utilities subject to bidding.
[9]CVPS and GMP do not preclude bidding in their own RFP but they chose not to in the first RFP.
[10]WA UTC allows utilities or their subs to bid in their own service territory and allows IPPs to bid subject to UTC approval.

Table VI

SUMMARY OF COMPETING AND WINNING BIDS BY TECHNOLOGY (Through June 1, 1989)

Fuel Type	Total Bids Submitted in All RFPs (#Projects/MW)	Bids in Completed RFPs (#Projects/MW)	Winning Bids (#Projects/MW)
Biomass	54/ 1,079.8	33/ 796.7	11/ 200.9
Geothermal	69/ 2,147.0	48/ 997.0	1/ 13.0
Hydro	106/ 649.5	89/ 358.6	31/ 88.4
Resource Recovery	14/ 249.4	13/ 224.4	3/ 34.4
Solar	1/ 80.0	None	-
Wood	94/ 1,798.2	72/ 1,315.7	29/ 524.8
Wind	5/ 164.9	4/ 163.9	None
Other Renewables	16/ 412.8	9/ 237.8	3/ 104
Coal	124/14,697.9	89/12,153.3	12/1,569
Natural Gas	169/12,067.1	112/ 8,537.6	19/1,697.6
Oil	26/ 843.9	21/ 938.0	2/ 183.3
Nuclear	1/ 60.0	None	-
Other	15/ 801.7	10/ 451.7	None
Utility System Sales	14/ 2,845.0	3/ 1,320.0	2/ 225.0
Energy Conservation	15/ 51.4	15/ 51.4	6/ 17.0

projects, including hydro, geothermal, resource recovery, wood, and other biomass, account for 965.5 MW or 20.7% of the total megawatts awarded as of June 1, 1989.[5]

Of the renewable energy technologies that have been bid, the majority of megawatts has come from wood-fired and geothermal projects, with biomass coming in third. Among these bids, wood-fired projects have been the most frequently selected. *See* Table VI and Table VII.

While more hydro projects have been bid than any other renewable energy technology, most of these projects are very small. They represent only 12 percent of the renewable technology capacity bid. Of the 649.53 MW bid by 106 hydro projects, only 31 projects totaling 88.4 MW were awarded contracts as of June 1, 1989. *See* Table VII. Hydro's poor showing in bidding to date highlights the difficulties that the costly and lengthy hydro licensing process and high capital costs create for hydro developers competing in "all-source" competitions.

Hydro projects face the "double jeopardy" of a costly and uncertain multi-year state and federal licensing process and the challenge of competing for capacity credits once regulatory approval is received. The fuel cost pass-through provisions in many power purchase agreements, accompanied by the fuel adjustment clause in utility rate regulation, to some degree, take away hydro's natural advantage of a free fuel cost.

The Massachusetts DPU, in proposed regulations filed December 6, 1989, suggests ways in which environmental externalties may be taken into account and provide incentives for making it easier for renewable and DSM projects to compete. *See* Mass. D.P.U. 86-36.G. What success hydro has enjoyed was primarily in the early years of bidding. By now, many of the best sites for hydro projects have already been developed and very few hydro bids have been successful in recent solicitations.

Most Bidding Programs Are Modified

Once adopted by a state or utility, bidding programs are not static; they are frequently adjusted on the basis of lessons learned.

Examples of the changes made in RFPs by utilities that have conducted solicitations either under a state bidding rule or self-initiated program include:

- Increasing the importance of non-price factors in the RFP;
- Increasing, in many cases, the weight given to fully dispatchable units;
- Requiring more information about fuel supply arrangements;

Table VII

RESULTS OF SMALL POWER PRODUCER BIDS SUBMITTED IN ALL RFPS HELD BY JUNE 1, 1989 (#Projects/MW)

OWNERSHIP[1]	TECHNOLOGY								
	Biomass[2]	Geothermal	Hydro	Resource Recovery	Solar	Wood	Wind	Other	Total
Bids in All RFPs									
QF	39/636.3	69/2,147.0	105/646.1	13/246.9	1/80	54/1068.5	5/164.9	16/412.8	302/5,402.7
QF/U	-	-	1/ 3.4	-	-	3/ 54.0	-	-	4/ 57.4
Bids in Completed RFPs									
QF	19/390.7	48/ 997.0	88/355.2	12/221.9	-	35/ 664.0	4/163.9	9/237.8	215/3,030.6
QF/U	-	-	1/ 3.4	-	-	2/ 29.0	-	-	3/ 32.4
Winning Projects									
QF	7/143.9	1/ 13.0	31/ 88.4	2/ 31.9	-	14/ 261.6	-	3/104.0	58/ 642.8
QF/U	-	-	-	-	-	1/ 16.0	-	-	1/ 16.0

[1]QF = No utility or utility subsidiary participation.
QF/U = Some type of utility/utility subsidary participation.
Some utilities could not provide ownership breakdown so the QF category may include projects which have utility/subsidary involvement.
[2]Biomass includes municpal wastes but not wood wastes. Resource Recovery is everything other than true biomass, municipal wastes and wood wastes.

Table VIII

RESULTS OF COGENERATION BIDS SUBMITTED IN ALL RFPS HELD BY JUNE 1, 1989 (#Projects/MW)

OWNERSHIP[1]	Biomass[2]	Coal	Natural Gas	Oil	Resource Recovery	Wood	Total
	TECHNOLOGY						
Bids in All RFPs							
QF	15/443.5	84/7,937.1	128/7,455.8	10/490.6	1/2.5	35/623.7	273/16,953.2
QF/U	-	13/ 862.0	16/ 567.8	6/ 28.3	-	2/ 52.0	37/ 1,510.1
Bids in Completed RFPs							
QF	14/406.0	62/6,195.5	78/5,348.6	6/405.0	1/2.5	34/585.7	195/12,943.4
QF/U	-	8/ 584.0	10/ 227.8	6/ 28.3	-	1/ 37.0	25/ 877.1
Winning Projects							
QF	4/ 57.0	9/1,142.0	13/ 731.6	1/180.0	1/2.5	12/180.2	40/ 2,293.3
QF/U	-	3/ 427.0	3/ 37.8	1/ 3.3	-	2/ 67	9/ 535.1

[1]QF = No utility or utility subsidiary participation.
QF/U = Some type of utility/utility subsidary participation.
Some utilities could not provide ownership breakdown so the QF category may include projects which have utility/subsidary involvement.
[2]Biomass includes municipal wastes but not wood wastes. Resource Recovery is everything other than true biomass, municipal wastes and wood wastes.

Table IX

RESULTS OF INDEPENDENT POWER PRODUCERS BIDS SUBMITTED IN ALL RFPS AS OF JUNE 1, 1989 (#Projects/MW)

OWNERSHIP[1]	Coal	Natural Gas	Oil	Nuclear	Other[2]	Total
	TECHNOLOGY					
Bids in All RFPs						
IPP	21/4,983.8	21/3,015.6	9/250.0	-	2/118.7	53/8,367.8
IPP/U	1/ 200.0	2/ 488.2	-	-	-	3/ 688.2
IPP/W	5/ 715.0	2/ 540.0	1/ 75.0	1/60.0	13/683.0	22/2,073.0
Bids in Completed RFPs						
IPP	19/4,758.8	20/1,933.0	9/250.0	-	2/118.7	50/7,060.5
IPP/U	-	2/ 488.2	-	-	-	2/ 488.2
IPP/W	4/ 615.0	2/ 540.0	-	-	8/333.0	14/1,488.0
Winning Projects						
IPP	-	-	-	-	-	-
IPP/U	-	2/ 488.2	-	-	-	2/ 488.2
IPP/W	-	1/ 440.0	-	-	-	1/ 440.2

[1]IPP = No utility or utility subsidiary involvement.
IPP/U = Some utility or utility subsidiary involvement.
IPP/W = Total ownership by utility or subsidiary.
Some utilities did not break down the ownership between IPP and IPP/U
[2]Includes pumped storage, hydro, geothermal and peat projects.

- Requiring information about wheeling arrangements;
- Requiring that bidders post a bond to guarantee that certain elements of their proposal do not change between notification of finalists and contract signing;
- Increasing the level of earnest money deposits;
- Increasing the amount of detail about the level of project development, financial status, experience, and ownership;
- Including a model contract in the RFP, with the requirement that the bidder list contract exceptions in his proposal; and
- Opening the procurement to all sources, not just QFs.[6]

Few Projects Awarded Contracts Have Suffered Significant Delay or Defaults

The majority of bidding RFPs have been held so recently that it is premature to judge the success of the projects under contract. But for those RFPS where sufficient time has elapsed to evaluate viability, there have been few cancelled projects. Those projects which have failed have generally been small.[7] Host utilities report that thirteen projects totaling 441.4 MW have failed. However, this figure may underestimate the attrition rate because pur-

Table X

RESULTS OF UTILITY SYSTEM SALES BIDS SUBMITTED IN ALL RFPS HELD BY JUNE 1, 1989 (#Projects/MW)

	Total Competing Bids	Bids in Completed RFPs	Winning Bids
System Sales	14/2845	3/1320	2/225

chasing utilities, in response to political pressures or specific contractual provisions, may keep troubled projects on their book of planned capacity until the developer formally withdraws.

The largest capacity loss due to the cancellation of projects was in Virginia Power's 1988 bid. Five projects totaling 414 MW dropped out. Three of these projects, 324 MW, were due to failure to get transmission access from an adjacent state. As this RFP was over filled by 338 MW, this only leaves a shortfall of 64 MW.[8]

The second largest amount of capacity lost due to project failure in a single RFP was 43.6 MW in Boston Edison's first RFP. Of the five projects, four had the same utility participating in them. These cancellations did not, however, result in a shortfall of capacity for the utility since the supply block had a surplus of 144 MW still leaving Boston Edison with a 100 MW margin.[9]

The causes for project failure include failure to secure a steam host, difficulty in obtaining a hydro license, siting problems, failure to get transmission access and failure to find financing.

Table XI

COMPETING AND WINNING DEMAND SIDE MANAGEMENT BIDS IN ALL RFPS HELD BY JUNE 1, 1989 (#Projects/MW)

	Total Competing Bids		Winning Bids	
	DSM*	DSM/U	DSM*	DSM/U
Bids:	12/49.125	3/2.3	3/14.7	3/2.3

*DSM = these projects do not have any utility/subsidiary participation.
DSM/U = has some type of involvement of a utility or its subsidiary.

Most utilities that rely on purchased power to fill part of their capacity needs incorporate reserve margins in calculating the size of the supply block to be put out to bid. For capacity planning purposes, Virginia Power assumes, until the close of the project's financing, that 20 percent of the capacity awarded will not be built and that 50 percent of the capacity will be delayed one year.[10] Results to date from Virginia Power's 1986 competitive negotiation and 1988 solicitations are consistent with the utility's capacity purchase attrition estimates.[11]

On the whole, most utilities that have conducted bidding RFPs and have seen those projects come on-line, express satisfaction with the reliability of the power provided.[12]

Footnotes

1 This number includes the two RFPs in which all of the bids were rejected. The only exception to the consistent oversubscription to RFPs was an RFP by Nantucket Electric in Massachusetts. Nantucket Electric did not receive any bids for its 4 MW request, however, this is not surprising because Nantucket Electric is an isolated utility and therefore no outside market exists.

2 *Id.*

3 *Id.*

4 These figures include all RFPs completed by June 1, 1989.

5 Although wood, biomass and resource recovery projects are often grouped together under the "renewable" category, they have been separated in the tables to provide more specific data on individual fuels.

6 This information was compiled from the NIEP Bidding Questionnaire, as of June 1, 1989.

7 NIEP Bidding Questionnaire and follow-up telephone interviews from February 1989 through December 1989.

8 Telephone interviews with Robert Carney, Director of Capacity Contracts, Virginia Power and Electric Company (December 1989).

9 NIEP Bidding Questionnaire and follow-up telephone interviews with Boston Edison Company.

10 *See In the Matter of: Application of Doswell Limited Partnership For a certificate of public convenience and necessity pursuant to Virginia Code* § 56-265.2 and, to the extent applicable, for approval of expenditures for new generating facilities pursuant to § 56-243.3. Case No. PUE890068, Prefiled Testimony of Larry W. Ellis, Senior Vice President of Virginia Power (1989) (*hereinafter* Application of Doswell Limited Partnership).

11 Virginia Power's first competitive negotiation in 1986 is not considered an RFP for purposes of the figures in this study.

12 *See* Rebuttal Testimony of Larry W. Ellis, Senior Vice President, Power Operations and Planning, Virginia Case No. PUE890007 at pp.5-6. *See generally*, Hamrin, "Non-Utility Power and the Reliability Issue," The Electricity Journal 14-27 (June 1989).

IV.
PARTICIPATION IN BIDDING

Initially, bidding was adopted as an equitable means of determining avoided cost and allocating capacity credits when potential QF supply exceeded the utility's current need for power. Only QFs were allowed to bid. However, in the past year and a half, the goal of bidding in many states has shifted to soliciting the maximum amount of competition from the widest variety of projects. As a result, participation in competitive bidding has expanded to include both demand-side projects and QFs and non-QFs among supply-side projects.

Participation Expansion

Of all the bidding programs, only California and Colorado still restrict participation to QFs. In the case of Colorado Public Service Company (CPSC), only 20 percent of the capacity needed in its service territory is available for bidding by QFs. The remaining capacity will be filled by CPSC.[1] *See* Table V - Participation in Bidding Solicitations.

Of the seven state regulatory commission sponsored programs, six have included non-QF participants or are in the process of expanding participation to include non-QFs. In Connecticut, Maine, and Massachusetts, the expansion includes demand-side management projects. California may consider expanding the participants in its bidding program in the future. Nine of the ten IOU-sponsored programs and all four public power utility programs allow all QFs and IPPs, including other utilities, to bid.[2] *See* Table V.

Utility Participation In Bidding Is Increasing

As the number of utilities using bidding to fill all or part of their future capacity grows, more utilities are competing in RFPs—either directly or through their affiliates. While utilities or their affiliates originally bid only as part-owners in QF projects, much of the recent growth in utility participation in bidding is through IPPs or by bidding power from system sales.

In the RFPs where non-QFs are allowed to bid, the majority have received bids from IPPs, which were either wholly owned by utilities or had utility participation. One of the most interesting examples of increased utility participation is the NCPA solicitation. Of the 3,890 MW bid in response to NCPA's RFP, almost half were for projects wholly owned by other utilities. This amount does not include any of the QF projects that may have some type of utility participation. Another example is AMP-Ohio's recent RFP. Nine out of fourteen bids (800 MW of the total 1,075 bid) were from utilities, eight were system sales and one was a portion of a future coal plant. All three of the winning bidders were utilities. FP&L's filings for its Notice of Intent to Bid (NOI) are also an indication of increased utility participation. In response to FP&L's NOI there were five filings for 1,800 MW of nuclear power. In addition, fifteen NOI filings equaling 7,260 MW were from out of state; at least a portion of which were from utilities. At a minimum, six projects equaling 2,300 MW were from utilities. (Review of bidding RFPs to date shows that less than half of the megawatts included in Notices of Intent to bid are actually submitted in final proposals).

There was a conspicuous lack of participation, however, by utilities in Virginia Power's 1988 RFP, the largest solicitation to date. This may be explained in part by utility concern about the "wheeling in" proposal in the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking (FERC NOPR) on competitive bidding,[3] issued at the time of the RFP, which, if approved, would have required utility bidders to wheel power from competing facilities to the border of their service territory.[4]

A. Host Utility Affiliate Participation In Own RFP

A significant development in 1988-1989 was the growing interest among public service commissions in allowing the host utility or its affiliates to participate in the utility's own bid solicitation. New York and Washington have issued final bidding rules allowing such participation under specific conditions.[5] Several other state commissions are considering adopting similar policies. Under these rules, an affiliate of Puget Sound submitted a DSM bid in its parent's 1989 RFP, one of the first times that such participation has occurred.[6]

In proposed rules issued December 6, 1989, the Massachusetts DPU proposed that the host utility be *required* to participate in its own solicitation as though it were a third party. The Department concluded that such participation was necessary to avoid "creating an arbitrary *a priori* preference for non-utility resources."[7]

A more typical situation can be found in Virginia. Virginia Power, the host utility, has self imposed a prohibition on participation by its affiliate in its RFPs, a restraint that has been endorsed by the State Corporation Commission but not formally required.[8] Many utilities have followed Virginia Power's example because of concern that participation in their own RFPs would invite new regulatory controls that would reduce the flexibility of their acquisition process. Public service commissions, particularly if buffeted by complaints from losing third party bidders, might decide to take control of the selection process away from the host utility if contracts are awarded to its affiliate.

Several potential problems are associated with allowing the host utility or its affiliates to participate in its own solicitation or even in bid solicitations within its zone of economic influence. These problems, which are addressed in detail in Chapter VII, include various anti-competitive practices such as self-dealing, cross-subsidization, access to proprietary and inside information, unequal access to transmission services, and rate treatment of utility-built generation. As the discussion in subsequent sections will indicate, most of the significant issues associated with utility or affiliate participation have not been dealt with in the bidding programs.

B. Utility Affiliate Participation Outside the Service Territory

Another dramatic change since NIEP's 1987 bidding study has been the increased interest by utilities in bidding through their affiliates as QFs or IPPs. This trend is seen particularly in RFPs initiated by utilities. Although not all utilities were able to supply a detailed breakdown of ownership for all bids, the data collected from the NIEP Bidding Questionnaire and Interviews as of June 1, 1989, indicated that for all RFPs issued at that time, a minimum of 2985.7 MW for 46 projects were submitted by utility affiliates as bids. Fourteen of these projects equaling 1,539.5 MW were chosen as bid winners. *See* Tables VII - XI.

One graphic illustration of utilities' interest in bidding is found in PG&E's 1989 Five-Year Planning Strategies. The plan states that "The objective is to be well positioned to capture 25 percent of the U.S. market for non-utility electric generation after 10 years." Their strategy is to "have 5,600 MW of non-utility electric generation in operation or under construction by 1993 (10 percent of national market) but not in PG&E service area."[9]

Bidding provides a vehicle for utility affiliates to directly compete with QFs, IPPs, and other utilities to meet future capacity needs. All of the bidding programs surveyed allow utility affiliates to participate in bidding outside their parent company's service territory, as part owner of a QF or when applicable, as an IPP.

Public Power Participation

While rural electric power and public power utilities do not participate in the majority of competitive bidding programs, the reason is generally not one of policy, but because most of these utilities have not focused on their potential role in bidding. Since rural electric and public power utilities rarely build power plants outside of their service territory, they are limited to bidding capacity from existing or planned plants in their own service territory. Most states or utilities developing bidding programs have simply not addressed the issue of rural electric and public power participation as yet.

Few RFPs Include Demand-Side Management Projects

Demand-side management projects have been incorporated in bidding either by letting these projects directly compete with the supply-side proposals or by issuing separate RFPs at the same time that supply-side RFPs are issued. Requests for bids from demand-side management projects have been included in seven solicitations by CMP (3), Green Mountain Power, JCP&L, Orange & Rockland, and Puget Sound. Fitchburg Electric received an unsolicited DSM proposal in their solicitation. CMP, Orange & Rockland, and JCP&L have awarded contracts to DSM projects. New Jersey now leads the country in the number of DSM bids received and DSM contracts awarded.

Massachusetts has just issued a proposed all-source bidding rule that will include DSM projects. Its proposed rule allows for either joint or separate RFPs for DSM and supply-side resources; however, both DSM and supply-side projects will be applied to the same supply block. In addition, the rule requires that all proposals be evaluated using the same selection criteria although the ranking systems may use different subscoring systems within each category.[10]

A few utilities have issued selective procurement RFPs limited to demand-side projects only. These RFPs are different from the competitive bidding RFPs covered by this report because most of them are designed to encourage as many DSM proposals as possible (most do not have a specified block of capacity) and frequently offer a flat rate for all projects. Such solicitations have been held by Boston Edison, Massachusetts Electric Company, Western Massachusetts Electric Company (WMECO), Metropolitan Edison in Pennsylvania, Pennsylvania Electric and Commonwealth Edison in Chicago.

Footnotes

[1] Colorado Decision No. C88-736 at 8 - 9; NIEP Questionnaire and Interviews.

[2] HECO doesn't include other utilities because it is the only utility on the island.

See Notice of Proposed Rulemaking; Regulations Governing Bidding Programs, 53 Fed. Reg. 9324 (1988)(to be codified at 18 C.F.R. Parts 35 and 293)(proposed March 16, 1988), *reprinted in* Federal Energy Regulatory Reporter (CCH) Volume IV ¶ 32,455 at 32,046 (1988) (*hereinafter* Bidding NOPR).

[4] *See* Regulations of Connecticut State Agencies, § 16-243a-6.D

[5] *See* N.Y. Opinion No. 88-15 at 13-15; WAC Chap. 480-107-160.

[6] Telephone interview with Puget Sound.

[7] Mass. D.P.U. 86-36-G at 34.

[8] *See Pre-Filed Staff Testimony, Application of Virginia Electric and Power Company*, Case No. PUE890007, (testimony of Robert Lacy, Utilities Research Manager, Division of Economic Research and Development, at p. 9) (*hereinafter*, Virginia Power Staff Report PUE890007).

[9] *PG&E Five-Year Planning Strategies*, p. 15 (January 1989).

[10] *See* Mass. D.P.U. 86-36-G at 12, Section 10.03(6)(b)(2).

V. THE ROLE OF INDEPENDENT POWER PRODUCERS

IPPs, as defined by the FERC in its IPP NOPR[1], are wholesale generators that do not meet the criteria for classification as QFs under PURPA and do not have the opportunity to rate base their costs.[2] As shown in Table V, the majority of RFPs issued in state or utility sponsored competitive procurements allow or soon will allow IPPs to bid. Of the 29 utilities that have issued RFPs under either state-imposed bidding programs or utility-initiated programs, 21 have allowed IPPs to participate. *See* Table V.

If Massachusetts, as expected, changes its rules to require that IPPs be allowed to participate, the doors will be open to IPPs at seven additional utilities. The five utilities subject to bidding in Connecticut and Washington may include IPPs in their bidding programs, but only if their state commissions provide advance approval.[3]

While IPPs are beginning to participate in bidding,[4] three regulatory hurdles may ultimately deter IPPs:

- Regulation under the Public Utility Holding Company Act (PUHCA);
- Regulation of IPPs as utilities under state law; and
- Uncertainty about regulation of IPPs under the Federal Power Act and possible conflict between state and federal jurisdiction over IPPs.

PUHCA's Impact on IPP Development

Owners of IPPs, unlike QFs, are vulnerable to regulation as holding companies under PUHCA. The financial and corporate restrictions imposed by PUHCA and enforced by the Securities and Exchange Commission are considered so burdensome by developers that most will not proceed if they fail to get an exemption under the Act. This problem is compounded for companies owning a majority interest in QFs. Even if such companies were to gain an exemption from PUHCA for an IPP project, the project may still be classified as an electric utility under the Federal Power Act, making the developer subject to the utility ownership restriction under PURPA. In such a case, the developer who wishes to proceed with an IPP would either have to divest of all QFs, or reduce the ownership percentage to no more than 50 percent.[5]

A number of developers have bid IPPs with the expectation that Congress will pass a law exempting IPPs from PUHCA before the delivery date of the project. For this speculation to pay off, modification of PUHCA would have to occur within the next one to two years, a cloudy prospect at best.

Regulation Under State Utility Laws

Most states have utility statutes that are designed to regulate the corporate and financial structure of traditional utilities that have the ability to raise revenue through their rate structure and to pass through costs to consumers. In many states, IPPs are classified as utilities and therefore are subject to the jurisdiction of these statutes. Many IPPs believe that these regulations are not appropriate for entities that do not have the pass-through capability. They believe that the organizational and financial burdens that these laws impose put IPPs at a competitive disadvantage with QFs, which are exempt under PURPA.

Some IPPs have tried to have it both ways, however. They complain about being regulated as a utility under state law and then assert zoning and condemnation privileges extended only to utilities. This contradiction has not gone unnoticed by the Massachusetts DPU.

Potential Federal-State Conflict in IPP Regulation

As generators engaged in wholesale transactions, IPPs must seek approval of their rates from FERC under Section 205 and 206 of the Federal Power Act. The federal regulation of IPPs is not exclusive, however. Developers of IPPs may also need to obtain a Certificate of Convenience and Necessity from state public service commissions before plant construction can begin in most states.[6] Through this certificate proceeding, the state commission has the power to decide the fate of the IPP. If the state commission determines that there is no need for the facility, that the selected location is a poor one, that the facility will not be reliable, or that it will have an adverse impact upon the environment, the state commission has the authority to deny the certificate. Moreover, despite the fact that the FERC has jurisdiction over rates, an aggressive commission could decide that a project was not reliable because of an insufficient margin between the contract rate and the developer's cost of constructing the project. Finally, in most cases, the state commissions can evaluate the prudence of a utility's purchase of power from an IPP when the utility seeks to recover the costs of a power purchase in a retail rate case.

By contrast, QFs are usually not required to seek Certificates of Convenience and Necessity, and state commissions, when confronted with the mandatory purchase requirement of PURPA, generally do not review the prudency of utility purchases from QFs.[7]

No state in its bidding program has attempted to address the potential jurisdictional conflict between the federal government and the states in the regulation of IPPs. The possibility exists, however, that an IPP whose rates have been approved by FERC may find its contract with the purchasing utility in jeopardy if a state commission, engaging in after-the-fact prudency review, disallows pass through of costs of the power purchase to ratepayers. Such a disallowance would trigger the regulatory out clauses in many contracts, rendering invalid the utility's payment obligation to the IPP. Similarly, if an IPP project were denied a Certificate of Convenience and Necessity, the project could not go forward even though its rate had been approved by FERC.

Many state regulatory commissioners and their staffs contacted for this report expressed uncertainty about the scope of their role in regulating IPPs. The confusion about how IPPs may be treated under state regulations may discourage some bidders from proposing an IPP project. This confusion gives QFs and utility "build" options a competitive advantage in procurements. For example, the broad spectrum of regulatory uncertainties involved in seeking IPP approvals under state law, the Federal Power Act, and PUHCA was cited by Virginia Power in its decision in 1989 as one reason why it rejected all IPP proposals in the 1988 peaking capacity solicitation in preference for a utility-built plant free of this regulatory vulnerability.[8]

However, the state commissions can alleviate some of this uncertainty and thereby encourage IPP participation in bids. If the state commission approved the RFP and supply block in advance, there is less of a risk that the IPP's project will be rejected on the basis of need. Furthermore, the state commission could approve the FERC rate upfront before the plant is built. Although, there is always the question of whether one state commission can bind a subsequent commission, the Michigan legislature has tried to address this problem, at least for QFs, by requiring that once a capacity payment is approved by the commission, that decision shall not be reconsidered during the financing period of the project. Similar legislation could also be applied to IPP contracts.

FERC Jurisdiction over IPPs

As noted above, the FERC has jurisdiction over wholesale rates. Therefore, when the utility signs a contract with an IPP, the contract rate must be filed with the FERC. The FERC then examines the rate to determine if it is "just and reasonable." Prior cases have shown that the FERC will accept the bid price, rather than impose a cost-of-service rate if the bid price meets certain tests. In essence, the rate must be within the "zone of reasonableness," which means that it cannot be so low as to confiscate the IPP's property without compensation, and it cannot be so high as to gouge the utility and then the ratepayers. The FERC test is stated most succinctly in the D.C. Circuit's *Farmers' Union* case.[9] In that case, the D.C. Circuit set up a three part test: the process must be "workably competitive," the rate must be subject to a cap, and there must a process for monitoring.

The Massachusetts bidding process is an example of a bidding system which clearly meets FERC's "workably competitive" test. In the eyes of the FERC, this is true because Massachusetts invites all sources to participate in the process, and the DPU ensures that no bidder will exercise market power. Either through the selection of bidding criteria or through the examination of the application of those criteria to individual bids, the DPU will effectively determine that no IPP or group of IPPs can influence price by withholding service and excluding competitors. This determination would almost certainly cover the items of concern to the FERC; namely, the percentage of the purchasing utility's need represented by the IPP, the extent of the IPP's ownership or control over transmission facilities, and the existence or non-existence of an affiliation between the IPP and an entity with a franchised service territory.

As for the second arm of the *Farmers Union* test, the cap, the Massachusetts offers the utility's own bid. A contract will never be awarded at a price greater than that bid by the utility itself. This ceiling price is in many ways similar to an administratively determined avoided cost, because the DPU first sets criteria, then requires the utility to respond to those criteria, and finally scrutinizes the utility's response to assure that each of the criteria is fully and accurately addressed.

The last arm of the *Farmers Union* test, the monitoring process, is easily fulfilled in the case of the long-term contract with fixed or formula rates. The FERC would simply compare the contract price to the cap or the utility's bid at the inception of the contract, and determine the relative positions of those two prices throughout the contract term. Thus, by the time an IPP has signed a contract in Massachusetts, the record will surely be sufficient to satisfy the FERC's requirements, and the FERC should approve the contract rate quickly.

There is no reason that every state cannot set up the same type of bidding procedure with respect to IPPs. Control over the bidding system allows the state commission to ensure that there is a need for the power, that the facility is and will be reliable, and that the price will never exceed a certain level.

Despite these obstacles, IPPs have made up an increasing share of bids in recent solicitations. For example, in the 1989 Florida Power and Light solicitation for which bids were submitted on January 4, 1990, over 6000 MW were bid by IPPs, or 60 percent of the total MW proposed. Whether IPPs bids will continue to be grow will depend on how responsive state and Federal regulatory commissions, in the large pipeline of cases now awaiting action, are to the problems discussed above.

Footnotes

[1] *Notice of Proposed Rulemaking: Regulations Governing Independent Power Producers*, 53 Fed. Reg. 9327 (1988) (to be codified at 18 C.F.R. Parts 38 and 392) (Proposed March 16, 1988) *reprinted in* Federal Energy Regulatory Commission Reporter (CCH). Volume IV 32,456 (1988) (*hereinafter* cited as IPP NOPR).

[2] *Id.* at 32,103. The Commission also noted that a key characteristic of IPPs is their "lack [of] significant market power." *Id.*

[3] *See* Table III for a listing of utilities in each state subject to bidding.

[4] In Virginia Power's 1988 solicitation, 20 percent of the capacity totaling 708 MW was awarded to four IPPs. FP&L received Notices of Intent to Bid (NOI) from 34 IPPs equaling 14,117 MW, over half the capacity filing NOI forms.

[5] IPP NOPR, Comments of National Independent Energy Producers, at pp. 15-18 (filed July 18, 1988).

[6] *See e.g.* Application of Doswell Limited Partnership.

[7] QFs are exempted from state regulations of electric utility rates and financial and organizational structures under PURPA. 16 U.S.C. §824a-3(e); 18 C.F.R. §292.601(c).

[8] *See* Transcript of Hearings in Virginia Case No. PUE890007. (Testimony Larry W. Ellis, Senior Vice President, Virginia Power and Electric Company, July 3, 1989). However, if IPPs are granted waivers from state utility regulation they should also be willing to give up any special privileges, such as the power of eminent domain, which the state grants utilities.

[9] *Farmers Union Central Exchange, Inc. v. FERC*, 734 F.2d 1486 (D.C. Cir.), *Cert. denied* 469 U.S. 1034 (1984)

VI. CONTRACTING OUTSIDE OF BIDDING

In states that have adopted bidding, the issue frequently arises whether utilities should be allowed to acquire new electric capacity from third parties outside the all-resource solicitation. Most states have opted for flexibility in resource acquisition outside bidding. The FERC, in its Bidding NOPR, conceived of bidding as a useful but *non-exclusive* method of acquiring capacity from non-utility sources[1] and no state or utility program has prohibited contracting for such power outside bidding.

However, the states recognize that there is a tradeoff between giving utilities the flexibility to respond to special opportunities outside bidding and the need to protect the integrity of the bidding process and the incentives to participate in it. The Massachusetts DPU, for example, has proposed that purchases outside bidding be permitted but that each purchase be strictly reviewed on a case-by-case basis. The burden is placed on the host utility to demonstrate that the purchase is consistent with the objective of obtaining least-cost, reliable service and that the purchase cannot reasonably be accommodated within the solicitation cycle.[2]

Purchases outside bidding fall into the following categories:

- *Purchases from small power facilities below a specified size.* Usually such purchases are limited to QFs which are paid on the basis of an administratively determined avoided cost such as Rate X in Delaware or Schedule 19 in Virginia.[3] This exception is justified, in part, on the view that the transaction costs of bidding would be unfair for such small facilities.
- *Emergency and short-term purchases with durations less than the time frame of the bidding cycle.* These are usually utility-to-utility sales. As barriers to transmission access come down and developers build "merchant" plants with some or all capacity not committed to long-term contracts, pressure will increase to put even short-term purchases out to bid.
- *Purchases from preferred technologies or fuels.* New Jersey, for example, permits waste-to-energy plants to contract outside bidding for three years after adoption of the bidding program.[4] Newport News (municipal waste), and Ultra Cogen Systems (local coal) have used reliance on indigenous fuels as arguments before the Virginia State Corporation Commission in support of petitions for contracts outside bidding.[5] Incentives for the development of a new technology may provide another occasion for such an exception.
- *Long term purchases from foreign sources.* New York has exempted negotiations for purchases of Canadian power from Ontario and Quebec from its all-source bidding program. The Maine Public Service Commission used foreign purchases as a basis for determining CMP's avoided cost, which in turn was used in CMP's bid solicitation.
- *Purchases resulting from arbitrations.* As discussed in more detail below, losing bidders and non-bidders have in some cases successfully petitioned state commissions to require utilities to negotiate contracts outside bidding. Their petitions may be justified on the basis of some of the exceptions listed above.

Since review of the merits of power purchased outside of bidding does not have the benefit of current market data from an all-source competition, some IPPs and QFs have expressed concern about the potential for favoritism and other anti-competitive abuse when contracts are awarded outside bidding. Virginia Power, in resisting petitions for contracts outside bidding, has warned that such contracts may undermine the bidding process by reducing incentives to participate. Most third party suppliers, however, would favor giving utilities the flexibility to contract outside bidding in special circumstances subject to careful review by the state commissions.[6]

In Virginia, several claimants have sought arbitration from the state commission, alleging that PURPA and/or state commission requirements entitled them to contracts independent of the results of bidding competitions. Newport News, Tellus, and Ultra Cogen Systems all suggested that Virginia Power was obligated to purchase power from the QFs they proposed in spite of the fact that these same projects had previously been rejected in Virginia Power's December 1986 solicitation. A brief history of each of these cases is attached as Appendix B.

The PURPA-based challenges of Newport News, Tellus, and Ultra Cogen Systems in Virginia were all successful.[7] The Virginia State Corporation Commission has repeatedly ignored suggestions by Virginia Power that the awarding of contracts outside of bidding would undermine the utility's orderly allocation of capacity credits and perhaps discourage bidders from participating in future solicitations.[8]

Footnotes

[1] *See* Bidding NOPR at 32,030-32,031.

[2] *See* Mass. D.P.U. 86-36-G at 52.

[3] Virginia Power Company, Interim Schedule 19-1990, Power Purchases from Cogeneration and Small Power Production Qualifying Facilities; P.S.C. Del. No. 7-Electric Service Classification "X": Cogeneration and Small Power Production.

[4] *See* New Jersey Docket No. 8010-687B at 29-31.

[5] *See* Virginia State Corporation Commission, *Petition of Ultra Cogen Systems, Inc., Petition for Arbitration*, PUE870088 (1987) (*hereinafter* Petition Ultra Cogen Systems); Virginia State Corporation Commission, *Petition of Smith Cogeneration of Virginia, Inc.—For Arbitration of a Purchase Agreement with Virginia Electric and Power Company*, PUE890076 (*hereinafter* Smith Cogeneration Petition). The Ultra Cogen Systems Petition is discussed in greater detail in the Appendices.

[6] *See* Mass. D.P.U. 86-36-G at 50-52.

[7] *See* Appendix B.

[8] *Id.* In fact, 95 companies proposed over 14,500 MW of generating capacity in Virginia Power's November 1987 solicitation and 50 companies proposed over 2,100 MW in the March 1988 solicitation despite the State Corporation Commission's decisions to award contracts to Newport News, Tellus and Ultra Cogen Systems outside of the bidding system.

VII. PREVENTION OF SELF-DEALING AND CROSS-SUBSIDIES

The potential for self-dealing and cross-subsidization by utilities that both administer and participate in bidding was the major focus of comments by the independent power industry on the FERC's "electric policy initiative" of 1988.[1] The four NOPRs of 1988—the Bidding NOPR, IPP NOPR, the Avoided Cost NOPR, the PURPA NOPR—constitute the electric policy initiative.[2] In the Bidding NOPR, FERC noted that "states should take steps to protect against potential abuses due to self-dealing" and sought advice on how to prevent it.[3] As utility participation in bidding increases, the need for policies to deal with potential self-dealing and cross-subsidization becomes more acute. Although four states (Massachusetts, New Jersey, New York, and Washington) have addressed some aspects of this problem in rules or guidelines,[4] the majority of bidding programs do not offer any measures, other than traditional rate regulation, to prevent abuse.

Overview of Potential Abuse of Market Power

The potential for self-dealing and/or cross-subsidy exists in three situations: when a utility desires to build and must evaluate its proposed plant against proposals from other bidders; when a utility directly bids in another utility's solicitation; and when a utility competes in bidding inside or outside its territory through an affiliate.

Several market power concerns are raised by utility participation in competitive generation markets:

- *Self-Dealing*. When a utility controls the criteria, evaluation, selection, and negotiation of contract terms and conditions in a competitive procurement and is also participating in the procurement—either through its "build" option or an affiliated entity—there is an opportunity for self dealing that favors the utility's facility over other unrelated suppliers. If information regarding the utility's proposal is not filed under seal with the state commission in advance or at the same time that third party bids are filed, the utility may be able to make use of data provided by respondents to its RFP in developing its "build" proposal. If an affiliate gets early notice of the timing, size, or type of capacity (peaking versus intermediate or base load) of a solicitation, it can get a head start on planning, allowing it to, among other things, gain a "critical path" advantage in the turbine market. Non-price factors involving subjective judgments about project viability, financial stability and experience of bidders may also be an area where utility evaluation is vulnerable to bias or the perception of bias.
- *Cross-Subsidy*. Cross-subsidization occurs when costs incurred by an unregulated affiliate are recovered from ratepayers of the affiliated utility. It is especially difficult to discern and protect against cross-subsidies when an unregulated activity is in the same business as the regulated activity, since costs are similar and may be juggled from one account to another. Cross-subsidization is unfair to ratepayers because ratepayers' assets are used to reduce the costs of the unregulated affiliate, while profits earned by the affiliate benefit the shareholder of the utility but not the ratepayer. This cost shifting would allow the utility affiliate to underbid artificially in a generation market, causing long-term damage to the competitive process.
- *Discriminatory Access to and Pricing of Transmission Facilities*. If a utility affiliate were to gain transmission access and pricing terms from a parent utility that were more favorable than those available to unrelated suppliers, the affiliate would have an unfair advantage in a generation market in which both parties were competing. Even if the affiliate were outside the territory of the parent utility but competing in a generation market with unrelated suppliers located in the affiliated utility's service area, abuse of market power might occur if the affiliated utility denied access to the unrelated supplier.

As noted above, the NIEP survey found that very few bidding programs provide protections for ratepayers or non-utility competitors against abuse of market power other than traditional regulatory oversight and rate proceedings.

Few Regulatory Commissions Have Specifically Addressed Cross-Subsidy Prevention

The majority of regulatory commissions have not addressed the prevention of cross-subsidies by utilities when their affiliates participate in bid solicitations in their own service territories. Only three states (New York, New Jersey, and Washington) have specific requirements designed to prevent cross-subsidies, and two are limited in scope.

New Jersey's bidding program has the most comprehensive cross-subsidy prevention measures, requiring all bidders to certify that they have no affiliation with the host utility and barring affiliate participation in a parent company's bid solicitation for three years.[5] In addition, New Jersey established a series of practices to prevent cross-subsidies under its Holding Company Orders.[6]

Washington and New York allow utilities to participate in any auction, including their own, provided that they do so through a separate affiliate.[7] In New York, the affiliate is required to maintain its own accounting records and keep separate computer facilities as well as separate operating, marketing, and maintenance personnel. Their officers must also be separate from those of the parent utility.[8]

New York requires sealed bids in any auction in which a utility affiliate participates, with the bids opened by independent parties. In New York, the utility parent must submit a full justification when it rejects a competitor's bid. If unfair or abusive activity is discovered, sanctions such as denial of cost recovery or reduction in the allowed return on equity will be applied.[9]

Washington, in its bidding regulations[10] and Massachusetts, in its proposed regulations of December 6, 1989,[11] have served notice on utilities that any bid awarded to a affiliate in preference to third-party bids will be subject to increased scrutiny by the regulatory commission. If any abuse of market power is discovered, cost recovery will be denied.[12]

Several utilities have taken the initiative, sometimes prompted by state "affiliate" statutes[13], to keep their affiliates from participating in the parent's solicitation: NEP, GMP, Virginia Power, Sierra Pacific, Central Vermont Public Service, and Delmarva. In Virginia, the State Corporation Commission staff endorsed this policy in 1987, stating that "it seems to us that considerations of fairness, equity and the appearance of arm's length dealing would prohibit the host utility or any affiliated firm from participating as a potential power supplier in such negotiations."[14] Some utilities have decided against affiliate participation out of concern that the steps that the state regulators would then have to take to protect against self-dealing would cause unacceptable regulatory constraints and delay.[15]

Only One State Has Addressed Cross-Subsidy Prevention Outside the Utility Service Territory

Only New Jersey, through its Holding Company Orders,[16] has addressed the issue of possible cross-subsidies for projects proposed by a utility or its affiliate in competitive bidding outside its service territory. All the other states have either not addressed the issue at all or assume that traditional rate-making procedures will detect any cross-subsidies.

Access to Inside Information and Proprietary Data

With the exception of Massachusetts in the D.P.U.'s December 6, 1989 proposal, no state commission has addressed the problem of how to make access to inside information more equitable for all bidders when the utility or its affiliates are participating in its own bid solicitation. The Massachusetts DPU has proposed to require the host utility to disclose in pre-bid filings capacity planning and timing, evaluation criteria and analytic models, and other data useful to potential third party bidders.

As evidenced by the great disparity in the length of the RFPs (10 pages to over 200 pages), the level of background information provided to potential bidders in the RFPs varies from utility to utility.[17] In contrast, when the utility or its affiliates are bidding in the utility's own bid solicitation, the utility and/or its affiliate may have advance knowledge of when RFPs will be released, the amount of capacity needed, the type of power preferred, and other information relevant to preparing a bid. Such access could give them an edge over the competition.

The disparity in access to information is a more serious problem with utility-initiated bidding programs than with state-initiated programs because most utility programs are conducted in a far less public process. For instance, 13 out of the 14 utility-initiated programs[18] do not require regulatory commission approval of their bidding programs, and do not allow for public comment on their program or on their resource planning process. This makes it difficult for other bidders to get a sense of the timing or requirements of the RFP prior to its issuance. If utilities wish to obtain the bids from the most mature projects, it is to their advantage to provide this information.

Bid documents often contain a large amount of proprietary information about projects. As is the case in any type of RFP, a competitor that gains access to another company's bids has an unfair advantage. The potential for abuse exists because, as we have seen, with only two exceptions, all bidding programs make the host utility responsible for reviewing and selecting winning bidders. In Colorado, a third party selects the winning bidders and in New York, a third party will probably select bid winners if the host utility's affiliate is bidding.[19] In Connecticut, sealed bids are filed with DPUC, which opens them and then gives copies to the utilities for their review.

Some utilities are willing to sign confidentiality agreements but these are designed to protect against disclosure to other unrelated bidders, not to the utility's affiliates or facility planning staff. While some utilities will allow bidders to request that dissemination of certain proprietary information inside the utility be restricted, there frequently is a price tag for such a request: it may disqualify the bidder from being considered.

The problem of confidentiality also exists with state commissions and their staffs. The Massachusetts' legislature has enacted a statute in 1988 giving the DPU authority to protect the confidentiality of bid documents.[20]

The host utility could use its access to proprietary data from unrelated bidders to gain an unfair advantage in several ways:

- It is not unusual for bidders to submit the same project in several bid solicitations and, therefore, the utility's access to other bidders' proposals in its RFP may enable the utility or its affiliate to learn about its competition's projects in advance of filing a competing proposal in another RFP.
- A utility that desires to build a cost-of-service plant must justify its "build" option. The RFP, however, provides the utility with proprietary information about other proposals, which it can use to its advantage in justifying its decision to build rather than buy.

For a discussion of ways to prevent misuse of proprietary information, See the Guidelines.

Enforcement

Many states are depending upon their standard rate-making procedures or prudence reviews to uncover any cross-subsidies. However, these procedures or reviews may not take place until months or years after a bid solicitation has been completed. If any cross-subsidies are identified it may be too late to cancel the project and select one of the losing bidders. For the losing bidders, the time frame for bringing their projects on-line may be too short or they may have given up options on a site, had fuel supply contracts expire, or gone through other changes that would foreclose their ability to build the projects originally proposed.

There is an additional problem associated with relying on traditional rate-making procedures to uncover cross-subsidy abuse. If a utility's affiliate is building a project in another service territory either as an IPP or as partial owner of a QF, it may be unlikely that cross-subsidization of such projects would be identified in a rate-making case.

There are many bidding procedures that compound the difficulty of preventing or identifying possible cross-subsidies. Some of these policies include:

- The utility's bid price is not filed under seal with the regulatory commission in advance or at the same time as responses to the RFP;
- The utility selects the bid winners and the regulatory commission does not review the selection;
- The regulatory commission does not review the final contracts;
- The final contracts are not made public; and
- The potential of cross-subsidies is addressed only long after the bid—during cost-recovery in rate-cases—or not addressed at all.

The combination of these circumstances would make it difficult to even identify possible cross-subsidies. While such a scenario sounds unlikely, there are several bidding programs where all of these policies are present (e.g., NEP and NCPA). Numerous other bidding programs have several of these policies in their programs.[21]

Filing A Complaint

A losing bidder concerned about alleged cross-subsidies may file a complaint with the regulatory commission, unless the commission initiates an investigation of the bid awards on its own. If such a bidder has any interest in competing in future RFPs, a complaint places him in the awkward position of offending his only customer. This is a dilemma for bidders filing complaints regarding bid selection on any grounds, not just because of alleged cross-subsidy abuses, and may explain the small number of challenges to bid results.

The survey identified six challenges to bidding solicitations: four involving Virginia Power's solicitations and one each involving Commonwealth Electric Company's 1988 RFP and Western Massachusetts Electric Company's 1988 RFP.[22]

Each of these complaints attacked some aspect of the bidding process itself. Commonwealth Electric, for example, was taken to task for its failure to demonstrate sufficient flexibility in the early stages of the bidding process by disallowing a change in location after submission of a notice of intent to bid.[23] Tellus, Inc. raised a similar question about Virginia Power's refusal to permit modification of a proposal after its submission (Tellus's request arrived one day before the date Virginia Power had set to announce the solicitation's selections).[24] Ultra Cogen Systems later protested Virginia Power's insistence on allegedly "unfinancable" provisions in the model power purchase agreement.[25] Finally, the City of Newport News and Mission Energy Company accused Virginia Power of bias in the selection of the winners in the December 1986 and November 1988 solicitations, respectively.[26]

A losing bidder challenged its exclusion from the awards group in WMECO's first RFP. WMECO rejected the 54 MW project proposed by MassPower because the price filed was on a $kw basis instead of the $kwh basis requested in the RFP and the wrong escalator indices were used. MassPower petitioned the MDPU that they were unfairly rejected because the RFP was not very precise about how the pricing should be filed.[27] MDPU is expected to issue a decision in early 1990.[28]

Although it is difficult to draw conclusions from such a small sample, it would appear that state commissions have been initially sympathetic to claims that bidding processes are unfair or improperly structured. Both the Massachusetts Department of Public Utilities and the Virginia State Corporation Commission responded favorably to the first challenges made to the early use of bidding by utilities under their jurisdiction. Eventually, however, state commissions may be less inclined to respond to such claims. The Virginia Commission, for example, refused the relief requested by Mission Energy in its notice of protest against the outcome of Virginia Power's third solicitation.

Cross-Subsidy Prevention for Non-Regulated Utilities

As discussed in detail in Chapter XI, wholesale utilities, public utilities and rural electric cooperatives may not be subject to state regulatory commission rules. As a result, bidding solicitations held by these utilities or their participation in other utilities' RFPs raise a particularly difficult set of problems with regard to preventing cross-subsidies.

If these utilities are not subject to state regulatory commission review, the losing bidders are forced to turn to FERC in the case of wholesale utilities or to municipal governments and rural electric cooperative governing bodies to register a complaint. As the procedures for such complaints are not clearly established, it may be a time-consuming and costly process.

Access to the books of these utilities is another problem. If one of these utilities or their affiliate participates in another utility's RFP and wins, how will the state regulatory commission check for cross-subsidies if they do not have jurisdiction?

Cross-Subsidies from Natural Gas Companies

Little attention has been paid to the possibility that a regulated gas company may subsidize its affiliate's bid. While NIEP's survey did not ask how commissions were dealing with this issue, it was clear from the responses to the issue of preventing cross-subsidies by electric utilities that a similar policy needs to exist for preventing cross-subsidy abuse by gas companies competing in bidding.

Footnotes

[1] In 1988, the FERC issued four notices of proposed rulemakings: Bidding NOPR, *Notice of Proposed Rulemaking: Administratively Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities* 53 Fed. Reg. 9331 (1988) (to be codified at 18 C.F.R. Part 292) (Proposed March 16, 1988) *reprinted in* Federal Energy Regulatory Commission Reporter, Volume IV ¶ 32.457 (1988) (*hereinafter* cited as Avoided Cost NOPR);

Notice of Proposed Rulemaking: Regulations Governing the Public Utility Regulatory Policies Act of 1978, 53 Fed. Reg. 31,021 (1988) (to be codified at 18 C.F.R. Part 292) (Proposed July 29, 1988) *reprinted in* Federal Energy Regulatory Commission Reporter, Volume IV ¶ 32,465 (1988) (*hereinafter* cited as PURPA NOPR).

2 As of January 1, 1990, the FERC has not adopted any of the NOPRs a final rule.

3 Bidding NOPR at 32,041.

4 *See infra* notes 5-12 to this Chapter and accompanying text for a discussion of the applicable rules and orders.

5 *See* New Jersey Docket No. 8010-687B at 33-35.

6 *See* State of New Jersey Board of Public Utilities, *Petition of Public Service Electric and Gas to Reorganize under a Holding Company*, EM 8507-774 (January 17, 1986) (*hereinafter* N.J. Holding Company Case—EM 8507-774); New Jersey Board of Public Utilities, *Petition of Atlantic City Electric Company to Organize Under a Holding Company*, EM 8608-866 (December 18, 1986) (*hereinafter* N.J. Holding Company Case—EM 8608-866).

7 *See* WAC. Chap. 480-107-160; N.Y. Order No. 88-15 at 13, 17.

8 *See* N.Y. Order No. 88-15 at 13-14; *see also* New York Public Service Law § 66-c(3)(a).

9 *See* N.Y. Opinion No. 88-15 at 15-16.

10 *See* WAC Chaps. 480-107-001, 170.

11 *See* Mass. D.P.U. 86-36-G.

12 WAC Chap. 480-107-160; Mass. D.P.U. 86-36-G.

13 The states also regulate the financial and corporate matters of their utility holding companies. Many of these regulations, for example special accounting rules, enable the state commissions to oversee and thereby regulate utility affiliate transactions. In addition, some states, such as Kansas, require specific reporting requirements designed to keep the state commission fully informed of all transactions. Another approach is that taken by Mississippi which requires a utility to file, with the state regulatory commission, all contracts a utility enters into with affiliates. For a good review of the state affiliate's laws, see the NARUC *Annual Report on Utility and Carrier Regulation 1987*.

14 *See* Virginia State Corporation Commission—*Ex-Parte: In the matter of adopting Commission Policy regarding the purchase of electricity by public utilities from qualifying facilities when there is a surplus of power available. Final Order.* PUE870080 at 5N.5 (1988).

15 *See* Comments to Mass. D.P.U. 86-36-F *cited in* Mass. D.P.U.86-36-G at pp.33-34.

16 *See* N.J. Holding Company Case—EM 8507-774, and EM 8608-866.

17 *See* Chapter VIII for a discussion of utilities' failure to provide bidders adequate data about transmission capacity, access and pricing.

18 Utility refers in this case to both investor-owned and public power utilities.

19 The California PUC gives utilities the option of having a third party select the winning bidder when the utility's affiliate is a participant in its bid. *See* California PUC, *Decision No. 87-0560* at 16-18 (May 28, 1989).

20 The Massachusetts legislature recently passed a law authorizing the protection of confidential documents submitted to the state commission. According to a commissioner of the Massachusetts Department of Public Utilities, this law should protect such information from disclosure pursuant to request under the Freedom of Information Act. Conversation with Susan F. Tierney, Commissioner, Massachusetts Department of Public Utilities (January 29, 1990).

21 Data gathered from all RFPs as of June 1, 1989 covered by NIEP Bidding Questionnaire and Interviews.

22 *See* Appendix B for a discussion of these cases.

23 Conversation with Massachusetts DPU.

24 *See* Virginia State Corporation Commission, *Petition of Tellus, Incorporated for a Declaratory Order that the Refusal of Virginia Electric and Power Company to purchase electric energy from Tellus Incorporated is a violation of the Public Regulatory Policies Act and the Implementing Regulations of the Federal Energy Regulatory Commission*, PUE870046 (*hereinafter* Petition of Tellus).

25 *See* Petition of Ultra Cogen Systems, Supra.

26 *See* Virginia State Corporation Commission, *City of Newport News, Virginia v. Virginia Power Company*, PUE870029 (*hereinafter* Petition of City of Newport News); Virginia Case No. 890007, *Protest of Mission Energy Company* (filed June 14, 1989).

27 *See* Commonwealth of Massachusetts Department of Public Utilities, *Massachusetts Power v. Western Massachusetts Electric Company, Reconsideration*, Docket No. 89-52.

28 Telephone interview with T. McGregor, Massachusetts Department of Public Utilities (January 2, 1989).

VIII. TREATMENT OF TRANSMISSION ACCESS IN BIDDING

For a competitive generation market to fully develop, bidders must have predictable access to transmission facilities. Most bidding programs introduced to date have not addressed the problems confronting bidders when they deal with utilities on issues of transmission capacity, pricing, access, construction, and ownership. Limited access to transmission is one reason why the typical wholesale generation market is characterized by monopsony power: where one purchaser (the host utility) is buying from numerous sellers (QFs, IPPs, and other utilities). It should come as no surprise, therefore, that the great majority of contracts, awarded through bidding, have gone to facilities located in the service territory of the purchasing utility.

The lack of transmission policy in state bidding programs reflects federal law. Under existing federal law, the states must look to the federal government for direction on transmission issues. Section 205 of the Federal Power Act gives FERC exclusive jurisdiction over the rates, terms, and conditions of interstate wheeling, which includes transactions in which all parties are located within the same state. (*Federal Power Comm. v. Florida Power & Light Co.*, 404 U.S. 453, 30 L.Ed. 2d 600, 92 S. Ct. 637, (1972); *reh'g. denied Federal Power Comm. v. Florida Power & Light*, 405 U.S. 948, 30 L.Ed. 2d. 819, 92 S.Ct. 929 (1972).) The regulations implementing the Federal Power Act make it clear that this jurisdiction extends to "all rules, regulations, or contracts which in any manner affect or relate to" transmission service. (18 C.F.R. § 35.2(b).)

To date, the FERC has been reticent about injecting transmission access issues into discussion of guidelines for state bidding programs. In its Bidding NOPR, FERC specifically rejected proposals by ELCON, among others, that utilities' voluntary participation in a bidding system be conditioned upon their agreement to provide non-discriminatory open access for transmission services.

Electricity Consumers Resource Council (ELCON) argued that implementation of the bidding rule without mandatory access to transmission would not be consistent with the goal of a competitive generation market.[1] FERC responded that although bidding might result in increased competition, competition was not the primary purpose of bidding.

According to FERC, the primary objective of bidding is to further the purposes of PURPA, by providing a more accurate and less cumbersome way of determining the utilities' avoided cost.[2] "PURPA does not require a competitive market for QF sales."[3] This policy helps explain why, under current PURPA regulations, a QF is not entitled to a sale to a utility in whose territory it is not located unless it is able to negotiate its own transmission agreement with intervening utilities.

Before FERC would consider conditioning utilities' participation in bidding upon their willingness to grant transmission access, FERC "must be able to find specifically that utilities have already engaged in unduly discriminatory and anti-competitive conduct."[4] Without a finding of specific anti-competitive activities or anti-trust violations, the courts have held that FERC is without authority to compel wheeling under the FPA. *See e.g.*, *Florida Power & Light Company v. F.E.R.C.*, 660 F.2d 668 (5th Cir. 1981) *cert. denied Ft. Pierce Utilities Authorities v. F.E.R.C.*, 459 U.S. 1156, 74 L.Ed.2d 1003, 103 S. Ct. 800 (1983).

Given the reluctance of FERC to tackle transmission issues in the context of bidding, it would be unrealistic for bidders to look to the states for much relief on transmission problems. Nevertheless, the states, in implementing FERC's rules under PURPA, may have some latitude to impose transmission conditions in connection with bidding. State regulators may require a utility to provide wheeling services as a condition of its being allowed to participate in a bidding program. Such conditions will be subject to review to ensure that they promote the objectives of PURPA and avoid burdening interstate commerce or conflicting with FERC's exclusive jurisdiction over rates, terms, and conditions of service under the Federal Power Act.[5] A number of states and a few utilities have in fact taken modest steps to increase bidders' access to markets outside the service territory where the bid is conducted. NIEP identified the following trends and associated problems related to transmission policy in bidding programs:

Most Bidding Programs Fail to Address Transmission Issues

Most bidding programs provide no assistance to bidders who need transmission access from intervening utilities because the bidder's project is located outside the host utility service territory. In three states (Connecticut, New Jersey, and Massachusetts), in-state utilities are required to wheel through for winning bidders in RFPs conducted within the state. New York requires a utility to wheel for other bidders only if the utility's affiliate is participating in bidding, either in its parent's service territory or in other RFPs issued by other New York State utilities.[6] Virginia Power, alone, will voluntarily wheel out for the losing bidders.[7]

As experience in Virginia recently demonstrated, bidders located outside the host utility service territory are at a distinct disadvantage in any competitive procurement. In Virginia Power's 1988 solicitation, contracts were awarded to bidders who proposed facilities in West Virginia. However, Virginia Power recently terminated contracts with three West Virginia projects, a 300 MW waste coal-fired plant and two 12 MW mine-mouth projects, after the developers failed in their efforts to obtain wheeling agreements with the intervening utility.

American Electric Power (the reason given for the refusal was lack of capacity) and their efforts to finance a new transmission facility to interconnect with the Virginia system failed.[8] This experience led two other developers to relocate their projects to sites within Virginia Power's service territory to avoid wheeling problems.[9]

To avoid such problems in the future, Virginia Power has recently announced that it will now require all bidders with proposed projects outside of the service territory to include in their bid proof that they have firm transportation service available from intervening utilities. As Larry Ellis, Senior Vice President of Power Operations and Planning for Virginia Power stated: "Without that assurance, we won't even consider the bid."[10]

There are no reliable data on how many bidders have not competed in RFPs because of concern that they would not be able to obtain transmission access. However, Green Mountain Power's experience in Vermont illustrates how competition may be increased if the utility eliminates transmission access as an issue in the bid solicitation.

Unlike the vast majority of bidding programs, which make transmission arrangements the sole responsibility of the bidder, GMP offered to try to negotiate wheeling contracts for any winning bidder. The purpose of GMP's policy was to have the bidder concentrate on "what they were good at" and leave the issue of transmission access up to the host utility.[11] By this policy, they hoped to increase the number of bidders in the RFP and therefore enrich their options for providing the most reliable and cost-effective capacity for ratepayers. GMP reasoned that they were in a better position than a non-utility generator to negotiate wheeling contracts with the neighboring utility.

With this policy, GMP was able to elicit a variety of projects from outside Vermont. Of the 24 bids made in response to their RFP, 7 were from Vermont and 17 were from projects located in New Hampshire, Massachusetts, Connecticut, and New York. A project located in New York was selected, but GMP's ability to arrange wheeling with intervening utilities was not tested because the bidder dropped out after receiving a higher price for its power in New York.[12]

Availability of Transmission Rates, Terms, and Conditions

Only New Jersey and Massachusetts require that transmission rates, terms, and conditions be made available to bidders by the host utility.[13] All other bidding programs have either not addressed this issue or refer bidders to FERC for transmission information. By not having access to transmission data for other utilities in the same state as the host utility or from adjacent, out-of-state utilities, bidders are hampered in determining the feasibility of possible locations. Utilities may be unwilling to volunteer this information and state commissions do not have the authority to compel utilities located outside the state to provide the information. Utility affiliates, on the other hand, may have greater access to such information because of their "insider" status in the utility industry. Such preferred access may place other bidders at a competitive disadvantage.

Information on Transmission Capacity

While, in theory, bidders can research wheeling prices, terms, and conditions in the transmission contracts filed at FERC, information about transmission capacity for all in-state utilities is not routinely required in any state except Connecticut. Indeed, 23 out of the 38 bidding RFPs issued as of June 1, 1989, included no transmission data at all.[14] The closest most RFPs came to providing transmission data was in discussion of the utility's interconnection requirements. Few RFPs included more than a small map showing the location of different sized transmission lines in the host utility's grid.

Connecticut, on the other hand, requires all in-state utilities to provide a map indicating load center concentrations, information on transmission limitations and planned and proposed changes to the transmission system within the franchise area during the forecast period of their annual filings.[15]

Lack of information about transmission capacity is a barrier to the expansion of the competitive generation market. Utilities opposed to providing transmission access can always claim lack of capacity. While some data is available from transmission filings made by utilities at FERC, most bidders are largely dependent on the utility for transmission capacity information, making it difficult to know how accurate such claims are.

This forces bidders into one of three positions: They will drop the project because of the cost or time delay associated with upgrading the transmission system; they will proceed with the project and pay for part or all of the system upgrade if they feel the project will still be feasible; or, finally, they will challenge the utility's claim that there is no transmission capacity.

Putting aside the problems of the correct forum for a proceeding to consider such a challenge, and the difficult evidentiary problems involved, even if the bidder proves that the utility has excess capacity, this does not necessarily give the bidder the right to demand wheeling. Although it appears that states may be able to condition participation in a bid upon offering transmission access, wheeling can only be *ordered* by the FERC pursuant to Section 211 of the Federal Power Act. The evidentiary requirements under that Section could make a successful suit exceedingly difficult and costly. For these reasons, none of these options encourage bidders to propose projects that need transmission access.

Perhaps the best solution to this problem would be for the state public service commissions to take responsibility for determining the transmission capacity available before an RFP is announced. The Florida Public Service Commission, for example, recently opened an investigation of a transmission bottleneck in the northern part of the State that threatened the ability of independent power producers to sell to Florida Power Corporation.[16] State commissions, by anticipating the need for such assessments, may avoid future bottleneck problems and provide the information necessary to allow the maximum amount of competition for new generation.

Other State Wheeling Initiatives

In the states where bidding is being used, only two states surveyed indicated that they have wheeling regulations unrelated to bidding programs. Maine, which does not require wheeling in its bidding rule, does require its utilities to wheel for affiliated companies, such as between two paper plants owned by the same company. This was the only retail wheeling requirement identified in the survey.

Florida has required all utilities in the state to "wheel through" for QFs.[17] This requirement was not established in the context of bidding. Although bidding is authorized for IOUs but has not yet occurred in Texas, the Texas Commission does have the same wheeling policy as Florida.[18]

Impact on Bid Selection

Only California has a policy that prohibits utilities from discriminating against QFs in bid selection because the QF will need to obtain transmission access outside the service area of the host utility.[19] Ironically, California does not have any requirement that its utilities wheel through for QFs. Other bidding programs include the need for transmission access from other utilities and the associated cost as a non-price factor in the evaluation of bids.

In the majority of the RFPs, the impact of transmission access and cost factors on the evaluation of bids can be found in one of the following categories:

- Bids are rejected that do not have proof of any necessary agreements for transmission capacity and terms;
- Projects are ranked higher the closer they are to the host utility service territory; and
- Projects are ranked on the basis of their economic impact on the host utility transmission system.

Allocation of Limited Transmission Capacity

No bidding program has addressed the issue of how to allocate limited transmission capacity among winning or losing bidders. In addition, it does not appear that any bidding program has addressed the problem of allocating transmission capacity between bidders and contracts signed outside bidding.

Site-Specific Projects at a Disadvantage

Without a policy assuring transmission access, site-specific projects, such as hydro, geothermal, mine-mouth coal plants, wind, and to a lesser degree, cogeneration projects needing steam hosts are limited to bidding in the host utility service territory (the sole exception is Virginia, where Virginia Power has agreed to wheel out losing bidders). If such a project loses a bid, it may be years before they have another opportunity in that service territory. The lack of transmission access for losing bidders, therefore, may particularly restrict the development of renewable energy projects.

Footnotes

[1] *See* ELCON, *Memorandum to FERC Staff, Efforts to Encourage Competition Without Transmission Access are Fatally Flawed*, (September 7, 1987).
[2] *See* Bidding NOPR at 32,022.
[3] *Id.* at 32,045.
[4] *Id.* at 32,045.
[5] *See* Remarks of Robert G. Fitzgibbons, Jr., Associate General Counsel, FERC, before the Workshop on Electric Transmission Access, San Francisco, CA (Jan. 26, 1989).
[6] *See* N.Y. Opinion No. 88-15 at 16. This is similar to the "wheeling in" approach on which FERC requested comments in its Bidding NOPR. *See* Bidding NOPR at 32,046.
[7] Virginia Power response to NIEP Questionnaire and Interviews.
[8] Telephone Conversations with Robert Carney, Virginia Power and Electric Company (December 28, 1989; January 2, 1990); *Wheeling Woes Kill 2 West Virginia Plants; Leads Others to Va. Power Territory*, Independent Power Report (September 22, 1989).
[9] *Wheeling Woes Kill 2 West Virginia Plants; Leads Others to Va. Power Territory*, Independent Power Report (September 22, 1989).
[10] *Id.*
[11] Response by GMP to NIEP Questionnaire and Telephone Interviews with GMP (Spring 1989).
[12] *Id.*
[13] Although the Massachusetts's rule (§ 220 CMR § 8.03(c)) requires utilities to maintain, for public review, all wheeling agreements and copies of its FERC-approved tariffs for wheeling, as well as current rules and practices, some utilities do not have rate schedules on file and a QF may not be able to obtain very much information. Conversation with Susan F. Tierney, Commissioner, Massachusetts Department of Public Utilities (January 26, 1990).
[14] NIEP Bidding Questionnaire and Interviews.
[15] Regulations of Connecticut State Agencies § 16-243a-2(b)(3).
[16] Florida Public Service Commission *Investigation into the Adequacy of the Electrical Transmission Grid in North Florida*, Docket No. 890779-EU.
[17] Because the Florida wheeling rule was challenged in FERC's Docket EL 87-19-000, it was never codified. The proposed rule has been modified to reflect that FERC held it has exclusive jurisdiction over the rates, terms, and conditions of wheeling, although it continues to assert Florida Public Service Commission jurisdiction to requires wheeling. *See* Florida Public Service Commission, *Docket No. 891049-EU, Proposed Revisions of Rule 25-17.082, 17.0825, 17.083, 17-0831, 17.088, 17.882, 17.091 and Creation of Rules 25-17.081, 17.0883, 17.0834, 17.0832, 17.0883, and 17.089: Cogeneration Rules*, Memorandum at p. 10 (October 26, 1989).
[18] *Texas Public Utility Commission* Substantive Rules § 23.66, Sept. 1, 1988.
[19] Response by California Public Utility Commission to NIEP Bidding Questionnaire and Interviews.

IX.
THE ROLE OF THE HOST UTILITY IN NEW PLANT CONSTRUCTION

In testimony on S. 406 (the Competitive Wholesale Electric Generation Act introduced by Sen. Johnston to modify the Public Utility Holding Company Act), utility executives opposed to PUHCA reform stated that the introduction of competitive bidding will sharply reduce or essentially eliminate the opportunity for traditional utilities to build new generation in their own service territories.[1] They argue that the public interest in a reliable power supply requires that the entity with "the obligation to serve" should continue to participate in supplying new capacity to meet system needs.

According to this view, many state-sponsored bid programs view host utilities as "builders of last resort," in other words, as stop-gap suppliers to fall back on only if bidders fail to propose enough capacity to meet projected needs at a price lower than what the utility would incur if it built the plant itself. The alleged effect of this "last resort" status is to discourage the host utility from building.

In rebuttal, representatives of the Utility Working Group, made up of utilities favorable to competitive bidding and PUHCA reform, testified that bidding created a market-tested method for determining the optimum supplier, and that utilities and their affiliates would seize the opportunity to compete and be successful in such an arena.

Utilities Continue To Build in Bid States

While bidding is still too new for empirical data to resolve this debate, the NIEP survey shows that utilities have continued to propose and gain approval of rate-based facilities in bid states. Although in the 24 completed bidding RFPs of December 31, 1989, only two utilities Virginia Power and IMPA have selected a benchmark or "build" plant over all bid proposals, utilities continue to gain approval outside of bidding for new construction, which is given traditional cost-of-service rate treatment.

In Virginia, for example, where more megawatts of capacity have been awarded through bidding than any other state, the State Corporation Commission has continued to approve rate-based plants. Between 1987 and 1989, contracts for 3,648 MW have been signed with third-party suppliers (3370 MW through solicitations, the rest through contracts outside bidding). During the same period, the SCC approved Virginia Power proposals for 1,201 MW of rate-based capacity, approximately 25 percent of the total.[2]

No bidding program makes competitive procurement the exclusive method for approving new capacity additions. FERC, in its Bidding NOPR, and all state bidding programs see bidding not as an exclusive process but as part of an integrated capacity planning and procurement process that includes a variety of methods of meeting demand.[3] No bidding programs adopted under state or utility auspices specifically prevent utilities from building new rate-based plants in their service territory. However, as is discussed below, Massachusetts allows utilities to build but on terms similar to those required of non-utility suppliers.[4]

Developing the Benchmark Price

Much of the controversy about the role of the host utility in building new capacity turns on how the costs of such facilities will be treated by state regulators after bidding has been adopted. In states that have adopted bidding, few have changed their treatment of the cost of utility-built generation. In those RFPs where benchmark prices are included and the utility becomes the builder of capacity, only Colorado holds the utility to the benchmark price. At best, the remaining commissions use the price established through bidding as a guideline during rate proceedings for the utility-built plants.

Unless bidding is open to all possible sources of capacity, the host utility and/or the public service commission must still determine the avoided or "benchmark" cost administratively. Any capacity source excluded from bidding must be accounted for in a benchmark cost calculation.[5] Determination of the benchmark price is required *both* under PURPA so that public service commissions can ascertain that prices paid to QFs awarded contracts through bidding do not exceed the utility's avoided cost *and* under the Federal Power Act so that FERC can ascertain that prices paid to IPPs are "just and reasonable."

The benchmark may be based on the capacity that the utility could theoretically provide under cost-of-service regulation. The avoided cost estimate or benchmark price should be calculated in the same manner whether a utility "builds" or "buys." But, in practice, this is not always true. When the host utility has embraced a corporate preference not to build and is relying on market competition through bidding to identify the least-cost supplier, its calculation of the benchmark price may be somewhat of an academic exercise. For example, rather than solicit bids for equipment, fuel, or construction costs related to a specific project at a specific location, the utility may rely on standard cost estimates such as the Technical Assessment Guide Manual (TAG) published by EPRI to estimate the cost and operating characteristics of the benchmark plant.[6]

When these estimates are higher than the prices offered by bidders, they are unlikely to be challenged by third-party suppliers. On the other hand, they may be challenged by a public service commission concerned about excessive reliance on purchased power[7] or by FERC in reviewing an IPP's petition for rate approval under Sec. 205 and 206 of the FPA.

Making the Benchmark Bid Binding

Much more controversial is the situation in which the host utility prefers to build its own capacity and the proposed utility price is used to justify a "build" option over market-tested offers from bidders.

Under traditional cost-recovery procedures for rate-based plants, a utility is entitled to a return on its actual, rather than estimated, cost, so long as those costs are prudently incurred. In other words, if a utility has misjudged its cost, and has not been unreasonable in doing so, it can pass excess costs along to the ratepayer. This is true even when the utility's cost estimate for building its own capacity has been used as a basis for rejecting bids from third-party suppliers. In theory, the utility is able to use one price to gain a contract over bidders and another price as a basis for cost recovery from ratepayers.

In the bid NOPR, FERC recommended a change in traditional methods of cost recovery to protect competition. The FERC NOPR states that "all the prices offered, whether by the purchasing utility in a bid or in a benchmark or by other participants, should be binding."[8] This view has generally not been adopted by the states. All bidding programs initiated by state commissions and five of the 11 utility-initiated programs issued as of June 1, 1989[9] require a benchmark price. Only one utility, Public Service of Colorado, of the 42 utilities using or subject to existing bidding rules, is bound by its benchmark price when it is the builder of last resort. In New York and Washington, utilities are held to the benchmark price only when they participate in their own RFPs.

Wholesale generators have recommended to FERC and state commissions that when a utility prefers its judgment over the market in determining the least cost for ratepayers, it must assume the burden of proving that its cost estimates are fair and accept the consequences of this decision. They believe that holding the utility to its cost estimate serves several purposes. It recognizes that while bidders have little opportunity to review or modify the evaluation methodology used by the utility in comparing its build option against the bid proposals, they may gain some confidence in the fairness of the procurement system if the utility is held to its estimated price. Without this discipline in the system, competitive procurement may degenerate into protracted disputes over the calculation of avoided cost that bidding was designed in part to avoid. Furthermore, losing bidders will be less inclined to challenge the utility's determination of its avoided cost if they know that the utility will pay a penalty during cost recovery for an artificially low price.

Many wholesale generators also believe that to provide efficiency incentives, the utility cost estimate should be the basis for a fixed recovery, not a cap on recovery. In other words, the utility should be allowed to recover the estimated cost fully, even if its actual costs are less than the estimate. Many utilities strongly disagree with the policy of making the benchmark price binding. According to EEI, the benchmark price should be used:

> "strictly as a device to facilitate bid evaluations and/or to prevent acceptance of QF or non-QF bids above avoided costs. A benchmark is not a utility bid, and it should not be treated as such. . . Moreover, because of the differences in costs and risks between cost of service estimates and a bid, a cost of service benchmark estimate is not directly comparable to a bid. Thus, the benchmark estimate cannot be binding on the utility."[10]

In testimony before the Virginia State Corporation Commission in 1989, William W. Berry, Chief Executive Officer of Dominion Resources, defended this view, stating that "there is nothing unfair or unreasonable for the utility's recovery of cost to be different from that of the entrepreneur, because that is merely reflective of the fundamental difference between regulated utilities and unregulated businesses."[11]

In response, IPP and QF developers note that when there is a competition for the right to build capacity, the utility's build proposal is in direct competition with bid proposals from third party suppliers and therefore must be evaluated on an equal basis. If as proposed below the cost recovery system is altered to allow utilities to gain up front approval for a new plant, then IPPs, QFs, and utilities should be bound by the bid price.

Pre-approval of Contracts for New Generating Facilities

Under traditional cost-of-service regulation, utility planning and construction of new plants were subject only to after-the-fact review by the regulatory commission. This system has led to three problems: the utility's uncertainty over its ability to recover costs, cost overruns and inefficiencies, most of which fall on the ratepayers, and a lack of a timely opportunity for losing bidders to challenge the utility's cost proposal. It also leads utilities to include "regulatory out" clauses in power purchase agreements which relieve them of the obligation to make contract payments if the pass-through of costs is denied. These clauses may become an obstacle to the financing of power projects.

These problems may be mitigated if, when a host utility's facility appears to be the preferred supplier, the commission's review of the utility's cost recovery requests is conducted at the same time that the commission considers the utility's petition for approval of construction of the plant. This concurrent review will ensure that alternative suppliers have an opportunity before construction begins to test the cost assumptions of the utility. The Massachusetts Department of Public Utilities enacted such a rule on October 28, 1988.[12] Utility-built facilities approved under this system would not be rate-based and therefore not subject to the profit-cap on the utility's regulated rate-of-return.

When a non-utility supplier wins the bid, pre-approval of contracts provides some assurance that the payment stream under the contract has been found to be in the public interest and therefore is not likely to be interrupted by state action after the fact. The Michigan legislature passed legislation requiring that such approvals be binding on future commissions.[13] In New Jersey, contracts do not become operative until approval of the pricing terms by the Board of Public Utilities, and the BPU has issued an order stating its intention that such approval not be subject to reconsideration in rate proceedings.[14]

Footnotes

[1] *See* Bidding NOPR Comments of Edison Electric Institute. (filed June 18. 1988).

[2] *See* Pre-filed testimony of Robert L. Lacy, Utilities Research Manager. Virginia State Corporation Commission, Virginia Case No. PUE890007.

[3] *See* Bidding NOPR at 32,031.

[4] In Massachusetts, a utility cannot recover costs associated with a major incremental investment in electric power generation without first obtaining pre-construction approval of the Department. Cost recovery under the terms of a Department Order issue pursuant to these rules is thereby deemed "proper, just and reasonable and required by the public interest, and incurred reasonable and prudently." 220 C.M.R. § 9.02. If the utility incurs costs below what has been approved it retains the profit and conversely, it cannot recover more than what has been approved. For a definition of 'major incremental investment' see footnote 19 to the Introduction, Chapter I.

[5] *See* Bidding NOPR at 32,031.

[6] *See* Pre-filed Testimony of Robert L. Lacy, Virginia Case No. PUE890007.

[7] *See e.g.* Transcript of Hearings in Virginia Case No. PUE890007 at 83-89 (Testimony of Larry Ellis).

[8] *See* Bidding NOPR at 32,036.

[9] Detailed NIEP Bidding Questionnaires were filled out for state programs and utility bidding programs initiated before June 1, 1989.

[10] *See* Bidding NOPR, Comments of Electric Edison Institute, p. 63 (filed July 18, 1988) (emphasis in original).

[11] *See* Testimony of William Berry, Chairman of the Board and Chief Executive Officer, Dominion Resources Inc., Virginia Case No. PUE890007 at 23.

[12] *See* Mass. D.P.U. 86-36-E.

[13] Under the Michigan statute, once the Michigan Public Service Commission has approved a capacity payment in a contract with a QF, that decision shall not be reconsidered during the financing period of the project, which is considered 17.5 years. *See* Mich. Stats. Ann. § 22.13(6j)(13)(b).

[14] *See* New Jersey Docket No. 8010-687B.

X. "BUILD VERSUS BUY": COMPARING COST-OF-SERVICE PROJECTS TO LONG-TERM PURCHASE CONTRACTS OFFERED IN BIDDING

Very few state commissions or utilities have much experience in comparing "build" and "buy" cost estimates in the context of a competitive procurement. On only two occasions—Virginia Power's 1988 solicitation for peaking capacity and Indiana Municipal Power Authority's solicitation—has a utility rejected all bids responding to a solicitation and decided to build the requested capacity itself. If the utility believes that it can "outperform" the market and provide cheaper and more reliable power than could be supplied by bidders, then it should be allowed to build. However, it is essential that this analysis be fair and accurate to ensure that the ratepayer obtains the most reliable power at the lowest cost. For this to occur, the utility should evaluate its own build option using the same criteria it uses in analyzing bid proposals.

Even in states with the most experience in bidding, the build vs. buy evaluation methodology may be imperfect. A review of Virginia Power's bid solicitation and evaluation process, conducted by the Virginia State Corporation Commission's Division of Economic Research and Development in 1989, concluded: "Our main concern with Virginia Power's techniques was not with the Company's solicitation and evaluation of bids, but rather with its comparison of the bids received to its own build options. . . . However, Virginia Power's evaluation program is structured to differentiate among non-company suppliers and not to compare company options to non-company bids."[1]

For competitive bidding to be successful, utilities and state regulatory commissions must develop a rigorous methodology for making the build vs. buy comparison. Listed below are suggestions for an appropriate methodology derived from review of bidding RFPs:

- *The inherent value to ratepayers and to shareholders of shifting capital and the operating risk to third-party suppliers should be recognized.* As noted above, a utility rate-based plant is given a return on its actual, rather than estimated, costs when those costs are prudently spent. Ratepayers are, therefore, exposed to the risk of poor performance, the risk of cost overruns, and the risk of construction delays. On the other hand, if the supplier of purchased power, building the same type of plant, exceeds its estimated costs, the overruns will be absorbed by the supplier, without additional costs to ratepayers.

  This risk-shifting should be a factor in evaluating alternatives to utility rate-based construction. In the Virginia hearing on Virginia Power's decision to build combustion turbines rather than award contracts to bidders, the SCC staff testified that Virginia Power had not made an effort to modify the price considerations to reflect the benefit of risk-shifting and urged the development of an expanded risk analysis to compare "build" and "buy" options.[2]
- *The cost of the build option should be evaluated in parallel with, not after, the bid solicitation.* The host utility, in preparing its cost estimates for its build option, should solicit proposals for equipment supply, fuel supply, and construction contracts before or at the same time that the RFP is sent out to bidders. Utilities should not be allowed to engage in a "post-hoc" bid, i.e., evaluating its build option only after it has had the advantage of evaluating bids from competitors.
- *The cost of security provisions must be fairly allocated in comparing build and buy proposals.* In power purchase agreements, bidders are subject to liquidated damages for shortfalls in performance or delays in construction. Security deposits of up to $30 a kilowatt are often required, representing a significant additional cost item that must be factored into the bids (Security deposits can sometimes be made in the form of letters of credit and therefore do not always require direct cash outlays). By contrast, performance criteria and liquidated damages are frequently not taken into account in connection with the build option.
- *The in-service dates of build and buy options should be the same.* If third party suppliers are required to meet an earlier delivery date than proposed utility facilities, the cost of equipment delivery, permitting, and the provision of other services on an expedited schedule dictated by an earlier delivery date will substantially increase the cost of constructing a facility. One of the allegations of disappointed bidders in the 1989 SCC hearing on Virginia Power's peaking solicitation was that the utility calculated the cost of its build units based on an in-service date three-to-six months later than the in-service date required of bidders. Virginia Power responded that the cure period in the proposed contract with third party suppliers made the delivery dates equivalent.
- *Build options should not be allowed to take advantage of economies of scale that the solicitation does not make available to bidders.* Many bidding RFPs include as a non-price factor the encouragement of diversity of ownership as a means of improving system reliability. This leads to the spreading of capacity awards among several bidders rather than just one. This requirement, which leads to smaller projects, should not be used to give a cost advantage to the utility's build option

because it can gain scale economies from building all the capacity at a single site.

- *Cost estimates for build options should be market-tested and site specific, not based on standard manuals such as EPRI's Technical Assessment Guide.* The energy and capacity payments proposed by bidders are typically developed for specific projects in specific locations. Build options should have a comparable level of detail. Utilities should not rely on generic cost and performance data derived from the Technical Assessment Guide Manual published by the Electric Power Research Institute or any other non-market standards. The cost and performance data in TAG are provided for R&D comparison only. As the TAG Manual itself says, "the data should not be used as benchmarks, for example, for comparison with actual construction projects or operating plants."[3] Another reason for not using TAG for this purpose is that the data are often dated. The current manual was published in 1986.[4] Even if adjusted for inflation, there may be a significant difference between these numbers and the market-tested numbers reflected in the bids.[5]
- *The build option must incorporate cost factors comparable to those included in bids.* State regulators, in reviewing the cost profile of build options, should ascertain that the following checklist of costs are included: interconnection costs; environmental control costs; the costs of arranging fuel supply, fuel transportation, and fuel storage; fixed O&M costs, including the costs associated with life cycle repair and replacement; permitting and regulatory approval costs; site acquisition costs; and financing costs. In all cases, the costs must be market-tested in a manner comparable to those of bidders.
- *The utility should be held to the costs projected for the build option in future cost recovery proceedings.* As noted above, holding the utility to its cost estimate is the only way to ensure that the cost comparison with bid proposals is conducted fairly. Even this remedy is no panacea. It will still require vigilance by the state commissions to make sure that ratepayers are not subsidizing the project through inappropriate allocation of overhead during construction and operation. On the other hand, if the utility legitimately brings the project in under budget, its shareholders should be rewarded for its efficiency and allowed to recover the full estimated, rather than actual, costs. (See Sect. II A and II C of the Guidelines intro.)

Footnotes

1 Virginia Case No. PUE890007, Testimony of Robert Lacy at pp. 9-10.
2 Transcript of Hearings in Virginia Case No. PUE890007 at 154, 279 (Testimony of Robert L. Lacy.)
3 Transcript of Hearings in Virginia Case No. PUE890007 at 616 (Testimony of Larry W. Ellis).
4 *Id.* at 293 (Testimony of Robert L. Lacy).
5 *See* Virginia Case No. PUE890007 *Brief of Protestant Mission Energy Company*, 22, (filed July 17, 1989).

XI.
BIDDING PROGRAMS DEVELOPED BY MUNICIPAL, RURAL ELECTRIC, AND MULTI-STATE UTILITIES

Only two municipal, two rural electrics, and one multi-state utility have held bid solicitations to date (IMPA, NCPA, Seminole, Sam Rayburn, and NEP). *See* Tables III and IV. It is expected, however, that bidding may become increasingly common as a means of filling capacity needs for these utilities in the future.

Least Public of Bidding Systems

Of all the bidding systems developed, these non-state regulated utility bidding programs have had the least opportunity for public or regulatory input and provide the least amount of information in the RFPs for bidders. For instance, most of these programs do not include a benchmark price, do permit the execution of contracts outside of bidding, and do not include a standard contract in the RFP.

Limited Oversight or Control

With the exception of having to get FERC's and, in one instance, the state's approval of the prices paid to bid winners, no other aspect of the bidding program used by this class of utilities is subject to oversight by a government agency.

Although state regulatory commissions have traditionally had little, if any, control over these utilities, bidding introduces a new set of concerns about the lack of state participation or oversight. A growing number of commissions would like, at a minimum, to see the FERC bidding rule apply standards on bidding programs instituted by these utilities.

Numerous regulatory commissions expressed concern about their inability to prevent potential cross-subsidies occurring in non-state regulated utilities, particularly multi-state utilities. Regulatory commissions and bidding participants have raised concerns about the potential for anti-competitive practices of such utilities wishing to participate in bid solicitations outside their service territories.[1]

Perhaps the best example is Northern California Power Agency's recent solicitation. As noted earlier, almost half of the MW bids were from other utilities. The bids included power from a nuclear plant, an existing rate-based, utility-owned hydro plant that will be taken out of the ratebase during the contract period and then returned to the ratebase, and two other utility-owned proposed hydro plants that are already approved for future construction but would be built sooner to provide power for NCPA's needs in the interim. There were also nine bids representing 1,200 MW of utility system sales.[2]

For projects located outside of California, it is not clear what regulatory authority will assume responsibility for any cross-subsidies that either adversely affect ratepayers or undermine fair competition.

The split in oversight of these utilities will make it difficult for a state regulatory commission to ensure that one set of ratepayers is not subsidizing another or that anti-competitive practices have occurred. For example, if a wholesale utility located in state "X" wants to bid some of its surplus power in the RFP of a utility in state "Y", how will any state regulatory commission or a losing bidder challenge the selection of the wholesale utility's bid if they suspect the bid price was subsidized.

Programs Difficult To Challenge

Without a FERC bidding rule, there will be no consistent treatment of bidding programs developed by municipal, rural electric, or multi-state wholesale utilities. Although bidding programs for IOUs subject to state regulatory commissions vary, ratepayers and bidders are at least assured of having some regulatory oversight. If either of these groups has a complaint about the actions of non-state regulated utilities, they must rely on FERC or other governing bodies, such as municipal governments, to seek redress. Filing such a complaint may be extremely time consuming and costly, especially as no system for responding to complaints in a timely fashion exists at this time.

Bidding Allows Circumventing of PURPA by Utilities

Although non-state regulated utilities are subject to the same PURPA requirements as all other utilities, bidding provides them an excellent opportunity to circumvent the requirements of the Act if they are opposed to buying PURPA power. While this is possible for some IOUs too, as discussed earlier, it is a particularly serious problem for this class of utilities due to the lack of regulatory oversight.

Conflicts with State Bidding Policies

The lack of state regulatory commission jurisdiction over these types of utilities may conflict with requirements of the state's bidding program. For instance, in Massachusetts, utilities are required to "wheel through" for winning bidders.[3] If a bidder happens to find a steam host for its proposed project in the NEP (a wholesale multi-state utility) service territory, NEP unlike all of the other utilities regulated by the Massachusetts DPU, does not feel it is subject to that requirement although it may wheel power voluntarily.[4] This could eliminate some of the competition in bidding if NEP does not wheel voluntarily.

Remedies

Several suggested remedies to these problems are discussed in the Guidelines, *supra*.

Footnotes

[1] NIEP Bidding Questionnaire and Interviews.
[2] NIEP Bidding Questionnaire and Interviews.
[3] *See* 200 CMR § 8.03(5)(b).
[4] NEP is a multistate utility and therefore believes it is subject to FERC jurisdiction with respect to wheeling rather than Massachusetts.

XII. GUIDELINES FOR COMPETITIVE BIDDING PROGRAMS

Introduction

Developing a competitive bidding program that addresses the myriad of economic, technical, and social issues associated with building new generation is a significant challenge. For competitive bidding to be beneficial to the ratepayer, it must maximize the opportunity for fair competition; solicit projects that meet the capacity, fuel, and environmental needs of the area served; and deliver facilities that provide reliable sources of electricity.

Each state, in conjunction with its utility and wholesale generators and the ratepayer, must determine what the appropriate method is for meeting its electricity demand. A bidding program that works for one state may not produce the desired results in another.

It is important to note that in all bidding systems there is a trade off between flexibility and reviewability. A rigid regulatory framework may favor regulatory oversight but choke off the flexibility in resource acquisition and negotiation needed by buyers and sellers to make projects work in the changing conditions of the real world.

While recognizing this need for flexibility, this study has nevertheless attempted to identify some of the basic issues that should be addressed in all bidding programs. NIEP has drawn from the experience and problems associated with the 41 RFPs issued as of December 31, 1989, and has developed basic guidelines for competitive bidding programs. These guidelines fall into three major categories:

I. Guidelines for preparing the foundation for competitive bidding;
II. Guidelines for determining the procedures of the bidding RFP; and
III. Guidelines for implementing and overseeing the bidding program.

Further elaboration upon each of these categories follows.

I. GUIDELINES FOR PREPARING THE FOUNDATION FOR COMPETITIVE BIDDING

A. *Develop an Electricity Resource Plan*

An important first step in implementing a successful bidding program is to determine what the demand for electricity is and how that demand is to be met. These questions are normally answered in resource plans. More specifically, a resource plan should include data on the amount of and schedule for needed capacity, the timing of solicitations, the preferred fuels, environmental considerations affecting future power projects, the role of demand-side management, transmission line constraints, and other details that together provide a blueprint on how the state will meet future energy needs. Some states require each jurisdictional utility to submit a resource plan for its service territory. A statewide plan may also be necessary to provide the overview required to achieve a coordinated energy policy. The key point is that the public service commissions must review and approve such plans after appropriate public participation.

The information contained in a resource plan should play a key role in determining the size of the supply block, the timing of RFPs, and the RFP selection criteria. For example, the conclusions of a resource plan may lead a state to encourage clean coal and renewable energy projects; the selection criteria can then be weighted to elicit proposals for these fuels. Even in states where bidding programs have already been initiated, development of a resource plan can provide an important yardstick for measuring how well the bidding program is achieving the state's over-all energy goals.

California has developed such a statewide plan and has adopted but not yet used bidding. Connecticut and Massachusetts require jurisdictional utilities to develop resource plans which are then reviewed by the public service commissions. New York is currently developing a statewide resource plan that will follow implementation of its bidding program.

B. *Determine the Role of the Regulatory Commission in the Bidding Program*

The state regulatory commission should decide the nature of its role in developing and implementing bidding programs. In Connecticut, for example, the regulatory commission developed the bidding program and conducted the first solicitation. State commissions in Massachusetts, New Jersey, New York and Washington have established guidelines for bidding and then had the utilities develop RFPs subject to state commission review. At the other end of the spectrum, utilities in Florida, Hawaii and Vermont have taken the initiative in developing bidding programs. The extent of the commission's role will, to some degree, depend upon the staffing capability of the commission.

The findings of this study suggest that regulatory commissions should exercise the following functions, at a minimum, to assure that bidding will be a predictable and fair competitive process.

1. *Public Participation*: Regardless of whether the state commission or a utility initiates the bidding program, opportunity for public comment should be provided at the critical stages in the development of the bidding process as well as on the structure of the bid itself. This requirement provides an important protection for all participants—the regulatory commission, ratepayers, host utility and bidders—by offering a safety valve for complaints and making bidding a self-correcting program. Thus far, the commissions in Massachusetts, New York, New Jersey and Washington have opened the door to active public involvement in the development of their bidding programs. The Massachusetts and New York pro-

grams, in particular, are excellent models of public participation in bidding.

2. *Active Role in Program Development*: Although the degree of commission participation in the development of competitive bidding will vary, there are certain key phases of the bidding process in which every commission should participate. At a minimum, the state commission should review and approve the design and content of the RFP. The determination of the utility's price for proposed facilities should also be subject to careful commission review. Where the state commission lacks the expertise or the staff to develop its own bidding program or guidelines, neutral third parties are available to provide assistance. The Maryland Public Service Commission, for example, has relied upon an advisory committee of third parties to help develop a bidding program.

3. *Oversight of Program*: Just as important as the development of the bidding program is the oversight of the program once it has been created. Commission oversight is particularly important to prevent anti-competitive practices. Among the responsibilities which the state commission should undertake are:

- the settlement of disputes about selection of winners, the contracting process, or other problems associated with bidding;
- the approval of winning bidders' contracts; and
- the approval of contracts signed outside of bidding to ensure their fairness in reference to the bidding program in use.

II. GUIDELINES FOR DETERMINING THE PROCEDURES OF THE BIDDING PROGRAM

Close attention to pricing, evaluation methodology, cost review, prevention of market power abuse and other factors is necessary to make bidding fair and predictable for all parties. These procedures should be subject to public review and approved by the public service commission in advance of the solicitation.

A. *Determination and Treatment of Pricing*

Perhaps the most controversial questions to be decided in the development of a bidding program are how pricing will be determined under bidding and how this price will apply to power plant construction by utilities.

1. *Utility Price Required*: The utility should file a price for its "build" proposal in every bidding solicitation. This price should be sealed and filed by the utility with the regulatory commission at the same time or before the bids are opened. Those utilities which are not subject to the jurisdiction of state regulatory commissions should similarly be required to file their prices with the FERC prior to the opening of bids.

2. *Utilities, Like Other Participants, Should Be Bound by Their Bid Price*: Any utility that is ultimately determined to be the lowest-cost supplier in a bid solicitation should be bound by the price it declared before the bids were opened. In other words, if the utility hosting the bidding competition is selected to build a generating station, it should only be allowed to recover from its ratepayers the price which it filed in advance with the public service commission. To accomplish this objective, states or state commissions may find it necessary to alter their traditional rate-making procedures for utility construction.

3. *Methodology for Determining Scoring, Ranking, and Pricing Must Be Public*: Utilities should submit the methodology for evaluating projects and calculating their proposed facility price to the appropriate regulatory commissions at the same time as they file their bid price. This information should be made public and reviewed at the commission hearing on approval of the utility facility. Access to this information is necessary in order for regulators, bidders and the public to ensure that the price determination was reasonable.

While developing its 1989 solicitation, LILCO's proposed scoring system awarded points for a company's experience in the construction of combined cycle gas plants. LILCO subsequently decided to propose a combined cycle plant of its own even though it lacked such firm experience. When the New York Public Service Commission notified LILCO that it would be held to the same scoring system, the utility changed the scoring system to eliminate the experience factor. *See* remarks of Mark Reeder, staff of NYPSC, Pacific Northwest Supply and Demand Side Competitive Bidding Workshop, Portland, Oregon, January 25, 1990.

4. *State Commissions Should Give Pre-Approval of Contracts for New Generating Facilities*: If a host utility's facility appears to be the preferred supplier, the commission's review of the utility's cost recovery requests should be conducted at the same time that the commission considers the utility's petition for approval of construction of the plant. This concurrent review will ensure that competing suppliers have an opportunity to test the cost assumptions of the utility before construction is commenced and the decision cannot easily be undone. Where state law permits, utility-built facilities approved under this system would receive the proposed price whether or not actual costs were greater or lower. The facility would not be rate-based, and, therefore, the utility would not be entitled or limited to the regulated rate of return. The Massachusetts DPU enacted such a rule on October 28, 1988. (See Chapter IX.)

B. *Develop Cross-Subsidy and Self-Dealing Prevention Policies*

The issue of cross-subsidies and self-dealing needs to be addressed regardless of whether the host utility submits its own bid in the RFP, builds because its proposed price is lower than the other bidders in its RFP, or participates in an RFP issued by another utility within the host utility's state or power pool area ("cross-subsidies" and "self-dealing" are defined in Chapter VII). Public participation in the development of these policies is essential.

1. *Enact Cross-Subsidy Rules or Prohibit Participation*: States should either adopt strong measures to prevent cross-subsidies, or the states should prohibit the host utility or its affiliates from competing in the host utility's own bid solicitation. Similarly, if a utility or its affiliates wish to participate in a bidding solicitation hosted by a neighboring utility within that utility's power pool, its public service commission should adopt measures to prevent cross-subsidies.

To date, few states have adopted measures to prevent cross-subsidies by state-regulated utilities. In New Jersey, for example, there is a three-year moratorium on participation by the host utility's affiliates in the host utility's RFP. In addition, New Jersey and New York both require the host utility and its affiliates to maintain separate books and operations. Although not required by law, several utilities, such as Virginia Power, have voluntarily decided not to allow participation by their affiliates in their RFPs.

2. *Place Burden of Proof on Utility*: States should require each utility to demonstrate that its internal transactions, transactions with affiliates, and transactions with other utilities within its power pool are arms-length transactions. If, for example, a utility is selected to build a new facility, the utility should submit proof that the components of its bid price accurately reflected market prices and that none of the components was subsidized by other parts of the utility's business. Similarly, if a utility selects its affiliate as a winner in an RFP or a utility or its affiliate participates in a bid solicitation outside the utility's service territory, the utility should demonstrate that none of the components of the bid relied upon the utility's rate-based assets or services. All of this information should be available for public review.

Of interest is a measure adopted in New Jersey that requires each bidder to certify that it has no financial, operating or consulting association with the host utility or its affiliates. To facilitate enforcement of cross-subsidy prevention rules, this measure could be expanded so that each bidder is required to certify whether its project has any utility affiliation and, if so, the nature of that affiliation.

3. *Develop Cross-Subsidy Prevention Measures for Non-State Regulated Utilities*: For those utilities which are not subject to the jurisdiction of state commissions, the FERC should issue cross-subsidy prevention measures such as those discussed above. Multi-state, investor-owned utilities, in particular, are appropriate for FERC regulation.

4. *Develop Cross-Subsidy Prevention Measures for Gas Companies*: Many of the same cross-subsidy problems which are raised by electric utilities are raised by regulated, gas utilities. State commissions should take steps to prevent cross-subsidies when gas utilities submit bids in RFPs.

C. *Procedures for Selecting Winning Bidders*

The system used to select winning bidders will depend upon the participants in the solicitation and the amount of review exercised by the public service commission. These Guidelines propose that a purchasing utility should be required to participate in each solicitation by submitting its own proposal to fill the capacity requested. While some states have proposed turning selection over to a neutral third party when the host utility is participating, on balance, it makes more sense to keep the utility involved, providing the safeguards discussed in these guidelines are followed. A successful project requires the utility and its supplier to work as partners in carrying out the terms of the contract. Therefore, as long as protections against self-dealing are in place, the utility should play a central role in the selection process.

1. *Proposed Selection Procedures* Therefore, as noted above, these Guidelines propose that the utility should submit to the public service commission the price or cost-recovery terms for the projects the utility proposes at the same time that proposals from third parties are received by the utility. The proposed scoring system, including the price and non-price factors and the weighting of each evaluation criterion, would be submitted to the commission in advance and included in the RFP. The utility should then evaluate individual project proposals using this evaluation methodology. While the utility would have discretion to negotiate some changes in the proposals of the top-ranked projects, the host utility would not be able to modify its own proposals because of the risk of self-dealing unless specifically approved in advance of final selection by the public service commission. The projects in the final award group would then be reviewed by the commission to ascertain that the RFP selection criteria and evaluation methodology had been correctly applied and that a mix of resources which optimizes its goals had been selected. Public comments would be permitted.

2. *Utility Staff Should Protect Against Disclosure of Proprietary Information*. When the utility is responsible for evaluating the bids, the state commission should require that the utility separate the staff which performs the evaluation from other staff. The evaluation staff should be prohibited from disclosing proprietary data submitted by bidders to other utility personnel. Unless ordered by the courts or a regulatory commission, the utility should also refrain from disclosing such information to other bidders until the information is no longer commercially sensitive.

D. *Treatment of Renewable Energy and Demand Side Management*

If the state determines it wishes to encourage renewable energy technologies or demand side management, then it must adjust the bidding system so that these projects are evaluated fairly when compared to other alternatives. The state might require that the selection criteria be weighted so as to provide an incentive to these types of projects, or it might develop a set-aside mechanism whereby a certain portion of the supply block is reserved for these projects.

E. *Establishment of Entrance Requirements*

Regulatory commissions should ensure that entrance requirements, such as security deposits and evidence of project maturity, do not become so burdensome as to unduly discourage potential bidders. A public review process would facilitate the achievement of a balance between ensuring that serious projects are submitted and encouraging the maximum participation in the process.

F. *Require Minimum Levels of Information in the RFP*

In addition to providing a detailed description of the filing requirements and selection criteria, the RFP should include background material that will enhance the quality of the bids received. Among the information that might be included is:

- any minimum thresholds that must be met by respondents;

- information on available transmission capacity and constraints, rates, terms, and conditions for both the host utility and adjacent utilities;
- preferred site locations within the service territory;
- a standard power purchase and operating agreement; and
- the price and non-price resource evaluation criteria.

G. *Treatment of Contract Re-Openers and Regulatory Out Clauses*

Among the most controversial provisions seen in power purchase agreements are pricing re-openers and regulatory out clauses which permit the host utility to reduce payments to the independent generator if the state commission disallows some or all of the recovery of those costs.

These clauses often make it difficult to finance projects and, in the case of QFs, may in extreme cases constitute a violation of PURPA. Utilities and state commissions have addressed this problem in several ways:

- in the event of a disallowance by a regulatory authority of some portion of contract payments by the utility, permit the payments to continue through the end of the financing period of the contract, with payments to be reduced thereafter to make up the disallowed amount (see Virginia Power's "model" contract).
- require pre-approval of bidding contract costs before the contract is made operative and the facility is financed. While this does not completely eliminate the possibility that a subsequent commission may disallow pass-through of contract costs, it makes the regulatory out clauses less threatening. The New Jersey Board of Public Utilities has ordered that once it has approved a power purchase contract which results from a solicitation, the Board "shall not readjust the contract rates previously found by it to be reasonable, or preclude their flow-through and/or full and timely recovery from the utilities' ratepayers through the levelized energy adjustment clause (LEAC) or its successor provision . . ." *See In the Matter of Consideration and Determination of Cogeneration and Small Power Production Standards Pursuant to the Public Utility Regulatory Policies Act of 1978*, Stipulation of Settlement, Docket No. 8010-687B at 47.
- require the public service commission to respect the sanctity of contracts by enacting state legislation requiring commissions to pass-through costs once initially approved (*See* Mich. Stats. Ann. § 22.13(6j)(13)(b)).

State public service commissions should review contract terms to ascertain that unduly burdensome "reg out" clauses and contract reopeners are not imposed on wholesale generators. Pre-approval of contract costs and a recognition by state commissions or their legislatures of the need to protect the sanctity of contract are recommended steps.

H. *Transmission Policies for Bidding Programs*

Although competitive bidding has advanced in many states without an obligation to provide transmission access for winning and losing bidders, there is evidence that the lack of transmission access is limiting the ability of some projects to compete and has even contributed to the failure of some winning bidders. In Virginia Power's March 1988 solicitation, for example, three winning projects later withdrew in part because of the inability to arrange for wheeling from an adjacent service territory.

1. *Transmission Access Policies*: State regulatory commissions should require that transmission access within the state be incorporated into every bidding program. At a minimum the transmission access policy should require that:

   a. utilities within the same state (or even the same power pool) should be required to wheel power from winning bidders to the host utility at non-discriminatory rates;
   b. the host utility should be required to wheel power from losing bidders within its service territory to adjacent utilities outside of its service territory; and
   c. when a utility or its affiliate is participating in bidding in an adjacent service territory, the utility should be required to wheel power out of its service territory to the adjacent service territory or through its service territory for projects in the state.

2. *Access to Transmission Information*: All bidding programs should require that transmission rates, terms and conditions for all in-state utilities be included in the RFP or be readily available to the public. This information should include, at a minimum:

- the amount of transmission capacity available on existing lines within the service territory;
- the location and capacity of planned transmission line additions; and
- the location of major load centers where power is needed.

Connecticut is one of the few states to require its utilities to provide comprehensive data about transmission capacity in the planning process. Because this information is publicly available, it assists bidders in siting projects where they are needed on the grid.

3. *Non-Discriminatory Wheeling Contracts*: The rates, terms and conditions used for wheeling power generated by winning or losing bidders must be comparable to those governing the wheeling of other wholesale purchases.

III. GUIDELINES FOR IMPLEMENTATION AND OVERSIGHT OF BIDDING PROGRAMS

A. *Oversight of Bidding Process and Contracts Awarded Thereunder*

While bidding programs should allow for flexibility in the selection of winners, particularly where non-price factors are involved, and in the negotiation of the exact terms and conditions of contracts signed between the host utilities and winners, too much flexibility can allow for abuse. To ensure a fair bidding program, state commissions should be available to resolve disputes among the participants and to review or approve final contracts. The Virginia State Corporation Commission has played an active role in resolving disputes, and the Massachusetts and New Jersey commissions have implemented procedures to approve final contracts.

1. *State Commissions Should Resolve Disputes Which*

Arise In Connection With the Bidding Process: To the extent that the state commission designs the bidding program and approves the winners, there should not be significant disputes between the host utility and the bidders as to the evaluation process. If, however, the host utility undertakes those responsibilities, bidders may well question the utility's actions, and the state commission should provide a forum for the resolution of such disputes. In Virginia, for example, the State Corporation Commission has already heard complaints from five bidders, and the Massachusetts DPU has arbitrated similar complaints.

Another area that is rife with conflict is the negotiation of contract terms. Where the state commission has not determined, with public participation, the exact wording of key provisions, it may come to pass that the host utility and the bidder cannot agree on contract language. In those situations, the state commission can play an invaluable dispute resolution role.

2. *Regulatory Commissions Should Ensure That Final Contracts Comply with the Basic Terms and Conditions Stated in the RFP*: To avoid after-the-fact complaints from losing bidders, the terms of the executed power purchase agreements should be consistent with the basic requirements of the RFP. Therefore, when the state commission reviews the final contract, it should ensure that the contract terms continue to satisfy the basic requirements of the RFP while allowing for flexibility on specific terms and conditions in the contract that would not affect the evaluation of other proposals.

3. *Utility Construction and Bulk Power Purchases Should Meet Terms and Conditions Required Under Bidding*: When a utility becomes the builder of capacity requested in its own RFP, it should be bound by the same contract terms and conditions which would have been imposed on other bidders. Since the utility cannot negotiate with itself, the regulatory commission must enforce this requirement to ensure the fairness of the bidding program and to protect the ratepayers.

B. *Oversight of Contracts Awarded Outside of Bidding Program*

One of the important roles of the state commissions is to ensure that contracts signed outside the context of bidding do not undermine the fairness of the bidding program.

1. *Determine in Advance How Much Capacity Can Be Withheld from Bidding*: During public review of the bidding program before the solicitation is issued, the host utility should justify why it is withholding capacity, if any, from bidding. If capacity is withheld from bidding, PURPA requires that QFs should be given the first opportunity to fill that capacity need.

2. *All Contracts Subject to Comparable Terms and Conditions*: If power purchase agreements are executed by independent generators outside of the bidding process, state commissions should require that the terms and conditions of these contracts be comparable to the terms and conditions of contracts awarded through bidding. Most importantly, the pricing of contracts awarded outside of bidding should not exceed the price determined in the most recent, comparable RFP issued by that utility. Otherwise, the potential exists for favoritism and other anti-competitive activities.

C. *Review Existing Regulatory Framework to Identify Additional Needs*

When developing competitive bidding programs, it is important to review existing state laws and regulations to ensure that there are no impediments to the implementation of the new programs. One of the principal issues on which state commissions and utilities have taken varying positions is the question of who may participate in the bidding program. As discussed in Chapter V of this report, the trend in most states is toward expanding the universe of eligible competitors bidding beyond QFs. The acceptance of bids from IPPs, DSM projects, and utilities may trigger the need for other statutory and/or policy changes.

Some of the areas in which amendments to existing law may be required include:

1. *Treatment of Independent Power Producers*: To the extent that IPPs are invited to participate in bidding programs, state commissions will be called upon to decide the treatment of these entities under state law. Unlike the situation with the traditional utility plant, the pricing of IPP contracts is not subject to the jurisdiction of the state commission. Moreover, most states could theoretically impose certificate, financial, reporting, procurement, and special tax requirements on IPPs. Each state must determine which of these burdens, if any, should be imposed on IPPs.

2. *Prevention of Cross-Subsidies*: As discussed earlier, state commissions must take steps to prevent cross-subsidies and self-dealing. No state has yet instituted comprehensive measures to prevent cross-subsidies while allowing full utility affiliate participation in any RFP, but, as utility participation in RFPs increases, the need for comprehensive cross-subsidy prevention measures will grow. These measures may entail new legislation or, at a minimum, review and revision of existing regulations pertaining to utility cost accounting. Each commission will need to determine the approach that is most appropriate.

3. *Review of Transmission Policies*: As discussed frequently in this report and in other bidding studies, transmission policies play an important role in the bidding process. State commissions may need to review their policies on transmission access to ensure that the absence of such policies or the limited nature of the provisions (such as requiring wheeling for QFs but not IPPs) will not hamper the state's ability to maximize the benefits from bidding. In addition, state commissions may need to review their policies with respect to a utility's release of information concerning transmission capacity, rates, terms and conditions.

4. *Review of Rate-Treatment Prudency Review Policies*: Depending upon how the state commission decides to treat the host utility in the bidding program, it may be necessary for the commission to revise the traditional rate-making process. It may also be necessary to perform an economic analysis of the utility's incentive to solicit power from independent generators and DSM projects; if there is no benefit in bidding for the host utility, the state commission might find it desirable to revise rate

treatment so as to provide some type of financial incentive to the host utility.

5. *Review and Revise the Treatment of Non-State Regulated Utilities*: In order to prevent non-regulated utilities from misusing competitive bidding and gaining an unfair advantage over potential competitors, either the FERC or the state commissions must have the authority to supervise their bidding activities. One solution would be for the FERC to issue the NOPR on competitive bidding as a final rule. This rule should establish clear guidelines for the bidding programs of utilities which are not regulated by the states and establish mechanisms for resolving challenges to these programs. Alternatively, FERC and Congress could take the necessary actions to give state regulatory commissions a greater role in the oversight of bidding activities for these types of utilities.

D. *Periodically Review Bidding Programs*

It is reasonable to expect that existing bidding programs will continue to evolve. States can play a significant role in this evolution by actively monitoring the programs. It is particularly important that the results of in-state RFPs be reviewed regularly and measured against the resource plan. If, for example, a state determines that too many winning bidders utilize a particular fuel or fail to move forward with their projects on a timely basis, modifications to the bidding program might correct the problem. If the review is conducted on a statewide basis, the state can compare the results of different types of solicitations to analyze its successes and failures in achieving the goals of its resource plan. Unfortunately, many commissions do not currently require their jurisdictional utilities to submit a detailed breakdown of the results of each RFP; without this information, efficient review and planning is difficult.

APPENDIX A
NIEP QUESTIONNAIRE

(The following is a sample questionnaire which was completed by all state public utility commissions and utilities who had bidding programs in place as of June 1, 1989.)

NATIONAL INDEPENDENT ENERGY PRODUCERS SURVEY OF U.S. BIDDING PROGRAMS

State/Commission: ____________________

Regulatory Commission Contact: ____________________

Utility: ____________________

Utility Contact: ____________________

Date Contacted: ____________________

PART I: STATUS OF BIDDING

1. *What is the status of bidding in your state?*

- ☐ have not considered bidding
- ☐ reviewing idea
- ☐ rejected concept of bidding
- ☐ developing program
- ☐ holding hearings/promulgating regulations
- ☐ issued bidding order/utility(ies) responding to order
- ☐ adopted bidding but have not used yet
- ☐ adopted bidding program and used it*
- ☐ about to issue a solicitation*
- ☐ solicitation underway*
- ☐ completed bid solicitations*
- ☐ modifying existing bidding program*

*See Part V for further details.

2. *If you are in the process of developing a bidding program, what is the timetable for implementation?*

3. *Has the state legislature mandated the use of bidding or is it considering legislation which will mandate the use of bidding?*

4. *Has the state legislature passed or is it considering legislation that changes a regulatory commission or utility developed bidding program? For example, the Connecticut legislature passed a bill requiring that demand side management be incorporated in the state's bidding program. Does such legislation obligate the regulatory commission to issue an order or rules? If so, has the regulatory commission acted yet?*

5. *If you have not considered bidding or have rejected the idea, please explain why.*

- ☐ have excess capacity and therefore do not need bidding
- ☐ prefer to negotiate contracts under existing PURPA rules
- ☐ waiting for action from FERC on bidding
- ☐ other (please explain)

PART II: DESCRIPTION OF PROPOSED OR ADOPTED BIDDING PROGRAM

6. *Does the state have a resource plan for its electricity production? If so, has the plan played a role in the development or implementation of the bidding program? For example, if the state plan favors a particular technology, does the bidding program reflect that preference?*

7. *Who develops the bidding system, the regulatory commission or the utility?*

8. *If the utility develops and implements the bidding program, does the regulatory commission approve in advance the concept of bidding or approve the bidding program prior to any solicitation?*

9. *Are there opportunities during bidding program development for public comments? For example, can the public comment on which selection criteria should be used, the benchmark price (if any) and how much capacity should be put up for bid?*

10. *What is the supply block and how is it determined? Does the regulatory commission approve the supply block?*

11. *Who can respond to an RFP for bidding?*

- ☐ Qualifying Facilities (QFs)
- ☐ Independent Power Producers (IPPs)
- ☐ Other Investor Owned Utilities
- ☐ Public Power Companies
- ☐ Host Utility or its Subsidiaries
- ☐ Rural Electric Cooperatives
- ☐ Demand Side Management/Energy Conservation Projects
- ☐ All of the above
- ☐ Other (Please explain)

12. *How frequently will solicitations be held?*

13. *If the host utility cannot participate in bidding, what role can it play in building new capacity?*

14. *If the utility is developing the bidding program (and its subsidiaries can bid), will there be safeguards to insure that the utility's subsidiaries do not receive advance notice of the structure of the program or other vital inside information such as the preferred technologies or locations? When the host utility's subsidiaries can bid in its parent company's service territory, how will cross subsidies between the host utility and its subsidiaries be prevented?*

15. *Will the regulatory commission institute measures to prevent cross-subsidies when utilities participate in bidding* ***OUTSIDE*** *their service territory? If so, how?*

16. *What safeguards are included in the bidding program to protect proprietary information in bid proposals from being used by competitors, including the utility or its subsidiary, in their proposals?*

17. *Will set-asides be used for any technology type? If so, what are the conditions for such set-asides?*

18. *If demand side management/energy conservation is included in the bidding program, how is it treated? Will projects compete directly with supply side projects or will there be separate bid solicitations?*

19. *What criteria will be used to determine who wins the competition and how will the criteria be weighted? (Provide a brief summary, full text of bidding program will be attached)*

20. *Is there a benchmark price? If so, who determines it and how? If the utility determines it, does the regulatory commission review it and/or approve it?*

21. *When the host utility can participate in bidding is the bid price binding on the host utility as well as on all other participants? If the utility cannot participate in bidding but is the builder of last resort, is it held to the benchmark price/avoided cost set for QFs and others in the bidding competition?*

22. *What is required of bidders in order to enter into a bidding solicitation? For example, are bidders required to post a security deposit in order to participate?*

23. *How does the bidding system balance the objectives of maximizing participation by a large number of players versus insuring that proposed projects have reached a certain level of maturity?*

24. Who selects the winning bids? If the utility selects the winners, does the regulatory commission review the selection?

25. *Will a standard contract containing the material terms and conditions of any bid award be included in the bid solicitation?*

26. *What other information does the bidder receive in the solicitation? For example, will there be information on the status of transmission capacity?*

27. *Does the regulatory commission issue a certificate of public convenience and necessity to all winning bidders prior to construction?*

28. *If an IPP wins in bidding, how will it be treated under state law in comparison to a QF? For example, an IPP may have to obtain a certificate of public convenience and necessity after it wins in bidding. Has any legislation been passed or proposed to provide equal treatment for IPPs and QFs under state law?*

PART III: CONTRACT ISSUES

29. *What is the length of a contract for power purchases under the bidding system? If different length contracts are allowed, how will they be compared in the selection process?*

30. *Does the regulatory commission review and/or approve the bid winners' final contracts? If there is a contracting problem, does the regulatory commission offer dispute resolution?*

31. *Is any effort being made by the regulatory commission to see that final contracts are consistent with the original terms of the solicitation and/or the standard contract (if there is one)?*

32. *Are the final contracts made public? If so, how soon after they are signed?*

33. *Are there re-openers in the contract to allow for fuel price adjustments or other changes? If so, what are they?*

34. *Do the contracts contain regulatory-out clauses permitting the utility to abrogate the contract or lower the payments? If so, what are they?*

35. *Are winning bidders required to make a security deposit? If so, what is the required deposit and under what circumstances, if any, are these deposits refunded?*

36. *Do the final contracts require any other security provisions such as the payment of liquidated damages to the utility or utility takeover of a project under certain circumstances? If so, please explain.*

37. *Will contracts under negotiation prior to the institution of bidding be grandfathered*

38. *Can contracts be signed outside of the bidding process? If so, under what circumstances? What is the basis for the price and other terms included in these contracts?*

PART IV: TRANSMISSION ISSUES

39. *Does the bidding program provide for access to transmission outside the host utility's service territory? If so, how? For example, is there a provision for wheeling power into the host utility's service territory for competing bidders or out of the host's service territory for losing bidders?*

40. *Where transmission access is provided in conjunction with a competitive bid solicitation, are the tariffs, terms and conditions posted in advance or included in the bid solicitation?*

41. *Are there any other transmission access rulings in existence in your state which are relevant to bidding such as on wheeling-in or wheeling-out?*

42. *How is the availability of transmission capacity or access for competing projects effect their evaluation in a competitive bid? In addition, how will limited transmission capacity within the host utility's service territory or into and out of the host utility's service territory be allocated among winning or losing bidders needing transmission access?*

43. *If a project requires an upgrade in transmission capacity, who pays for, builds and owns the new transmission line?*

44. *If the winning bidders need transmission access from a utility outside the host utility's service territory, will the host utility help negotiate the wheeling agreement or will the regulatory commission order it?*

PART V: RESULTS OF BID SOLICITATIONS

45. *Have any of the losing bidders challenged the outcome of the bid awards? If so, what has happened as a result?*

46. *Have any changes been made or considered in the structure of the bidding program as a result of the bid solicitations held to date or for other reasons? If so, what?*

47. *(Respondents who had completed bid solicitations were asked to fill out a series of charts (not attached). The information collected is summarized in tables throughout the text of this report.)*

APPENDIX B
THREE CASE STUDIES

The City of Newport News

The City of Newport News, Virginia, entered into negotiations with Virginia Power for the sale of power from an 18 MW municipal solid waste plant in November 1985. When Virginia Power terminated the pending negotiations with Newport News in December 1986 and announced the implementation of its first competitive solicitation, Newport News protested but submitted a bid nevertheless. After examining all of the bids submitted, Virginia Power advised Newport News that it would not commence or recommence negotiations. Newport News thereupon filed a complaint with the Virginia State Corporation Commission.

Newport News made three allegations in its complaint. First, Newport News accused Virginia Power of collusion with its sister company, Virginia Natural Gas (VNG), and with several large cogenerators offering to arbitrarily locate along the proposed VNG pipeline for the purpose of furthering VNG's plans to construct that pipeline and Virginia Power's plans to construct a large combined-cycle facility at its Chesterfield Station near that pipeline. Second, Newport News maintained that Virginia Power had arbitrarily changed its forecast of load growth so as to justify its decision. Finally, Newport News insisted that it was a violation of the Public Utility Regulatory Policies Act for Virginia Power to refuse to negotiate with a QF. Newport News requested a stay of the SCC's consideration of VNG's and Virginia Power's certificate applications relating to the proposed pipeline and Chesterfield Unit 7, and an arbitration of the outstanding contractual issues.

The SCC denied the request for stays, but it agreed to arbitrate the contractual dispute. Hearings were held and briefs were filed by the parties. Eventually, the parties agreed upon acceptable terms and conditions and Newport News was allowed time to obtain local approval of the project. Because of strong local opposition, Newport News was unable to obtain this approval and was forced to withdraw its proposal to Virginia Power.[1]

Tellus, Inc.

Like Newport News, Tellus, Inc. commenced negotiations with Virginia Power prior to the institution of the first competitive solicitation. In September, 1986, Tellus submitted a proposal to build a 208 MW, combined-cycle cogeneration plant near Leesburg, Virginia. Virginia Power, however, terminated those negotiations in December 1986, and invited Tellus to submit a bid in the competitive solicitation. Although Tellus accepted most of Virginia Power's criteria by a letter dated January 12, 1987, Tellus reserved the right to restrict Virginia Power's requirement for full dispatchability. When Tellus attempted to clarify this limitation in March 1987, over one month after the deadline for responses to Virginia Power, the utility refused to consider the clarification, in part because the Tellus request arrived one day before the announced date for informing bidders of the solicitation results. Accordingly, the project proposed by Tellus was not selected by Virginia Power to fill the capacity block, and Virginia Power merely offered to buy energy from the project at its avoided energy cost.

Tellus promptly filed a petition with the SCC for a declaratory order alleging that Virginia Power's refusal to contract with Tellus on the basis of its original offer and its subsequent revised offer was a violation of PURPA and the procedures established by the SCC in its January 1983, order implementing the provisions of PURPA and requiring Virginia Power to negotiate with large QFs. More specifically, Tellus argued that it was entitled to capacity and energy payments as of the January 1987 date when Virginia Power refused to contract with Tellus because Virginia Power needed capacity at that time (by contrast to the situation several weeks later when Virginia Power had selected other QFs to provide the needed capacity). Moreover, Tellus asserted that it was not required to comply with Virginia Power's selection factors and that those factors should only be used to affect the rate for purchases, not whether the purchases would be made at all. Tellus also claimed that Virginia Power was improperly relying on the cost of Chesterfield Unit 7 to determine its avoided cost and not on the avoided cost methodology approved by the SCC that required a comparison of Virginia Power's production costs with and without QFs. For these reasons, Tellus requested the SCC to order Virginia Power to enter into a contract with Tellus and to use the approved methodology for determining avoided cost.

In December 1988, the SCC agreed to hear argument on the issue of whether federal law or SCC decision barred Virginia Power's discontinuation of the negotiations with Tellus. The SCC expressly postponed consideration of the question of whether Virginia Power was unreasonable in dealing with tellus. Subsequently, the SCC ordered Virginia Power to negotiate with Tellus. Those negotiations are still in progress.

Ultra Cogen Systems

In November 1987, Ultra Cogen Systems filed with the SCC eight petitions for arbitration in connection with six different QF proposals and two small power production proposals. Some of these proposals were rejected in Virginia Power's 1986 solicitation and others were proposed long after the conclusion of that process. Ultra Cogen argued that Virginia Power had refused to contract with it by offering only unfinancable terms and, in some cases, by refusing to negotiate at all. Specifically, Ultra Cogen requested the SCC to arbitrate a long list of contractual issues relating to payments for power, terms of the agreement, penalties, security, interconnection costs, obligations during force majeure events and changes in law or regulation, and utility takeover of the project.

In response, Virginia Power maintained that it had not failed to negotiate but that it had selected other proposals that met its requirements. Ultra Cogen's early proposals, on the other than, were not responsive to the solicitation because, for example, there were limitations on full dispatchability and alterations to the pricing provisions. Moreover, Virginia Power was always willing to purchase energy from the facilities. Virginia Power also complained that these arbitrations would undermine the pending SCC investigation into Virginia Power's capacity procurement practices and that it would afford Ultra Cogen an unfair advantage over other developers.

Upon the conclusion of the SCC investigation, Virginia Power announced that it was preparing to issue another solicitation, and it asked the SCC to dismiss the arbitration petitions in February 1988. Rather than dismissing the petitions, however, the SCC agreed to arbitrate to conclusion those disputes pending at the time on the basis of the SCC's January 1983 order. Virginia Power was authorized to proceed with its next solicitation, but the SCC made clear that he amount of capacity available for bids would be adjusted depending upon the outcome of the arbitrations.

In a series of orders, the SCC arbitrator then shepherded the parties through the unresolved issues. The first ruling established that Ultra Cogen was entitled to avoided cost payments determined as of the date on which it filed its petitions for arbitration, and it described the methodology to be used in that determination. The second ruling approved the results of a month of negotiation: the proper payments and other terms. The arbitrator also ordered that Ultra Cogen would ultimately receive contracts for only four projects in Virginia Power's service territory. After resolving a dispute over the escalation index, the parties submitted four identical contracts for the arbitrator's approval on September 30, 1988.

Footnotes

[1] In the interim, having learned of Virginia Power's intention to issue another competitive solicitation, Newport News requested an order from the SCC restraining Virginia Power from soliciting or accepting proposals. Tellus filed a similar motion which was joined with the request of Newport News. Consideration of this matter was postponed, however, when Virginia Power voluntarily agreed to delay the second solicitation until the conclusion of the SCC's investigation of Virginia Power's capacity procurement practices.

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