ENERGY FOR THE FUTURE

# PLANNING FOR COMPETITION:

## INTEGRATED RESOURCE PLANNING AND THE INDEPENDENT POWER INDUSTRY

July 1993

NATIONAL INDEPENDENT ENERGY PRODUCERS

# PLANNING FOR COMPETITION:

INTEGRATED RESOURCE PLANNING
AND THE INDEPENDENT POWER INDUSTRY

# ACKNOWLEDGMENTS

This report was drafted by Nancy Sutley, Policy Director, NIEP. NIEP gratefully acknowledges the contribution of Bob Sherman, Cogen Technologies, Chairman of NIEP, who, in his previous capacity as Chair of the Markets & Competition Task Force, oversaw the production of this paper over its many months of gestation.

Reviewed by the NIEP Markets & Competition Task Force:

Lawrence W. Plitch, (Chairman)
Wheelabrator Technologies, Inc.

Robert T. Sherman, Jr.
Cogen Technologies

Roger Naill
The AES Corporation

Robert Frees
Air Products and Chemicals, Inc.

Thomas M. Campone
Coastal Power Production Company

Carol Cunningham
Consolidated Pumped Storage, Inc.

Timothy R. Dunne
CRSS Capital, Inc.

Charles J. Micoleau
Curtis, Thaxter, Stevens, Broder & Micoleau

Stephen C. Jenkins
Destec Energy, Inc.

John Stauffacher
Destec Energy, Inc.

Richard H. Davis
Destec Energy, Inc.

Ellen S. Roy
Intercontinental Energy Corporation

Bernard H. Cherry
Oxbow Power Corporation

Steven D. Burton
Sithe/Energies Group

David R. Works
U.S. Generating Company

Joseph C. Lane
ABN-AMRO N.V.

David F. McDermitt
BMc Strategies, Inc.

Ms. Kim H. Doyle
Deloitte & Touche

Gerard W. Kurek
Deloitte & Touche

John Buehler
Energy Investors Funds

Robert R. Reilley
Enron Power Corp

E. Odgers Olsen, Jr.
Ernst & Young

Timothy Allaire
Gas Ventures Advisers

Louis S. Zimmerman
Fulbright & Jaworski

W. Harrison Wellford
Latham & Watkins

Reinier H.J.H. Lock
Leboeuf, Lamb, Leiby, and MacRae

Roger Feldman
McDermott, Will & Emery

# TABLE OF CONTENTS

| Chapter | | Page |
|---|---|---|
| I. | Introduction | 1 |
| II. | Competitive Procurement in IRP Processes | 5 |
| III. | Utility Incentives in IRP Processes | 9 |
| IV. | Conclusion | 15 |

# CHAPTER I
# INTRODUCTION

ntegrated Resource Planning (IRP) processes are spreading across the country. Their popularity can be linked to the growing consensus that traditional utility planning, focused only on utility-owned generation additions to the utility system, simply will not satisfy the expectations of regulators or consumers. There is no mystery why this is true. With its focus on broad public participation and evaluation of many alternatives, IRP proponents believe that IRP is more flexible, anticipatory and ultimately more satisfactory to ratepayers, regulators, suppliers and utilities, than traditional utility planning. IRP addresses issues that had often been ignored in the past, such as who should build generating facilities, investment in demand-side management, and consideration of social goals such as minimizing environmental costs.

The forces behind the shift to IRP became evident twenty years ago. In the early 1970s, utility planning began to show its vulnerability by being unable to respond to volatile economic conditions and swings in consumption patterns. The shortcomings of utility planning hit home as commissions disallowed an estimated ten percent of all utility construction expenditures in the 1980s.

Clearly, this trend of disallowances could not continue unchecked without jeopardizing the financial health of the entire utility industry. As a result, commissions began to explore more collaborative and comprehensive IRP processes which integrate utility planning functions, such as need determination and resource acquisition, into a single process as an alternative to traditional utility planning. IRP processes, it is hoped, better respond to the new economic realities such as the disappearance of the natural monopoly in generation or volatility in demand. IRP also reflects changes in the regulatory compact since the early 1970s — for example, the need for broad early public acceptance of planning decisions. Finally, IRP processes provide a more useful framework for responding to and managing the vast array of new suppliers and supply and demand alternatives which have been introduced in the marketplace.

The growth of IRP processes in the 1980s sought to move utility planning out of the backroom and into the sunshine. How utilities made decisions to seek new resources, what new resources they would seek and how those new resources would be acquired were opened to public scrutiny. The mid-1980s saw

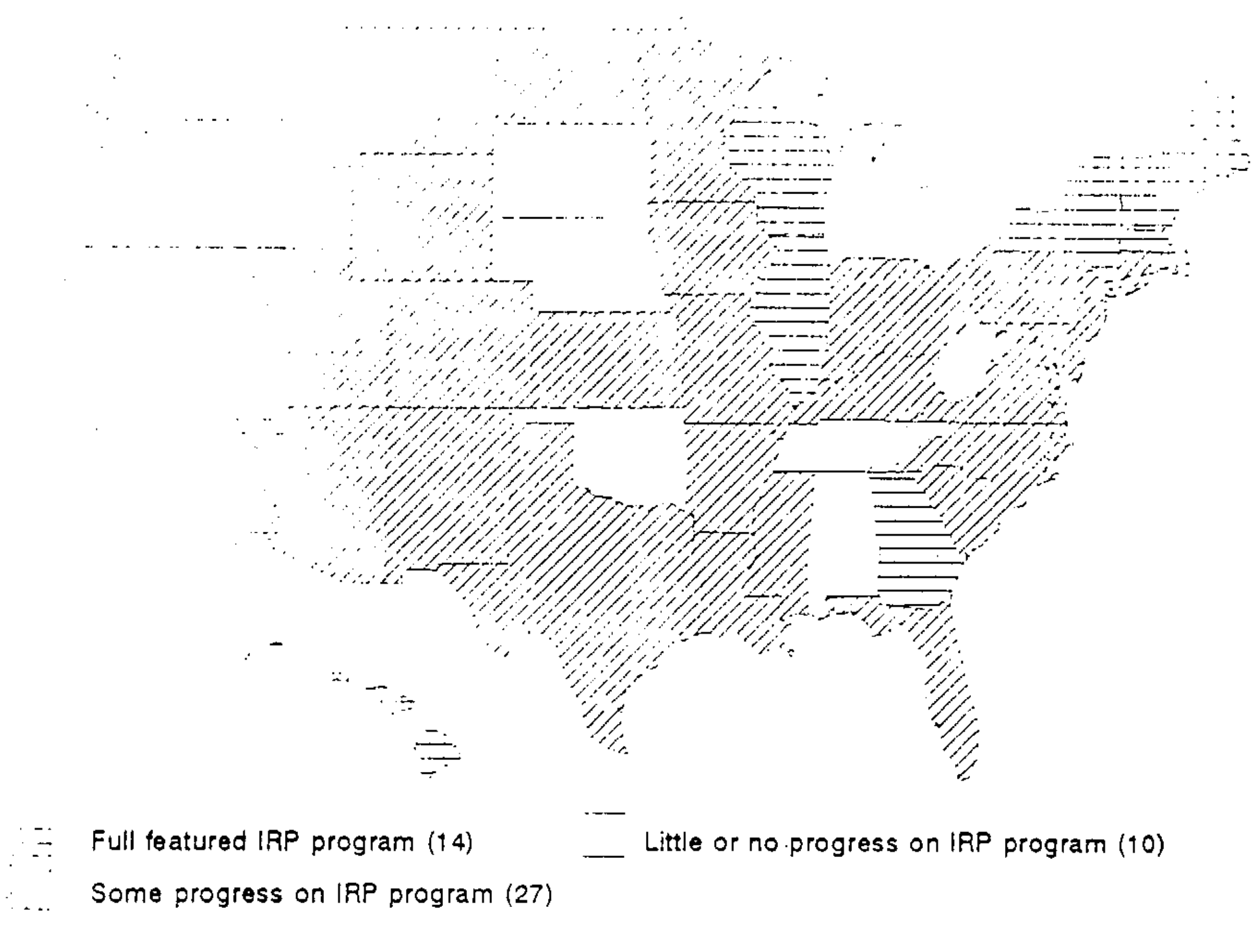
*IRP addresses issues that had often been ignored in the past, such as who should build generating facilities, investment in demand-side management, and consideration of social goals such as minimizing environmental costs.*

IRP processes popping up in places such as California, Maine, Nevada, New York, Washington and Wisconsin. Today, a recent survey reports 14 states have "full-featured" IRP programs in place, while another 27 states have made some progress in establishing an IRP program. The survey found only ten states which had "little or no progress implementing an IRP regulatory framework." [1] (See Table 1)

IRP processes take on different faces in different parts of the country, but they share a number of common elements. Generally, the process begins by defining the goals of IRP. Then the utility develops load forecasts and identifies need over the forecast period. Next, the utility evaluates alternatives and prepares a preferred resource plan. The commission approves the plan and it is implemented by the utility. The utility and commission monitor its implementation, making changes as necessary.[2] IRP proponents note that these processes represent an improvement over past planning because they separate consideration of the cost of utility-owned generation done in the evaluation stage from cost-recovery and ratemaking in the implementation phase, rather than considering both together after-the-fact. In many cases IRP processes also explicitly focus on financial incentives and disincentives to the utility in planning, decision making and cost recovery.

**TABLE ONE**

## IRP Implementation in the States




Source: Mitchell, Cynthia, *The Electricity Journal*, May 1992

## WHAT IS IRP?

DEFINITION AND IMPLEMENTATION

**The National Association of Regulatory Utility Commissioners (NARUC) defines IRP as "a way of analyzing growth and operation of utilities that considers a wide variety of both supply and demand factors so the optimal way of providing electric service to the public can be determined."[3]**

NARUC goes on to note that IRP usually consists of a number of discreet steps:

1. Identifying objectives;
2. Developing forecasts;
3. Determining the levels of capacity for each year;
4. Identifying needed resources;
5. Evaluating resources consistently;
6. Selecting the most promising options;
7. Integrating supply and demand;
8. Constructing scenarios under a variety of circumstances;
9. Evaluating mixes of options under various scenarios;
10. Analyzing the uncertainty;
11. Screening alternatives;
12. Ranking alternatives;
13. Testing the cost-effectiveness of alternatives;
14. Reevaluating the alternatives;
15. Selecting and approving an implementation plan;
16. Developing an action plan;
17. Implementing an action plan;
18. Monitoring and evaluating operation of the plan.[4]

The notion of integrated resource planning (IRP) means many things to many people. For the independent power industry, IRP can provide an opportunity to examine and participate under equal terms and conditions in utility resource acquisition — a process which should naturally lead utilities to evaluating all supply and demand options. With Congressional enactment of Public Utility Holding Company Act (PUHCA) reform and transmission access in the Energy Policy Act of 1992, utilities will be faced with ever increasing choices as the boundaries of competition expand. IRP processes should give utilities a comprehensive and consistent method for evaluating alternatives and making choices which fit the needs of their ratepayers.

Moreover, regulatory and public participation in IRP processes presents greater opportunities for collaboration and consensus building. In the long-run, this should make utility resource acquisition decisions more likely to stand up over time and less likely to be subject to after-the-fact, prudence-based challenges if market conditions change.

Public participation is critical to the success of any IRP program. Opportunity for public comment should be provided at critical stages of development of the IRP and any resource acquisition program which springs forth from it. Such participation provides a "safety valve" for identifying contentious issues early and allowing the process to correct itself. Broad public participation also invests participants with an interest in the outcome — such interest may make them less likely to challenge assumptions, mechanisms and decisions in which they participated if market conditions change.

Efforts to update regulatory practices also reflect changes in the industry, including the growth of supply-side competition. For both utilities and independent power producers, that can translate into less apprehension on the part of the financial community about the certainty of future revenue streams. Certainty translates into lower-cost capital. Lower-cost capital translates into lower electricity prices.

Successful IRP programs create an unbiased framework for competitive markets to flourish. IRP efforts which beget a rigid, adversarial planning process or which focus on the "social engineering" aspects to the exclusion of all others may ultimately only succeed in frustrating competition. For example, IRP processes which require complicated reviews over a long period of time end up being very expensive, difficult in which to encourage broad participation, and risk falling out of step with shifts in demand. Therefore, potential competitors may stay away from certain IRP processes if final decisions cannot be made relatively quickly.

Moreover, demand-side management (DSM) and environmental externalities have been the practical and political engines fueling interest in IRP — workable systems and good results will keep the movement alive. For instance, IRP programs which look only to encourage utilities to invest in DSM without regard to evaluation of performance or demonstration of system-wide benefits may ultimately provoke a backlash against IRP and those investments. Recently there have been stirrings of rebellion against such programs. Regulatory trends occasionally sweep the industry only to sink under their own weight, to be remembered by regulatory junkies and academics.

## NOTES

1. Mitchell, Cynthia, "Integrated Resource Planning Survey: Where the States Stand," *The Electricity Journal*, May 1992, page 11 - 12.

2. This general process is described in E. Hirst, B. Driver, and E. Blank, "Integrated Resource Planning: A Model Rule," *Public Utilities Fortnightly*, March 15, 1993, pp. 24 - 28.

3. National Association of Regulatory Utility Commissioners, *Least-Cost Utility Planning Handbook for Commissioners*, Volume 1, Washington, DC, October, 1988, pages 2 and 3.

4. NARUC, page 19 - 20.

# CHAPTER I I
# COMPETITIVE PROCUREMENT IN IRP PROCESSES

Central to the conduct of a successful IRP process is the evaluation of alternatives to meet future need. While much attention has been focused on using IRP to promote demand-side alternatives, regulators should view acquisition of supply resources as an equally, if not more important, facet of the IRP process. However, all supply acquisition programs are not created equal. This section of the paper will focus on the goals and principles of successful procurement of new generating resources. We believe that competitive procurement systems, as opposed to traditional methods of resource acquisition, will be most likely to yield results which are most consistent with the goals of the IRP process.

The ways in which new supplies of electricity are secured by utilities has changed drastically over the last decade. From the advent of the independent power industry, the generally accepted notions of prudent acquisition have changed in many states. The Public Utility Regulatory Policies Act of 1978 (PURPA) required utilities to purchase the output of qualifying cogeneration and small power production facilities (QFs) at prices set at the avoided cost of utility generation. The growth of independent generation in many states demonstrated the extent to which the natural monopoly characteristics of generation had given way to economies more consistent with competition such as, fewer economies of scale and ease of entry.

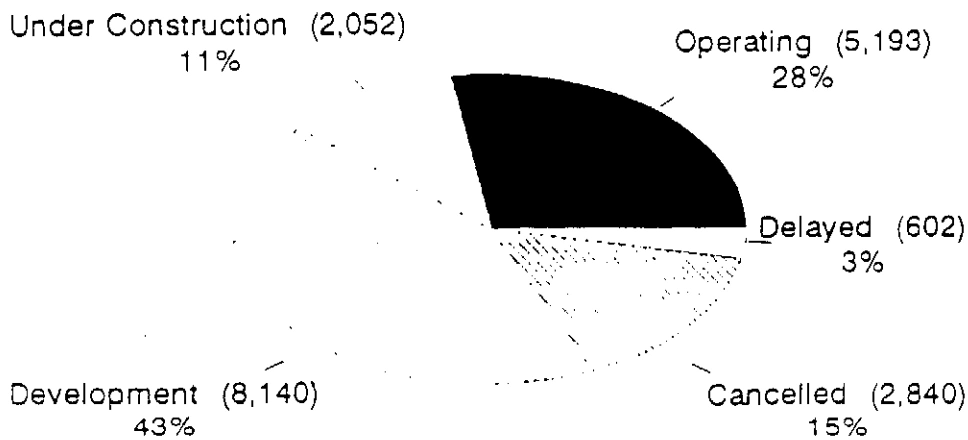
Since PURPA, much has been made of the imperfections of states' interpretations of avoided cost. Yet, despite the difficulties of administrative determination of avoided cost, PURPA served to demonstrate to utilities and regulators the promise of competition in securing new supplies of generation.

One only needs to examine the evolution of competitive bidding to understand the powerful potential of competition. In the early 1980s, avoided costs based on a nuclear powerplant unleashed a flood of QFs on the doorstep of utilities in Maine. In a defensive response, Maine turned to competitive bidding to allocate or ration capacity contracts. By contrast, only a few years later, Virginia Power took the initiative in favor of competitive bidding which they recognized could bring them competitively priced supplies of power to meet burgeoning demand without the need to commit extensive capital of their own to an ambitious powerplant construction program.

Since then, utilities and regulators have shown increasing acceptance of the potential of bidding. Bidding for new power supply is widely used in the electric utility industry. As of February, 1993, 70 utilities have issued 107 requests for proposals for 26,237 megawatts. In response, they have received bids for 230,074 megawatts and selected 18,679 megawatts of winning bids.[5] (See Table 2)

**TABLE TWO**

## Status of Winning Bids In Megawatts
(From 1984 through February 1993)




Source: Current Competition, Vol. 4, No. 1, February 1993

Bidding systems continue to evolve as utilities and regulators experiment with different formats. A 1991 National Independent Energy Producers' (NIEP) report on bidding noted concerns about bidding systems which were overly rigid and those with too high an emphasis on price to the exclusion of other important evaluation criteria, such as reliability, fuel supply security, site selection and others.

It is important to consider the role of competitive procurement in its many forms — competitive bidding, competitive contracting or competitive negotiation — in integrated resource planning processes. IRP processes are designed to ensure that utilities thoroughly consider the range of alternatives available to meet future demand and to make choices which satisfy the needs of ratepayers and the community at a reasonable cost. In many jurisdictions, these needs must be met at the lowest reasonable cost. Generally included in the definition of lowest reasonable cost is the requirement that costs be adequate to maintain the reliability and viability of the utility system, with consideration of, for example, availability rates, security of fuel supply, benefits to the environment and other considerations affecting operating reliability. The use of competitive procurement in integrated resource planning can help utilities meet these requirements.

### A. Goals of Competitive Procurement

Competitive procurement can help utilities meet IRP goals by offering a range of market-priced supplies and suppliers from which the utility can choose the option which best meets the needs defined by the resource plan. Whether instigated by the utility or conducted under commission rules, competitive procurement must rely on market-driven forces to produce the desired competitive results.

Towards this end, market-driven competitive procurement systems should meet a number of general criteria. The process should be one that competitors believe they understand and in which they feel they have a reasonable chance to be successful. Such a process would entail clear criteria, consistent evaluation of supply alternatives and an overall sense of fairness or neutrality. The procurement process should also communicate sufficient relevant information to allow participants to submit the most competitive proposal they can. The rules or structure should be fair and not permit any competitor, including the utility itself, to gain an unreasonable advantage.

Special attention must be paid to the role of the utility in design and evaluation of the procurement system. Where it desires to build a powerplant to meet its own need, the utility should abide by the same rules, terms and conditions it would impose on third parties. Failing that, the market may be undermined.

These market-driven processes should be conducted without unnecessary delay so that the circumstances upon which the solicitation is based do not change materially. Competitors will often commit substantial resources to the preparation of a competitive proposal. Moreover, the process should seek to keep the cost of participation reasonable to encourage as many qualified suppliers as possible to submit proposals.

Well-designed and fair competitive procurement processes should lessen the likelihood of lengthy challenges to the conduct and result of the solicitation process. Challenges to conduct of the solicitation are less likely when parties agree up front with the criteria and design of the program and where the process is conducted fairly and openly. The results should also be more likely to be accepted under those conditions.

Systems which are well-designed and implemented should also instill confidence by regulators in the conduct and result of the process. Regulators recognize that competition gives them a powerful new economic tool against which to evaluate utility performance. However, the system should give regula-

*IRP processes are designed to ensure that utilities thoroughly consider the range of alternatives available to meet future demand and to make choices which satisfy the needs of ratepayers and the community at a reasonable cost.*

tors assurance that the utility will continue to be able to meet its obligation to serve. Also, the process should result in resource selections which can be financed, come on-line, on-time and operate reliably over time at a competitive price.

everal steps should be taken to assure an effective IRP process. First, the regulatory commission should establish up front in a public process the policy goals of the IRP, including the public policy goals of competitive supply acquisition. Second, the individual utility should develop an IRP process, including its competitive procurement process, which the commission would evaluate in a public process to determine how well it will meet the established goals.

his process implies a fair amount of utility discretion in designing and implementing its IRP process, including how it conducts its competitive supply acquisition. Such a grant of discretion will require clearly stated goals, active participation by affected parties in all phases of design and implementation, and careful oversight of design and results by the state commission.

### B. Principles for Competitive Procurement

These goals then must be translated into design and implementation of workable competitive procurement processes. When considering competitive procurement, it is important to keep in mind a few basic principles. A healthy, viable competitive power industry is essential for ratepayers to continue to receive the benefits of competition in electric power markets. Competition does more for ratepayers than just reduce costs — it also:

- stimulates innovation;
- shifts risk away from ratepayers;
- promotes efficiency and penalizes weak management;
- establishes a competitive benchmark for commissions with respect to resource acquisition; and
- encourages the development of various fuels and technologies.

Having many qualified suppliers willing to propose new generation should ensure selection of the best mix of resources. A fair, efficient and effective procurement process will help ensure the continued viability of competitive power markets and participation by qualified suppliers. The worth of a competitive procurement system is often judged in terms of the ratio of megawatts proposed to megawatt requested. However, a more effective measure of success may be whether the system results in generating a number of project proposals which can be brought on-line, on-time and at the contracted price. System reliability is a valued hallmark of the U.S. electricity sector, whether powerplants are constructed by utilities or independent power producers.

In designing a successful procurement system, a number of steps should be followed. First, policy and social goals for resource procurement should be clearly articulated up front through a public process. For example, regulators need to make determinations about how decisions will be made in the IRP process regarding the mix of fuels and technologies, supply and demand-side resources, utility-owned powerplants and power purchases from third-parties. How these decisions will be made will vary from state to state depending on geography, climate, environmental needs, the labor market, the fuel market, the age of existing plants, the current fuel mix and other variables. In addition, policy goals may include any number of issues important to ratepayers, citizens, utilities, and third-party competitors, such as:

- promoting cost-effective demand-side management;
- evaluating verifiable environmental impacts;
- addressing the role of renewables and other technologies in the generation mix; and,
- considering long-term incentives for utilities to purchase power.

Commissions should require utilities to evaluate all potential resources to meet need. This contrasts with traditional utility planning where the utility considered a limited number of system additions which it would then construct itself. Opening the process to many qualified suppliers will ensure that utilities consider all possibilities to satisfy future demand. In addition, to protect ratepayers, the commission should set standards of accountability which are applicable to buyers and builders, for example, setting out the conditions for cost recovery. These measures of accountability should include determining the proper balance of long-term versus short-term resources where the evaluation of alternatives and the mix are based on life-cycle analysis over the planning horizon. The utility should be prepared to demonstrate that its selection best meets the criteria established up front in the public process.

For many reasons, utilities may choose to participate in their own solicitation processes. When the utility participates, a neutral third-party should evaluate all proposals under the supervision of the state regulatory authority. The utility should be required to submit a sealed response at the same time that other proposals are due. Finally the utility should agree to be bound by the same contractual terms and conditions as other competitors. These contractual requirements often include limitations on cost recovery to the bid price, treatment of unforeseen cost changes, penalties for missing milestones and criteria for operating performance. So long as the selection process is fair, this contractual approach implies that, to the extent the utility's actual costs are lower than their bid price, the utility should still be able to recover the bid price.

If a utility chooses to proceed in building its own plant, the utility should be prepared to publicly justify its selection, as well as the basis for eliminating other proposals. Moreover, in any solicitation process, there should be sufficient mechanisms to assure that the utility employs a fair evaluation process for all resource proposals, including its own. Also, the commission should oversee the results with special attention paid to the treatment of the utility build option.

Competitive procurement systems may vary from utility to utility and state to state. While commissions should require utilities to employ some kind of competitive supply acquisition, it is not always necessary for a commission to issue detailed rules regarding the actual structure of resource solicitations. In some cases, detailed rules may be warranted and appropriate and may produce desired outcomes, but the need for such detail may not be uniform across the country. Moreover, in most circumstances, commissions can and should allow utilities discretion to take into account qualitative factors in the solicitations consistent with established guidelines.

There is a wide variety of designs of competitive procurement systems, ranging from standard offers at avoided cost, formula-type bidding and "pure" negotiation. A system which provides some measure of flexibility to both supplier and purchaser will likely be desirable in most cases. The ingredients necessary for successful acquisition, completion and operation of a powerplant may not always be able to be captured in a series of generic or rigid requirements. The structure of the procurement process also should not place undue restrictions on the flexibility of parties in the contracting process as well, so long as the fundamental characteristics on which the project selection was based do not change significantly and thereby undermining the inherent fairness of the process.

Commissions and utilities may consider alternatives to "formula" bidding which use a multistage screening process to first eliminate low quality bidders through pre-qualification. In the second step, the utility should screen projects based on specific technical and financial detail submitted by the supplier. This detail should include, but be not limited to, price. Price should be an important determinant, but not necessarily one overemphasized to the detriment of other critical subjective criteria, such as reliability, developer experience and capability.

**NOTES**

5. *Current Competition*, Volume 4, Number 1, February 1993, page 16.

# CHAPTER III
# UTILITY INCENTIVES IN IRP PROCESSES

inancial incentives to utilities in IRP processes have largely been confined to demand-side management (DSM) activities. Under many of these incentive programs, utilities have generally been made whole for program expenditures, often at least partially compensated for lost sales, and in some cases, been permitted to earn profits from DSM. The emphasis on financial incentives for DSM has led, in some states, to concerns over high program costs and questions about the long-term value and effectiveness of some DSM investments. Moverover, increasingly there has been discussion in the industry about extending incentive programs to supply-side acquisition and other activities by utilities.

Some of the interest in incentives for supply-side activities has arisen from concerns that competition is changing the fundamental nature of the utility business. Utilities treat purchased power as an expense, recovered dollar for dollar from their ratepayers. However, under current regulation, utilities are typically only permitted to earn a rate of return on the value of the capital assets in their ratebase. This can create an asymmetry in how utilities view building their own powerplants as opposed to buying power to meet need. If utilities do not continue to add assets to ratebase, it is argued, they will have less opportunity to profit and attract shareholders. In addition, the credit rating agencies which rate utility debt argue that some portion of purchased power expenses should be viewed as a "debt-like obligation," limiting a utility's financial flexibility and perhaps, increasing risk. Some utilities and rating agencies argue that permitting financial incentives for purchased power could compensate them for this perceived increased risk.

This section considers some of the advantages and disadvantages of financial incentives for utilities. It also reviews a number of options for structuring incentives. Finally, it addresses a number of critical policy considerations.

### A. Advantages to Considering Financial Incentives for Utilities

The popularity of incentives on the demand side and the potential financial implications of the changing nature of the electricity industry on utilities do not necessarily, in and of themselves, establish the merit of financial incentives for utilities as a public policy goal of an IRP process. However, there are certain potential advantages of financial incentives which have been accepted in other regulated or monopoly industries. In addition, financial incentives can eliminate disincentives and encourage the symmetric treatment of utility build and buy options. Currently, since power purchases are treated as expense items on which utilities earn no profit, it can be argued that there exists a financial disincentive to purchase power.

The utility business clearly is changing. With the advent of competitive power, demand-side management and other purchased power options, utilities are evolving more towards becoming portfolio managers and necessary middlemen for consumers rather than only investors in capital assets. However, they also maintain their obligation to serve. Therefore, permitting financial incentives in ratemaking could allow the utility to earn a reward for smart, effective and reliable portfolio management. Current regulatory structures generally only allow utili-

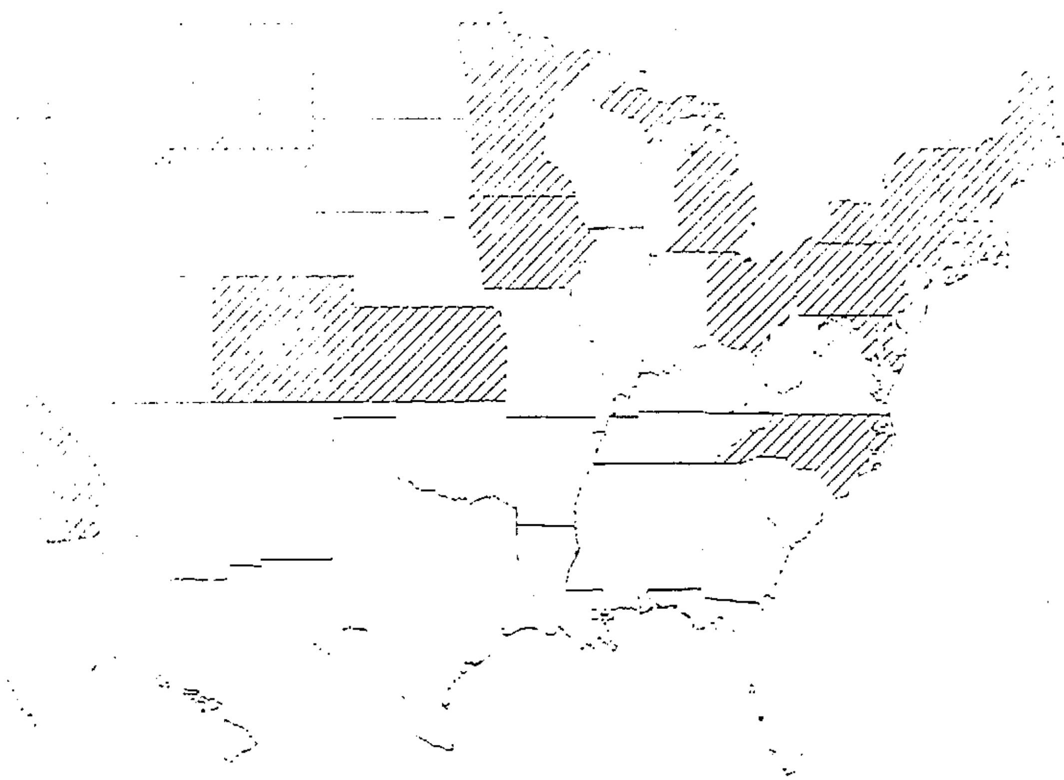
***With the advent of competitive power, demand-side management and other purchased power options, utilities are evolving more towards becoming portfolio managers and necessary middlemen for consumers rather than only investors in capital assets.***

ties to earn profits from capital assets. It then may be appropriate to consider alternative ways for utilities to earn a return for the services they provide.

Regulators are becoming increasingly sympathetic to the value of incentives for regulated monopolies, such as electric utilities, natural gas pipelines, local telephone service. A number of states allow electric utilities to profit from DSM investments. Twenty-two states permit some kind of financial incentive or lost revenue recovery mechanism for utility DSM programs.[6] (See Table 3)

**TABLE THREE**

## DSM Incentives by State



Permits some form of incentive for DSM (22)

Has no incentive for DSM (29)

Source: NARUC Compilation of Utility Regulatory Policy, 1991-1992

ome states, such as Mississippi and New York, are considering or have allowed performance-based incentives for categories of utility costs. In October, 1992, The Federal Energy Regulatory Commission (FERC) issued a policy statement on design and implementation of financial incentives, primarily aimed at natural gas pipelines. Finally, some states have set performance-based price caps for local telephone companies. Proponents of these incentive programs argue that rewarding utilities based on long-term performance may be a more effective tool of regulation than relying solely on punishing utilities for mistakes as the prudence standard under cost-of-service regulation often does.

Moreover, there are already some incentives present for electric utilities in traditional cost of service regulation; for example, the opportunity to earn a reasonable profit on capital investments or the ability to take advantage of fixed-cost recovery between rate cases (regulatory lag). These incentives can occasionally reward certain utility activities, but they may do little to stimulate efficiency. As a staff report to the California Public Utilities Commission noted: "These weak incentives and the monopoly franchise historically enjoyed by ... utilities tend to foster an environment in which the utility develops and puts to use skills that differ considerably from those on which firms operating in an intensively competitively market must rely."[7]

Some economists believe these regulatory incentives may in fact result in over investment in capital assets due to the Averich-Johnson (AJ) effect. The AJ effect postulates that because utility shareholders earn a return only on capital investments, but not operating expenses, utilities have an incentive to over invest in fixed or capital assets such as powerplants, transmission facilities and the like. Current regulatory structures may also lead utilities to become overly risk averse to avoid the possibility of prudence disallowance. For example, to meet its Clean Air Act obligations, a risk-averse utility could choose to build scrubbers with some efficiency loss, rather than risking a more efficient outcome in the less certain allowance market. Finally, incentives available under current regulation, such as regulatory lag which allows utilities to take advantage of the period between rate cases, may produce other inefficiencies.

n addition to overcoming some inefficiencies of cost-of-service regulation, FERC argued in its incentives policy statement that performance-based incentives can in fact enhance efficiency in non-competitive markets, such as monopoly natural gas pipelines or monopsony (single buyer) electric utilities. Without incentives to encourage efficient power purchases and smart portfolio management, other non-price benefits from competition might otherwise be lost.

inally, the utility industry is in a state of transition and financial incentives for utilities can be viewed as part of the transition. The generation monopoly has virtually disappeared and the structure of the industry is evolving to accommodate greater competition. For example, one problem often cited with the current state of competition in generation is that utilities often sit on both sides of the table as both potential builder and buyer of new resources.

ome observers argue that the trend towards increasing competition will inevitably lead to disintegration, with utilities separating generation companies from the transmission and distribution functions. Utilities we know today will emerge as smaller companies whose profits will be earned on investments in transmission and distribution. Under this scenario, financial incentives for the transmission and distribution utility to purchase power would no longer be necessary. In any case, as bulk power markets evolve, so must regulation. Principles of economic regulation as applied to rates and ratemaking for electric utilities have not changed that much. It seems self-evident that regulation should change as the industry evolves.

## B. Issues in Considering Financial Incentives for Utilities

Proponents of incentives must be prepared to answer credible arguments against incentives. First, it is often argued that as regulated monopolies, utilities have an obligation to provide services at the lowest reasonable cost. In fact, this principle underlies the current regulatory structure. Some incentive proponents have postulated a "Wal-Mart" analogy. Utilities, they argue, just as Wal-Mart, a retailer reselling products produced by others, are entitled to a mark-up on items they resell. However, critics of this approach have noted that utilities differ from Wal-Mart in three major respects: 1) utilities are monopolies; 2) Wal-Mart has no other opportunity to earn profits; and 3) Wal-Mart profits only from sales at its stores, not from the sales by competitors.

As a regulated monopoly with an administratively determined rate of return, any financial incentive above cost recovery in effect raises the rate of return a utility is permitted to earn. A higher rate of return can be justified in economic terms to compensate utility shareholders for taking on more risk. Therefore, allowing a utility to earn a higher rate of return for purchased power can be read to imply that such purchases increase utility shareholder risk for which they must be compensated. Understandably, some in the independent power community disagree with this view and have suggested alternative approaches to utility incentives. For example, by tying incentives to improved long-term utility system performance, this objection can largely be removed as a concern.

Moreover, IPPs shift risks away from utilities. Contractual provisions in power-purchase agreements (PPAs) define a wide range of risks which are shifted from utilities and their ratepayers to the independent power developer including: permitting, construction, operational, performance, financial, legal compliance, change in law, some regulatory disaster and certain fuel risks. Buying power from a third party rather than building a powerplant to meet need generally decreases a wide variety of other risks to the utility and its ratepayers. IPPs bear permitting and other development risks, especially prior to the time their projects are selected for completion in competitive procurement situations. The construction risks of non-completion, delays and cost overruns are borne by IPPs and their lenders. With respect to operating risks, most IPPs do not get paid if their projects do not perform to the utility's specifications. In addition, through greater diversification, IPPs historically produce high availability rates. Contractual security deposit and penalty provisions reduce financial risk to the utility.

The IPP is responsible for complying with laws relating to the operation of power facilities such as increasingly expensive environmental requirements. Most costs cannot be passed through existing contracts to purchasers. Furthermore, IPPs take the risk that these laws will change in the future, resulting in significant additional costs under a fixed-price contract or any other contract under which the prices does not vary due to changes in such costs.

The force majeure clauses in many contracts force the IPP and its lenders to bear some or all of the financial risk of destruction of the powerplant due to causes such as accidental fires and explosions occurring on the premises. Many fuel-related provisions and operating requirements shift some portion of fuel risks to the IPP owner/operator, particularly when such provisions have been negotiated as the result of a competitive procurement process designed to bring the power on-line at the lowest reasonable price. The end result of the shifting of the risks away from utilities and ratepayers to IPPs is a reduction in the cost of capital for utilities and lower price for ratepayers.

Another argument to consider is that the alternative to risk and reward is to avoid risk. There is no reward, but neither is there risk. In the early days of PURPA, utilities sought to insulate themselves from risk by arguing for treating power purchases from QFs as an expense item rather than rate-basing the capacity (or fixed) payments. They did not want to jeopardize their rate of return and put their shareholders at risk for QF non-performance. Incentives then should be symmetric. Utilities could be allowed the opportunity for performance rewards, but should similarly be expected to risk performance penalties. Again by linking incentives to long-term utility performance, such as better RFP design and management, or improved powerplant operation, this concern can largely be eliminated.

Finally, FERC noted in its policy statement that incentives were not intended for competitive markets. In a competitive market, any financial incentives ( or "rents") are theoretically competed away. Therefore, FERC posits that incentives may be more appropriate in monopoly segments of industries, such as gas pipelines. The extent to which incentives are appropriate for competitive wholesale electric power markets depends on whether utilities are viewed as exercising market power as monopsonists in markets where they are single buyers.

All in all, financial incentives may have a place in utility regulation. The industry is in a transition and regulators should consider how current regulatory structures help or hinder that transition. It appears to be better to look at ways to help utilities remain profitable (not necessarily maintain profits) by following economically efficient decision-making rather than the convenience of utilizing traditional regulation.

### C. Options for Utility Financial Incentives

#### 1. FERC's Policy Statement on Incentive Regulation

On October 30, 1992, FERC issued a Policy Statement on Incentive Regulation which "defines the essential elements of an incentive ratemaking policy and sets guidelines for incentives rate proposals for" entities it regulates. [8]

In its policy statement, FERC identified five basic performance-based incentive mechanisms:

a. automatic rate adjustment mechanisms which adjust rates as economic conditions change;

b. targets or external price indexes which permit utilities to keep part or all of the difference between the target price and actual costs;

c. flexible pricing, such as selective discounting;

d. benefit sharing between shareholders and ratepayers, such as split savings arrangements; and

e. consumer welfare bonuses. FERC puts adjustments to a utility's rate of return due to DSM in this category.

#### 2. Other Policy Statements

In addition to the FERC policy statement, there have been other proposed incentive structures at the state level which bear mentioning. In a settlement pending before the New York Public Service Commission, which included independent power interests as well as others in the settlement discussions, Rochester Gas & Electric's cost recovery will be capped and indexed to changes in NY Power Pool costs.[9] Costs subject to the cap would include purchased power costs. Also in New York, a number of entities have entered into a settlement agreement with New York State Electric & Gas (NYSEG) which includes certain incentives.[10] Under the settlement, NYSEG can share savings with its ratepayers when its actual IPP capacity and energy costs are less than the forecast cost specified in the settlement. The NYSEG plan also provides for an "embedded production cost incentive" which rewards the utility for production cost performance relative to a peer group of utilities.

In a collaborative process in New England, a proposal to adjust the utility return on equity has been widely discussed. As a financial incentive, a utility would be permitted to adjust its return on equity to compensate it for increased riskiness due to the level of power purchases on its system. One New England utility has proposed such an incentive in discussions with parties involved in the New England collaborative. However, utilities have yet to prove that such alleged riskiness sufficiently threatens utility finances to require compensation. Moreover, the most widely accepted conclusion is that buying power, rather than building new powerplants, reduces risk to utilities, their shareholders and ratepayers.

Other incentive mechanisms which have been discussed would tie achieving life-cycle performance goals for target areas, such as power purchases, to the opportunity to earn a premium on the rate of return. Finally, in a paper submitted to the Texas Sunset Review Commission in June 1992, RCG/Hagler, Bailly[11] discussed several types of possible supply-side incentives for utilities that purchase power from IPPs, including:

- putting independent power capacity payments into a utility's ratebase;
- adjusting utilities' returns-on-equity to reward them for efficient power purchases;
- granting shared savings to utilities based on the difference between avoided cost and purchased power costs;
- paying a "bonus" for every independent power project or MW under contract; and
- including a rate "adjustment" to utility payments to independent power producers.

NIEP believes it is more appropriate to reward utilities for overall performance, including power purchases, rather than targeting only supply-side decisions for incentives.

### D. Policy Considerations for Incentives

In considering financial incentives for utility power purchases, some guiding criteria must be established. The criteria should ensure that an incentive program rewards performance and efficiency and brings benefits to ratepayers. Otherwise, incentives would merely be a mechanism for a regulated entity to earn a monopoly rate of return and monopoly rents, without providing added measurable value to ratepayers.

In its Policy Statement on Incentive Regulation, FERC looked at the criteria for evaluating the reasonableness of incentive proposals. FERC's policy requires incentives to be:

- applied prospectively;
- voluntary;
- understandable;
- able to result in demonstrable and quantifiable benefits to customers, including an absolute upper limit on risk to consumers; and,
- able to demonstrate how they encourage efforts to improve service.

FERC also requires that initial rates filed in conjunction with the incentive proposal be subject to and conform with just and reasonable standards.

### E. Recommended Principles for Financial Incentives

To promote competition and efficiency in electric power markets, the following principles are recommended in considering financial incentives for utilities. Incentives should be examined very carefully to determine whether they will encourage efficiency, competition and improved service and reliability.

First, incentives, where appropriate, should be tied to long-term performance whether rate-based plants are built, bulk power is purchased, independent supply or demand-side management is used. Performance measures upon which the incentive is based should be demonstrable and quantifiable. For example, utilities may qualify for incentives for good RFP design, high plant performance or availability, or improved fuel-cost management due to any improvements in the system, including those resulting from purchases from independent power plants. Performance measures should look at system-wide performance, rather than just one class of costs. For example, performance measures based on powerplants should consider the performance of both existing and new powerplants, whether owned by the utility or an independent power producer.

Performance-based price caps, targets or automatic rate adjustments constitute one potentially attractive category of financial incentives. Under such schemes, utility costs within its control and subject to performance targets would be indexed or measured against factors external to the utility or beyond the utility's control, such as the performance of similarly situated utilities. However, the California Public Utilities Commission (CPUC) staff report suggests a form of price caps which would use current cost-of-service principles to establish the initial rate cap and then abandon cost-of-service ratemaking. Rates would change only to reflect actual changes in productivity or inflation and other factors the utility could not influence.[12]

Targets based on forecasts or theoretical costs such as "avoided resource" costs may be subject to manipulation and therefore be less desirable than actual performance measures. Moreover, adjustments which do not track power costs, such as general rates of inflation, are likely to be inefficient. The targets could be set at absolute levels or evaluate the rate of change in utility costs relative to the rates of change in target costs.

Second, increases in authorized rate of return need to be carefully structured or they may leave independent power vulnerable to the argument that purchased power increases rather than decreases a utility's riskiness. Premiums to a utility's return on equity could reward the utility for the value of the IPP project over the life of the contract, utilizing measurable objectives such as the extent to which the plant is: brought on-line, on-time; achieves environmental objectives; and meets or beats projected operating performance criteria. The value of the IPP plant may be measured, for example, in terms of its contribution to lowered overall system cost or energy cost or higher system powerplant availability. Incentive programs therefore must clearly articulate the risks for which the utility will be rewarded (i.e. overall performance or performance in certain areas). For example, the RG&E plan includes measures of service quality, as well as performance measures relative to expected expenditures for capital additions, fuel and transmission costs. Also, the NYSEG incentive plan establishes specific performance measures and thresholds to earn the incentive. The plan looks at electric reliability and power quality, as well as issues of service quality.

## NOTES

6. National Association of Regulatory Utility Commissioners, *Utility Regulatory Policy in the United States and Canada: Compilation, 1991 - 1992*, Washington, DC, August 1992, Table 179.

7. Department of Strategic Planning, California Public Utilities Commission, *California's Electric Services Industry: Perspectives on the Past, Strategies for the Future*, San Francisco, CA, February 1993, page 150.

8. Federal Energy Regulatory Commission, Policy Statement on Incentive Regulation, Docket Number PL92-1-000, issued October 30, 1992.

9. See Settlement filed by Rochester Gas & Electric (RG&E) with the New York State Public Service Commission in Case Nos. 92-E-0739, 92-E-0740, 92-G-0741, January 29, 1993. The Settlement was signed by the Staff of the New York State Department of Public Service, RG&E, the New York State Department of Economic Development, the Oil Heat Institute of Upstate New York and the Independent Power Producers of New York.

10. See Settlement filed by New York State Electric & Gas (NYSEG) with the New York State Public Service Commission in Case Nos. 92-E-1084, 92-E-1085, 92-G-1086, April 8, 1993. The Settlement was signed by the Staff of the New York State Department of Public Service, NYSEG, the Cogeneration Partners of America and the Independent Power Producers of New York.

11. RCG/Hagler, Bailly, Inc., "Comments on Incentives for Purchases of Non-Utility Generated Power in the Proceeding to Consider Reauthorization of the Texas Public Utility Commission before the Sunset Review Commission of Texas," June, 1992.

12. *California's Electric Services Industry*, page 173.

# CHAPTER I V
# CONCLUSION

With the focus on broad participation and evaluation of many resource alternatives, IRP processes are more robust and satisfactory than traditional utility planning. IRP processes, it is hoped, better respond to the new economic realities such as the disappearance of the natural monopoly in generation or volatility in demand. There is no one model of IRP which would be appropriate in every state, but for independent power producers, two IRP related issues should be addressed.

First, the IRP process should establish guidelines for fair and efficient procurement of supply side resources. Commissions should require utilities to evaluate all potential resources to meet need. Opening the process to many qualified suppliers will ensure that utilities consider all possibilities to satisfy future demand. Competitive procurement should be designed with fairness, flexibility and accountability in mind.

Second, IRP rules should consider whether incentives for utility performance, including areas such as the purchase of power from IPPs, would bring value to ratepayers. Financial incentives can encourage symmetric treatment of utility build-and-buy options. Incentives can also allow a utility to earn a reward for smart, effective and reliable portfolio management. Finally, incentives available in traditional utility ratemaking may not be efficient.

***IRP processes, it is hoped, better respond to the new economic realities, such as the disappearance of the natural monopoly in generation or volatility in demand.***