INTEGRATED RESOURCE PLANNING FOR ELECTRIC AND GAS UTILITIES

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During the past few years, the scope and nature of resource planning at electric utilities has changed dramatically. The scope of planning has expanded to consider energy-efficiency and load-management programs as resources, the environmental costs of electricity production, and a variety of resource-selection criteria beyond electricity price. The nature of planning has expanded to include regulatory commissions, nonutility energy experts, and customers, as well as utilities themselves. Similar changes are beginning to occur at gas utilities.

This paper discusses a few of the key issues related to resource planning: provision of financial incentives to utilities for successful implementation of integrated resource plans, incorporation of environmental factors in resource planning, bidding for demand and supply resources, development of guidelines for preparation and review of utility integrated resource plans, resource planning for gas utilities, and greater efforts by the U.S. Department of Energy to encourage integrated resource planning.

INTRODUCTION

Integrated resource planning (IRP) helps utilities and state regulatory commissions consistently assess a variety of demand and supply resources to cost-effectively meet customer energy-service needs. Key characteristics of this planning paradigm include: 1) explicit consideration of energy-efficiency and load-management programs as alternatives to some power plants and new supplies of natural gas, 2) consideration of environmental factors as well as direct economic costs, 3) public participation, and 4) analysis of the uncertainties and risks posed by different resource portfolios and by external factors.

IRP differs from traditional utility planning in several ways, including the types of resources acquired, the owners of the resources, the organizations involved in planning, and the criteria for resource selection (Table 1). Cavanagh (1986), Electric Power Research Institute (1988), Gellings, Chamberlin and Clinton (1987), Hirst (1988a and 1988b), and the National Association of Regulatory Utility Commissioners (1988a and 1988b) discuss IRP and its development.

This paper reviews recent progress in IRP and identifies the need for additional work. Key IRP issues facing utilities and public utility commissions (PUCs), discussed in this paper, include:

- Provision of financial incentives to utilities for successful implementation of integrated resource plans, especially acquisition of demand-side management (DSM) resources;
- Incorporation of environmental factors in IRP;
- Bidding for demand and supply resources;
- Development of guidelines for preparation and review of utility resource plans;
- Resource planning and DSM programs for gas utilities; and

Table 1. Differences Between Traditional Utility Planning and Integrated Resource Planning

Traditional Planning	Integrated Resource Planning
Focus on utility-owned central-station power plants	Diversity of resources, including utility-owned plants, purchases from other organizations, conservation and load-management programs, transmission and distribution improvements, and pricing
Planning internal to utility, primarily in system planning and financial planning departments	Planning spread among several departments within utility and often involves customers, public utility commission staff, and nonutility energy experts
All resources owned by utility	Some resources owned by other utilities, by small power producers, by independent power producers, and by customers
Resources selected primarily to minimize electricity prices and maintain system reliability	Diverse resource-selection criteria, including electricity prices, revenue requirements, energy-service costs, utility financial condition, risk reduction, fuel and technology diversity, environmental quality, and economic development

- Increased efforts by the U.S. Department of Energy (DOE) to
  - include DSM resources in FERC approval of wholesale contracts,
  - expand the DSM programs run by federal Power Marketing Agencies,
  - expand DOE's Integrated Resource Planning Program, and
  - collect data on performance of utility DSM programs.

Many other issues related to resource planning are important, but are not discussed in this paper. Such issues include alternative ways to organize planning within utilities; the role of collaboration and other forms of nonutility involvement in planning (Ellis 1989; Schweitzer, Yourstone, and Hirst 1990); the relationships among competition, deregulation, and utility planning; treatment of electricity pricing as a resource; fuel switching (primarily between electricity and gas); treatment of uncertainty in utility planning and decision making (Hobbs and Maheshwari 1990; Hirst and Schweitzer 1990); the appropriate economic tests for utility DSM programs; ways to measure the performance of DSM programs (Argonne National Laboratory 1989); development and use of improved data and planning models; and transfer of information among utilities and commissions (Goldman, Hirst, and Krause 1989).

REWARDING UTILITIES FOR EFFECTIVE IRP IMPLEMENTATION

A key element of IRP is the treatment of utility energy-efficiency programs as a resource that can substitute for some power plants. Unfortunately, traditional regulation of utilities pits the interest of utility shareholders against those of utility customers. This conflict occurs because "each kWh a utility sells ... adds to earnings [and] each kWh saved or replaced with an energy efficiency measure ... reduces utility profits" (Moskovitz 1989). The growing realization that effective implementation of least-cost plans may hurt utility shareholders led the National Association of Regulatory Utility

Commissioners (1989) to adopt a resolution urging PUCs to consider the loss of earnings associated with DSM programs and to adopt ratemaking mechanisms that encourage utility DSM programs.

Several proposals to reform PUC regulation have been made that incorporate one or more of the following three factors:

- Recovery of the utility costs to operate DSM programs,
- Utility recovery of the net lost revenue (difference between revenue foregone because of reduced electricity use and reduced operating costs) caused by DSM programs, and
- Provision of financial incentives to utility shareholders for exemplary delivery of DSM services.

The first two elements remove disincentives to utility operation of DSM programs, while the third element adds positive incentives to run such programs. The underlying idea is that utilities should operate under regulatory practices that make it financially attractive for them to implement all aspects of their integrated resource plan, not just acquisition of supply resources (Moskovitz 1989; Wiel 1989).

Simple incentive methods have been in place for several years in a few states, including Washington and Wisconsin. In 1989, PUCs in several states, including Maine, Vermont, Massachusetts, New York, New Jersey, Minnesota, Nevada, California, and Washington began inquiries into the desirability and form of different incentive procedures. Progress has been most rapid in California, Massachusetts, New York, and Rhode Island. The New York Public Service Commission (1989) approved proposals from several utilities to test incentive schemes. And the Rhode Island and Massachusetts PUCs adopted incentives for New England Electric.

According to Moskovitz (1989), a key element of a successful regulatory system is the decoupling of profits from sales. That is, utility earnings should not depend on the amount of sales achieved. The Electric Revenue Adjustment Mechanism, used in California since 1982, accounts for the over- or under-collection of authorized base revenues (essentially all nonfuel costs) caused by discrepancies between actual and forecast sales of electricity (Marnay and Comnes 1990). Utilities use balancing accounts for over- (or under-) collection of revenues. These revenues are then returned to (or collected from) customers the following year through an adjustment to the price of electricity. This mechanism breaks the link between sales and profits, thus eliminating a major disincentive to utility DSM programs.

Moskovitz also discusses methods that go beyond removal of disincentives to reward utilities for effective programs. He groups incentive proposals into three groups: rate-of-return adjustments, shared savings, and bounty. The shared savings approach is the most widely discussed because it seeks to reward utilities for acquiring resources that deliver desired energy services at least cost. (The two other approaches are less appealing because the utility incentive does not depend directly on the benefit provided by the utility DSM programs.)

New England Electric (Sergel 1989; Destribats, Lowell, and White 1990) proposed such a shared-savings incentive scheme (Fig. 1) in Rhode Island, New Hampshire, and Massachusetts. The proposal has two parts. The first incentive, intended to maximize the size of the company's DSM programs, is equal to 5% of the total benefit of the programs. The benefit is equal to the electricity savings caused by the programs multiplied by the company's avoided costs (i.e., kWh-saved x ¢/kWh). The second component, intended to reward program efficiency, is equal to 10% of the net benefit of the programs, where net benefit is the difference between (a) the product of reduced electricity use and utility-system avoided costs and (b) the costs to operate the DSM programs. The Rhode Island PUC approved a modified version of this proposal. The Massachusetts Department of Public Utilities (1990b) approved an incentive system with "a fixed payment for each kW and kWh saved that is verified through an after-the-fact evaluation and monitoring system."

As part of the 1989 collaborative in California, Schultz (1990) examined alternative shared-savings proposals for utility DSM programs. His analysis

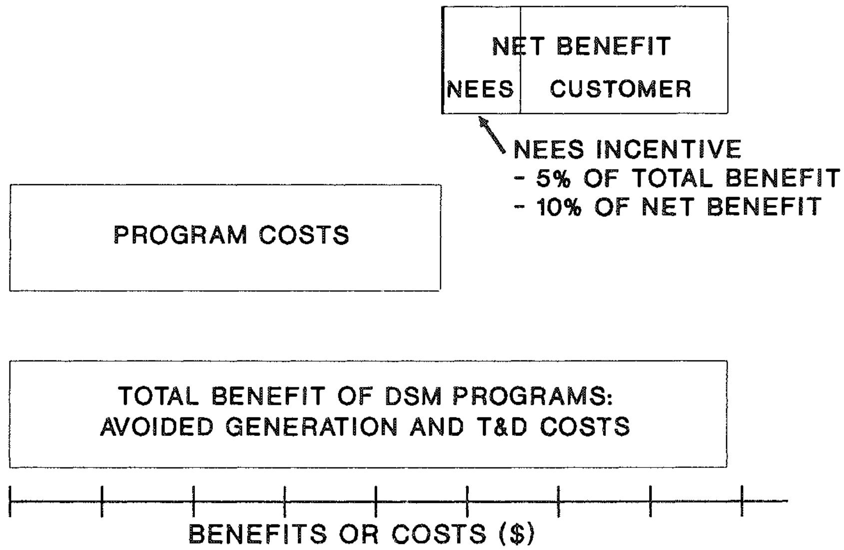

Figure 1. The DSM Incentive Proposed by New England Electric is Proportional to the Total and Net Benefits of the Company's DSM Programs

focused on the purposes of the DSM programs and on the risk/reward relationships implicit in different incentive proposals. These proposals differ in their sensitivity to changes in total resource costs, utility costs, avoided costs, and electricity savings stimulated by the DSM programs. Schultz suggested that incentive mechanisms should seek to maximize the net benefit of DSM programs, require minimum performance, or minimize program costs.

Reforming utility ratemaking is now an important part of integrated resource planning. Discussions among utilities, commissions, and others are underway in many states. And, in a few states, utilities are testing such schemes on a trial basis. Additional analyses are needed to better understand the pros and cons of different regulatory reforms within the context of the accounting rules used by individual states and utilities. And careful evaluations of the effects of these schemes are needed. These evaluations should identify the effects of regulatory reform on the size and effectiveness of utility DSM programs and on the costs to utility customers. In addition, the energy savings and load reductions caused by utility DSM programs must be carefully and accurately measured (Argonne National Laboratory 1989), because these measurements determine the incentive payments to utilities.

INCORPORATING ENVIRONMENTAL FACTORS IN UTILITY PLANNING

The environmental impacts that accompany operation of power plants have significant effects on society. For example, electricity production accounts for two-thirds of the SO_2, one-third of the NO_x and one-third of the CO_2 emitted in the U.S. These airborne pollutants are linked to secondary effects (e.g., acid rain and global warming) that affect society (e.g., reduced forest production and damage to coastal land). These effects of electricity production are externalities, defined as any cost not reflected in the price paid by customers for electricity (Chernick and Caverhill 1989).

External effects cease to be externalities once their costs are paid by the entity responsible for their production and are reflected in the price charged for the product. For example, existing federal and state regulations (e.g., pollution control rules that require mitigation of negative environmental impacts on land and water use) internalize some of the environmental costs associated with electricity production.

PUC Approaches

Partly in response to increased public concern about acid rain and global warming, several PUCs are insisting that environmental impacts be explicitly accounted for in utility resource planning and acquisitions. A recent survey found that 15 PUCs have procedures for considering environmental externalities in their resource planning and acquisition (Cohen et al. 1990).

This internalization is typically done in one of three ways. These approaches seek to influence the choice and relative magnitude of selected resources. They do not change the direct economic costs of the various resource alternatives to ratepayers, but may raise the ultimate cost of electricity if environmentally-benign resources are more expensive than other alternatives.

The first approach relies on qualitative treatment of environmental externalities by the utility in its integrated resource planning process. For example, the Nevada Public Service Commission has broad discretion to "give preference to the measures ... that provide the greatest economic and environmental benefits to the state." Under this approach, PUCs require utilities to consider environmental costs in resource planning but do not specify the methods to be used.

Table 2 illustrates an example of this approach, used by Ontario Hydro (1989). Its analysis included 1) development of natural and social environmental criteria (e.g., land and water use, atmospheric emissions, solid waste production, and socio-economic effects such as regional employment and local community impacts) and 2) a comparative analysis of alternative demand/supply plans and the environmental advantages and disadvantages of each plan. For natural environmental criteria, Ontario Hydro developed quantitative indices (e.g., total waste, thermal discharge, air emissions of various pollutants, and land and water use) that were estimated for alternative resource plans.

The second approach involves use of a percentage adder that either increases the cost of supply resources or decreases the cost of DSM resources. For example, the Wisconsin Public Service Commission (1989) recently implemented a "non-combustion" credit of 15% for non-fossil supply and demand-side resources because of reduced pollution.

The third approach involves direct quantification of the cost of the externality, which often occurs if the utility is developing a competitive resource

Table 2. Environmental Analysis Process Used by Ontario Hydro

1. Develop criteria for environmental effects
   Resource use
   - Non-renewable resources: coal, oil, gas, and uranium
   - Water use
   - Land use

   Emissions, effluents, and wastes
   - Atmospheric emissions: SO_2, NO_x, CO_2, radionuclides, and trace elements
   - Aquatic effluents: thermal discharges, radionuclides, uranium mining effluents, and coal mining effluents
   - Wastes: coal ash, flue-gas desulphurization wastes, used nuclear fuel, low-level radioactive wastes, and uranium mine tailings
2. Evaluate the environmental implications of alternative plans
3. Consider mitigation/compensation to offset the potential environmental effects
4. Determine the environmental advantages and disadvantages of the alternative plans

procurement process (i.e., bidding). For example, the New York Public Service Commission (1989) recently approved utility bidding proposals that assigned values to different levels of air and water emissions and land degradation of each bid, which can add up to 1.4 ¢/kWh. Several of the New York utilities use this method to adjust the cost of each bid, while other utilities use a "point system," which weights environmental factors relative to the price factor in scoring competing supply and demand projects.

Alternative Methods to Quantify Environmental Costs

A key challenge in treating environmental externalities in utility planning is deciding on the proper costing method to use in calculating external costs. Thus far, studies have adopted one of two basic approaches. The first approach involves calculation of damage costs imposed on society by a generating technology. Costs to society are estimated by tracing impacts through each step of the fuel cycle (i.e., emissions, transport of pollutants, and the effects of these pollutants on plants, animals, people, etc.). The extent of each effect that arises from an externality is estimated and a value is assigned to that effect. For example, SO_2 emissions can be linked to lost forest products, damage to buildings, and human respiratory problems. In direct cost estimation, the challenge is to identify and quantify the dollar cost of each effect, which yields an explicit estimate of the social cost of the externality. However, estimating damage costs is quite difficult. For example, the technical and methodological issues are complicated because valuation is not possible for some environmental-resource damages, dose-response relationships are uncertain, valuing intangible costs (e.g., recreation facilities and endangered species of wildlife) is difficult, valuing human mortality is controversial, and some damages are very site specific (Chernick and Caverhill 1989; Ottinger 1989).

The second approach relies on the cost of control (or mitigation) of the pollutants emitted by the generating technology to estimate the value of pollution reduction (Chernick and Caverhill 1989). The rationale for this approach is that the cost of controls provides an estimate of the price that society is willing to pay to reduce the pollutant. This approach has limitations (e.g., cannot directly be applied to pollutants such as CO_2 which are not now regulated. But the technique is attractive because the most thorny policy issues that arise in direct cost estimation (e.g., assigning dollar values to human life, valuing ecosystems) have implicitly been dealt with by the legislators and regulatory bodies that formulated the pollution control standards. The disadvantage of using control costs to calculate environmental externality costs is that they typically bear little relation to the actual damages imposed on society by power plant emissions.

New England Electric System developed a hybrid approach that it calls an issue-based rating and weighting index (Destribats, Lowell, and White 1990). NEES assigns various environmental factors (e.g., global warming, acid rain, land use, indoor air quality) a weight based on a survey of experts. The company then uses an impact index ranging from zero to four for every contributing factor (e.g., SO_x and NO_x contribute to acid rain) to score resource options. NEES then assigned the highest rated project (i.e., the most environmental degradation) a cost adder of 15 percent; the costs of other projects were increased based on a sliding scale (e.g., ratio of their score to the highest score). This method is easy to understand, but its lack of scientific basis is troubling. Therefore, this approach may be useful primarily as an interim method for including environmental factors in resource planning.

Clearly, valuation of external environmental costs in the context of utility planning is an emerging field, one in which estimates and methods will evolve based on projects underway in various states, including New York, Massachusetts, and California. There is significant disagreement among experts on key methodological issues. These issues include whether costs should be based on the payments that people are willing to make to avoid environmental damages or the money that must be paid to them to accept these damages, appropriate discount rates, uncertainty about the effects and costs of different pollutants, and effects that are hard to price (Ottinger et al. 1989).

The complexities and consequent disagreements about the magnitudes of environmental costs are shown in Fig. 2. The lower bars show the direct costs for a coal-fired baseload plant, gas-fired combined-cycle plant, and gas- and oil-fired combustion turbines. The low estimates of environmental costs are from the New York Public Service Commission and the high estimates are from Chernick (Koomey 1990). Interestingly, the low costs include the environmental impacts on water use and land use as well as air pollution, while the high estimates include air pollution only.

In the future, policies that consider environmental costs in resource acquisition will increasingly rely on pollutant-based methods of assessing environmental impacts, rather than most initial efforts which were technology-based. One effect of this shift will be that bidding processes will further differentiate among supply-side and DSM technologies based on individual project characteristics (e.g., expected emissions, project size, location). New approaches, such as that adopted by the New York utilities in their bidding systems, may well be adopted by other states.

In addition, increased attention to environmental concerns may provide an important impetus for public policy makers and PUCs to broaden the boundaries of IRP. For example, PUCs may ask gas and electric utilities to compare the social costs and benefits of providing energy services (e.g., water heating or cooking) using gas directly or through gas-fired electric generation. Future public policy concerns about the environmental effects of energy technologies may force significant changes in the demands for electricity and gas. For example, the policies of local air quality boards that limit vehicle emissions (and, for example, encourage electric cars) or national legislation affecting greenhouse gas emissions could affect future electricity and gas uses.

Finally, electric utilities and others are likely to raise basic questions about the role of PUCs and utilities to address environmental externalities versus the roles of federal and state government agencies that deal with environmental quality (e.g., the U.S. Environmental Protection Agency).

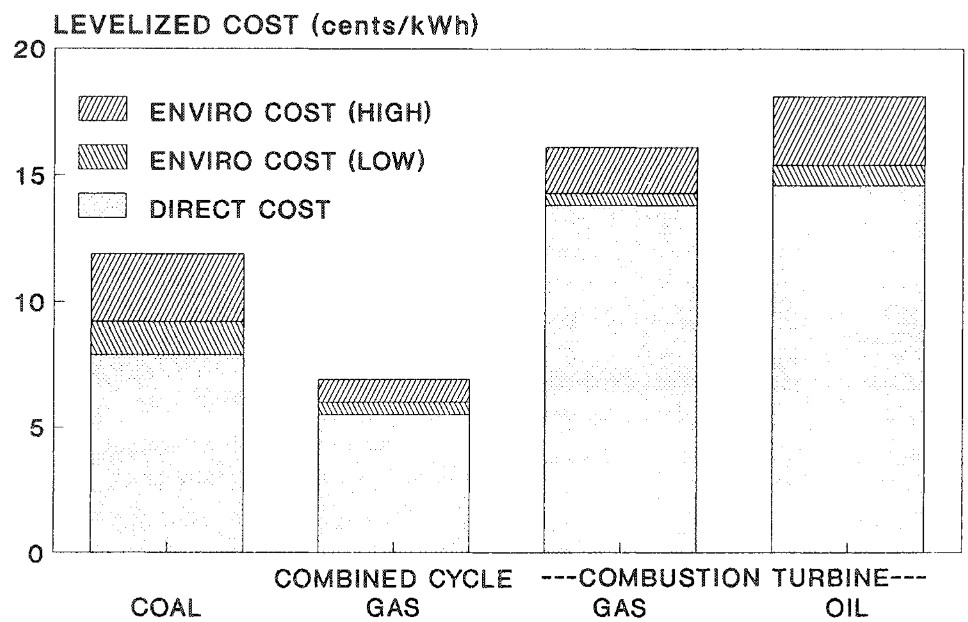

Figure 2. Alternative Estimates of the Direct and Environmental Costs of Electricity Production from new power plants (Koomey 1990). The assumed capacity factor is 65% for the coal and combined-cycle plants and 10% for the combustion turbines.

NEW APPROACHES TO ACQUIRING ELECTRIC POWER RESOURCES

Nonutility power production has emerged as a major source of new generating capacity, principally because of the 1978 Public Utility Regulatory Policies Act (PURPA). Cogenerators and small power producers built nearly 15,000 MW of non-utility capacity during the 1980s. Under PURPA, PUCs are responsible for implementing pricing arrangements under which electricity is purchased from Qualifying Facilities (QFs) at the utility's avoided cost. Avoided costs were determined administratively and some states, which sought to encourage QF suppliers, offered long-term contracts based on forecasts of avoided costs. In several states, the response by private producers was much greater than expected, partly because avoided cost forecasts turned out to be high given events in world oil and gas markets. Some utilities also claimed that the obligation-to-purchase provisions of PURPA and the open-ended nature of standard-offer contracts introduced substantial uncertainty about how much power would ultimately be developed. Thus, PURPA was not an unqualified success, because the supplier response created major planning and operational problems for some utilities.

During the past few years, some utilities and PUCs have experimented with competitive resource procurements (CRPs) as one way to obtain supply and DSM resources, partly in response to the problems associated with PURPA. Since 1986, about 25 solicitations have been issued by 14 utilities. Thus far, capacity offered by private producers has typically been 10-20 times greater than the utility's requirements. However, some utilities have found that a significant fraction of bids do not meet the requirements specified in the bid package and are therefore dropped from serious consideration. For example, Central Maine Power received bids for over 2300 MW of generating capacity in response to a 1989 solicitation; only about 1000 MW remained as realistic options after CMP's initial review of the bids.

CRPs are attractive to private producers because the purchasing utility offers long-term contracts, which are needed to get financing on attractive terms. For the utility, competitive acquisition allows it to ration contracts for non-utility resources in an efficient manner. Moreover, these contracts commonly transfer to private developers some of the risks associated with project siting and permitting, construction cost overruns, and environmental impacts. In addition, a competitive process can reduce the burden of estimating avoided cost by providing a market benchmark to determine value.

Despite its theoretical virtues, there are formidable practical problems involved with developing competitive procurement programs. Traditional utility planning requires trade-offs among financial, operating, and environmental features of resource alternatives. Competitive bidding requires the utility to address these issues through arms-length contracting. To assess bids from developers, a utility must account for and value the multiple attributes of projects. This unbundling and explicit valuation of attributes is a new phenomenon in resource planning. Typically, utility bidding systems differentiate projects on pricing terms, operating characteristics, project status and viability (e.g.,likelihood of successful development), and in some cases environmental impacts. Determining the economic value of these non-price factors is probably the most difficult problem that utilities confront in designing bidding systems (Kahn et al. 1989).

Two design features are particularly critical for utilities as they develop CRPs: 1) the method used to assess or score proposals, specifically the extent to which the utility discloses assessment criteria and the weight assigned to each feature before bid preparation, and 2) incorporation of DSM options into bidding schemes.

Bid Evaluation Criteria

There are two general approaches that utilities have taken to the bid solicitation and evaluation process. In the first approach, the utility develops an explicit scoring system that clearly states the assessment criteria and weights for various features. Bidders self-score their projects, assigning points in various categories (e.g., price, level of development, dispatchability) based on project characteristics. This self-scoring approach can be considered an "open" system, in the sense that the utility's bid evaluation process is transparent. PUCs and most utilities in Massachusetts, New Jersey, and New York rely on self-scoring systems.

A principal advantage of self-scoring systems is their transparency. The utility's project rankings can be audited easily by regulators and there should be little controversy over the utility's selection of the winning bids. In addition, some PUCs favor self-scoring because it allows the regulators to shape utility planning decisions in the initial stages of the resource-acquisition process rather than the more limited role of after-the-fact prudence review of contracts. However, some utilities are concerned that self-scoring denies them the flexibility needed to select the optimal mix of projects. Another potential disadvantage of self-scoring systems is that they assume that projects can be evaluated independent of their interactions with other projects. When the utility's resource need is small compared to the existing system, the independence assumption is reasonable; however it becomes increasingly untenable for resource procurements that are large relative to the existing utility system.

In the second approach, utilities reveal bid evaluation and project selection criteria in qualitative terms only, providing only general guidance about its preferences (Kahn et al. 1989). Bidders submit detailed proposals, which provide the basis for the utility's evaluation and ranking of projects. In this approach, the utility retains more discretion to select the optimal mix of projects as well as flexibility to negotiate with bidders in light of all offers received. This approach can be considered "closed" because the utility has information about the evaluation process that is not available to bidders. Prominent examples of this approach include procurements issued by Virginia Power, Florida Power and Light, and Public Service of Indiana.

The closed approach acknowledges the inherent complexity in optimizing resource selection given that the value of proposed projects is multi-dimensional and uncertain, particularly over long times. Theoretically, this approach allows the utility to select the most efficient mix of bids, because it explicitly recognizes the interactive effects among individual projects and their effects on the utility system. Implicitly, PUCs that endorse this approach trust the utility's judgment. Utilities that want flexibility and discretion in bid evaluation and selection often agree that their subsidiaries will not participate in the bidding process. This tradeoff can ease concerns about abuses of market power by the utility and unfair competitive advantages (e.g., potential impropriety and difficulty in maintaining arms-length transactions).

Some utilities have experimented with hybrid approaches that combine elements of self-scoring systems and closed bid systems. For example, Central Maine Power includes elements of self-scoring, although the utility retains substantial flexibility to select attractive projects for further negotiation. Niagara Mohawk uses a self-scoring system for initial screening and then negotiates with bidders in the initial award group. The Massachusetts Department of Public Utilities (1990a) recently proposed a similar approach. This hybrid approach represents an attractive option that could successfully balance the utility's need for flexibility and discretion with the need to assure fairness. Bid evaluation methods are an evolving art rather than a science and we expect continued experimentation with information requirements and risk-sharing between utilities and private power producers.

Bidding for DSM Resources

Another key issue that arises in CRPs is the type of resources and entities to include (e.g., QFs, independently-owned generation facilities, energy service companies [ESCOs], large commercial and industrial customers, as well as the sponsoring utility). Among these entities and resource options, the appropriateness of including "saved kWh and kW" provided by ESCOs or individual customers has been the subject of vigorous debate (Cavanagh 1988; Cicchetti and Hogan 1989; and Joskow 1988 and 1990). Much of this debate has focused on theoretical problems with integrating DSM and supply resources in the same "all-source" bidding process and the principles to use in determining the appropriate ceiling price to pay for DSM resources (Goldman and Hirst 1989).

These debates raise interesting issues. These concern ways to measure the expected energy and demand savings, whether all sectors and demand-side options should be included in a bidding program or whether the utility should target certain customer classes and end uses for a bidding program, and how to integrate the DSM bidding program with a utility's own DSM programs. A key question is whether the ceiling price for DSM bids should be based on avoided cost or on the difference between avoided cost and average revenues (to reflect lost revenues). Some of these issues are not unique to DSM bidding and arise in utility DSM programs also.

Table 3 summarizes results from utilities that include DSM options in their bidding approach, including the MW offered by bidders as well as the MW selected by the utility. In addition, results are shown for recent supply-side procurements conducted by New England Electric and Boston Edison, along with results from their DSM performance contracting programs involving ESCOs. Typically, there have been 5 to 15 DSM bids submitted by ESCOs and individual customers. The DSM bidders have a stronger likelihood of winning (35 to 50%) than do supply-side projects. The amount of DSM savings proposed by winning bidders, while significant (10 to 47 MW over a 3 to 5 year period), represents a small part of a utility's overall DSM program for the same time (5-20%). Initial results reflect current infrastructure limitations in the ESCO industry as well as a cautious approach being adopted by ESCOs given the risks associated with guaranteeing the savings and their limited experience with DSM bidding.

In summary, experience with incorporation of DSM options into bidding processes is limited. There are a few programs nationwide, although bidding programs are proliferating rapidly. Initial experience suggests that DSM bidding may have a limited role in a utility's overall DSM strategy but may not be appropriate for all market segments. For example, it is difficult to imagine DSM bids for the new construction market. The relative immaturity of the ESCO industry contrasts markedly with the strength of private power producers. In practice, this means that the quantities offered under DSM bidding programs will be small, and will not reflect the full market potential of DSM. For utilities, DSM bidding programs may represent a potential business opportunity if they establish unregulated ESCOs. Several utilities have adopted this strategy, but most are skeptical about DSM bidding and prefer other ways to deliver DSM programs.

Table 3. Supply and DSM Resources (MW) in Utility Bidding Programs

Utility	Amount of Resource Requested	Supply Projects		DSM Projects	
		Proposed	Winning	Proposed	Winning
Central Maine Power	100	666	--	36	17
Central Maine Power	150-300	2338	--	30	--
Orange & Rockland	100-150	1395	141	29	18
Public Service Electric & Gas	200	654	210	47	47
Jersey Central	270	712	235	56	26
Puget Power	100	1251	127	28	10
Separate auctions					
New England Electric	200	4279	204	NA	14
Boston Edison	200	2800	200	NA	35

GUIDELINES FOR PREPARATION OF UTILITY PLANS

Many electric utilities periodically prepare long-term resource plans, often in response to requirements from their PUC. These plans inform regulators and customers about the utility's analysis of alternative ways to meet future energy-service needs and the utility's preferred mix of resources to meet those needs. The plan is an opportunity for the utility to share its vision of the future with the public and to explain its plan to implement this vision.

In principle, utility plans should be assessed on the basis of the utility's resource-acquisition activities. But IRP is so new that insufficient implementation has as yet resulted from these plans. Currently, utility plans can be assessed only on the basis of their planning reports. This section discusses guidelines for long-term resource plans, based on the written reports (Hirst et al. 1990; Schweitzer, Yourstone, and Hirst 1990). The purpose of these guidelines is to help PUC staff who review utility plans and utility staff who prepare such plans. The plans prepared by Carolina Power & Light (1989), Green Mountain Power (1989), New England Electric (1989), Northwest Power Planning Council(1989), Pacific Power & Light (1989), Puget Sound Power & Light (1989), and Seattle City Light (1989) contain many of the positive features in the guidelines.

The "goodness" of a plan can be judged by at least four criteria (Table 4):

Table 4. Checklist for a Good Integrated Resource Plan

Clarity of plan - adequately inform various groups about future electricity resource needs, resource alternatives, and the utility's preferred strategy

- Clear writing style
- Comprehensible to different groups
- Presentation of critical issues facing utility, its preferred plan, the basis for its selection, and key decisions to be made

Technical competence of plan - positively affect utility decisions on, and regulatory approval of, resource acquisitions

- Comprehensive and multiple load forecasts
- Thorough consideration of demand-side options and programs
- Thorough consideration of supply options
- Consistent integration of demand and supply options
- Thoughtful uncertainty analyses
- Full explanation of preferred plan and its close competitors
- Use of appropriate time horizons

Adequacy of short-term action plan - provide enough information to document utility's commitment to acquire resources in long-term plan, and to collect and analyze additional data to improve planning process

Fairness of plan - provide information so that different interests can assess the plan from their own perspectives

- Adequate participation in plan development and review by various stakeholders
- Sufficient detail in report on effects of different plans

- The clarity with which the contents of the plan, the procedures used to produce it, and the expected outcomes are presented;
- The technical competence (including the computer models and supporting data and analysis) with which the plan was produced;
- The adequacy and detail of the short-term action plan; and
- The extent to which the interests of various stakeholders are addressed.

Report Clarity

The primary purpose of a utility's IRP report is to help utility executives decide (and PUC commissioners review) which resources to acquire, in what amounts, and when. Thus, the report must be useful both within and outside the utility. The utility's plan should be well-written and appropriately illustrated with tables and figures. The report should discuss the goals of the utility's planning process, explain the process used to produce the plan, present load forecasts (both peak and annual energy), compare existing resources with future loads to identify the need for additional resources, document the demand and supply resources considered, describe alternative resource portfolios, show the preferred long-term resource plan, and present the short-term actions to be taken in line with the long-term plan. Important decision points should be identified, and the use of monitoring procedures to provide input for those decisions should be explained. The most significant effects of choosing among the available options (e.g., capital and operating costs, resource availability, and environmental effects) should be discussed. The report should also describe the data and analytical methods used to develop the plan. Finally, the plan should point the reader to more detailed documentation on these topics.

Technical Competence

Typically, computer models are used for a variety of functions in developing a plan, such as load-forecasting; screening, selection, and analysis of demand and supply resources; and calculations of production costs, revenue requirements, electricity prices, and financial parameters. These models are used to analyze a wide range of plausible futures and available resources in developing the utility's preferred resource portfolio. The basic structure of the models used, the assumptions upon which they are based, and the inputs utilized should be explained.

The technical competence of a utility's IRP is reflected most critically in the ways that the demand and supply resources are presented as an integrated package. The analytical process used to integrate these different resources should be discussed. The criteria used to assess different combinations of resources (e.g., revenue requirements, annual capital costs, average prices, reserve margin, and emissions of pollutants) should be clearly stated.

Results for different combinations of supply and demand resources should be shown explicitly. It is not sufficient to treat demand as a subtraction from the load forecast and then do subsequent analysis with supply options only. Subtracting DSM-program effects from the forecast and using the resultant "net" forecast for resource planning eliminates DSM programs from all integrating analysis. This approach makes it difficult to assess alternative combinations of DSM programs and supply resources and the uncertainties, risks, and risk-reduction benefits of DSM programs (e.g., small unit size and short lead time).

Demand-side resources must be treated in a fashion that is both substantively and analytically consistent with the treatment of supply resources; demand and supply resources must compete head to head. The plan must show how the process truly integrates key parts of the company: load forecasting, DSM resources, supply resources, finances, rates. And the important feedbacks among these components (especially between rates and future loads) should be shown.

A thorough analysis of a variety of plausible future conditions and the options available to deal with them is essential. This analysis should consider uncertainties about the external environment (e.g., economic growth and fossil-fuel prices) and about the costs and performance of different resources. The analysis should show how utility resource-acquisition decisions are affected by these different assumptions and show the effects of these uncertainties and decisions on customer and utility costs. The assumptions must be varied in ways that are internally consistent and plausible. Differences among resources in unit size, construction time, capital cost, and operating performance should be considered in terms of how they affect the uncertainties faced by utilities. Finally, the links between the results of these multiple runs and the utility's resource-acquisition decisions must be demonstrated.

Action Plan

The action plan, in many ways the "bottom line" of the utility's plan, must be consistent with the long-term resource plan. This is necessary to assure that what is presented as appropriate for the long haul is implemented, and implemented in an efficient manner. The action plan also should be specific and detailed. The reader should be able to judge the utility's commitment to different actions from this short-term plan. Specific tasks should be identified for the next two to three years, along with organizational assignments, milestones and budgets. For example, the action plan should show the number of expected participants and the expected reductions in annual energy use, summer peak, and winter peak for each DSM program. The action plan also should discuss the data and analysis activities, such as model development, data collection, and updated resource assessments, needed to prepare for the next integrated resource plan.

Equity

A final criterion by which a plan can be judged is the effect of its recommended actions on various interested parties. Because the interests of all stakeholders are not identical, the ways in which they will be affected by short- and long-term costs, power availability, and other results of utility actions will likewise differ.

Without the involvement of customers and various interest groups, which requires two-way communication, a plan may ignore community needs. Accordingly, the plan should show that the utility sought ideas and advice from its customers and others in developing the plan. Energy experts from a state university, state energy office, PUC, environmental groups, and organizations representing industrial customers could be consulted as the plan is being developed. For example, utilities in New England are working closely with the Conservation Law Foundation to design, implement, and evaluate DSM programs (Ellis 1989).

Additional work is needed to refine the guidelines discussed here and to ensure that they are helpful to utilities and PUCs. In particular, PUCs should articulate better the reasons they want utilities to prepare such plans and how they will use the plans in their deliberations. This articulation should avoid the "data list or cookbook approach" and focus on the purposes of the planning report. In the long-run, the success of IRP should not be measured by assessing utility reports. Rather, the level and stability of energy-service costs, the degree of environmental protection, and the extent to which consensus is achieved on utility resource acquisitions will be the important criteria.

RESOURCE PLANNING AT GAS UTILITIES

IRP is just beginning to be applied to the natural gas industry. At gas utilities, called local distribution companies (LDCs), resource planning addresses only options for purchasing and storing gas. Traditional planning for LDC resource acquisition seeks to purchase the lowest cost and most reliable mix of supplies. This is done by determining the design day send out, the provisions of various supply contracts, and their available storage options. (Design day send out is the maximum amount of gas required for the coldest day in the coldest month.)

LDC experience with DSM programs is limited to federally mandated programs, such as the Residential Conservation Service (created in 1978 and repealed in 1989) or low-income weatherization efforts mounted to create a positive image in the community or to reduce bill arrearages. Interruptible contracts with large industrial gas customers are also used by many LDCs to shave peaks (e.g., during very cold weather).

The gas industry is concerned about declining sales and profits, largely because of experience during the

1970s and 1980s, when gas customers adopted energy-conservation actions because of price increases and government programs. Gas consumption per customer fell 22% between 1974 and 1988 (Energy Information Administration 1988). To many LDCs, their focus now should be on increasing gas sales (rather than encouraging conservation)because supplies of gas are ample and prices have been falling for several years.

Gas and Electric Industry Differences

Electric utilities are vertically integrated, while gas utilities are not. Production, transmission, and distribution of electricity are regulated primarily by PUCs, with FERC involved only in wholesale contracts. The gas industry is organized and regulated differently. In contrast, natural gas is produced, transported, and distributed by three different sets of companies. Gas is produced by unregulated companies. Pipeline companies, regulated by FERC, move gas to local distribution companies. And LDCs, regulated by PUCs, distribute gas to consumers.

The time horizon for resource planning is generally shorter in the gas industry than in the electric industry. Electric utilities, which construct power plants that last 30 to 40 years, plan accordingly. Gas utility planning depends on equipment lifetime and market conditions as well as the length of contracts (less than 20 years).

Electric utilities meet load instantaneously and maintain high reliability to avoid outages. They do not store electricity and therefore maintain extra generating capability to ensure reliability. LDCs, on the other hand, store gas and use interruptible contracts to maintain reliability for their core customers.

For electric utilities, procedures to determine avoided costs are reasonably well-defined because of the decade of experience with PURPA. Avoided cost provides a benchmark against which to assess the value of resources offered by private producers and by DSM programs. Unlike electric utilities, gas LDCs have only a limited obligation to serve dual-fuel industrial customers, which complicates the definition of avoided cost. The avoided-cost benchmark for natural gas, at least for the noncore market, is based on world oil prices. This benchmark is volatile and difficult to predict. Moreover, marginal-cost pricing is much less developed in the gas utility industry. For example, the marginal cost for gas could reflect limitations in pipeline capacity and alternative uses of the gas (e.g., for generating electricity), upstream considerations for the LDC.

Gas Market Characteristics

The LDC market is divided into two segments, core and noncore. The core market consists of residential, commercial, and small industrial customers that depend entirely on the LDC for gas supplies. The noncore market consists primarily of large industrial customers and electric utilities. These entities can make their own arrangements for gas transportation, and can forego purchasing gas from the LDC and, instead, purchase gas directly from producers. In the noncore market, the LDC offers two products: 1) the gas as a commodity, for which there is competition with gas marketers and independent producers, and 2) gas transportation, for which the LDC has a monopoly.

Recent reports on natural gas production capability show that the gas bubble may disappear within a year or two (American Gas Association 1990). As a consequence, LDCs will rely more on long-term contracts and less on spot-market purchases for their gas supplies. Because the amount of gas will likely remain constant, U.S. supply and demand will be roughly equal. Significant regional differences in gas supply and prices are likely to persist, however, because of differences in pipeline capacity and distance between gas supplies and markets.

Regulatory Environment

Throughout the 1980s, there was little interest in applying IRP to the gas industry for three reasons: 1) resource planning for electric utilities dominated PUC interest, 2) regulators emphasized deregulation of the gas industry, and 3) estimates of gas resources seemed to assure an adequate supply of gas at low cost, reducing the importance of long-term planning.

However, regulators in a few states, especially the District of Columbia, Nevada, Washington, and Wisconsin, are beginning to examine IRP for the gas industry. PUCs are interested in gas planning because of:

- Benefits of electric-utility IRP, especially in implementing DSM programs;
- Recent requests for investments in new pipeline;
- Possible environmental benefits of using gas versus electricity; and
- Interest in fuel switching, including the use of gas air-conditioning technologies to cut electric system peaks in summer.

Because IRP is often viewed skeptically by gas utilities, efforts to date have been started by regulators. Gas utility experience is often limited to its RCS and low-income retrofit programs. These programs are generally not based on reliable forecasts of future gas demands, sensitivity testing via pilot programs of DSM marketing and incentive mechanisms, or evaluation of DSM programs. To achieve the next level of program development, more rigorous analysis (e.g., end-use models to forecast gas demands for each customer class) should be conducted to quantify the DSM potentials in specific market segments. To date, little end-use data are available except for residential retrofits (Ternes et al. 1990) and some new technology applications (Brodrick and Patel 1990; Gas Research Institute 1989). The next stage will be the integration of demand and supply options to assess the best resource mix.

The ability to move to the next stage in gas IRP is constrained because of the lack of analysis exploring the implications of DSM as an alternative to gas supplies. Few methods, such as the California Standard Practice Manual (California Commissions 1987), exist to assess the cost-effectiveness of gas-utility DSM programs. Almost all current analyses examine least-cost purchasing, selecting the best mix of supply and storage options to achieve low prices for consumers and high earnings for shareholders (McDermott 1987). DSM is important for commercial and industrial customers with interruptible service and/or dual-fuel capability, when gas supply is limited, or gas costs become too high because of extreme weather conditions.

To advance gas IRP, several key questions need to be addressed. What effect will DSM programs have on LDC supply reliability and profitability? What are the economic implications of electric-utility cost-effectiveness tests - societal, all ratepayer, participant, and no-losers - to LDCs, their customers, and shareholders? How should fuel switching be included in gas IRP? Can gas-utility DSM programs be used to reduce industrial bypass? What regulatory adjustments are necessary to encourage gas IRP while maintaining company profitability?

IRP is beginning to change the way gas DSM programs are designed, implemented, and evaluated. Gas LDCs can learn from the IRP methods developed in the electric industry, but they must be creatively applied given the different circumstances in the gas industry. Gas DSM programs are in the early phases of development. Activity is expected to increase substantially as supply reliability and energy efficiency influence more PUCs to encourage LDC adoption of IRP concepts.

FEDERAL ROLES TO PROMOTE INTEGRATED RESOURCE PLANNING

Because electricity production consumes almost 40% of the primary energy used in the U.S., electricity must be a major part of national energy policy. In addition, concerns about environmental quality, economic productivity, international competitiveness, and national security suggest a larger role for the Federal Government in working with utilities to expand their planning and to implement DSM programs.

Improving energy efficiency through utilities may be a particularly effective way to reach millions of U.S. energy consumers. Utilities have direct monthly contact with all their customers (i.e., meter reading and billing) and are usually well respected organizations in their communities. Thus, the Federal Government can work with a few hundred utilities and, through them, reach tens of millions of households and millions of businesses.

Require FERC to Incorporate DSM Programs in Utility Wholesale Contracts

FERC approves all wholesale transactions among utilities. Currently, FERC reviews of proposed contracts involve no consideration of energy efficiency. FERC, in its review of long-term contracts, could require the buying utility to show that it has acquired all the conservation and load-management resources in its service area that cost less than the proposed purchased power before FERC approves the contract. Presentation of an integrated resource plan, approved by the utility's PUC, could satisfy this requirement. Use of such a state-approved plan in FERC proceedings would eliminate concerns that FERC was pre-empting state regulation. Implementing such an expanded review of wholesale contracts might require modification of the Federal Power Act.

Require Federal Electric Utilities to Expand DSM Programs

The federal Power Marketing Agencies (PMAs, part of DOE) and TVA (an independent federal corporation) account for one-tenth of the electricity consumed in the U.S. Traditionally, TVA and the Bonneville Power Administration (the largest PMA) have operated large DSM programs, which saved energy for their customers and served as examples for other utilities. Unfortunately, short-term budget considerations forced reductions in these programs at both agencies. Indeed, TVA canceled all its conservation programs in 1989. Bonneville, on the other hand, plans to increase its conservation budgets over the next several years.

New legislation could require these federal power authorities to expand their DSM programs and to explicitly consider environmental and social factors in their benefit/cost analyses of all resource alternatives. Such legislation would be a logical extension of the 1980 Pacific Northwest Electric Power Planning and Conservation Act (P.L. 96-501), which explicitly made conservation the electricity resource of choice and gave it a 10% bonus to be used in economic analyses of alternative resources. The 10% bonus reflects the environmental and social benefits of conservation compared to supply resources. The other federal utilities could employ similar factors in their resource assessments.

Expand DOE Technology-Transfer Activities to Utilities

DOE's Integrated Resource Planning Program manages a variety of projects aimed at improving the long-term resource-planning process and tools (data and analytical methods) used by utilities (Goldman, Hirst, and Krause 1989; Berry and Hirst 1989). DOE sponsored conferences on utility planning in 1988 and 1989, and plans additional conferences in 1990 and 1991. The DOE program could be expanded to fund additional cooperative projects with utilities and PUCs. This approach focuses on cost-sharing projects, with DOE assistance provided through the DOE national laboratories and other government contractors.

The underlying rationale for expanding DOE's technology transfer efforts on IRP is the knowledge that many innovative and successful programs operate throughout the country. However, information on these successes is hard to get because the sponsoring utility and/or PUC has little incentive to publish information on the program. Thus, DOE can play a valuable role by participating in these programs, ensuring that the programs are carefully evaluated, and then funding preparation of reports and conference presentations that effectively and widely disseminate information to other utilities and state agencies. The Northeast Region Demand-Side Management Data Exchange (NORDAX), funded in part by DOE, is a good example of such technology transfer. The initial phase of NORDAX, a consortium of more than 20 utilities, yielded a data base with information on 90 DSM programs operated by 17 utilities in the region (Camera, Stormont, and Sabo 1989). Another critical area for DOE attention is the transfer of planning methods, data, and processes from electric to gas utilities.

Collect More Information on Energy Use

EIA is responsible for collecting, evaluating, analyzing, and disseminating information on energy reserves, production, demand, and technologies. EIA focuses on the supply of, rather than the demand for, energy. For example, EIA's *Annual Energy Review* (EIA 1989b) contains separate chapters on fossil-fuel reserves, petroleum, natural gas, coal, electricity, nuclear energy, renewable energy, financial indicators, and only one chapter on energy consumption.

EIA (1989a) collects detailed information from electric utilities on individual power plants related to their construction cost and capacity; annual operations and maintenance expenses; and monthly fuel consumption, generation, availability, and emissions. Data collected by the Federal Energy Regulatory Commission (e.g, FERC Form 1) are similarly detailed with respect to electricity production and disposition; purchases and sales; construction costs and operations for power plants; and costs and characteristics of transmission lines, substations, and transformers. Unfortunately, EIA and FERC collect no comparable data on utility energy-efficiency and load-management programs. EIA and FERC could expand the data-collection forms completed by utilities (both electric and gas) to require information on utility DSM programs. This would help to redress the imbalance between the supply and demand sides in data-collection activities.

CONCLUSIONS

More than half of the primary energy consumed in the U.S. flows through electric and gas utilities. Therefore, the economic and environmental effects of utility actions are enormous. Integrated resource planning represents a new way for utilities to meet the energy-service needs of their customers. Because IRP is a comprehensive and open process, its implementation is likely to yield large benefits in terms of an "optimized" mix of resources and fewer controversies over utility decisions.

Much work is needed to convert the potential benefits of IRP into reality. This paper dealt with a few of the most important topics, including changes in regulation to align the interests of utility customers with those of utility shareholders, incorporation of environmental factors into resource planning, competitive auctions for resources, guidelines for review of utility plans, planning for gas utilities, and increased activities by the Federal Government.

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