ECONOMIC AND POLICY IMPLICATIONS OF INTEGRATED RESOURCE PLANNING IN THE UTILITY SECTOR

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ABSTRACT

The planning environment for utilities is undergoing rapid change. Energy markets are becoming more competitive, customers are adopting new technologies that displace the need for particular utility services, future fuel costs are uncertain, and regulators are increasingly questioning the economic advisability of large centralized capacity additions to utility systems. The traditional supply-side orientation is considered highly risky in the current planning environment.

Integrated resource planning (IRP), in which different mixes of demand- and supply-side options are evaluated, has been advocated as a response to system load growth. The advantages claimed for IRP are that it can minimize capital risk, expand consumer choice, and result in the delivery of "least cost" energy services. A central concern for utility policy analysis is the reliability and adequacy of the economic cost assessment components of the IRP approach.

This paper examines how typical assumptions and data inputs employed in IRPs affect the outcomes of the evaluation of demand-side and supply-side options. Through sensitivity analysis and simulation, we identify possible problems and improvements in the economic analyses conducted under an IRP approach. An actual utility IRP is used to illustrate the issues involved. By examining an actual utility case, this paper seeks to provide a practical understanding of the planning and implementation problems associated with this utility planning strategy.
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Until the 1970s, utilities commonly adopted supply- and capacity- based orientations to planning (what others have called “grow and build” strategies). The regulatory framework established in the early part of the century as well as economies of scale and the technics of electrical generation reinforced this orientation. As a result, little attention or debate was given to demand or alternative policy options. But with the rapid escalation of energy prices, growing uncertainties of supply, and changing national economic and policy structures, the consensus supporting supply and capacity expansion began to erode. The utility industry responded to energy instability by shifting to planning approaches which involve multiple policies, or policies planning. Integrated resource planning (IRP) is such an alternative. IRP seeks to balance a wide range of supply-side, transmission/distribution, and demand-side options at “least-cost”. Many utilities are now involved in these planning practices.¹

The impetus for IRP is the rapidly changing planning environment of utilities.² Capital costs of generating plants are rising, energy markets are becoming more competitive, customers are adopting new technologies that displace the need for particular utility services, future fuel costs are uncertain, and regulators are increasingly questioning the economic advisability of large centralized capacity additions to utility systems. In this environment, the traditional supply-side orientation of utilities is acknowledged to be highly risky. As Bull and Ford point out, “planning for uncertainty” has become the preoccupation of the utility industry (1988: 1).

Following a description of the general characteristics of IRP, this paper examines a case of actual utility application. The intent is to provide a practical understanding of the planning and implementation problems associated with this new planning strategy. The case analysis evaluates the IRP program of the Delmarva Power & Light Company (hereinafter Delmarva or the Company) which is located in the State of Delaware. Delmarva’s integrated resource plan, “Challenge 2000”, proposes that, under present load and energy forecasts, it will be cost effective to ratepayers to use DSM options to avoid 225 MW of peak demand and defer major additions to base load capacity by at least 12 years. Through an analysis of this case, we identify strengths and weaknesses of the IRP approach. Major emphasis is on how the assumptions and data inputs employed in IRP affect the evaluation of DSM options. Through sensitivity analysis and simulation, problems in the economic analyses conducted under the IRP approach are identified. The final section of the paper considers conditions for successful implementation of an IRP.

¹ Roughly half the state public utility commissions require utilities to prepare IRP plans (Hirst, January 1988: 1). Utilities have also increased their implementation of DSM programs over the past decade. A recent EPRI study indicates that over 300 utilities have undertaken one or more DSM initiatives (EPRI, February 1987: 1–9).

² Similar arguments can be applied to the current interest by electric utilities in demand-side management activities. See EPRI’s report, Moving Toward Integrated Resource Planning: Understanding the Theory and Practice of Least-Cost Planning and Demand-Side Management (EPRI, February 1987).
ANALYTIC AND INSTITUTIONAL CHARACTERISTICS OF IRP

IRP includes distinctive analytical and institutional features which are significantly different from conventional supply-side approaches. Typically, supply-side approaches depend upon load forecasts to determine capacity requirements in accordance with a reliability of service standard. By contrast, IRP involves a more comprehensive and active approach to utility planning that seeks to enhance management capacity to control as well as to respond to load growth in a cost-effective manner. In particular, IRP requires that utilities evaluate a wider range of environmental conditions and resource alternatives than traditional supply-side planning, and it offers the prospect of greater flexibility in policy planning.

Despite these differences, the analytical methods used in IRP are not significantly different from traditional supply-side planning, except at the evaluation stage in which DSM options compete with supply-side management (SSM) options. As in traditional utility planning, broad policy goals guide the IRP process. Within these broad policy goals, utilities set specific objectives for DSM and SSM. These objectives, combined with the end-use characteristics of customers and structural characteristics of the utility system, guide the selection and evaluation of both DSM and SSM options. For each option, information on technological feasibility, cost, and performance is required. The identification of relevant alternatives is not easy in the case of DSM because of the wide variety of options and the limited available data of technical and economic feasibility.

Successful integrated resource planning is not simply a technical combination of supply-side and demand-side planning approaches. The broad scope of IRP requires integration of utility management functions that have traditionally been separate administrative domains. There are at least six key areas that need to be integrated: corporate planning, forecasting, demand-side planning, market research, supply-side planning, and financial planning. Historically, these areas have operated largely independent from each other. In the IRP process, coordination and communication among these administrative divisions may be achieved through the creation of task forces with representatives from the relevant departments. This approach opens up the planning process and enhances the participants' perceptions of "own(ing) the planning process and results", thereby easing the utility's "transition to a new corporate culture" (Hirst and Knutsen, January 1988: 5).

The amount of attention given to demand-side options in IRP makes public participation in the planning process necessary. Such participation increases the potential for successful implementation since customer preferences for DSM alternatives are crucial for an effective IRP. Involvement of customers, particularly residential customers, in the planning process is a novelty for both utilities and customers. While potentially threatening to established decision-making practices, broad public participation introduces a diversity of viewpoints into the planning process and gives the utility an opportunity to clarify disagreements, and ultimately reduce adversarial situations. Advice and participation by external experts is also required when utilities lack in-house capabilities to fully evaluate new and unfamiliar resource alternatives.

Uncertainty is high in a planning environment where traditional assumptions about utility performance are subject to challenge and where unfamiliar alternatives are considered. Uncertainty exists at every phase of the IRP process: energy and demand forecasting, market penetration, cost and performance of DSM and SSM options, availability and cost of purchasable power, regulatory practices, etc. In dealing with these uncertainties, the key

3 EPRI has identified approximately 150 different DSM options undertaken by utilities (EPRI, February 1987: 3–5).
factors in the process need to be conceived as broad distributive functions within a
decision-analysis model that incorporates upper and lower limits of variation and seeks to
maintain flexibility of choice in responding to environmental shifts (Hirst and Knutsen,
January 1988: 6). In effect, successful IRP is a utility learning process that requires a
tolerance for experimentation and redesign.

CHALLENGE 2000: DELMARVA’S IRP

The Delmarva Power and Light Company is a medium-sized public utility serving 340,000
customers in Delaware and parts of Maryland and Virginia. In 1987, Delaware had 62 percent
of the utility’s total customers, and Maryland and Virginia 33 percent and 5 percent,
respectively. Electricity sales totaled 9,600 GWh in 1987; residential sales were 2,700 GWh,
while combined commercial and industrial sales were 5,200 GWh. Viewed in terms of spatial
distribution, Delaware sales (6,700 GWh) were more than twice the size of combined sales to
Maryland (2,500 GWh) and Virginia (400 GWh). Delmarva experienced a peak load of 2,084
MW in 1987 which exceeded its previous highest peak load of 1,840 MW recorded in 1986.4
During the last three years, peak load has increased by 460 MW, over 3 times the amount of
load growth during the previous decade. Recent peak load growth is mostly attributable to
sustained economic growth in the service area and declining electricity prices.

Delmarva’s experience in the late 1980s offers a useful example of the current trend of
utilities’ shifting their planning orientation towards a blend of DSM and SSM. An Integrated
Resource Planning Study conducted by the Company’s Electric Resource & Conservation
Committee in 1987 documented that the Company’s generation capacity and load growth
situations necessitated an alternative planning approach represented by the Challenge 2000
Plan:

Given Delmarva’s current planning environment, the Company can no longer
afford to evaluate major construction investments by examining the present value
of revenue requirements... events have shown that load growth can vary
dramatically, oil and gas prices are very volatile in today’s energy markets, and
past and current regulatory commission policy is no longer a reliable indicator of
future actions... Delmarva is developing a planning system (suitable for studying
these issues) within the constraints of the planning cycle and available
manpower. The evaluation of generation plant and load management alternatives
for the Challenge 2000 Program...was the first use of this new planning system

Delmarva spent approximately 18 months developing its Challenge 2000 Plan prior to an
April 20, 1987 regulatory filing.5 Their efforts started in November 1985 when a Company

4 The weather-adjusted summer peak in 1987 was 2,012 MW and 110 MW greater than that
of 1986. The system peak demand occurs in the summer. Delmarva’s actual winter peak
demand was 1,699 MW in 1987. Delmarva’s DSM programs are intended to shave summer
peak load demand in 1996 by 225 MW. Residential DSM programs are to achieve a 95
MW peak load reduction; while 130 MW of peak savings are to be obtained by reducing
demand among commercial and industrial customers.

5 Challenge 2000 was initiated by the Company but was designed to meet several
requirements (including least-cost requirements) of the Delaware Public Service
Commission (DPSC) for approval of future generating plans. In Findings and Order No.

8.267
team, organized to review the schedule for Delmarva's generating capacity additions, concluded that demand-side management (DSM) programs offered a potential for delaying the addition of new generation capacity by at least five years. On January 6, 1986, the Company convened a Load Management Task Force (Task Force) to develop an acceptable DSM program plan. The Task Force sought to develop a broad strategy for delaying the in-service date of the next base-load generation unit by reducing summer peak-load demand. Altogether the Task Force identified 99 DSM options: 49 residential options, 37 commercial options, and 13 industrial options. The Task Force did not fully evaluate all the options, but used six judgementally applied criteria to narrow the number of DSM options and identified four programs considered to have great potential for reducing peak-load demand: direct load control of residential air conditioners and water heaters; commercial and industrial cogeneration; commercial and industrial interruptible service rates; and commercial cool storage. Through a combination of market research, load simulation, review of other utilities experience, and judgmental estimates, the Task Force projected that 225 megawatts of peak load reduction could be achieved by 1996.

Through Integrated Resource Planning (IRP), Delmarva sought to balance supply-side and demand-side options in a manner which yielded the "lowest cost consistent with maintaining the Company's financial health" (Delmarva Power, April 1987:9). The Company compared the cost of plans for new capacity addition against plans that combined DSM and supply-side programs to determine if the integrated program was the least-cost approach. A team drawn from Corporate Planning, System Operations, and Production Engineering & Construction was assembled as the Electric Resource and Conservation Committee (ERCC) and given responsibility for cost evaluation of the options selected by the Task Force (Delmarva Power, June 1987).

The ERCC used high, low and base peak load growth forecasts provided by Corporate Planning to determine the minimum annual capacity requirement to satisfy PJM 1871 (September 1978), the Commission required Delmarva to file demand- and supply-side studies in support of its request (under Docket No. 878) to proceed with the construction of a 400–600 MW coal-fired generating plant. The Company has since decided not to proceed with the construction of this plant, choosing instead an integrated plan, Challenge 2000.

6 The six criteria were: 1) substantial impact on existing and/or new load; 2) proven technology; 3) cost-effectiveness; 4) customer acceptance; 5) greatest impact through utility involvement (rather than, for example, government regulation); 6) the "fit" with existing utility programs and policies.

7 Specific program targets were set as follows: 95 MW from direct control of residential air conditioning and water heating loads; 79 MW from commercial and industrial cogeneration; 42 MW from commercial and industrial interruptible rates; and 9 MW from commercial cool storage.

8 Forecasts were prepared using econometric estimates furnished by Corporate Planning in November, 1986. For the peak load equations, actual seasonal peaks were first normalized to average peak-hour weather conditions. The normalized values were then regressed on residential customer growth and air conditioning/ heating saturation, seasonal commercial and industrial sales, and the seasonal average real electric price. Sales and customer growth equations were estimated quarterly, by class. Personal income, employment, population, degree days, and electricity prices were key variables.
interconnection reserve obligation rules. The Production Engineering and Construction Department provided generation plans for meeting Delmarva's installed capacity requirements. Specific operating data developed for each generating unit in each plan, along with the schedule for generating unit additions, were incorporated into the production cost model, PROMOD, to determine expected total system production costs. Sensitivity runs were conducted to determine whether changing fuel prices would impact the selection process using three different fuel price forecasts (low, base, and high).

Using the PROMOD cost estimates, construction cash flows were developed for each generation plan, and both data series were entered into a financial screening model PROSCREEN (also developed by EMA). The latter compared a number of supply-side and integrated resource plans using common financial indicators including electric revenues per kWh (base rate and fuel charges combined), base rates alone, earnings per share, extent of internal and external financing, and total revenue requirements. In addition to the above quantitative criteria, qualitative criteria also were developed to assess the impact on system reliability and flexibility, the capacity of the utility to maximize use of its 'fuel of choice', and the effect on generating capacity mix. This analysis led to the selection of a 20-year integrated resource plan. The plan calls for the implementation of 225 MW of DSM programs by 1996 in combination with the construction of two 150 MW circulating fluidized bed coal units to come on-line in 1999 and 2004.

**STRENGTHS AND WEAKNESSES OF IRP**

Challenge 2000 is only one model of IRP, but it is an approach that is similar in many respects to other utilities' efforts at IRP. There are notable advantages in the overall planning and analytic features of such an approach. At the same time, a number of important shortcomings also exist in the manner in which this type of IRP is commonly pursued.

**Strengths**

As previously noted, IRP introduces a comprehensive policy planning approach that many enhance utility flexibility in response to a changing environment. IRP also expressly commits utilities to a planning approach that more fully considers efficiency improvements as an option for meeting its customers’ needs. Although no plan can be expected to take into account all possibilities or all economic implications, IRP can make a significant stride in that direction and signal a utility’s intent to innovate in its planning by incorporating strategies which target improved electric user efficiency.

IRP warrants additional capacity only when doing so is more economical than DSM and only in amounts that are economical compared to DSM. In case of Delmarva, for example, IRP forestalls capacity additions until they are least-cost options. It also gives the utility greater control over their system's load shape. Pursuing IRP helps to assure that utility rates charged for electrical service are minimized. In addition, IRP can increase the consumer's choice of service options and create conditions for the utility and consumers to more effectively respond to energy supply and demand uncertainties.

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9 Delmarva belongs to a regional electric interconnection system, PJM, comprised of utilities in Delaware, Pennsylvania, New Jersey, and Maryland.

10 PROMOD and PROSCREEN are commercial software products of Energy Management Associates (EMA).
Finally, IRP enables utilities to add capacity as needed while avoiding overbuilding in response to uncertainties in load growth. A supply-side strategy like that selected by Delmarva can focus on small-scale generating units to serve peak load needs. Such a strategy allows utilities to plan capacity additions in amounts and according to a schedule which seeks to minimize capital risks.

In sum, IRP can represent a substantial commitment to economic efficiency in electricity production and consumption; a common part that establishes cost to the customer as the key efficiency criterion. In an increasingly competitive market, focusing on customer costs can serve both the utility and the long-run public interest in affordable electric service.

**Weaknesses**

The weaknesses of IRP derive from the increased demands which this more comprehensive approach places on utility planning resources. Utilities are rarely well equipped to fully implement an IRP without improving their analytic resources. Such improvements contribute to long range benefits, but may engender substantial transition costs. As matters stand, utilities like Delmarva exhibit a number of deficiencies in carrying out IRP. The limitations of utility load forecasts, for example, reduce the analytic credibility of IRP. In Delmarva's case, these limitations include the following: systematic underestimation of future peak load and sales requirements; acknowledged forecasting errors of a magnitude approximately equal to the total targeted load reduction from Challenge 2000; and absence of significant sensitivity analyses. Problems of these types are not unique to Delmarva; for the most part, utility forecasting methods are not effective in anticipating load-shift trends. Precisely because IRP seeks to influence load shifting, a heavy reliance on traditional forecasting methods is counter-productive.

When IRP focuses on peak load issues it may neglect the larger-and longer-term contribution that DSM can make to servicing base load demand. Challenge 2000, for example, focuses exclusively on peak load management even though Delmarva's base loads are growing faster than anticipated. Without systematic or quantitative evaluation, the Company selected, for further evaluation, only those options which were judged as likely to reduce Delmarva's peak load and which were controllable by the Company. When IRP is pursued in this narrow context, it is not possible to determine whether the programs selected will make the greatest, most lasting or most cost-effective contribution to load reduction. Indeed, conservation opportunities may be ignored. In the case of Delmarva, for example, conservation alternatives were not systematically evaluated. IRP should include evaluation of options to influence long-term demand growth as well as meeting short-term peak load problems.

IRP creates new demands for the evaluation of prospective and actual program performances of DSM options, but few utilities have established the capacity for such assessments. In the case of Delmarva, evidence in support of key assumptions concerning customer participation rates, expected load reductions, program implementation and operating costs, and the costs of generation alternatives was not well documented. Even in the case of supply options, analysis was deficient. While assessment capacities of utilities

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11 Sizable increases in actual summer peak loads (by 171 MW in 1985, by 45 MW in 1986, and by 244 MW in 1987), and a significant increase beyond its forecast for 1987 (72 MW) led the Company to revise its forecasting procedures and, consequently, re-examine much of the analytic basis for the integrated resource plan supporting Challenge 2000.

12 As of January 1988, the Company had not adequately demonstrated the costs of
vary, we expect that the deficiencies exhibited by Delmarva are hardly unique and that they constitute a serious constraint on efficient IRP.

The complexity of comparisons of integrated program options, the common lack of utility experience with the process, and the limited investment of many utilities in new analytic techniques, often mean that there is no simple, widely recognized, quantitative measure that can demonstrate the superiority of one plan option over another. This introduces a wide area for planning judgements that are difficult to justify systematically. Delmarva admitted, for example, that their analysis did not render conclusive evidence for the choice of the selected plan over some other options. Indeed, six IRP options resulted in essentially the same cost per kWh. The Company indicated that, "Even after the results were ranked using a matrix system...no clear choice came forth from the analysis. As one company executive described the situation, 'The good news is that the results are very close. The bad news is that the results are very close. You can make a case for almost any choice.'" (Delmarva Power, June 1987: 10-1). Indeed, the Company has pointed out that "ultimately, the selection of a new base plan came down to the consideration of qualitative factors" (Delmarva Power, June 1987: 10-1).

Because IRP is a learning process, substantial demands are made on monitoring program performance and reevaluating planning options in light of new data. In particular, the performance of all new demand-side programs needs to be carefully evaluated during the early stages of implementation. Only well-conceived monitoring and evaluation efforts in the early stages will provide a utility with a reliable basis for decisions regarding full-scale implementation. Unfortunately such evaluation procedures are often inconsistent with conventional utility practices designed for traditional supply-side approaches that rarely involve a step-by-step learning approach to implementation. Delmarva's Challenge 2000, for example, included no systematic monitoring and evaluation plan; nor did the Company specify the design and performance criteria to be used to assess their programs. In the case of DSM options, the absence of monitoring and evaluation is a serious limitation on policy learning.

In sum, the weaknesses of IRP usually result from its departure from earlier utility planning experience and, thereby, from the additional demands it places on institutional capacities for analysis and innovation.

SERVICE RELIABILITY, UNCERTAINTY, AND IRP: A CASE FOR SENSITIVITY ANALYSIS

By recognizing both the prospect of large orders of uncertainty in load forecasting and
the necessity of evaluating load shedding and load shaping policies alongside supply promotion policies, an IRP offers an opportunity to evaluate policy and environment-induced variation in electricity demand and supply. While this is its chief advantage, it should also be clear that an IRP process is conceptually at variance with the traditional logic expressed in the reliability-of-service standard (Woychik, 1987). It can no longer be assumed that the priority of the utility is to deliver sufficient capacity to meet forecasted loads when the object of an IRP is to change loads. Reliability, analytically and institutionally, shifts from a capacity standard to a policy standard, namely can policies be devised which reliably achieve the reduced or reshaped loads and which allow supply additions to be planned in smaller increments (and from diverse sources).

Obviously, the implications of this change in planning stance are far-reaching. One way to illustrate these implications is to show how sensitive the IRP process is to variations from policy assumptions. For this purpose, we conducted simulations on load patterns and costs under different assumptions related to the DSM program elements in the Delmarva Plan. To ease exposition, the supply program, submitted as part of the Company's IRP, was not changed.

Table 1. Major Assumptions and Input Data on Residential DSM Initiatives

<table>
<thead>
<tr>
<th>1. General Assumptions</th>
<th>4.50%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inflation Rate</td>
<td>11.58%</td>
</tr>
<tr>
<td>Base Discount Rate</td>
<td></td>
</tr>
<tr>
<td>Residential DSM Incentives to Customers</td>
<td>$24/Yr/Point (with escalation)</td>
</tr>
<tr>
<td>2. Performance Assumptions</td>
<td></td>
</tr>
<tr>
<td>Peak Load Reduction per Central AC Unit</td>
<td>0.8kW</td>
</tr>
<tr>
<td>Peak Load Reduction per WH Unit</td>
<td>0.6 kW</td>
</tr>
<tr>
<td>Switch Failure Rate</td>
<td>0.5–9.0%/Yr</td>
</tr>
<tr>
<td>Customer Dropout Rate</td>
<td>2.5%/Yr</td>
</tr>
<tr>
<td>Lost Customer Replacement Rate</td>
<td>100%</td>
</tr>
<tr>
<td>Customer Participation Proportion for Each Year</td>
<td></td>
</tr>
<tr>
<td>Single Point–AC</td>
<td>21%</td>
</tr>
<tr>
<td>Single Point–WH</td>
<td>56%</td>
</tr>
<tr>
<td>Combination–AC and WH</td>
<td>23%</td>
</tr>
<tr>
<td>3. Installation Costs per Residence (1988)</td>
<td></td>
</tr>
<tr>
<td>Switches–AC or WH</td>
<td>$75</td>
</tr>
<tr>
<td>Installation</td>
<td>$50</td>
</tr>
<tr>
<td>Combined–Additional Installation</td>
<td>$20</td>
</tr>
<tr>
<td>Replacement Costs</td>
<td>$20</td>
</tr>
<tr>
<td>Removal Costs</td>
<td>$30</td>
</tr>
</tbody>
</table>

Although Delmarva has identified 225 MW needs from residential, commercial, and industrial DSM programs by 1996, this study included only residential DSM program in our sensitivity analyses because the commercial and industrial DSM programs involved less uncertainty and stronger potential for cost-effective implementation.
The residential DSM initiatives analyzed in the Company's IRP were based on assumptions concerning per point (residence) energy savings by major appliance (in this case, water heater and air conditioning systems), customer participation (including the relative participation of households with either electric water heating, central air conditioning, or both), customer dropout and replacement rates, DSM equipment failure rates, and equipment installation costs (including failed-equipment replacement and removal costs) (See Table 1). The relative economics of residential DSM options were assessed in relation to the cost of a 104 MW combustion turbine (CT), on the assumption that the relevant avoided cost for residential DSM is the purchase of peak-load capacity.

As a first step, cost sensitivity analyses were prepared in which program and avoided cost assumptions were varied by 10 percent. Of the 24 sensitivity runs completed, eight yielded significant shifts in the economics of DSM, as measured by the net difference of either the cost per kW or annual present value revenue requirements of a CT versus the proposed residential DSM package. Variations in assumptions regarding customer dropout and replacement rates, DSM equipment failure rates and installation costs had relatively little effect on the comparative economics of the DSM programs selected by the Company. However, changing assumptions about per point energy savings, customer participation, and CT costs materially affected the economics of DSM within the adopted IRP framework as shown in Table 2.

For the ten-year planning period of 1988-1997, a 10 percent reduction in achieved per point energy savings for air conditioning and water heating appliances worsened the per-kW economics of the residential DSM program by a factor of 10 (as exhibited in the 112 percent decrease in the net difference calculation) and actually reversed its standing as an alternative to the purchase of peak generating capacity (the shift in sign from plus to minus). No other sensitivity analysis, using the cost per kW criterion, led to a reversal of the ten-year comparative cost effectiveness of DSM, although a 10 percent decrease in per point savings on water heaters led to a 60 percent reduction in DSM cost effectiveness and virtually eliminated the economic advantage of the entire program. Since a 10 percent variation in per point savings is well within current industry experience (EPRI, 1985), these results underscore the existence of new uncertainties introduced by an IRP approach. As well, they point to the need for a regulatory and consumer environment which facilitates a weighing of these uncertainties versus others, and which permits prompt cost-effective plan adjustments in the face of actual performance (e.g., by changing appliance and customer targets, incentive levels for participation, and reconsideration of program options).

In the other direction, a small increase in carrying charges for the purchase of a CT greatly improved DSM economics in the ten-year planning period and nearly reversed its standing in the twenty-year plan. Again, consideration of changes in carrying charges of 10 percent are reasonable for the industry. This result emphasizes the initial point that in an IRP process, reliability is significantly affected by policy, for both the supply and demand of energy.

Finally, comparative economics, as measured by annual net present value revenue requirements, can be highly sensitive to capital costs in the case of supply options, and to incentive payments in the case of demand options. As Table 2 reports, a 10 percent decrease in achieved customer participation can actually lead to a positive evaluation of certain economic aspects of DSM (in this instance, reversing the assessment in the twenty-year plan). This is due to reduced requirements for incentive payments to attract and maintain program participants—the major continuing cost item in the particular DSM program studied here. Similarly, an increase in CT carrying charges of 10 percent may affect the comparative economic position of the far less capital-intensive DSM option (on a revenue requirements basis) to such an extent that, in a 20-year time framework, it becomes the more attractive option. Of course, this leaves open the problems of multiple-criteria for
### Table 2. Sensitivity Analysis of Residential DSM Initiatives

<table>
<thead>
<tr>
<th>Alternative Program Assumptions</th>
<th>Cost Per kW (Percent Change from Base Case)</th>
<th>Annual NPV Revenue Requirements (Percent Change from Base Case)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>1. Per Point Energy Savings</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. 10% Decrease in Savings</td>
<td>-44%</td>
<td>-41%</td>
</tr>
<tr>
<td>From AC Participants</td>
<td>(+)</td>
<td>(-)</td>
</tr>
<tr>
<td>b. 10% Decrease in Savings</td>
<td>-60%</td>
<td>-57%</td>
</tr>
<tr>
<td>From WH Participants</td>
<td>(+)</td>
<td>(-)</td>
</tr>
<tr>
<td>c. 10% Decrease in Savings</td>
<td>-112%**</td>
<td>-105%</td>
</tr>
<tr>
<td>From AC &amp; WH</td>
<td>(-)</td>
<td>(-)</td>
</tr>
<tr>
<td><strong>2. Customer Participation</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. 10% increase in AC Participation Rate and 10% Decrease in WH Participation Rate</td>
<td>+16%</td>
<td>+11%</td>
</tr>
<tr>
<td></td>
<td>(+)</td>
<td>(-)</td>
</tr>
<tr>
<td>b. 10% Increase in AC &amp; WH Participation Rate and 10% Decrease in WH Participation Rate</td>
<td>+32%</td>
<td>+27%</td>
</tr>
<tr>
<td></td>
<td>(+)</td>
<td>(-)</td>
</tr>
<tr>
<td>c. 10% Decrease in Customer Participation Rate</td>
<td>-20%</td>
<td>-14%</td>
</tr>
<tr>
<td></td>
<td>(+)</td>
<td>(-)</td>
</tr>
<tr>
<td><strong>3. CT Costs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a. 10% Increase in Carrying Charges</td>
<td>+108%</td>
<td>+82%</td>
</tr>
<tr>
<td></td>
<td>(+)</td>
<td>(-)</td>
</tr>
<tr>
<td>b. 10% Increase in O &amp; M Expenses</td>
<td>+4%</td>
<td>+2%</td>
</tr>
<tr>
<td></td>
<td>(+)</td>
<td>(-)</td>
</tr>
</tbody>
</table>

**Sign of Base Case**

| Net Difference                  | (+) | (-) | (+) | (-) |

Notes: n.c. denotes "no change."

*Net Difference equals (Present Value of CT Cost) - (Present Value of DSM Cost) using a discount rate of 11.58%.

**Signs of percentages indicate direction of change in Net Difference quantity under alternative program assumptions. Signs in parentheses indicate the sign of the Net Difference calculation under alternative program assumptions.

***Sign of Net Difference under alternative program assumption is the reverse of the Base Case.
choice and the selection of discount rates, both of which have been discussed extensively in the utility literature.

Beyond the cost sensitivity issues raised by IRP, there are potential impacts on generating capacity to be considered. The adequacy of available capacity at any point in the planning period is made dependent in an IRP approach upon not only supply schedules but program performance (supply-side or demand-side). And in some instances, pool reserve margin requirements may be affected by the type of programs adopted by a utility (e.g., reserve requirements may be increased in response to DSM-caused improvements in load factors and/or an increase in non-utility generation).

To illustrate this issue, simulations of the entire IRP (including the load and fuel price forecasting models, the generation and unit operation plans, and unit maintenance schedules) were run assuming a 10 percent shortfall in DSM, cogeneration and interruptible service programs. DSM's share of the shortfall was simulated under three conditions: (1) a 10 percent decrease in per point savings from residential air conditioning units; (2) a 10 percent decrease in per point savings from residential water heating units; (3) a 10 percent decrease in per point savings from both appliances (which is identical for load simulation purposes to a 10 percent decrease in overall customer participation). These simulations were run for a twelve-year planning period during which the Company is attempting to forestall the need for major capacity additions. In reviewing the results shown in Table 3, it should be kept in mind that the Company's IRP plan is seeking a relatively modest "supply" from load management options over the twelve-year interval, equalling approximately 10 percent of total installed capacity (approximately 2,300 MW).

### Table 3. Simulation Results of 10% Reduction in Load Contribution from DSM Programs

<table>
<thead>
<tr>
<th>Planning Period</th>
<th>Base Case</th>
<th>Simulation I</th>
<th>Simulation II</th>
<th>Simulation III</th>
</tr>
</thead>
<tbody>
<tr>
<td>1988</td>
<td>52</td>
<td>50</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>1989</td>
<td>33</td>
<td>30</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>1990</td>
<td>14</td>
<td>9</td>
<td>9</td>
<td>8</td>
</tr>
<tr>
<td>1991</td>
<td>5</td>
<td>-2</td>
<td>-2</td>
<td>-4</td>
</tr>
<tr>
<td>1992</td>
<td>0</td>
<td>-9</td>
<td>-9</td>
<td>-12</td>
</tr>
<tr>
<td>1993</td>
<td>7</td>
<td>-3</td>
<td>-4</td>
<td>-7</td>
</tr>
<tr>
<td>1994</td>
<td>15</td>
<td>3</td>
<td>2</td>
<td>-2</td>
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</tr>
<tr>
<td>1996</td>
<td>38</td>
<td>22</td>
<td>20</td>
<td>16</td>
</tr>
<tr>
<td>1997</td>
<td>52</td>
<td>36</td>
<td>34</td>
<td>30</td>
</tr>
<tr>
<td>1998</td>
<td>26</td>
<td>10</td>
<td>8</td>
<td>4</td>
</tr>
<tr>
<td>1999</td>
<td>0</td>
<td>-16</td>
<td>-15</td>
<td>-22</td>
</tr>
</tbody>
</table>

Note: Installed Capacity Difference is the subtraction of installed capacity requirements (computed as 1.19 of forecasted system peak load) from forecast capacity.
Under simulations I and II (per point savings shortfalls in AC and WH units, respectively), the Company's installed capacity requirement (which includes a 19 percent reserve margin) exceeds forecasted available capacity in four of the twelve years, and in five other years, the excess of forecast capacity over installed capacity requirements is less than one percent. In simulation III, the Company experiences five years of loads plus reserve requirements which are greater than forecast capacity, and three years where excess reserves are under one percent. For all three simulations, only one out-year (1997) has excess forecast capacity of more than one percent. Such results exhibit the potentially high level of sensitivity in service reliability when IRPs are employed to balance energy supply and demand.

The above analyses underscore the necessity for all concerned—utilities, regulators and the public—to appreciate both the nature (and magnitude) of planning uncertainties and the opportunities and risks presented by a policy-based standard of service reliability. Both the uncertainties and opportunities of IRP differ from traditional utility planning and need to be fully understood if compatible public policy is to be developed.

CONCLUSION

As Sawhill and Silverman point out, utilities can most effectively manage risk and uncertainty by "building more flexibility into their plans and by developing more responsive organizations" (1983: 17). Supply-side programs alone do not offer the flexibility to adjust economically to emerging and varying needs and demands (Breipohl and Lee, 1985: 17), whereas IRP can provide that needed flexibility. By including DSM options, and focusing on capacity additions only in amounts needed (and only when needed), IRP programs can be initiated, modified or terminated with short lead times and often at lower costs than traditional supply-side options. Through IRP, flexibility and responsiveness to changing energy demand- and supply- conditions can become an institutionalized feature of utility planning. Achieving this, however, requires a significant and sometimes threatening shift not only in the utility's orientation to planning, but also in the roles and responsibilities of all participants in the energy planning process. In this sense, to be effective, IRP must overcome the institutional inertia of established practices and policy perspectives.

Overcoming inertia requires a strong capacity for institutional learning. This is a daunting challenge for most utilities, which have not been notable as adaptive, learning institutions. In the case of IRP, utilities must be willing to invest in a long-term learning process; a process that can begin to accumulate a reliable base of knowledge on what demand-side options can and cannot reasonably achieve. Beyond this, there is a more general need for institutional tolerance with a new and unfamiliar planning process. At this point, IRP has the status of a demonstration project for most utilities. For IRP to be successful, most utilities must be willing to invest in gaining experience with a broader policy planning orientation that stretches conventional planning resources and perspectives.

In effect, IRP requires a transformation in corporate culture; a shift to a new conceptual and organizational paradigm for formulating and implementing planning decisions. The magnitude of this change will be unsettling for most utilities. It is, nonetheless, the required change for meeting the unstable environmental conditions and new policy challenges distinctive of the current decade.

The learning challenge exists not only for utilities but for customers and regulators as well. Effective IRP requires expanded customer participation and calls for protracted efforts...
to improve customer knowledge. Given the passive roles given to customers in the past, the magnitude of needed change in their behaviors may be as substantial as that facing the utilities. After seventy years of utility regulation that has been largely insulated from broad public involvement, most consumers, particularly residential consumers, are ill-equipped to take a more active role in ensuring the effectiveness of their electrical service. Our analyses in Delaware, for example, demonstrated that most residential customers were ignorant of the basic features of the regulatory system (most did not know that their electric services were regulated and could not name the regulatory body); they were equally ill-informed about the price they pay for electric service and the characteristics of their own electric service (Byrne, et al. 1986). This lack of information is not surprising, since neither the utility nor the regulatory commission had, until recently, taken steps to provide systematic information to consumers on their electric bills. The challenge of consumer adjustment is in significant part a challenge of consumer education. But it is also a challenge to the overall regulatory structure, which in most utility service areas has overseen a planning process that is systematically isolated from the public that it serves.

IRP requires opening up of the planning process that involves not only consideration of a wider array of policy options, but also a wider range of policy participants. But, a new approach to policy planning by utilities cannot be effective without a new approach to utility regulation. Moreover, the timeliness and extent of such shifts in regulatory thinking may well be the pacing element for the overall process of utility learning, and, surely, will be a key factor in the introduction of IRP.

Meeting the learning challenges posed by IRP involves a change in the institutional structure that guides utility policy planning. Achieving this institutional change calls for greater analytic capacities, however. Improving existing analytic capacities is not enough: it requires the development of new methods, new resource supports for these methods, and, most importantly of all, new advisory and decision-making networks. The quality of the analytic investment will be a key factor in institutional adjustment and in the overall effectiveness of IRP.

REFERENCES


develop their roles in improving the planning process and consequent plans." (Hirst, January 1988:v).


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