Future Directions: Integrated Resource Planning

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Integrated resource planning or IRP is the process for integrating supply- and demand-side resources to provide energy services at a cost that balances the interests of all stakeholders. It now is the resource planning process used by electric utilities in over 30 states. The goals of IRP have evolved from least cost planning and encouragement of demand-side management to broader, more complex issues including core competitive business activity, risk management and sharing, accounting for externalities, and fuel switching between gas and electricity. IRP processes are being extended to other interior regions of the country, to noninvestor owned utilities, and to regional (rather than individual utility) planning bases, and to other fuels (natural gas). The comprehensive, multivalued, and public reasoning characteristics of IRP could be extended to applications beyond energy, e.g., transportation, surface water management, and health care in ways suggested in the paper.

Introduction

Integrated Resource Planning or IRP is the process by which supply- and demand-side options are consistently planned, implemented, and evaluated to provide energy services at a cost that appropriately balances the interests of all stakeholders. Any assessment of the "future directions" of IRP must recognize that IRP has come to its present status through continuous evolution. It will certainly continue to evolve in the future to meet new resource challenges and opportunities and to incorporate ever changing consumer preferences and values.

This paper provides a status report on IRP as it is practiced today and then suggests how IRP is transforming itself to pursue new objectives in a changing energy and competitive landscape. The dimensions of this transformation suggest the immediate "future directions" for IRP. In addition, a final section of our paper pushes through the immediate transformation of IRP within the energy context to speculate about possible application of the IRP principles to other contemporary issues. To establish the basis for this speculation, we posit several defining features that appear to be prerequisites for IRP-type processes to be successful. Some, or even a substantial number of these features may be absent in other settings. Their absence, in turn, should engender caution in those who might otherwise be enthusiastic about the application of "IRP Principles" to other resource allocation issues.

There have been periodic updates on IRP (see, for example, Hirst and Goldman 1991). What distinguishes these status reports from the current one is that the current one aims less at summarizing where IRP is today in favor of attempting to describe how the IRP process, itself, is transforming itself to be a vehicle for doing very different kinds of things and meeting quite different objectives in the future. The transformation of IRP, in turn, reflects the major transformations occurring in the electric and gas sectors, as electric utilities adjust to the end of their vertically integrated monopolies status with the onset of vigorous competition in generation with independent power producers, as gas utilities adjust to an even more deregulated business environment, and as customers of both energy sources demand ever greater value for the energy services they purchase.

IRP: Its Current Status

IRP is primarily a process that has come of age within the investor-owned electric utility sector. Originating as "least cost utility planning (LCUP)" in the 1980s in a handful of states on the east and west coasts (as well as in the state of Wisconsin), the objective of the effort was to rationalize the means of providing energy services to ratepayers (Krause and Eto 1988). Utility motivation lay in avoiding the high cost of new generation, adopting smaller-sized resources, which would provide more flexibility to deal with all kinds of uncertainties, and repairing badly frayed regulatory and public relations.[1] Other parties had other motivations for seeking entry into the utility planning process. Energy conservationists sought to increase utility commitments to cost-effective energy efficiency. Environmentalists sought entry to advance an environmental agenda that, in turn, was closely tied to developing efficiency alternatives. In 1989, almost 25 states showed little or no progress in implementing an IRP regulatory framework; by 1991 the number had dropped to only nine (Mitchell 1992).

In this section, we summarize these developments around several themes: the emergence of energy efficiency as a resource option, the process of IRP as an improved means for balancing resource planning objectives, and finally the changing structure of the electricity industry. These themes, in turn, establish the points of departure for our views on the near-term challenges for IRP in the electric and gas sectors in the following section.

The Emergence of Energy Efficiency as a Utility Resource

The pursuit of all cost-effective energy efficiency was clearly a talisman of IRP in the 1980s. "Integrated" planning was seen by many in and outside the utility industry as the process through which energy efficiency and other "demand-side" management (or DSM) activities would become legitimized and part of the resource mix.[2] That history of the IRP-DSM linkage is why so many still tie IRP and energy efficiency so closely together even after IRP has outgrown its purely DSM roots.

In fact, utility-based DSM (derived through IRP) has made significant contributions to utility resource portfolios. Efforts at efficiency improvement which just a few years ago were pilot programs in a handful of semireluctant utilities (or actually declining in the case of California utilities; see, for example, Caldwell and Cavanagh 1989) have grown significantly at almost every utility (Nadel 1990). The Energy Information Agency (EIA) estimates that electric utility spending on DSM increased from less than $900 million in 1989 to over $1.2 billion in 1990 (Prete, Gordon, Bromley 1992).[3] Less than two years ago, EPRI estimated that DSM would reduce electricity demands by less than 6% (or 200 billion kWh) by the year 2010 (Faruqui, et al. 1990). EPRI's most recent estimate of DSM savings has increased dramatically; it now estimates that DSM (with incentives to reward DSM accomplishments) will save 11 percent or 450 billion kWhs by the year 2010 (Rabl 1992).

No understanding of utility adoption of DSM as a resource is complete without appreciating the tremendous influence of regulatory policies on utilities. A large part of the reason "unselling" electricity was unpopular to utilities was that it ran directly counter to their short-run economic interests. Early regulatory efforts that were focussed on the cost-standard for DSM (see, for example, CPUC/CEC 1987) often ignored the economic implications of aggressive DSM within the regulatory framework under which utilities operate. Explicit recognition of these inconsistencies (Moskovitz 1989) and innovative approaches to address them have been instrumental in providing utilities with a positive incentive for pursuing a least- (or lower) cost energy strategy in which the interests of the firm are consistent with those of society (see Nadel, Reid, and Wolcott 1992, and Reid and Brown 1992).

The Process of IRP

The emergence of DSM as a resource option also reveals a more fundamental transformation in the way in which energy resource planning decisions are now being made. At one time, DSM activities were seen as a way of placating "intervenors" who agitated for them on behalf of "ratepayers." The change even in the language with which we describe the players foreshadows how the motivations for and the role of DSM have evolved recently. "Ratepayers" have become "customers" and "intervenors" have become "stakeholders." These semantic changes are important. They suggest an entirely different relationship between utilities and the institutions and individuals who buy their services - much more discretionary and competitive than "ratepayers" or noblesse oblige charges might suggest. They also suggest a radically different relationship with other groups: shared stewardship rather than interrupting irritant.

For example, IRP processes have often evolved to bring in many more stakeholders. Collaboratives have been established in at least a dozen utility settings. So far, these collaborative processes have been concerned primarily with designing, implementing, and evaluating DSM programs (Raab and Schweitzer 1992). But the issues are beginning to shift into other areas to be discussed separately. Probably more important than the specific subject matter being discussed in collaboratives throughout the states, is the process itself. Previously adversarial groups have learned to "reason together" to come up with outcomes that are both richer in content and more efficient in process than the old way of slugging it out at Public Service Commission proceedings. Collaboratives in the utility setting are an interesting example of a broader legal development called alternative dispute resolution. In common, they hold out the hope of arriving at better quality public policy decisions at less cost than the adversarial alternatives.

The Changing Structure of the Electric Utility Industry

The emergence of state IRP processes and rise of utility DSM activities have taken place while the electricity industry has been undergoing basic restructuring at the generation end of the business. The passage of the Public Utility Regulatory Policies Act (PURPA) in 1978 signalled the beginning of a new era. The emergence of a new class of nonutility generators (in the language of PURPA, qualifying facilities or QFs) demonstrated that entry by new participants into the generation of electricity was a viable alternative to utility-owned and operated power plants. According to EIA, in 1990, nonutility generation accounted for nearly six percent of installed US electric generating capacity (42 GW) and eight percent of net electricity generation (215 BkWh) (Prete, Gordon, Williams 1992).

While many might well argue that PURPA was hardly "competitive" since utilities were required to buy all the offered output and pay full avoided costs, experiences with PURPA have made it a much more competitive procurement mechanism. Indeed, because so much more power was available than was needed by the utilities during the 1980s, mechanisms were established to choose among competing power supplies.

Bidding for QF power was initiated in Maine in 1984 and soon spread to other utilities as a way of rationalizing QF supply additions. According to a recent survey by the National Independent Energy Producers, as of mid-1991, a total of 67 RFPs had been issued requesting a total of 19,273 MW of power (Sherman, Sutley, and Wellford 1991).[4]

At the time of this writing (Spring 1992), there are competing bills in Congress that would continue the trend toward a more deregulated generating system. Which version of these bills is ultimately passed is immaterial; the trend is irreversible. The notion that utilities should maintain a monopoly on the generation of electricity is no longer tenable.

IRP: Where Is It Heading?

While some form of IRP is being practiced by many utilities across the Nation, IRP faces important challenges, if it is to prove a robust planning method for meeting society's energy service needs. The excess capacity of the eighties, where it can still be found, will disappear before the end of the century. Utilities will have to plan for the retirement or repowering of a substantial fraction of their current, aged, installed capacity. Nonutility generation and demand-side management have demonstrated that they have important roles to play in meeting future resource needs. At the same time, environmental and other nonmarket priced costs of delivering energy services have increased in importance. For IRP to be successful, it must fairly balance these concerns to ensure equitable market shares for these (and other, as yet, unknown) options for providing future energy services. Yet another important challenge for IRP is whether it can be successfully extended into new energy resource planning forums.

In this section, we describe these challenges under two broad headings: (1) the maturation of IRP within the IOU electric utility sector currently practicing IRP; and (2) the expansion of IRP principles beyond this part of the industry to other IOU electric utilities, non-IOU electric utilities, multi-utility or regional electricity planning, and the gas industry.

Maturation of IRP Within the IOU Electric Utility Sector

Within the parts of the electricity industry where IRP is already being practiced, new topics are constantly emerging to "push the envelope" of IRP. If the scope of this paper was to encompass solely the "state-of-the-art" of IRP, the discussions that follow in this subsection might form its core. We group our discussions into several categories: (1) the basic transformation in business orientation taking place at utilities as a result of IRP; (2) the ultimate implication of the IRP process for the allocation of responsibilities for resource planning decisions between the utility and its stakeholders; (3) the evolving planning techniques to deal with dramatic new uncertainties facing the industry on both the demand- and supply-side; (4) the proving of the DSM resource and the evolution of the utilities' role in acquiring it; (5) the emerging role of transmission and distribution planning issues in IRP; and finally (6) the incorporation of the nonmarket priced costs of energy services into IRP.

The Transformation of Investor Owned Electric Utilities into Energy Service Companies.

> "IRP has become the planning process for the company's core business" (Mueller 1992).

What is meant by this observation is that, for some utilities, IRP has become the process by which companies, facing increasing competitive threats and opportunities decide which markets to serve with which precise kinds of highly differentiated products and services - in order to maximize customer value. That's quite a bit more than deciding the resource "stack" based on some hypothetical, but never truly, level playing field. Rather, it represents the aggressive pursuit by utilities of those energy service opportunities that they are uniquely qualified to offer. In order to achieve this end, planning - IRP or otherwise - can no longer be solely the province of just a few departments within a utility. It has become an integrating activity involving virtually every department. The completion of this transformation is symbolized when IRP is no longer seen as simply a response to regulatory directives, but instead as the primary and defining business orientation of the firm.

It is of course only in response to the removal of barriers to the profitability of DSM activities by regulators that utilities are able to pursue these opportunities aggressively on the demand-side. One question that arises in the context of the changing business orientation of the utility is the proper role of regulation in an evolving and increasingly competitive energy services market. The specific issue that we believe arises is the appropriate future relationship between the use of rate-of-return ratemaking and other, market-based measures for compensating prudent utility uses of ratepayer dollars.

Shared Responsibility for Planning Decisions. We also foresee even more public involvement in unfolding IRP processes. Collaboratives have been so far mainly concerned with DSM. However, in the future, we foresee these collaboratives expanding the subject matter of their deliberations to include supply options, as well, and the tradeoff among public preferences for reliable, economic power and environmental protection and enhancement. In many states, IRP is already evolving away from the consideration only of DSM and having to choose among more expensive, larger resource options, e.g., utility generation vs. IPP generation.

Obviously, these prospects raise important challenges regarding the future efficacy of IRP. IRP implicitly shifts aspects of the resource planning decision from the utility to the public. That is, in return for increased input into the planning process, the public is implicitly accepting increased responsibility for resource planning decisions. If DSM, for example, fails to live up to its proponents' expectations and/or when the time arrives then, in addition to DSM, it is necessary to undertake siting and construction of a new powerplant, will the public then accept that outcome? If IRP has been successful, one would hope that these eventualities would be greeted with more equanimity than was the acrimony that occurred regarding cost-overruns and prudence disallowances throughout the late 1970s and 1980s. Indeed, public harmony even amidst difficult resource choices will be one of the important "success indicators" of IRP when the sledding gets rough. The future participative process for deciding resource mixes will include a more explicit consideration of complex risks and uncertainties and their allocation before, during and after resource development. The sharing of these risks will challenge institutions, like public service commissions, to honor approvals made in good faith by preceding authorities.

Managing New Planning Uncertainties. One significant advantage of IRP is its ability accept the inevitability of uncertainty formally into the planning process. The importance of contingency planning will only increase. On the demand-side there is significant uncertainty over the prospects for industrial (and, in some cases, municipal) by-pass reducing loads and new transportation loads dramatically increasing them. (We will focus directly on the uncertainty regarding the cost and performance of DSM in a subsequent discussion). On the supply-side, increased reliance on nonutility generation and increased environmental regulation are probably the most dominant new sources of risk.

What we have seen is that the determination of demand has evolved away from deterministic models to scenario approaches that illuminate how to manage uncertainty. Resource strategies are judged not only on whether they are economic; but, also, on whether they have enough flexibility to change course as circumstances change in the future (or enough "robustness" to work acceptably for alternative future circumstances).

Some creative contracting arrangements have been derived to deal with the uncertainties in future demand. The Boston Edison Edgar Project exemplifies preapproval of contingent construction (Boston Edison 1988). Boston Edison filed an integrated resource plan in 1988 which explicitly laid out the uncertainties that could affect the adequacy of the "least cost" plan.[5] The Massachusetts Energy Facility Siting Council approved the approach - at least to the extent of not refusing to rule because the Edgar Project might be hypothetical.

Another approach for managing uncertainty - this time on a pool-wide basis - is provided by the New England Power Pool or NEPOOL (NEPOOL 1991). Here, the idea was to reduce regional uncertainty by short-lead time acquisition of a combustion turbine and provide an estimate of what the price might be to reduce uncertainty. The study estimated that the change in revenue requirements from raising the planned confidence level of meeting the NEPOOL reliability criterion level from 50% to 80% was between $991 million to $2.6 billion, depending on load growth and whether a combustion turbine or combined-cycle gas turbine is chosen to bolster confidence. These costs, however, are but 1-2% of projected NEPOOL utility revenues, 1991-2005.

Yet another approach for reducing uncertainty is to reduce it through aggressive DSM. An analysis of such an approach has been undertaken in the Northwest region and for Bonneville Power Administration (Ford and Geinzer 1990). The study undertook a detailed examination of how uncertainty might be reduced in the Northwest region and for the BPA system through aggressive new building efficiency standards and at what cost. The analysis showed that more aggressive DSM could reduce uncertainty less expensively than alternative insurance policies (like a contingent supply acquisition). Comparing higher efficiency with a "build for the medium; option to the high" case in the Northwest, the 8 percent reduction in uncertainty achievable through aggressive building standards could avoid the cost of about 550 MW of preapproved coal plant options, costing $250 million.

The Future Role of DSM in IRP. There is no question that utilities have an important role to play in mobilizing cost-effective DSM. The emerging issues center on how big a role should utilities play, at what cost, and to whom. The hardest part of this issue lies in recognizing that the "right" answer will probably change over time. An important early justification for utility delivery of DSM was that significant market and institutional barriers prevented cost-effective DSM from being acquired through the "invisible hand" of the market place. Utility DSM is currently playing an important part in creating the infrastructure necessary to correct for this market failure, but so do a number of other activities (such as building and appliance efficiency standards). Moreover, while it appears politically acceptable for all ratepayers to suffer equally the increased costs of supply-side investments, there has always been a concern that it is less acceptable for some customers to benefit relatively more for lower total cost demand-side investments. Part of the answer lies in better understanding the total costs of DSM; another part can only be addressed by continually reassessing utility delivery of DSM compared to other providers.

With DSM programs underway at most utilities at resource levels approaching $2 billion per year, it is obvious that evaluation activities will take on increased importance. It is clear, for example, that DSM will never be "too cheap to meter." What is required is careful documentation of the full costs of DSM in a statistically defensible fashion. This work will be necessary not only to assist utilities in recovering the costs they incur in carrying out successful DSM but in informing the country how much of the future demand for energy can be reliably satisfied through DSM. Several important evaluation works have already reached fruition (Hirst and Sabo 1991, Violette, et al. 1990, and Hirst, eds. 1991).

Unprecedented levels of DSM by utilities also suggests that parallel evaluation should begin to assess critically the appropriate level of utility involvement in DSM delivery. DSM bidding, for example, can play at least two roles in IRP. It can address niche markets that utilities are ill-equipped or as yet unable to serve and, in those markets where both utilities and ESCOs compete, serve as a yardstick to measure the efficiency of utility delivery of similar programs (Goldman and Busch 1992). This second role may also shed light on the appropriate cost-standard to apply in assessing ratemaking modifications to reward successful utility DSM activities.

At the same time, the change in philosophy behind DOE's (and some state's) standards for minimum appliance and building energy efficiency suggests that many of the "creamier" markets for utility energy efficiency programs will soon be eliminated. For example, while the first generation of national residential appliance efficiency standards tended to remove the lowest efficiency models from the market, more recent updates to some of these standards have the effect of removing almost the entire current generation of products in favor of higher efficiency products that are not yet in the marketplace (see, for example, Turiel et al. 1990). Utilities, partly in response and partly through encouragement from EPA, have already initiated efforts to move jointly "upstream" in energy efficiency product markets to sponsor the next generation of energy efficient devices (the so-called "golden carrots" program) (Sachs, et al. 1992).

Finally, in light of these developments, we expect continued discussion of the issue of who should pay for utility DSM. In the short run, we expect to see DSM program designs that continually assess what is the minimum incentive (paid for with ratepayer dollars) required to encourage adoption of energy efficiency. We also expect to see ratemaking practices that recover these costs directly from the customer classes, or in some cases, customers that benefit directly from the energy efficiency activity. In the long-run, we expect more explicit discussion of the tension inherent between a public policy to rely on utilities to stimulate the development of a more energy efficiency economy and the utilities' fiduciary responsibility to protect ratepayer monies.

Transmission and Distribution as a Resource. Transmission and distribution were once thought of merely the means by which the product produced by power plants is delivered to the customer. We see future IRP activities involving this delivery system in a much more direct fashion as a resource option or consideration, and its siting and operation as an IRP issue. We foresee that transmission will become much more of a self-standing business with highly differentiated services offered to provide value to particular customer needs. With concerns about EMF and siting, we foresee the expansion of public participation - through collaboratives or other alternative dispute resolution mechanisms - into the transmission area.

Twenty years ago, transmission was enhanced where enhancement was necessary to strengthen reliability. The redundancy built into transmission permitted a substantial increase in inter-system economy transactions in the 1980s. These transactions have played a major role in reducing the industry's reliance on oil as a fuel source (Gordon 1985). But in the 1990s, utilities are critically reviewing all their assets individually to determine how with each of them they can increase value to the customer. Thus, transmission is becoming a vehicle for commercial exchange of highly differentiated energy services to meet tailored customer needs. No longer is it just "send the juice." Now wholesale exchange is characterized by a long list of attributes to adapt it to meet particular customer requirements. Attributes include amount of power, time of delivery, firmness of power, notice requirements, quality, and many other criteria (Kelly, et al. 1987).

In addition to the competitively induced forces that have made utilities reassess transmission as a marketable asset, these same competitive forces have increased the pressure for broader access by nonutilities. There always has been a tension within different segments of the utility industry, itself, regarding transmission. Many public utilities are full (or partial) requirements customers of investor-owned utilities for their wholesale power requirements. Public utilities have often sought greater access to less expensive sources of wholesale power (and the necessary wheeling services by intermediate utilities to get it to them). What is new today is the pressure by independent power producers (IPPs) to acquire transmission services to sell their output to other utilities and, indeed, by utility subsidiaries to sell wholesale power to remote utilities (again requiring intermediary wheeling services).

Amendments which would alter the present FERC wheeling authority have, in somewhat different form, passed both houses of Congress this year in conjunction with the omnibus energy legislation (H.R. 776 and S. 1226). While the final form of the legislation is unpredictable, both versions would alter the "findings" FERC would have to make to support a wheeling order. While preservation of reliability remains, the other daunting hurdles of Section 212 of PURPA are gone and the burden really shifts to the utility to prove to FERC why the application of a non-utility generator (IPP or EWG) for wheeling services should not be granted. The House bill more dramatically alters present access provisions than does the Senate version but both explicitly proscribe *retail* wheeling, a particularly objectionable prospect for most utility segments, if not their industrial customers.

The stage, at this point, seems irreversibly set for broader access to transmission by IPPs and Exempt Wholesale Generators or EWGs.[6] For most, the argument has been compelling that incentivizing independent power producers in order to permit customers to benefit from generation competition without assuring reasonable transmission access for them to reach distant markets would be ineffectual. In fact, the battlelines now seem to have shifted to a host of pricing concerns and about how native load customers should be protected as wheeling services are offered to IPPs/EWGs.

These still evolving developments have important ramifications for IRP, of course, because they help define the resource base outside the traditionally drawn utility service territory upon which planners and decision makers can build the appropriate IRP resource "stack." Of course, the ultimate reliability and practicality of this hybrid system will have to reveal itself. Fortunately, technical developments in real time control systems for utilities are proceeding to expand the capabilities of present T&D systems and better manage distributed sources (EPRI FACTS citation). At the local distribution level, for example, it is clear that explicit consideration of distribution system constraints (such as substation transformer capacity expansion) can substantially enhance the value of DSM activities targeted to these locales (Rosenblum and Eto 1986).

Accounting for the Nonmarketed Priced Costs of Energy Decisions. Perhaps the most important issue facing utility planners today is increased concerned over the environmental impacts of energy resource decisions. In this regard, IRP has evolved to encompass the fullest sense of the original "least cost" planning paradigm, which is the explicit recognition that important noneconomic (or more precisely nonmarket priced) costs should be considered in resource planning. Moreover, no issue in utility planning today (except perhaps transmission access) is likely to stir as much emotion.

In 1989, at least 13 states were trying to "internalize" environmental externalities in their resource planning (Cohen, et al. 1990). Some, like Massachusetts, California, Nevada, and New York, are a long way along - assigning specific "costs" to be assigned to resource alternatives. For the most part, these costs affect only resource planning, not ratemaking. While it is far from settled as to what role state public service commissions should play in "internalizing" externalities (see, for example, Joskow 1991[7]), there are substantial political pressures to act to improve and protect the environment. We expect that IRP will be the process by which the effects on resource choice caused by such internalization will be worked out.

A significant amount of analysis will be devoted in the future to quantifying the environmental and other external (such as socioeconomic) costs and benefits caused by various fuel cycles (including DSM) to help rational planning (see, for example, Ottinger, et al. 1990). Part of this analysis must include explicit consideration of the extent to which existing laws and regulation already internalize these costs (such as the recent amendments to the Clean Air Act). Another part is the appropriate role of utility commissions, vis-a-vis other authorities, in effecting policies to internalize these costs.

An encouraging sign is the leadership role being adopted by some utilities in the subject of environmental externalities.[8] These utilities recognize the value of getting out ahead of this issue. Leadership has at least two advantages in this context: (1) it can improve public relations over an issue that is emotionally charged; and (2) it provides a prudent business hedge (or contingency plan) against future regulations.

The Extension of IRP Principles to Other Utility Sectors

IRP started within the IOU electric utilities largely as a result of state rules and directives on the east and west coasts of the country (and in Wisconsin). In this section, we explore the prospects for applications of IRP in those parts of the industry where IRP has not been formally adopted. Our review includes other IOU electric utilities, non-IOU electric utilities, regional electric or multi-utility planning, and lastly the natural gas industry.

Other IOU Electric Utilities. Understanding why IRP is practiced extensively in some states lends insight in why it is not practiced formally in others. The states with leading IRP activities can be characterized as having at least one of two important features: (1) strong, activist commissioners and staff; and/or (2) impending major resource short-fall. For those states not actively practicing IRP, these conditions are often absent. In the case of Nebraska, for example, the answer is simple; there are no state-regulated investor owned utilities. For many of the midwest states, there has been significant over-capacity in the 1980s. In other parts of the country, regulatory capture is surely one of the reasons utilities have not been directed to pursue IRP aggressively.

Several factors suggest that more states will increase their involvement in IRP. First, the over-capacity of the 1980s will be worked off by mid-1990s. Many utilities will be faced with major decisions regarding future sources of power. IRP, we believe, will be a central element in allocating these needs among utility-owned and operated repowering and new construction, nonutility power producers, and utility-sponsored DSM.

Second, for states with coal-fired electric generation (where much of this excess capacity is being worked off), the Clean Air Act Amendments of 1990 have the potential to be a significant force in stimulating and catalyzing utility IRP activities (Brick 1992). Implementing the utilities' compliance plans will be expensive. IRP offers the promise to lower these costs through a reasoned consideration of compliance alternatives. In fact, the Clean Air Act Amendments provide explicit incentives for utility IRP and DSM activities[9] (US Congress 1990). The evidence to date, however, is less encouraging. Most states appear to be treating approval (and even pre-approval) of compliances costs wholly outside of the IRP process (to the extent one exists in these states).

Non-IOU Electric Utilities. Another direction we expect to see for IRP is expansion to include public power utilities and rural cooperatives. That is, IRP is underway in the electricity industry in some form in over 30 states. But, with the prominent exception of Bonneville Power Administration, the activity is largely confined to state-regulated, investor-owned utilities.

The planning and operational motivations in the publicly-owned segments of the industry are not well understood. While there certainly is public encouragement for "more efficient operations," reflected in lower public costs, the financing mechanisms, risk exposures, and incentives are quite different. The construction undertaken by public entities is typically financed through government bonds. Budgets and positions are likely to be greater for organizations with increased sales revenues, on the other hand. In addition, of course, many publicly owned utilities emphasize distribution functions and buy their power from investor-owned neighbors. So they are not faced with the same kinds of resource choices, although more public utilities are entering into generation functions.[10]

Many of the well-known attributes of IRP in the IOU sector do not translate readily into the public power context. From a regulatory perspective, public power is not rate regulated by a state utility commission, which suggests that the external forcing-function that commissions provide to get IRP going in IOUs is absent.[11] From a business perspective, public power is usually owned by the communities it serves and is operated as a nonprofit, which suggests, for example, that the need to overcome financial disincentives to DSM should be much lower. On the other hand, many municipally-owned utilities provide substantial revenues to the communities they serve, such that reduced sales from utility energy efficiency activities may be contrary to the community's interest in relying on this source of revenues. In fact, public power utilities have implemented significant load management activities, due in part to the expensive demand charges of the full or partial requirements tariffs they pay to other suppliers of electricity (APPA 1992). Finally, and perhaps most important of all, with a few notable exceptions, public power is characterized by a large number of relatively small utilities, which suggests that the personnel to implement IRP is often lacking. Two thirds of the over 2000 public power utilities across the country serve less than 3000 customers.

We see two encouraging trends within the public power sector that suggest that IRP activities will spread. While there are no PUCs, per se, to order IRP activities, there are institutions interested in accelerating the pace of IRP that have a unique catalyzing role within the public power industry. For example, the Western Area Power Administration, a Federal Power Marketing agency, has committed itself to tying requests for future sales of low-cost Federal electricity to the progress by their customers in implementing IRP (WAPA 1992). In addition, the Rural Electrification Administration, which is a major source of funding for cooperatives, has recently announced new lending rules that link access to future REA funds to borrower's IRP activities (REA 1992).

Regional Approaches to IRP. The emergence of transmission as a means to obtain new sources of power from neighboring utilities and nonutility power producers, coupled with increased concern over environmental issues is rapidly blurring the old service territory and state boundaries within which traditional IRP has been done. To many, it is increasingly clear that "optimal" IRP, if undertaken only on a service territory basis, will fail to achieve regional, let alone national optimality. But the evolution of IRP into regional issues will move planners into a thicket of issues.

One of the first problems, of course, is the absence of regional political institutions within our constitutional framework to deal with regional planning. Joint Boards, Joint Planning Agencies of various kinds on various issues, and state compacts have been proposed but not ever successfully implemented between FERC and state regulators. On issues in which there usually are "losers and winners" it is difficult to gain state unanimity and any aggrieved party always has recourse to the FERC for a contested issue. Federal reluctance to cede any of its authority to regions, on the other hand, is matched by state reluctance to cede any of their sovereign powers, either. Utilities worry about "layering" by regional entities that only seem to add to the existing already crowded framework. Joint Boards have worked "somewhat" in the field of telecommunications but, even there, only on very specifically drawn issues in which the several states could unanimously agree, e.g., on the principle of universal service. At bottom, it remains unclear who is responsible for regional outcomes in the same way state and federal government levels are responsible for outcomes today.

That is not to say that there haven't been regional planning models. Two well known regional entities are the Northwest Power Planning Council (see, for example, NWPPC 1991) and the New England Power Pool and its planning arm, NEPLAN. The Northwest Power Planning Council came into being by federal statute under very specific circumstances, viz. a regional concern for power supply adequacy as good hydro sites became scarce and growth was continuing - and - concern for the fair allocation of hydro power in the region. NEPLAN was a logical and somewhat unique outgrowth of NEPOOL which has centrally planned and dispatched New England powerplants for many years. New England enjoys the unique advantage of congruity between interstate political authority (in the New England Governors' Conference and Conference of State Regulators) and in electric industry structures.

There are also several other models for regional coordination, too. The New York Power Pool and perhaps the New York Power Authority really are engaged in regional planning and acquisition. In fact, they have been engaged in international planning through the large James Bay hydro resources they tap for power needs.[12] Another interesting example of regional planning is provided in the Western Systems Power Pool (WSPP) bulk power pricing experiment. After several years of FERC sponsorship on an experimental basis, market-based transmission services for bulk power exchange have proven to be both attractive and practical. Participants have recently petitioned FERC to make these arrangements permanent. Illinois, California, and Wisconsin have engaged in at least statewide electricity planning. Finally, the Entergy proposal currently before Congress promotes the concept of IRP for holding companies, which is a gap many now see in statewide IRP.

In the end, of course, regional IRP will be affected by legislative developments, e.g., the pending House and Senate omnibus energy bills, and the ultimate success of mixing some deregulated (market-based) generation sources with other existing and new regulated generation sources and transmission access and pricing developments.[13] A more realistic, but still quite valuable, outcome in the near term may simply be increased intraregional coordination of relevant planning activities, rather than fully integrated regional planning.

IRP and the Gas Industry. There is a natural tendency to assume that IRP for natural gas requires no more than a substitution of words. However, gas IRP is substantially more challenging from methodological, structural, and institutional standpoints. Gas end-uses include both those for which it competes directly with electricity (e.g., space heating and cooling, and water heating) as well as the generation of electricity for which it competes against other fuels (and renewables and conservation). The gas industry is vertically disintegrated, in contrast to the electricity industry, with the result that much of the delivered price of gas is outside the control of local distribution companies (LDCs). Gas prices at the wellhead are deregulated and those market-based prices typically account for 70% of the price at the burner tip. There is already substantial bypass with suppliers making separate deals with consumers and further unbundling of gas prices is in progress. The Federal government has both pricing and siting jurisdiction for pipelines so there aren't the same disconnects between Federal and state orders as occur in electricity. At the same time, the capital intensity of the gas supply infrastructure is significantly less than that for electricity. What is required is a broader understanding of how these issues and constraints affect the prospects for IRP in the gas industry.

There are several methodological and a shared (with electricity) infrastructure challenges for IRP in the gas industry. First, as was confirmed by a recent survey of IRP in the gas industry, there is no consensus on the appropriate long-run avoided cost standard by which to assess resource alternatives (Goldman and Hopkins 1991). This situation arises both from the vertically disintegrated nature of the industry and the movement toward price deregulation. Second, what the movement toward price deregulation really means is that the primary IRP challenge for gas LDCs will likely not be gas DSM, but rather the substantial planning burden created by the need to assess the range of gas supply options (with their fully unbundled costs) to develop a cost-effective and adequately reliable supply of future gas deliveries. Third, as with the small electric utilities, there is a significant shortage of qualified personnel to carry-out these dramatically more complex planning tasks.

Finally, as a matter of public policy, there are many who suggest that the real "gas IRP" issue is less an issue about how LDCs might undertake IRP and more an interface issue with the electrics. There have already been a number of quite controversial "fuel switching" proposals that would require electrics to provide consumers with information about competing gas end-use technologies. Utilities have resisted this, of course. But looking at the fuels together, it is important to point out that 50% of new electric generation coming into commercial operation is gas-fired. Electric utilities are becoming the largest marginal market for gas. The relationship between these energy sources has to be better understood and coordinated. For example, pipelines have their maximum requirements in the winter. Perhaps there could be some way to encourage electric heat pumps for winter applications and gas air conditioning in the summer (when electric utilities frequently have their peak demands). The process by which this may be done should be within IRP, but an IRP that integrates both electricity and gas service planning. The urgency for this interfuel IRP is only growing.[14]

Recapitulation

We have completed a survey of the emerging issues facing IRP in the coming years. In this section, we step back from these specifics to speculate on what we believe to be the defining characteristics for successful IRP applications. We focus on them explicitly in this section both as a summary of where IRP has come from and is going to within the electricity and gas industries, as well as to prepare the ground work for our thoughts in the following section as to where IRP might go in other resource allocation arenas. We will note that several of these important characteristics or preconditions are absent from the emerging public policy areas where IRP principles might be applied. Their absence, in turn, should engender caution in those who might otherwise be enthusiastic about the application of "IRP Principles."

IRP arose out of a breakdown in communications and resultant mistrust that developed between consumers (and regulators) and their utilities when existing regulation apparently failed to adjust to changes in the operating conditions in the industry. The precursor to IRP, viz. system planning, appeared to exclude resource choices (efficiency measures, particularly), stakeholder perspectives, and consumer preferences. IRP reflects attributes which evolved to overcome these perceived deficiencies. Its success seems to depend on the existence of several things:

(1) There must be some central institution accountable for a result; some institution that has matching authority and responsibility to choose among alternatives and

allocate resources accordingly; some institution accountable for how well resources are used for their purposes; some institution on whom the "chickens come home to roost."[15] IRP kinds of processes probably can't succeed if authority, responsibility, and accountability are diffusely shared by many institutions;

(2) There has to be a definable, coherent, and predictable governmental system which has the authority to make governmental decisions and establish governmental policies to implement the results of IRP planning;[16]

(3) There must exist widely understood forums, either traditionally constituted or informally conceived (e.g., collaboratives) to serve as conduits for timely two-way communication with the public on resource planning issues, including service quality expectations;

(4) It must be possible to articulate clearly and understandably resource alternatives and their implications on cost, quality of service, reliability, and the environment;[17]

(5) There must be action-forcing circumstances.[18] Someone has to make decisions to protect the public interest and these decisions will be publicly scrutinized. The situation won't make it on auto pilot.[19]

IRP: Speculations on Applications Beyond Energy

In prior paragraphs, we have hinted at the extension of IRP into regional and inter-fuel issues. Extending IRP principles to these applications will be a daunting task: challenged by a geometrically expanding number of affected institutions, jurisdictions, interests, and agendas to accommodate. Perhaps lessons learned from the IRP collaborative process will be helpful in managing this expanded number of interests toward common goals, successfully. But any success will depend upon appreciating what has to be in place for IRP to have a chance of succeeding. In the section to follow, we discuss those factors and speculate about the possible application of IRP type "thinking," at least, to a wholly different set of pressing public issues including, transportation, surface water management, and national health care.[20]

Transportation

Transportation planning authorities are attempting to rationalize modes of transportation in cities and to establish incentives to encourage carpooling, public transit, or trip substitutes. While much of the incentive for such measures is environmental rather than energy, its effect is to conserve liquid fuels in the sector where there use is most abundant. Thus, there are derivative energy security benefits from public transportation and more efficient automobiles. The new $156 billion Highway bill that passed this Congress evens the federal support for public transportation vis a vis highway moneys and places much more discretion in local hands. Environmentally inspired transportation planning in California and in the Northeast states in connection with the electrification of AMTRAK may be the first stage of IRP applied to transportation. CAFE standards, gas taxes, incentives to buy up old cars and replace them with more efficient (and less polluting) modern cars are other stratagems akin to DSM. Further out, however, the real analogue to DSM lies in telecommunications, faxes, work-at-home, or other measures to substitute more cost-effective alternatives to travel trips, themselves. Transportation, like gas, is also opening up inter-utility IRP: in this case electric utility - transportation authorities. Pacific Gas & Electric and other utilities are strongly supporting electric and clean fuel burning autos as part of a corporate commitment to the environment.

The costs of "supply" measured by highways and high cost transit systems are far greater than virtually unexplored ways to substitute demand side means for travel, e.g., electronics, staggered work schedules, etc. We have already discussed how transportation is becoming of greater concern to electric utilities as they try to find lower cost ways of meeting environmental goals and support electric vehicle usage for urban travel. These inter-utility efforts are really only precursors of what we could imagine, viz. IRP for transportation, itself. Some of the transportation plans that have been worked out, particularly in urban settings, really resemble an integration of alternative means of transport and a higher product differentiation even in any one of them (e.g., car pools for cars, more frequent schedules and time of use rates for mass transit). The systematics of IRP and the experiences from application to electricity could be helpful.

Surface Water Management

The costs of supply enhancement, as in electricity, far exceed the costs of conservation. Yet conservation at end use and, indeed, in the integrity of the distribution systems themselves (which typically are aged and leak a lot) have been underemphasized. Pricing frequently fails to reflect real costs to serve. Sewage systems and surface water run-off systems are connected in Massachusetts.[21] Among the effects of these circumstances is that a lot of water is wasted both at end use and in the transportation systems to bring it from supply points to consumers. Water management is ripe for IRP and fortunately that development is beginning (see, for example, Beecher, Landers, Mann 1991).

National Health Care

The nation's health care system is one of the most controversial and important current matters of public interest and attention. Various presidential candidates have their own proposals for "fixing" the system. "Fixing" the system seems to have at least two dimensions: improve coverage (some 40 million Americans have no health insurance currently) and control costs (in 1992, the U.S. paid a staggering $800 billion for health payments). The "national" health care system is highly fragmented. 1500 companies, each with their own unique forms, administrative requirements, and procedures, dispense this health care. Contrast this situation to that in Canada where one company and a single payer system is the means for insuring universal health care. The U.S. spends 20-40% of its annual health care budget on administration while Canada spends only 1-2% of its annual health care budget on administration.[22] Canada spends two-thirds (per capita) of what we do on health care; the U.K. one-third. Yet both provide universal coverage and comprehensive benefits. Some have suggested that the quality of care suffers under these kind of systems. Yet, only 400 Canadian patients per year travel to the U.S. for care.

> "The U.S. is not making (sensible, integrated) decisions on where to put its money in health care..at the beginning of life in sound preventative care or fruitlessly at the end of life in merely prolonging life incidentally at staggering financial cost to the health care system and, often, destruction to family finances." (Isikoff 1992)

Physicians are sending patients to specialized facilities for often unnecessary, as well as expensive, diagnostics - facilities in which the physicians own shares and stand to gain financially from such joint-ventured facilities.[23] Setting ethical questions aside, it is obvious that this staggering cost and abuse cry out for rational, integrated resource planning in our health care system.

The analogy to DSM is preventative health care. The analogy to supply side options is the large number of possible remedial interventions - all of which have quite different costs.[24] It is no doubt true that the analogies between electricity and health care are strained and that the diffusion and dispersion of service and regulatory institutions to carry out the implementation of any health care IRP make the problem difficult. However, the holistic thinking and systematic consideration of all alternatives, leavened with a relentless pursuit for service efficiencies, is the systematic of utility IRP that seems to have some application to other settings.

Concluding Thoughts

There are many other settings where IRP "instincts" could find application. As competition increases for scarce capital for public activities of all sorts and as the linkages between activities, e.g., gas-electricity, electricity-transportation, electricity-water, grow, it will compel an application of IRP-like principles to achieve efficient and adequate results to a large group of affected and active stakeholders. We should anticipate further transformation of IRP in the years ahead. Perhaps at the 1994 ACEEE Asilomar Summer Forum we shall all be treated to a paper on "Future Directions of IRP" in which the developments within electricity will be one-third of the discussion and the applications outside energy will be two-thirds. Then we might comprehend the ultimate value of the uncertainly defined, highly useful, and ever transforming process we have come to know as integrated resource planning.

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Endnotes

1. These relations had been strained for a variety of reasons both within and outside the control of utilities. Among the contributing causes for public friction were cost over-runs in large central power plants, especially nuclear plants, and rising real costs of energy. The rising real costs of energy related, in turn, to increasing oil and gas prices which were not really under the control of utilities. A manifestation of the public friction was the large power plant capital investment, on the order of $20 billion, that had been disallowed from ratebase under various regulatory grounds. A final source of tension stemmed from mounting evidence that significant,

lower-cost energy efficiency opportunities were not being captured by the normal operation of energy service markets.

2. Energy efficiency is but one part of several load shape objectives that are collectively referred to as demand-side management. Demand-side management encompasses all activities by utilities to modify the pattern of customer electricity use, including, for example, direct load control, time-of-use rates, and electrification. We use the term demand-side management to refer to all of these activities, but our focus is on those activities that seek primarily to increase customer energy efficiency.

3. Informal sources suggest that utility DSM expenditures in 1990 were closer to $2 billion.

4. It is interesting to note that, far from reducing the planning needs of utility, competitive procurement of nonutility power, if anything, requires even more planning. Since the purchase of nonutility generated power is inherently the purchase of a multi-attribute product (e.g., energy, capacity, dispatchability, fuel choice, location in grid, duration of project, etc.) the value of these attributes must be made explicit (at least) within the utility in order to evaluate competing bids. More importantly, the evaluation requires a systematic framework in which to trade-off these attributes. These activities are at the core of utility planning. See, for example, Kahn, et al. 1989.

5. The plan stated that only 70% of reasonably foreseeable ranges in fuel prices, qualifying facility installations, DSM, and future demand could be accommodated in the filed plan. To meet service requirements if events moved outside the 70% - covered situation, Boston Edison proposed early site work on the Edgar site in North Weymouth for a 300 MW combined cycle gas fired plant.

6. EWGs acquire that description by virtue of pending legislation that, among other things, would exempt such entities from jurisdiction under the Public Utility Holding Company Act (PUHCA), a jurisdiction most such entities view as an impediment to further independent power development.

7. Even Joskow admits that states and localities could legitimately establish environmental policies to mitigate local pollution which is beyond the reach of federal law (Joskow 1991).

8. Consider, for example, the preamble to PG&E's 1991 annual report: "PG&E is committed to a cleaner, healthier environment. We will conduct all aspects of our business in an environmentally sensitive manner. We are convinced that sound environmental policy and sound business practice go hand in hand. We will pursue both for the benefit of our customers, shareholders, employees, and the communities we serve."

9. For DSM broadly, increased energy efficiency activities will reduce electricity demand (and thereby utility generation) and so provide immediate relief in terms of the number of allowances a utility must obtain for its system. For utilities with phase 1 units, documented savings from energy efficiency program are credited directly toward reduced utilization of phase 1 units. In phase 2, a conservation and renewable energy allowance has been established with 300,000 allowances that will be allocated first come-first serve according to a fixed formula (500 MWh = 1 allowance) to energy savings attributable to a utility program and certified by the state PUC or EPA. The eligibility requirements are that the utility must have at least one affected unit, the utility must have a "least-cost" or IRP, and, for IOUs, there must be net income neutrality for sales lost due to utility DSM activities.

10. Some of this activity originated with the excess capacity that investor owned utilities had in the 1970s and 1980s. Some of this capacity was sold-down to the public and municipal utilities, providing them with an entry into generation activity, itself. Of course, in other settings, public utilities have always been in generation.

11. It is unknown whether the experiences of some public power leaders in IRP, e.g., Seattle City and Light; the City of Austin, Texas; and the Sacramento Municipal District (SMUD) provide transferable wisdom to other publicly owned entities without specific situations compelling that result. For example, SMUD's emergence recently into serious IRP and DSM activity was no doubt "incentivized" by the closure of Rancho Seco (representing 100% of the utility's generating capacity) and the immediate need that event created to find new resources. But it also was probably due to the personal commitment to energy efficiency and his TVA efficiency experiences of a decade ago which David Freeman brought to his General Manager role at SMUD.

12. The most recent hydro deal between Hydro-Quebec and the New York Power Authority fell through when the Power Authority asserted the price was too high. Hydro-Quebec has indicated it will go ahead

with the project anyway to meet Canadian needs. Thousands of acres of flooding will be required in the James Bay area - much to the consternation of Crete and Innuit natives. How to account for the Canadian externalities of New York power needs that are met through Hydro-Quebec is a current hot topic.

13. Transmission operations are likely to become even more complicated as a result of the freer entry of independent power producers facilitated by Congressional legislation. At this writing, it is not possible to estimate whether the Senate (S-2166) or House (HR-776) version of transmission policy will emerge from conference. Both bills amend the PUHCA and create a new class of exempt wholesale generators (EWGs), free to pursue power deals with utilities without fear of PUHCA jurisdiction. The House version clarifies FERC wheeling authority and makes it easier to obtain a wheeling order to facilitate power exchange. It is clear, however the final compromises are worked out, that the bulk power market will only become more competitive and that entry will increase to wholesalers. Transmission systems will have to evolve to handle this burgeoning market.

14. Some who have studied gas industry issues for a number of years believe that the reliability of electric service provided by gas fired plants will not be determined by the operation of gas plants. (They will likely operate quite reliably as they have in the past.) Instead, the issue will be in how well transportation and other mutual needs are coordinated. The reliability challenge will be in pipeline adequacy not in the volume of gas reserves in the ground or the operating details of current plants.

15. In the case of electricity provided by investor-owned entities, that institution is the regulated electric utility, of course: an institution "affected by a public interest" and with a statutory or common law "obligation to serve" all customers on a nondiscriminatory basis, charging "just and reasonable" rates for its services.

16. While there is shared responsibility in electrical power between the federal and state governments and while there are even a number of different agencies who become involved depending on the issue, the governmental institutional landscape is understandable, if complex.

17. The analytical developments in IRP have made it possible for practitioners to weigh demand and supply-side options on a "level playing field." Were not these methodologies and data systems developed, efforts at truly integrated resource planning would have been will of the wisp.

18. Again, for electric utilities, the "action forcing circumstance" is the obligation to provide sufficient and economic energy services (now in an environmentally sensitive way) to customers as part of a broadly understood public service obligation.

19. For electric utilities the "circumstances" requiring public scrutiny are the potentials for monopoly abuse and evidence that even where "market forces" are at work (as in wholesale markets), they may be less than "workably competitive". This potential for monopoly abuse was the cause for establishing public service commissions to decide "just and reasonable" (i.e., cost-based) rates as well as to establish service standards.

20. Again, we make the necessary observation that these applications may have diffuse responsibility assignments. This might complicate the implementation of IRP but it doesn't prevent some contemplation of whether smarter integration of the equivalent of "demand-" side and more inclusive supply-side options might provide better public results - in service adequacy, quality, cost, and environmental impact.

21. One of the implications of this ancient arrangement is that during prolonged wet weather, the sewage treatment systems (through which all the surface run-off as well as sewage runs) become over-loaded. They have to be bypassed with the result that raw sewage goes into Boston Harbor.

22. Some estimate that we could save $100 billion per year just in administrative costs if we went to a single payer system (with one set of forms, one procedure, etc.) for administering health care.

23. Magnetic Resonance Imaging (MRI) is an example of such a facility. There are 12 MRI facilities per 1000 patients in Baltimore, MD but 30 MRI facilities per 1000 patients in Brower County, FLA. These are joint ventured facilities which typically cost a patient (or his/her insurer) $1000-1500 per visit. Physicians in such limited partnerships are earning up to $200,000 per year just to send patients to these jointly owned facilities. Nearly half (49%) of Florida physicians own interests in such joint ventures.

24. Under the pressure of patient financial distress, physicians are beginning to limit follow-up visits, finding that phone call follow-up is often just as satisfactory as another expensive office visit. Faster release of patients to return home has often led to more rapid recovery as well as substantial cost savings. Hospices for the dying are another example of lower cost "supply" or remedial care strategies that make sense.

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