Is There a Future for Electric-Industry IRP?

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Historically, regulators imposed resource-planning rules on electric utilities because of the utility's obligation to serve. Given that obligation, regulators wanted utilities to plan for and procure a portfolio of resources that provided customers with low-cost electricity, stable prices, and a clean environment.

What, if any, portfolio-management responsibilities will the future utility have? To answer that question, one must first define a ''utility'' in the future industry. If utilities are distribution entities with an obligation only to connect customers to the grid, then integrated resource planning (IRP) as it has been practiced during the past decade is over. If distribution entities retain an obligation to serve ''core'' customers, then IRP will continue in some form.

This paper reviews recent IRPs to see how utilities and their regulators are responding to current and likely changes in the electricity industry. The paper then discusses how IRP might change in the future. These changes include the use of shorter time horizons for planning, a focus on contracts rather than utility built power plants, an emphasis on transmission and distribution planning, treatment of electricity pricing (with time and location dependence) as a resource, and substantial changes in how demand-side management (DSM) is treated.

In summary, resource planning will continue. But *integrated* resource planning will either disappear or will play a much smaller role in utility and regulatory affairs and be conducted quite differently than in the past.

INTRODUCTION

Between the mid-1980s and early 1990s, the majority of state public utility commissions (PUCs) adopted rules that require electric utilities to implement IRP processes and to prepare integrated resource plans. However, during the past few years, the electricity industry has begun a major transformation, which will fundamentally change the definition of a ''utility'' and the types of planning that such entities conduct.

This paper first defines what we mean by IRP. It then reviews recent utility and PUC IRP activity. Section 4 hypothesizes a particular structure for the future electricity industry, which section 5 uses to explain how planning might evolve during the next several years. Section 6 summarizes the discussion.

As Table 1 shows, the IRP process encourages broad public participation, explicitly considers the environmental effects of alternative strategies, and encompasses a broad array of ways to meet future customer energy-service needs. These IRP characteristics led to the selection of resource portfolios that lowered electric-energy service costs and the associated environmental effects. But the IRP process can be cumbersome and time-consuming. Also, traditional regulation does not encourage utility innovation, efforts to truly meet customer needs, or cost-cutting. On the other hand, competitive markets focus on meeting customer needs at the lowest cost (to maximize net benefits), increase customer choice, and reduce the costs of regulation. But not all markets are competitive; indeed competitors work hard to reduce competition. Also, some of the broad public-policy interests met in a regulated IRP environment might be lost in a retail-competition environment.

IRP BASICS

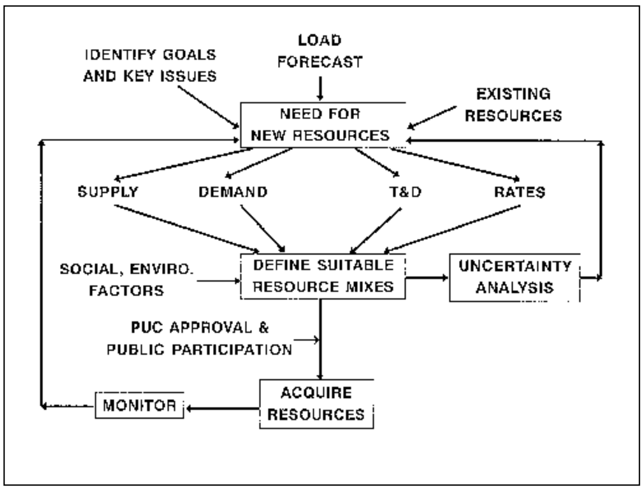
IRP is a process with which utilities and PUCs can consistently assess various demand and supply resources to meet customer energy-service needs at the lowest economic or societal cost. IRP involves deliberations among utility planners and executives, PUCs, customers, and other interested citizen groups (Hirst 1992). These deliberations are intended to lead to the development of a plan that will provide reliable and low-cost electric-energy services to customers, financial stability for the utility, a reasonable return on investment for investors, and protection of the environment.

Typically, a utility begins its IRP process by identifying its goals and the key issues that the resource plan must address (Fig. 1). Corporate goals often concern customer service, returns to shareholders, maintenance of low electricity prices, and protection of the physical environment. Specific issues might involve forthcoming decisions on an aging power plant that could be retired or repowered, DSM programs that might be expanded or modified, or a recent PUC

Table 1. *Comparison of Alternative Regulatory Approaches*

	Pro (benefits)	Con (concerns)
IRP	Public participation	Cumbersome process
	Includes environmental factors	Insufficient cost-cutting and innovation incentives
	Comprehensive planning, with DSM, renewables, and nonutility sources	DSM and renewables may raise prices
	Lower electric-energy service costs	
Markets	Greater customer choice	Markets may not be competitive
	Lower costs and prices	Possible unintended effects
	Lower regulatory costs	Loss of societal benefits

Fig. 1. *The Activities Involved in Traditional Integrated Resource Planning*



order requiring the utility to conduct a competitive bidding process to acquire new resources.

Next the utility develops alternative load forecasts. Then the utility assesses the costs and remaining lifetimes of its existing resources and identifies the need for additional resources. Here, ''resources'' refers to any method used to meet customer energy-service needs, including conventional and renewable power plants, contracts to buy electricity from other organizations, and programs that improve the efficiency or timing of customer electricity use.

The utility then assesses a broad array of alternatives that could satisfy the need for more electric-energy services. Such alternatives might include power-supply options, DSM programs, transmission and distribution (T&D) additions, and pricing options. Supply resources include modifications to existing power plants that extend their lifetimes or increase their output, purchase of power from other entities, as well as the construction of new power plants.

T&D resources include thicker conductors and additional lines that provide access to more generating units. Utility DSM programs might include (1) promotion of new lighting systems, motors, and other equipment to improve energy efficiency and/or (2) direct control of customer loads at critical times. These DSM programs constitute resources that can substitute for power plants and perhaps also for transmission lines and distribution systems. Pricing options include time-of-use rates that encourage customers to shift load from onpeak to offpeak periods as well as overall price changes that affect overall electricity use.

Different combinations of these supply and demand resources are then analyzed to see how well they meet future electricity needs and how expensive they are. These analyses are repeated time and again to test various resource portfolios for their resilience against different uncertainties. These analyses test the effects of uncertainty about the external environment (e.g., local economic growth and fossil-fuel prices) and about the costs and performances of different resources. Such uncertainty analysis helps to identify a mix of resource options that meets the growing demand for electricity, is consistent with the utility's corporate goals, avoids exposure to undue risks, and satisfies other environmental and social criteria.

The utility prepares a formal report based on the preceding analyses and on suggestions arising from public involvement. That report presents the preferred resource plan and the justification for that plan. After acceptance or approval by the PUC, the plan is implemented, and resources are acquired. Although the PUC formally reviews the plan and various nonutility parties participate in its preparation, the utility has the ultimate responsibility for its development and implementation.

While the plan is in force, the utility monitors changes in fuel prices, electricity demand, DSM participation, and a host of other factors and modifies the plan as events and opportunities warrant. Although resource planning is an ongoing process, only once every few years does the utility issue a formal plan along the lines discussed here.

In summary, IRP differs from traditional utility planning in several ways. First, it calls upon each utility to consider a broad array of ways to meet customer energy-service needs. In particular, IRP requires utilities to look through customer demands for energy and power to the demands for the underlying energy services. Second, IRP calls upon each utility to consult extensively with all parties that want to participate in the planning process. The expectation is that the IRP data, analysis, and process will lead to decisions that are more widely accepted and that reduce total risk. Third, IRP considers environmental and other externalities explicitly. Fourth, the process emphasizes uncertainty, developing plans that are flexible and robust. Finally, IRP involves implementation, the adoption of a short-term action plan.

RECENT IRP ACTIVITIES

A review of utility plans issued in 1995 shows several common characteristics, compared with the plans that these utilities had published earlier. Recent plans typically show much lower commitments to acquiring DSM resources, greater use of the rate-impact measure and less use of the total-resource-cost test in assessing the benefits and costs of DSM, greater use of competitive markets to acquire additional supplies (either auctions or purchases on the wholesale market), more emphasis on the short term and less on the long term, a willingness to publicly divulge less information, and less emphasis on IRP in general.

Duke Power's (1995) IRP illustrates well the changes in utility DSM programs. Duke's 1995 plan calls for a substantial reduction in rebates, with greater emphasis on customer payment for DSM services. This change is motivated both by substantial changes in the economics of DSM and by likely changes in the electricity industry. With respect to the former issue, with electricity spot prices very low, the economics of DSM are much less attractive than they were a few years ago (Hirst and Eto 1995). With respect to the second issue, utilities are very concerned about any activity that increases electricity prices; DSM programs that focus on energy efficiency generally have that effect. Niagara Mohawk's planned DSM programs (with few rebates) yield average rates about 1.5% higher than would occur without DSM. Because of these competitive concerns, Duke plans to increase substantially its marketing (i.e., load-building) efforts.

Utilities typically have no plans to build additional generating capacity. Many utilities anticipate slow enough load growth that they ''do not foresee adopting a resource plan that includes building new facilities or entering into long term purchase obligations'' (New England Electric System 1995). Where utilities see a need for additional supplies, they are focusing on external sources. For example, Duke Power and the Tennessee Valley Authority, two utilities with long traditions of building their own power plants, have conducted auctions to obtain options on future energy and capacity resources (Southeast Power Report 1995).

Niagara Mohawk (1995) and PacifiCorp (1995) commented that IRP is becoming less and less relevant as electricity markets become more competitive. PacifiCorp noted that ''As the electric utility industry becomes more competitive, the need for detailed resource planning under regulatory commission oversight will diminish.''

In part because the future structure and regulation of the electricity industry are uncertain, the utilities focused more on the next few years and much less on the 20- to 30-year analysis times that were formerly typical of IRP. Georgia Power Company (1995) indicated that competitive pressures led it to ''seek shorter-term supply-side power purchases'' instead of long-term commitments. Even though the Tennessee Valley Authority (1995) identified the need for an additional 3500 MW by the year 2002, its short-term action plan emphasized risk reduction and flexibility; thus, it will purchase call options for peaking and baseload resources and operate DSM programs that can be ramped up or down as needed.

Finally, many companies expressed concern about the publication of sensitive information that could place the utility at a competitive disadvantage. For example, none of the 1995 plans I reviewed include estimates of utility marginal costs, probably because utilities view this as crucial information in their wholesale-market negotiations and transactions.

PUCs have made few formal changes to their IRP rules and procedures during the past few years. The California PUC (1994) essentially eliminated its lengthy, cumbersome, and expensive IRP process. The Colorado PUC (1996) modified the IRP rule it had adopted three years earlier. The new rule emphasized competitive auctions as the way to acquire new demand and supply resources. In addition, the PUC sought to reduce the complexity of IRP filings and to reduce the amount of litigation associated with its IRP proceedings.

The Rhode Island PUC deferred utility submission of resource plans for one year because the utilities and the PUC were very busy dealing with industry-restructuring issues. In Arizona, the IRP process will focus on strategic issues rather than on specific resource acquisitions. The Wisconsin PSC is working to streamline its IRP process. And the New Mexico PUC, in March 1996, decided against adoption of IRP rules because of emerging changes in the electricity industry.

In most cases, PUCs have not modified their IRP rules. This lack of action probably stems from two factors. First, PUC time and attention are scarce resources, and most commissions have chosen to focus on competitive issues rather than on resource planning. Second, until the shape and structure of a new electricity industry is clear, PUCs may be reluctant to abandon current regulatory practice.

POSSIBLE INDUSTRY STRUCTURE

Figure 2 shows what may be the ultimate structure of the electricity industry. (I emphasize retail competition in part because IRP changes much less with wholesale-only competition than with full retail competition.) In this retail-competition scenario, the industry consists of six entities. Three of these entities—generating companies, marketers and brokers, and customer-service companies—are competitive and largely unregulated. Three of these entities—system operation, transmission, and distribution—are monopolies and would continue to be regulated. Under such a scenario:

- A variety of independent power producers would build and operate power plants, subject to state siting and environmental regulations. That is, investors rather than governments would decide on the sizes, types, timing and to some extent location of new generating units. The output from these units would be sold through a variety of contracts (either directly to end-use customers or through marketers and brokers) or on the spot market.

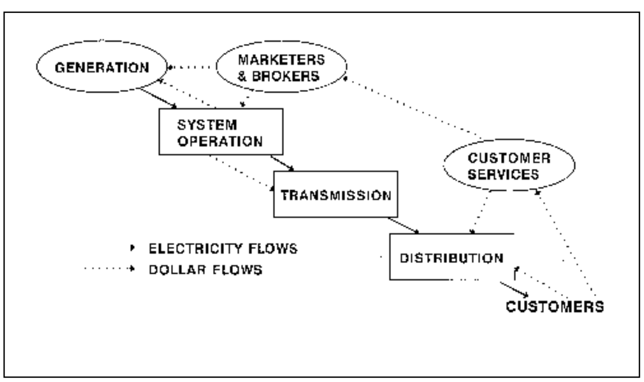
- The system operator would be responsible for matching generation to customer loads, given the constraints of the transmission network. The system operator would meet the North American Electric Reliability Council's control-area requirements. The system operator would have no affiliations with the owners of generating units or transmission facilities.

- The transmission company would own and maintain transmission lines, substations, and other transmission-network components. Similarly, the distribution company would own and maintain local distribution systems.

- The system operator and transmission companies would be regulated by the Federal Energy Regulatory Commission. State PUCs, on the other hand, would regulate local distribution companies.

- Marketers and brokers would arrange financial and perhaps physical trades of electricity between generating companies and customers. Similarly, customer-service companies would offer metering, billing, information, and other services (such as energy efficiency and load management) to end-use consumers. Because these entities, like the generating companies, would be operating in competitive markets, they would be only lightly regulated. For example, PUCs might impose minimum service standards on all companies that sell electricity at retail. But PUCs would not conduct rate cases and would not set tariffs for different customer classes.

Fig. 2. *Possible Future Structure of the U.S. Electricity Industry with Full Retail Wheeling. The Oval Functions are Competitive, and the Rectangular Ones are Regulated Monopolies.*



A key issue concerning the future of IRP is the role of distribution companies (Discos). If Discos have no customer-service functions (i.e., they are wires-only companies with an obligation only to connect), then there is little about resource planning that is integrated. However, if Discos retain an obligation to serve some customers (e.g., those that are unable or uninterested in buying from other suppliers), then some elements of IRP remain intact. In most of what follows, I assume that the Discos have no obligation to serve and no customer-service functions.

IRP IN THE FUTURE

What might the industry structure discussed above imply for IRP? In brief, such a structure would largely eliminate IRP. All of the kinds of planning that the traditional utility undertook as part of IRP would continue but they would no longer be *integrated*. That is, different entities would carry out different types of planning, generally for their own use.

Utility (Disco) Role

Perhaps the greatest change from the traditional industry structure is the allocation of risk. Historically, customers bore many of the risks associated with changes in environmental regulation, fuel supplies and prices, forecast vs actual demand, and decisions on the types and amounts of generating capacity to build. Indeed, this customer adoption of risk was a primary justification for IRP.

In the industry structure hypothesized above, individual market participants bear the risks for their decisions. The market, fuel, and environmental-regulation risks associated with, for example, the decision to build a 500-MW coal plant would be borne by the plant's owners and not by electricity consumers in general. If the forecast demand did not materialize, if the U.S. Congress taxed carbon dioxide, or if coal prices increased dramatically, the plant's owners—and no one else—would suffer the consequences. This major change in the structure of the electricity industry weakens the environmental, diversity, and central-planning elements of traditional IRP.

Distribution companies would continue to prepare load forecasts. However, these forecasts would be used to plan distribution-system expansion and not to acquire new demand or supply resources. Because distribution represents about 25% of total utility investment today (compared with 60% for generation), the benefits of distribution-investment deferral are modest. Also, the types of DSM programs suitable for distribution deferral emphasize local load management rather than systemwide energy efficiency. And the portion of a utility's customer base that can contribute to this deferral is limited to geographical areas with modest growth where DSM can defer distribution upgrades for two to seven years (Lenssen 1995).

Individual generating companies would assess the market for additional supplies and would expand their generating capabilities based on their assessments of what they could sell profitably. Similarly, customer-service companies would assess the likelihood that they could profitably sell different kinds of energy services, such as energy efficiency and alternative pricing approaches. Thus, supply and demand planning would occur as the consequence of many individual decisions, rather than as the result of a centralized planning process.

A key element that will tie demand and supply to each other in the future will be real-time pricing (Schweppe et al. 1988). With real-time pricing, many customers will face electricity prices that vary from hour to hour. Over the course of a year, prices will likely range by as much as a factor of 50 (e.g., from 1.5¢/kWh at low-load periods to as much as 75¢/kWh when supplies are severely constrained). Such pricing will accomplish several objectives. First, it will send appropriate economic signals to both suppliers and customers about the value of electricity production and consumption. This will help customers decide when to reduce and when to increased demand, and it will help suppliers decide when to add generating capacity. Second, it will reduce the societal need to implement traditional DSM programs. One of the key market failures used to justify DSM programs has been the inefficiencies in regulated electricity prices, which real-time pricing eliminates except for environmental damages, discussed below. Third, greater use of spot pricing will reduce the need to maintain large reserve margins. That is, the economic concept of price elasticity will displace the engineering concept of reserve margins (extra generating and transmission capacity), which should reduce the overall cost of electricity.

Instead of reliance on DSM, renewables, and other indirect mechanisms, environmental quality will be dealt with directly. That is, governments will tax emissions, impose regional or national caps on emissions, or directly regulate emissions from power plants rather than require utilities to acquire resources that are believed to be environmentally benign. This may be a more effective way to improve environmental quality (assuming that the political opposition to taxes and environmental regulations can be overcome), given the modest air-quality effects that DSM and renewables have had to date (Lee and Darani 1995).

Recent evidence suggests that the environmental effects of *new* electricity generating technologies are much lower than were previously thought (Freeman and Rowe 1995). To illustrate, for a plant near Ithaca, NY, externalities—excluding CO_2—total 7.2¢/kWh for a pre-1980 pulverized coal plant, 0.6¢/kWh for an existing pulverized coal plant, and 0.1¢/kWh for a new atmospheric-fluidized-bed-combustion coal plant. The environmental externalities for gas-fired power plants are much less than those for coal plants. These results suggest that possible increased use of old, dirty coal plants and the possible early retirement of nuclear plants could have much greater environmental effects than the construction of new renewable, fossil-fuel, or DSM resources (Lee and Darani 1995).

Because investments in new generation will be made by private unregulated companies, the discount rates will be higher than for traditional utilities. Because these private-sector investments will be riskier, investors will require a higher equity-to-debt ratio and a higher return on equity than was true for regulated utilities. These higher discount rates will lead to shorter time horizons in assessing alternatives. Time horizons will also shorten because most market participants will be dealing with contract lifetimes rather than with the lifetimes of capital investments. Suppliers will accept risks that customers have traditionally borne in exchange for higher returns on investments.

The factors discussed above all suggest that—given the fully competitive electricity industry outlined in the previous section—there is little left for traditional IRP. The distribution utility will conduct some analyses analogous to traditional IRP, but the amount of investment at stake will be much less than was true in the past. However, during what is likely to be a lengthy transition period, utilities and their regulators will struggle with the meaning and value of IRP.

Even if the Disco retains an obligation to serve some customers, IRP will differ from today's model in several ways. First, competition is likely to shorten the time horizon over which Discos plan and acquire new resources. Although utilities historically built plants expected to last 40 years (and Discos will likely continue that practice for their distribution systems), Discos will likely sign power contracts with a range of lifetimes, and the longer contracts are likely to be for less than 10 years.

Second, the Disco assessment of supply resources will generally focus on the purchase of energy and capacity from other parties. Because the Disco increasingly will be a buyer, rather than a producer, of electricity, it needs to know less about the details of production processes and more about electricity markets.

Third, Disco planning will focus on their T&D systems, because this is where the bulk of their capital investments will go. Also, T&D planning will be more complicated because it must encompass a larger number and variety of wholesale and retail transactions than was true in the past.

Fourth, because Discos may no longer have an obligation to serve all customers, they will focus their resource planning to meet the low end of their load forecasts. Historically, utilities focused more on the high end, to ensure that sufficient capacity was available for reliability purposes. Forecasting will also include separate analyses of the needs for additional T&D investments.

Fifth, pricing of electricity services will be increasingly unbundled and sophisticated. Distribution utilities, as a consequence, will pay much more attention to the temporal and spatial determinants of their costs to serve different types of customers. These costs, combined with information on customer value, will be used to set unbundled electricity prices.

The extent to which resource planning remains *integrated* will depend on industry structure. If competition focuses on wholesale markets and Discos retain much of their retail-monopoly franchise, IRP will change in its details but not in its overall concepts. However, if retail wheeling is widespread, the integrated part of IRP will disappear as the planning responsibilities are spread among competitive generation companies, transmission monopolies, distribution monopolies, competitive customer-service companies, and individual customers.

PUC Role

The role of the PUC will be substantially different (and diminished) from the typical PUC involvement in IRP today. Because the only entity regulated at the state level will be the Disco (which may not own generation), PUCs will have less influence than they did in the past on construction and operation of generation and transmission facilities.

PUCs will determine the ''rules of the road'' for the Disco's resource procurements but will have little to say about specific acquisition decisions. For example, PUCs may approve the structure of utility requests for proposals, such as the factors included in the scoring system. However, PUCs might not review and approve the utility's selection of resources acquired in response to its competitive solicitation. In addition, PUCs will increasingly use incentive regulation in lieu of the traditional cost-of-service regulation to cap prices or revenues. Such changes will further reduce the PUC role in IRP.

PUCs may use other mechanisms to achieve the public-policy objectives that utilities have traditionally met. These actions include DSM, renewables, energy research and development, and low-income programs (Tonn, Hirst, and Bauer 1995). For example, states could impose a universal system-benefits charge on all retail uses of electricity, structuring the charge so that it cannot be bypassed and is subject to state, not federal, regulation. The money so raised could be used to fund the types of programs listed above, either through Discos, other electric-industry participants (e.g., energy-service companies), or through new public, non-profit, or private organizations (California PUC Working Group 1995).

Discos will continue to prepare and submit to the PUC resource plans once every few years. These reports will be less detailed than their early 1990s counterparts because PUCs will impose fewer regulatory requirements on IRP filings. PUCs will continue to review these plans, may conduct public hearings (but with less litigation than now occurs), and may even ''approve'' such plans. However, the plans and their approvals will focus more on resource-acquisition criteria and strategies than on specific resources.

CONCLUSIONS

The late 1980s and early 1990s were the heyday of IRP. During that period, more and more utilities were developing

Table 2. *Differences Between IRP Environment and Retail Competition*

Issue	IRP	Retail competition
Planning		
goal	Minimize societal cost	Maximize earnings
horizon	Long term (20+ years)	Short term (~5 years)
key customer	State regulators	Retail customers
perspective	Centralized	Decentralized
Who bears risks	All customers	Investors and individual customers
Public input	Substantial	Through markets and siting decisions
Prices	Cost based	Market based
DSM and renewables		
motivation	Resource driven	Customer driven
funding source	All customers	Recipients only
Environmental		
compliance	Yes	Yes
externality adders	Yes	No

and improving IRP methods and—most important—making resource-acquisition decisions on the basis of their plans. IRP led to substantial improvements in the diversity, flexibility, and environmental characteristics of the resource portfolios that utilities use to meet energy-service needs. Thus, IRP is an important achievement in balancing economic growth with public-policy concerns, especially environmental quality.

During the late 1990s, IRP as an important public-policy and decision-making tool is fading quickly, to be replaced by the frequent interactions of buyers and sellers in competitive electricity markets. Much of the original rationale for IRP—the expected high long-term marginal costs of new energy-supply resources; the inflexibility of building large power plants; the adverse environmental consequences of electricity production; and the market, fuel, and environmental risks borne by customers—is disappearing.

During the past few years, the costs of new generating units have declined substantially, driven by low natural gas prices and improving combustion-turbine technologies. These gas-fired technologies are much smaller and take much less time to build than the plants they are displacing, which enhances flexibility. In addition, these gas-fired technologies are much cleaner than coal plants. Thus, much of the rationale for IRP is being undercut by new technologies, low fuel prices, and emerging market structures.

Where IRP focused on the long-term attainment of broad societal goals, retail competition is likely to focus on maximization of industry earnings and of customer value (Table 2). These changes mean that decision making will shift from centralized PUC hearings to decentralized individual market transactions. Risks will be borne by individual investors and individual customers, not by customers in general.

IRP emphasized public involvement, often through collaborative efforts to work with the utility in developing its resource plan and through the formal hearing process before PUCs. In a competitive market, consumers will vote with their dollars, and IRP forms of public participation will largely disappear. States will continue to oversee the siting process for large energy facilities and citizens will continue to participate in such deliberations. But the primary mechanism that citizens will use to make energy choices will be their choice of supplier and the types of contracts they sign for energy services. Therefore, suppliers will devote considerable effort to learning about and meeting customer needs and wants.

IRP emphasized energy efficiency, load management, and renewable technologies as resources that could substitute for traditional power plants. In competitive markets, these services and technologies will be offered by suppliers where the opportunity to earn money exists and will be chosen by consumers if the value of these services and technologies exceeds the costs. Here again, private decision making will supplant public decision making.

To the extent that society wishes to limit the adverse effects of electricity production, it will focus on direct, rather than indirect, methods. That is, governments will directly tax or limit the amounts of certain pollutants that can be emitted. These regulatory and tax changes will encourage producers and consumers to search for innovative and low-cost ways to comply, which should encourage use of DSM, renewables, and other environmentally benign ways to provide energy services.

During the lengthy transition period between today's industry structure and regulation and the competitive structure and regulation of tomorrow, IRP will also have to change. Transitional IRP will focus on strategies, rather than on specific resources. The plans will be dynamic and flexible (to allow companies to respond to rapidly changing market conditions), and will therefore focus on the short term. Resource plans will, as a consequence, be much shorter and less detailed than they were in the past.

While many will mourn the demise of IRP, others will be delighted with the rise of competitive markets. I am optimistic that a new industry structure will deliver more and improved services to customers at lower costs—lower in both dollars and environmental insults. Recent improvements in electricity-production technologies, the operation of wholesale power markets, the use of real-time pricing, our understanding of the environmental effects of electricity production, and the successful restructuring and reregulation of other U.S. industries motivate this optimism.

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