Trends in IRP Development – Where Are We Heading

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The purpose of this paper is to report on the trends in integrated resource planning (IRP) for gas and electric utilities. It is not intended as an accounting of the current state of IRP in the U.S. Rather it assesses where IRP requirements have evolved from and where that evolution might be headed. We conducted a survey of the 50 public utility commissions in order to compare where IRP had been and where it is now. This study is a comparison between the past and the present in order to provide guidance on future regulatory IRP trends.

Our paper reviewed some of the following issues such as the extent of IRP regulations, treatment of fuel switching options, types of cost-recovery mechanisms, treatment of environmental externalities as well as required cost-effectiveness tests. Our results will show how these requirements and processes have changed over time, how states are responding to new legislative requirements,” and what issues are likely to be addressed by state public utility commissions in the near future.

Introduction

Objective

The objective of this paper is to understand where we began, where we are and where we are headed in IRP. Our analysis focuses on planning trends occurring in IRP as opposed to an accounting of the current status of IRP at the state level.

Analytic Approach

We conducted this analysis by comparing the status of IRP requirements in three time periods - 1987, 1990, and 1992/93. Our source for the 1987 data was an ICF survey of the state public utility commissions for the Kentucky Public Service Commission as well as ongoing work at the state level in IRP development. The 1990 information was primarily found in industry literature including publications by the Lawrence Berkeley Laboratory (LBL), Electric Power Research Institute (EPRI) and the Edison Electric Institute (EEI). These initial comparisons were conducted in support of research for the Gas Research Institute. In order to gather recent information (1993/1994), ICF Resources conducted and funded a fifty state survey of public utility commissions. We have integrated these current survey results into our analysis.

Background

IRP is a process which assesses a comprehensive set of supply and demand-side options using consistent planning assumptions in order to find a resource mix that meets customers’ energy requirements reliably and at the lowest total cost. IRP criteria can include other measures in addition to cost such as social and/or environmental measures.

The current widespread interest in IRP grew out of circumstances in which electric utilities and state public utility commissions found themselves during the 1970s and 1980s. During this period, utilities committed themselves to the construction of large generating stations which, in retrospect, turned out to be unneeded or more expensive than available alternatives. Public utility commissions were faced with decisions of whether or not new generating facilities were “used and useful” and whether or not the decision to construct and complete these facilities was prudent. As a result of lower than projected demand growth, or higher than expected construction costs and longer completion times, some utilities were denied recovery of costs for these facilities.

As a result of these experiences, public utility commissions, utilities and other parties became interested in assuring that utilities considered all generation options available to them and that these options be reviewed in a public forum. An added concern by both commissions and utilities was to assure that utilities be afforded some protection from the retrospective reviews of planning decisions.

Besides IRP, another method used to assure accountability was including interested parties early in the planning process. Interested parties (e.g., consumer advocates, industrial customers) recognized a need to develop information and records over time through a cooperative process. This “collaborative” process included the regular review of planning assumptions and circumstances so that changes could be identified and appropriate responses taken **prior to** rather than **after** costly generation decisions had been made. The intent of this regulatory innovation was to avoid potential mistakes and encourage potential opportunities that could be identified early, and which utilities and ratepayers could reduce risks.

It has been suggested that with this added involvement, the public and interested parties are “implicitly accepting increased responsibility for resource planning decisions. ” (Source: Douglas Bauer, Joseph H. Eto, “Future Directions: Integrated Resource Planning,” ACEEE 1992 Summer Study on Energy Efficiency in Buildings, Proceedings, p. 8-4, August 1992). According to some utilities, this increased responsibility may decrease the risk of incurring costs for new resources, including IRP and DSM, that could be denied in future prudency hearings.

Another important development in IRP occurred in 1992 with the passage of the Energy Policy Act (EPAct). In that legislation, the Federal government encourages states to require IRP for electric and gas utilities. EPAct also encouraged electric IRP through its support of the continuing evolution in the electric industry towards competition and away from vertical integration. Initiatives to pursue an unbundled transmission and generation structure, such as in EPAct, have begun in electric regulation. This movement is significantly behind similar gas industry restructuring, but it may ultimately reduce the extent of regional integrations by local electric utilities for the same reasons as with natural gas.

Trends

We believed that the trends in IRP development among electric and gas utilities could be assessed by reviewing the following:

- Extent of IRP requirements
- Treatment of fuel switching options
- Inclusion of cost-recovery mechanisms and incentives
- Inclusion of environmental externalities
- Required cost-effectiveness tests.

Extent of IRP Requirements

Our most current survey indicates that forty states across the country have adopted electric IRP either formally or informally. Two states have IRP rules under development and seven are conducting proceedings to determine the need for and nature of IRP processes. In addition, some of these states are assessing the need to revise existing regulations and processes (Texas and Florida). Those states without any IRP requirements do not have any jurisdictional utilities (e.g., Nebraska and Tennessee). Other states without IRP currently have significant excess generating capacity. The number of these processes may be a function of the EPAct which explicitly encourages each utility to conduct IRP including the Tennessee Valley Authority and the Western Area Power Administration.

Interest has continued to grow in gas IRP primarily due to EPAct. Our latest survey shows that ten states (and the District of Columbia) have formally or informally instituted gas IRP processes (Hawaii, Iowa, Kansas, Maryland, Nevada, New Hampshire, Oregon, South Carolina, South Dakota and Vermont). Two states have rules under development (New Mexico and Arizona). Another five states have opened dockets or administrative cases to review gas IRP and twelve states are considering initiating a proceeding. This 1993 tally of states nearly doubles the number of states implementing gas IRP rules in 1990.

Perhaps one of the more important findings in our analysis was that before 1988, not one gas utility was required to submit an IRP (Figure 1) and yet nearly thirty states required IRPs for electric utilities. That trend shows that public utility commissions focused on electric IRPs are now moving towards gas IRPs. As shown in the figure, the categories used to classify IRP development include: IRP in practices, IRP in implementation, IRP under development, IRP under consideration, and IRP not actively considered.

Those states first in electric utility IRP early did not necessarily develop gas IRP simultaneously. We found that it does not always follow that an electric IRP requirements goes hand-in-hand with a gas IRP requirement. Of the states that are more involved in electric IRP implementation (24 out of the 50 in 1990), none are at the comparable level for gas IRP. For example, Illinois is discouraging DSM for natural gas at the same time it is one of the stronger supporters of IRP for the electric utilities in the country.

Our sample data do indicate however, that once IRP is reported “under consideration,” it moves towards the

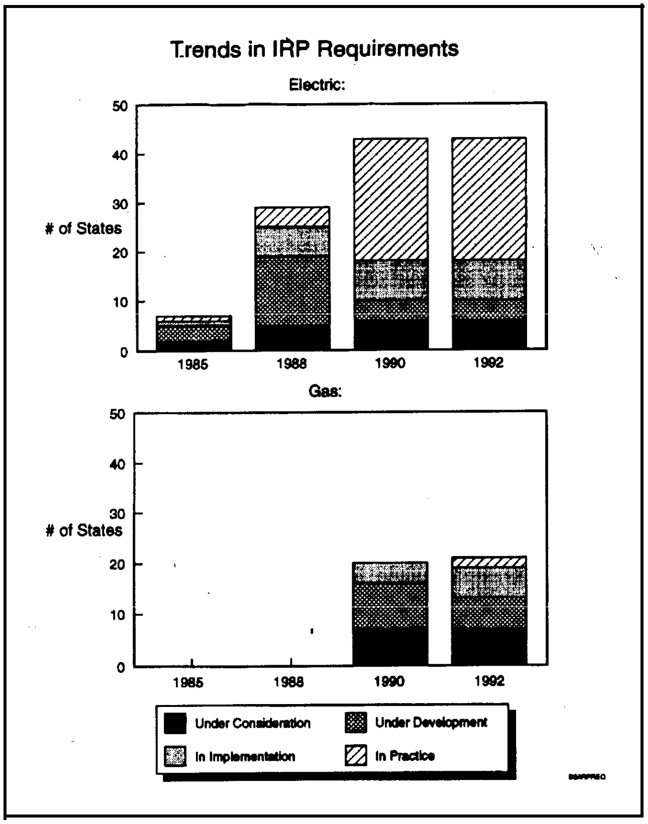

Figure 1. Trends in IRP Requirements

development stage. Every state has either maintained its original position or moved towards increased IRP regulatory development. The largest increase in the number of states that require electric IRPs occurred from 1992 to 1993 where 40 out of the 50 states passed or required IRP. We view this dramatic increase to the passing of EPAct requirements.

Treatment of Fuel Switching Options

Fuel switching opportunities broaden the number of energy efficient technologies that an electric or gas utility can evaluate within an IRP. Substituting gas cooling for electri~ cooling during an electric utility's peak may indeed be an economic and efficient alternative for an electric utility. However, because competition exists between an electric and gas utility for market share, these alternatives may not be appropriately evaluated and/or implemented by either utility.

To date, few public utility commissions are requiring that IRP fuel switching options be evaluated as it is in Oregon, but some are allowing the utilities to consider cross-utility alternatives in their IRPs (Florida, Georgia, and Kentucky). Through 1991, no other state had implemented fuel switching requirements. However there are nine states currently considering fuel switching as a part of IRP regulations.

On the whole, regulators appear hesitant to require utilities to evaluate other utilities' IRP options. Including fuel switching options such as gas cooling for electric cooling can often lead to conflicts between electric and gas utilities regarding market share, promotional practices and market competition. Michigan has reported guidelines so that utilities need to notify each other if the opportunity to develop a fuel switching alternative is potentially cost effective. In Florida the 1989 revision to its Energy Efficiency and Conservation Act encourages fuel efficient appliances. The Florida Commission considered specifying gas cooling as a required option to evaluate but decided against including it in the final requirements. Although the Georgia Public Utility Commission requires fuel switching analyses as part of its IRP, the electric utilities have not enthusiastically supported this requirement.

Two years ago it looked as though the public utility commissions were actively seeking ways to promote fuel switching opportunities. Since then, however, it appears that Commissions are retreating from directly mandating fuel switching analyses and options be included in IRPs. We have found that the public utility commissions may be less interested in pursuing fuel switching opportunities because of the potential Pandora's box it may open on competitive and legal issues.

Inclusion of Cost-Recovery Mechanisms and Incentives

Cost recovery and incentive mechanisms are important components for electric and gas utility IRP regulations. Increasingly, states are considering programs that are designed to accommodate utilities' financial responsibilities and that provide financial incentives to implement effective demand-side programs. Except in California, state commissions that have taken an active stance or a proactive position on IRP generally have provided not only for recovery of costs but also allowed mechanisms to recover lost revenues, and other incentives. California allowed recovery of lost revenues in 1978 but waited until 1990 to allow other incentive mechanisms.

The development of incentive and cost recovery policies for DSM has not necessarily followed a formal policy pattern –beginning with the opening of dockets followed by the issuance of an order and program implementation (Figure 2). Rather, incentives were often put in place before formal hearings or regulatory orders occurred. Many policies have developed on a case-by-case basis with utilities in the same state sometimes receiving different regulatory treatment. Our review found no differences in incentive program design between electric and gas utilities.

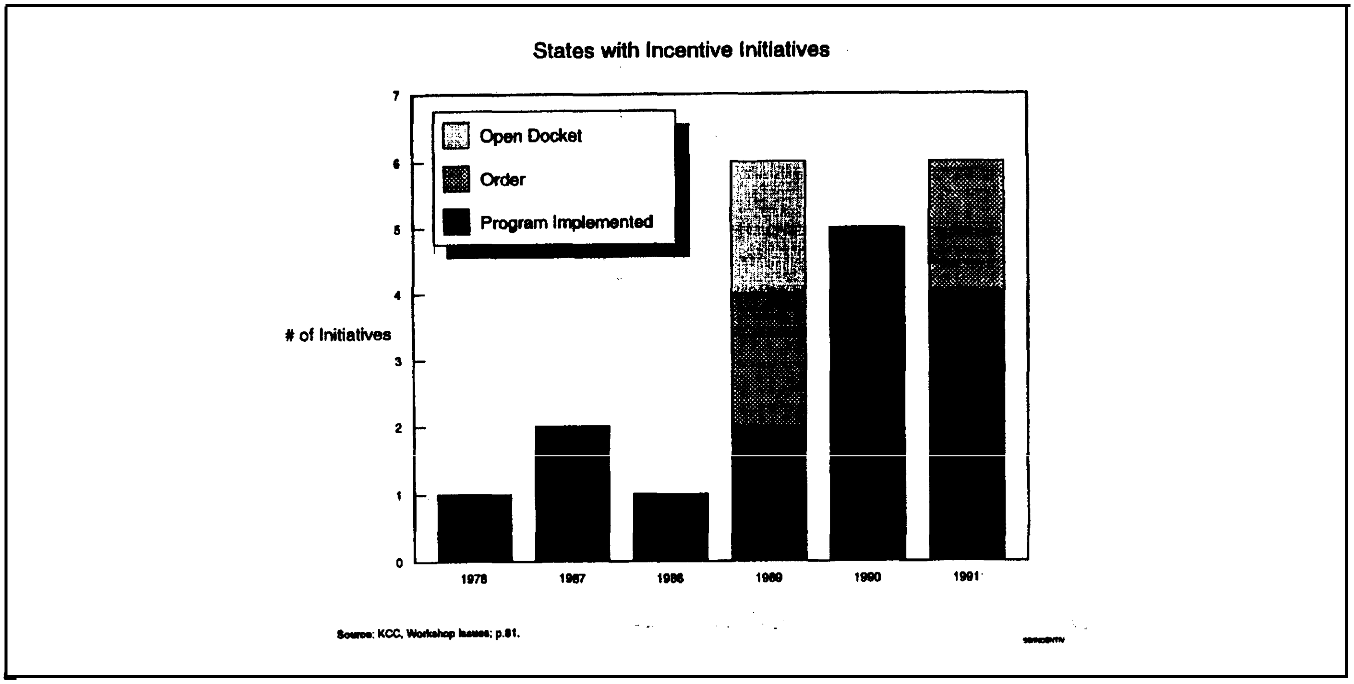

Figure 2. States with Incentive Initiatives

Inclusion of Environmental Externalities

Environmental externalities are the "costs of environmental damages caused by a project or activity for which compensation to affected parties does not occur." (Source: Massachusetts Department of Public Utilities, 83-36-G, p. 77). The treatment of environmental externalities is an important theoretical distinction between IRP and least-cost planning. IRP often includes costs and benefits to the environment and society of energy generation in the analysis of demand/supply alternatives. Approximately half of the states requiring electric IRPs have implemented or are developing approaches for measuring externalities (Figure 3). Seven states have either implemented or proposed that externalities be measured qualitatively. Seventeen state are either investigating or requiring quantitative methods. The quantitative methods include: cost adders, direct estimates, ranking and weighting and rate of return measurements.

Several states have adopted externality policies as part of their resource selection process in the last couple of years. This brings the total number of states which consider externalities in some form to seventeen. This includes those states which direct utilities to consider externalities and/or environmental impacts but impose no other explicit requirements. (Note: Some surveys count states that are considering externalities if they consider environmental impacts of siting decisions. We do not include these states in our tally.)

Our review of regulations found that externality approaches focus on the impacts associated with different electricity generation options. It appears that states have not decided on which externality approach is appropriate or which values accurately represent externalities for electric and gas utilities.

Required Cost-Effectiveness Tests

By 1990 a few states had specified the California Standard Practice Manual cost-effectiveness tests for analysis of demand-side programs for electric utilities. Sixteen out of thirty-one states interested in electric or gas IRP in 1990 specified a cost-effectiveness test. (Source: California Public Utilities Commission, Standard Practice Manual: Economic Analysis of Demand-Side Management Programs, CEC 400-87-006, 1987).

In 1991 states began to specify a combination of the standard California cost-effectiveness tests including the total resource cost, ratepayer impact measure (RIM), utility, societal and participant. A majority of the states (11 out of 16) required multiple test results and of those eleven, five required that all tests be conducted for each program and two required all but the societal test (Table 1). Of the four states that required two tests, the RIM and the utility test were most often required. Today, the shift has been towards including the total resource cost test with the RIM and utility test.

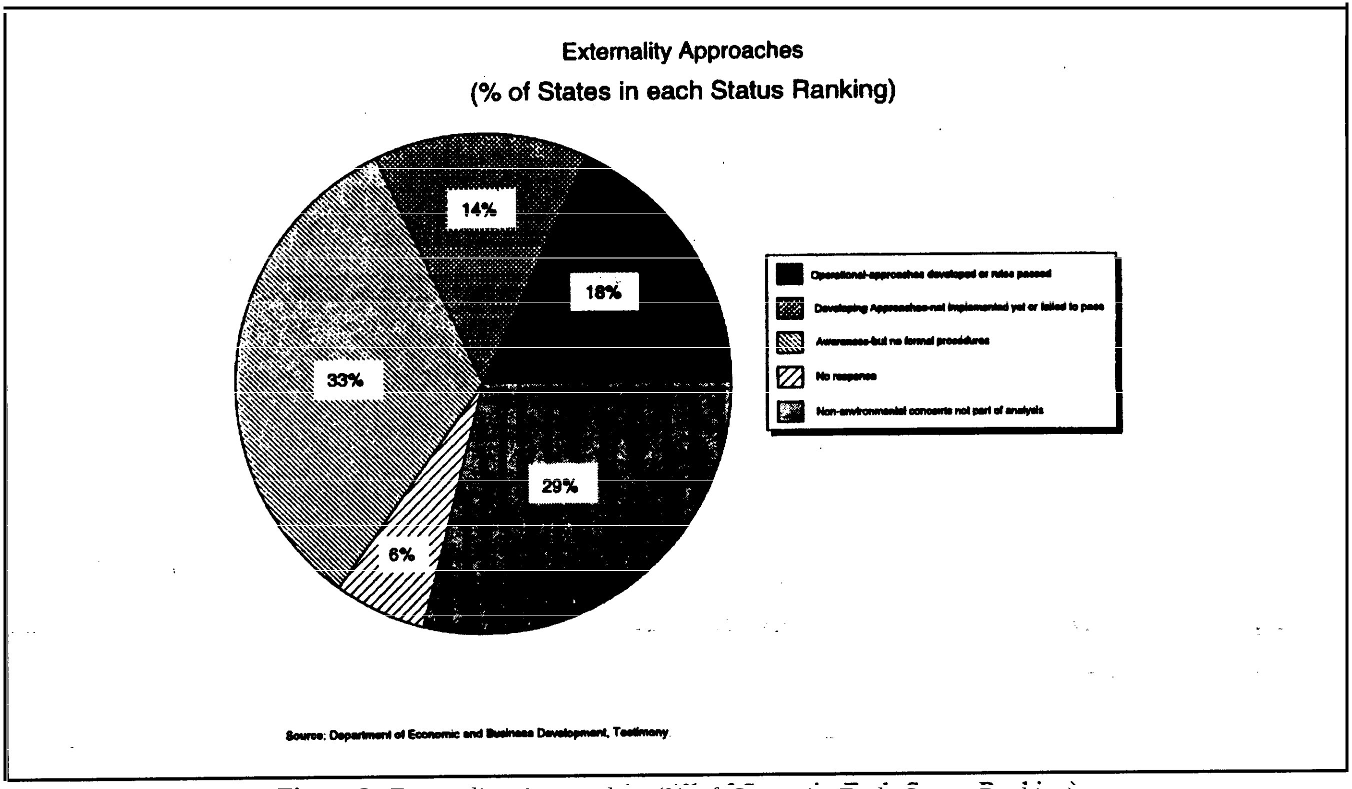

Figure 3. Externality Approaches (% of States in Each Status Ranking)

Table 1. Cost Effectiveness Tests

Gas Utility	Ratepayer Impact Measure	Utility Cost	Total Resource Cost Test	Societal Test	All 4	Other
AL	X					
CA					X	X
CT					X	X
DC					X	X
FL	X	X	X			X
IA					X	X
ME						Cost Benefit Evaluation
MI		X		X		
MN	X	X				
NV			X			
NJ			X			
NY	X	X	X			X
PA	X	X				
VT				X		
WA			X			
WI						
Total	6	5	5	2	5	

Findings

Key Finding: Early in IRP development, Commissions often tied the IRP process to other jurisdictional functions such as ratebasing of facilities, cost recovery and prudence reviews. Currently many of the IRP procedures rely on informal collaborative processes and there are few formal ties to future ratemaking.

In the earlier IRP processes, such as that established in Nevada, the importance of having a formal process with explicit incentives and punishment for failure to follow through on goals was recognized. Many of the new processes are more informal relying on workshops, collaborative and Staff reports instead of Commission order. Also, few of the new processes explicitly tie the Commission's hand with respect to future rate recovery or prudence based on IRP results. These states generally indicated that the IRP process should establish a record which would be used in future rate cases instead of setting" goals which could not be met.

Key Finding: The electric industry IRP requirements are far ahead the IRP requirements for the gas industry.

The application of IRP to the gas industry has lagged behind the electric power industry for several reasons:

Industry structure and operations. There is less vertical integration in the gas industry. There are more players at the different stages of production through distribution. The planning horizon is much shorter, with limited opportunities to control supply costs. The physical nature of the product and gas services have made implementation of IRP less necessary.

Industry Experiences. The gas industry has not experienced the rate shock phenomenon at the level of that in the electric power industry. Rather, the gas business is still trying to live down the curtailments of the 1970s and the subsequent hook-up moratoria. This is beginning to change rapidly because of the successful performance of the natural gas industry in delivering record peak volumes throughout the country in January 1994.

Load research. In the gas industry, load research lags the electric power industry. Very little has been accomplished on either load forecasting by end use or load shape studies. As a result, DSM planning and impacts are highly uncertain. This lack of verifiable information is a major barrier to accurately estimating the savings from DSM strategies. There is a need to measure and document DSM costs and impacts on load.

Avoided costs. The avoided costs are substantially lower for gas utilities than for electric utilities. The gas industry is not as capital intensive as the electric utility industry and variable costs tend to dominate. Whereas a KWH saved may mean a plant investment deferred, a therm saved usually means a therm not purchased.

While there are significant barriers to IRP in both industries (electric and gas), they appear more acute in the gas industry due to the absence of load/load shape information which in turn complicates the successful design of incentives and rate treatment and evaluation of options.

Key Finding: More and more states are allowing incentives as part of their IRP and ratemaking proceedings.

In our latest survey, nearly all of the states with electric IRP offer incentive opportunities for utilities' DSM programs. There are a few states that are still reviewing incentives mechanisms (Colorado, Kentucky, Oklahoma and Pennsylvania and Wisconsin). It is expected that this trend in incentives for DSM will continue for both gas and electric utilities as Commissions move towards increased free market competition.

Key Finding: Unlike IRP, we expect externalities policies will not be adopted universally.

Increased competition as a result of EPAct's EWG and transmission access provisions may force utilities away from embracing the policy of incorporating externalities into the utility's planning based on concerns of remaining competitive. Moreover, the difficult issue of valuing externalities and developing an appropriate framework will prevent many states from adopting rigid quantitative approaches. Some state commissions will not adopt externality policies because they do not have jurisdiction over environmental issues. Other states will be reluctant to adopt externalities policies because they inherently conflict with state economic policies and interests as is the case with coal producing states.

Key Finding: In 1992 the key issues of primary concern among regulators and utilities were the fuel-switching debate and jurisdictional ratebasing issues. In the beginning of 1994, the key issues have shifted to focus on the incentive mechanisms that will be available in a more competitive market.

An issue that many thought was important in the early development of IRP was the extent to which the IRP process was explicitly tied to Commissions' other jurisdictional functions. However, we observed in our recent survey that many of the IRP procedures and framework developed in recent years are not tied to these functions and rely on informal processes and few formal ties to future rulemaking.

Many new processes (e.g., Arizona and Kentucky) rely on the use of workshops, collaborative and the development of a staff report (rather than a Commission order) for IRP. These states generally indicated that the IRP process was to establish a record which would be used in the future for rate cases.

Key Finding: Cost-effectiveness tests will continue to be required by public utility commissions. The total resource cost test has become important. However, under the new competitive regime, and the threat of retail wheeling, the RIM may reemerge as an important utility measure of cost effectiveness.

Acknowledgments

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