INTEGRATED RESOURCE PLANNING FOR STATE UTILITY REGULATORS

A compilation of papers prepared from workshop presentations of The Regulatory Assistance Project

June 1994

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This book was funded by a Department of Energy Grant Number DE-FG41-93R11058.
The Regulatory Assistance Project is fully responsible for the content and opinions expressed in it.

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Introduction

This workbook is a collection of 13 papers that have been written based on workshop presentations of The Regulatory Assistance Project (RAP) to commissions and commission staff in states across the country. RAP is a non-profit corporation formed for the sole purpose of assisting state regulatory commissions in their adoption and implementation of Integrated Resource Planning (IRP). RAP's workshop and other assistance is provided free of charge to commissions. Each workshop is individualized to meet the needs of the host state. RAP is funded by the U.S. Department of Energy, the U.S. Environmental Protection Agency and The Pew Charitable Trust. Project Principals are: Cheryl Harrington, David Moskovitz, Thomas Austin, Carl Weinberg and Edward Holt. This workbook was prepared as a collaboration between them and Ellen Baum, with additional assistance from Elizabeth Quinlan and Karen Nielsen. A second volume is expected in 1995.

While the workbook is specifically designed to be used by workshop participants as preparation for an upcoming workshop or as an after-the-workshop reference, it also serves as a stand-alone document to guide regulators and planners through the IRP process.

The workbook describes, both broadly and in detail, the critical elements associated with least-cost planning. Commission staff familiar with the issues presented in this book and in RAP workshops will be in an excellent position to provide the utilities they regulate with leadership and oversight.

WHO NEEDS TO UNDERSTAND INTEGRATED RESOURCE PLANNING?

IRP provides an overarching framework guiding all utility planning and regulation. Because of this central role, its basic principles need to be understood by any commission staff person working on issues related to electric utilities. Too frequently, the responsibility for knowing about IRP falls solely on the shoulders of those staff members responsible for reviewing the utilities' long-term resource plans. Yet if the planning process is the backbone from which all other decisions flow — decisions ranging from rate design cases to prudence review cases to resource acquisition cases — then such a narrowly defined division of tasks can seriously undermine the ability of a commission to effectively and consistently do its job. Lack of internal commission consistency will result in inconsistent utility management decisions and higher risks for shareholders and ratepayers. To be sure that the flow of information and consistency of outcomes is not impeded by a lack of knowledge, a shared understanding of IRP concepts must be present among commission staff. Only if this common knowledge occurs, can ratepayers be assured that planning has been done to minimize their costs.

This suggests that nearly everyone on a commission staff would benefit from a working knowledge of IRP. At the very least, though, staff involved in the following types of cases or who undertakes any of the following functions should be well-versed in its principles.

Load Forecasting

Load forecasts are used for ratemaking, for calculating fuel cost adjustments and in the IRP process. Forecasts should be accurate and consistent with one another regardless of their particular purposes.

Rate Cases (in particular prudence review and fuel cost reviews)

Utilities must develop these cases in a manner consistent with good planning. Any commission staff reviewing rate cases must understand the original planning process and objectives undertaken by the utility to decide how good a job the utility is doing in its pursuit of its stated objectives.

Need or Certificate Cases

Cases involving a determination of needs or the issuance of a certificate of public convenience turn to load forecasts done under an IRP framework.

Fuel Cost Adjustments

Fuel costs should be consistent with the implementation of a utility's IRP, with variations explained. Connecting fuel and capacity expenditures with the plan is essential to the success of the plan.

Utility Rate Design

Rates that accurately reflect long-run costs promote the most efficient use of the utility system. When prices reflect long-run costs, customers can be expected to make wise purchasing decisions. If rates are inconsistent with long-term costs, customers are more likely to make inefficient electric and energy choices. Depending on what price signals customers receive, they are as likely to use too much as they are to use too little energy. But when the price signals send the wrong message, use will not match the demand predicted in the IRP process. Similarly, special rates, such as cogeneration deferral rates rely upon deciding which actions are economic and which are uneconomic. IRP informs commissions whether these rates make sense.

Utility Power Purchases

Staff reviewing wholesale purchase plans, including purchases from Qualifying Facilities, Cogenerators, Independent Power Producers, Exempt Wholesale Generators and other utilities need to be able to understand whether a utility's wholesale purchase decisions result in lower costs and are consistent with the utility's own planning projections.

Transmission And Distribution Planning

There are many examples across the country where utilities are spending more for transmission and distribution upgrades and improvements than for power plant additions. These expenditures should be consistent with a planning process that examines alternatives to transmission and distribution investments (including demand- and supply-side options) with the objective of minimizing system cost.

Clean Air Act Amendment Implementation

The Clean Air Act Amendments of 1990 (CAAA) made utilities across the country responsible for reducing their emissions of sulfur dioxide, nitrous oxides and selected toxics. The Act includes special provisions that rewards utilities with emission credits when emission reductions are made under an IRP framework. Also, reduced plant use achieved through demand-side management investments creates an even larger emission reduction benefit for utilities under the CAAA.

Energy Policy Act Implementation

The Energy Policy Act of 1992 (EPAct) requires that commissions consider having an IRP process for their state utilities. The Act also includes a new standard for commissions to consider adopting which oversees purchases from wholesale power producers.

Introduction To Integrated Resource Planning

WHY INTEGRATED RESOURCE PLANNING?

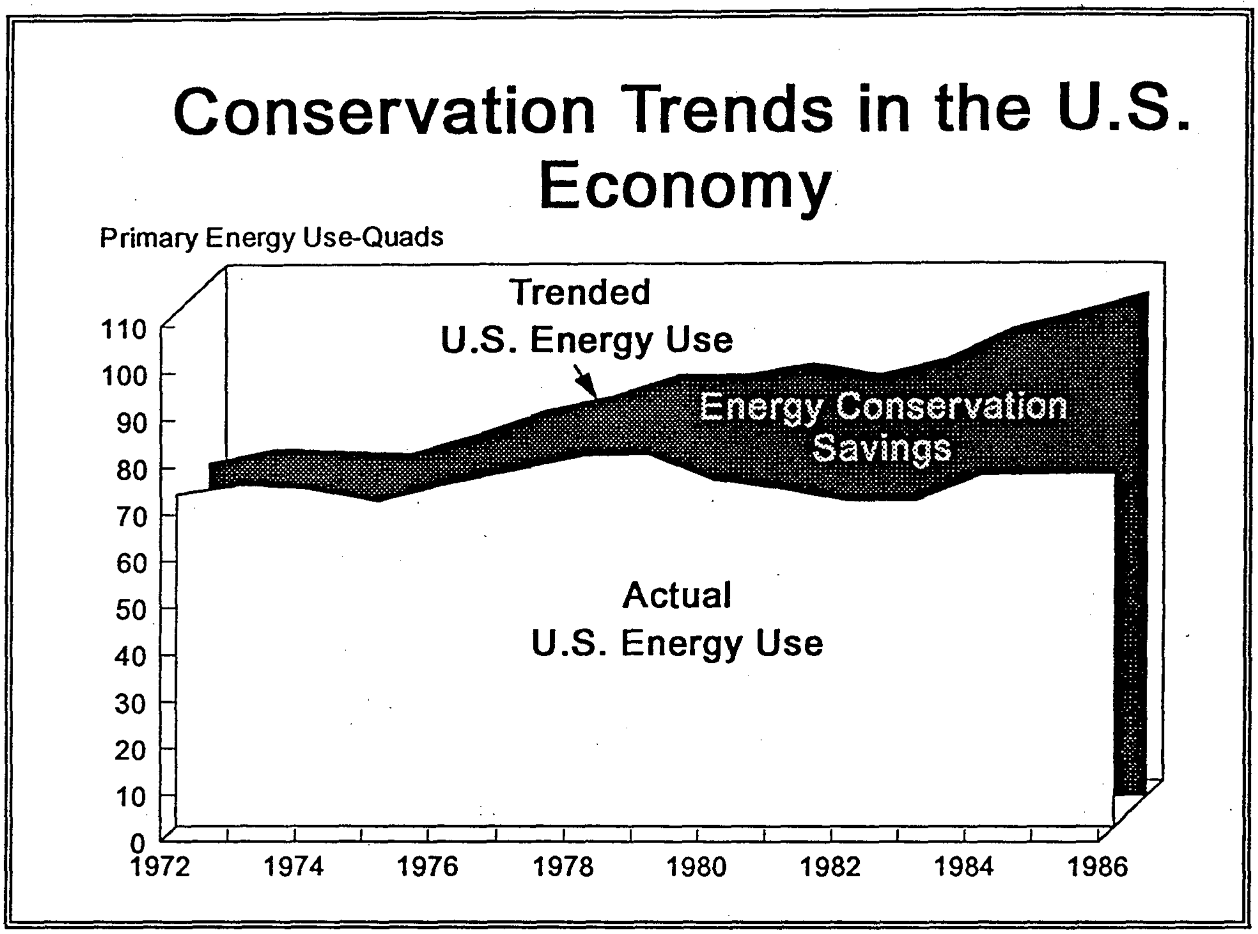
Today, roughly half of the states in the country require that their utilities practice some form of IRP. The impact of two recent pieces of federal legislation will likely mean that in the near future even more states will require that their utilities practice IRP. Both the Energy Policy Act of 1992 (EPAct) and the Clean Air Act Amendments of 1990 (CAAA) contain provisions designed to motivate state commissions to adopt standards to require utility participation in IRP. While this type of planning has now come to dominate utility analysis of long-term investments, this has not always been the case.

In the 1950s and 60s, it was relatively easy to produce, sell and regulate electricity. A constant and steady growth in demand for electricity paralleled, in general, the country's growth of gross national product. During this period, utilities captured larger and larger efficiencies — efficiencies in integration of operations, efficiencies in building of new power plants and efficiencies in transmission systems. Utilities provided the full range of energy services from producing electricity to owning and operating transmission lines to distributing power. These economies of scale led to declining costs within the industry, low electricity rates for customers and high electricity demand. It was a predictable and simple period for customers, utilities and regulators.

During this period, one of the biggest problem on the utilities' planning horizon was a predicted scarcity of fossil fuels. To prepare for this, utilities across the country built into their long-range decisions plans which would increase the country's reliance on nuclear power. By the early 1970s, there were roughly 20 nuclear power plants under construction and another 40 plants were on the drawing board. Nuclear power was positioned to be the clean, cheap source of power that would lead the nation into the 21st century.

These predictable times came to an abrupt halt in the early 1970s when the first energy crisis hit. The formation of OPEC in the Middle East led to higher and more volatile fuel prices which greatly increased the costs of generating electricity. In addition, the escalation in prices triggered a period of high inflation in all sectors of the country's economy, including the nation's budding nuclear power industry.

By the early 1970s the nuclear power industry was clearly in trouble. Plant construction was plagued by a number of factors including delays caused by both mismanagement of the construction and from regulatory changes, high interest rates, poor plant performance and load forecast errors. The cumulative impact of all these problems caused the cost of nuclear power plants to skyrocket. In response, building plans were canceled or abandoned. Plants that were completed came in at much higher costs than had been anticipated. State commissions and utilities faced crisis after crisis as they confronted the questions of who would bear the high costs of nuclear plant construction.[1] for their homes and businesses and bought cars that were more fuel efficient. Sales of Japanese cars in the U.S. rose rapidly as



In response to the resulting high and volatile electricity prices, consumers (residential, commercial and industrial) took the offensive and began looking for ways to cut their energy costs. They used all forms of energy more prudently, invested in energy efficiency sales of American gas guzzlers plummeted. As a result of these combined efforts, the demand for energy dropped precipitously, particularly in relationship to forecasted use, and left in its wake a great deal of unneeded, unused and expensive generating capacity — some of which was still under construction or on the drawing board.

[1] Large nuclear plant were not the only power plants to overshoot economies of scale in the 1980s. Traditional thermal plants peaked in technological maturity in the 1960s, having achieved all available efficiencies. This, together with rising fuel and environmental costs, changed the industry from one of declining to increasing costs.

EMERGENCE AND ACCEPTANCE OF DEMAND-SIDE RESOURCES

It was this era of uncertainty — high energy costs, nuclear power plant cost overruns and a consumer-driven energy conservation movement — that caused both utilities and commissions to concentrate on reducing risk in long term energy resource planning (Ford Foundation 1974 and Sant 1984).

If utilities could gain better control and understanding over customer demand, they could reduce the uncertainty in demand without sacrificing their ability to meet the electric needs of their current and future customers. By figuring out ways to manage demand the dollars at risk from new construction at any one time could be reduced. It was in this context, to reduce the uncertainty of energy demand, that the idea of DSM emerged as a resource tool of great financial value.

While over the past ten years recognition of DSM has come to encompass many useful purposes, in its infancy it was adopted by utilities and commissions as a risk reducing strategy. Risk reduction meant that the volatility of demand would decrease. There would be fewer dollars at risk, a lower risk of outages and lower reserve requirements. New demand- or supply-side resources could be obtained in smaller increments, with shorter lead times. Utilities and customers alike could benefit from resulting cost savings.

Quickly, though, utilities realized that DSM was also a valuable customer service. Utilities, many of which had received bad publicity during the period of nuclear power plant construction and cost overruns, were able to provide a friendly, direct and useful service to their customers. Customers liked the energy saving services that they received (insulated hot water heaters, energy audits, energy efficiency lighting) and liked the utility for providing these services.

In little time, a third benefit of DSM gained increased importance. If the early 1970s made people come face to face with the fact that fossil fuels were a scarce and finite resource, 15 years later people had to also confront the realization that availability of these might not be the only, or even the most important issue. The ability of the earth's atmosphere to absorb fossil fuel emissions emerged as, perhaps, the greater economic risk. Growing public concerns over global climate change, acid rain and the political risk accompanying this concern has given a new raison d'etre to the concept of energy conservation and DSM. Fuel not burned does not emit air pollutants. Kilowatts not produced and kilowatt hours not used are the very best method to reduce all types of harmful emissions.

UNDERSTANDING THE TERMS

IRP describes an economic planning process which, if implemented correctly, locates the lowest practical cost at which a utility can deliver reliable energy services to its customers. The ultimate intent of this planning process is to acquire a mix of energy resources that minimize the total dollars spent and maximize the energy service benefits gained.

IRP differs from traditional resource planning by requiring that utilities use analytical tools capable of fairly evaluating and comparing the costs and benefits of both demand- and supply-side energy resources. This means that when a utility surveys its planning horizon to determine how it will meet its expected demand at the lowest possible cost, it looks at its energy service requirements, not just its electricity demands. Demand- and supply-side resources are treated equally. Demand-side resources include services which conserve electricity such as water heater insulation, time of use rates and energy-efficient lighting. Supply-side resources include traditional sources such as electricity produced from fossil fuel plants as well as less traditional supplies such as wind and photovoltaics.

The objectives, as well as the techniques, of IRP are continually being refined, with the pace, sophistication and direction of the refinement varying from state to state. For example, some states have increasingly moved to include competitive market acquisition of wholesale generation resources. Others, such as California, are considering frameworks for retail competition.

DEFINING THE IRP OBJECTIVE

The critical issue for commissions in adopting IRP is the need to define the objective they seek to achieve . What is "most efficient"? What will "most economic outcome" mean in each state? Historically, the test for efficiency was simply to minimize the utility's revenue requirements for a given level of demand for electricity. This analysis consisted of a resource portfolio that depended 100% on supply-side resources. The level of demand was considered a given.

IRP takes a different perspective by distinguishing between electricity, kilowatts, kilowatt hours and energy services such as heat, light, motor drives etc. This energy service perspective recognizes that the costs customers face are the combination of the price of kWhs that drive a motor or refrigerator and the efficiency of the motor or refrigerator in converting kWh to motor drive or cooling. IRP, therefore, requires consideration of demand-side options in the resource mix. Most commissions strive to minimize the total costs of energy services, including the costs borne by the utility, the customer and, in some cases, society at large. For example, there are frequently costs to customers associated with their participation in demand-side programs. It is important to consider these costs in order to achieve a complete and fair comparison of all costs associated with one resource to that of another.

There are two ways of measuring efficiency that look beyond a utility's cost alone. Minimizing the Total Resource Cost (TRC) has been the most commonly adopted method. This measure considers both the utility's direct expenditures and the cost borne by consumers who participate in a utility, demand-side program. Several states have expanded upon the TRC objective by requiring utilities to optimize resource choices based upon total societal costs (SC).

This approach demands consideration not only of the direct costs incurred by the utility and its customers but also indirect social costs and benefits to society. Most often these indirect, or external, costs are those associated with environmental damage, but sometimes they include other external impacts as well such as economic growth and job development.

Example: Assume it costs the utility 2¢ per kWh for a water heater wrap and the customer pays .5¢ per kWh to participate in the program. A TRC analysis would include the customer's expense and calculate the total cost of saving a kWh as 2.5¢. An IRP analysis would then determine if consumers are better off saving a kWh for 2.5¢ or producing a kWh from existing, new power plants. The states that have taken IRP a step further, would add in other external costs, such as the cost of unregulated air emissions from the selected resource which, for a water heater wrap, will be zero. This new total cost would then be compared to the total cost, including unregulated air emissions costs, incurred by a competing power supply option.

In general, IRP focuses on minimizing cus tomers' bills rather than rates. An overall reduction in total resource cost achieved through the efficient use of energy will lower average bills. At the same time, as sunk costs shift to a smaller pool of kWh sales, higher rates may result. Commissions need to keep an eye on both bills and rates. Generally, bill savings greatly outstrip any rate increases (Hirst, 1991).

All customers benefit from lower system costs achieved through IRP, but customers who actually receive DSM programs get an additional benefit through the lower use. As utilities implement their demand-side programs, what happens to the customers who do not or cannot participate in any program? Their use does not decrease, but they do carry a higher and higher portion of the sunk costs. Commissions must pay attention to this effect, both by reviewing bill impacts and by making sure that the utility offers programs that will turn non-DSM participants into participants.

STEPS FOR SUCCESSFUL INTEGRATED RESOURCE PLANNING

IRP provides the instrument needed to incorporate the elements of DSM into everyday resource planning in order for utilities to make sound energy resource acquisition decisions.

There are nine basic steps that must be taken to support the development and implementation of IRP. These steps are divided between commissions and utilities since both have roles to play to make sure that the planning process succeeds.

The commission is fully responsible for directing and providing regulatory oversight for IRP. In setting the stage for utilities to begin the process, the commission must undertake the following tasks:

<u>Define Planning Goals</u>

To get anywhere with IRP, commissions must be clear about where they are going and must clearly communicate their expectations to the utilities they regulate. As a first step, states must decide whether the objective of lowering costs is gauged by the TRC or the SC.

<u>Define Planning Period</u>

The commissions should set out for their utilities exactly how long a time period the integrated plan should cover. In most jurisdictions, the planning period is between 15 to 20 years. This length of time better captures the life-cycle costs of long-lived assets and takes into consideration the time it takes a utility to plan and construct a new facility. A typical coal-fired plant, for instance, becomes operational about six years from its groundbreaking date. Once it is running, it operates for 30 to 40 years. Utilities have always used long planning horizons to account for their capital investments and set a reasonable amortization period.

Once a commission defines the planning goals and the planning period, the ball is passed to utilities develop their IRP. The elements which must be considered by utilities are:

Forecast Demand For Service

Utilities must forecast anticipated demand over the defined energy horizon. Forecasts should be multiple, looking carefully at a variety of feasible demand levels. To be most useful, the demand forecasts should be built from the bottom up by first identifying the likely demand for each end use, such as lighting, motor drive, residential water heating etc. End-use forecasts not only tend to be more accurate, but they also provide basic information as to where DSM programs are best targeted.

Identify Resource Options

After the forecast, utilities will identify all available supply- and demand-side options. It is very important that the array of resources be as broad as possible at the outset. Subsequent analysis will weed out those which do not advance the IRP goals. But resources overlooked, or deliberately not included, at the outset are unlikely to be picked up later, even if they would have been cost effective.

Identify Costs Of Resource Options

For each resource option, the capital and operating costs (and when social costs are required, these costs) of each option, over its operating service life are quantified. Often times the range of options considered and the costs of the options are informed through competitive bidding. To accomplish this, many states require the utility to solicit proposals for wholesale sales from outside sources. This provides both a reality check on the utility's plan and can lower the utility's total resource cost by making less expensive power purchases whenever possible. Given the passage of EPAct 1992, this step is likely to become more common in the utility planning process.

Optimize The Mix Of Resources

This step is the essence of IRP. It is the step that looks at all the collected information on forecasted demand for energy services and combines it with the detailed information on both new energy resources and the facilities and resources a utility already owns and operates. This is the step where all the potential uncertainties, such as likely range of fuel costs, variations in demand expectations and variances in construction time periods are taken into account. At this time, uncertainties are identified and dollars at risk due to uncertainties are quantified to the best extent possible. Various iterative scenarios are modeled so that the utility gets as accurate a picture as possible of its avoided cost and the mix of energy resources that best achieves the lowest possible cost, while reliably meeting the demand for energy services.

Insure Public Participation (Commission role)

A credible public participation process is an integral element of the IRP process. During the early stages of plan development, the public needs an opportunity to become acquainted with how their utility approaches the planning process. Members of the public are generally interested in what energy resources the utility is considering, how it proposes to use those resources, the methodology used to forecast demand and the information, both technical and predictive, used for to conduct the optimization exercise.

In some jurisdictions the public participation process starts on a regular, but informal basis during the planning period. In these cases, the utility may hold workshops and informational sessions prior to the final adoption of the plan. In other jurisdictions, public participation is more formally sought. In these situations, after a plan has been filed with the commission, an adjudicatory hearing is held. Still other states conduct paper hearings where written comments on the plans are submitted and filed.

The public participation element is one of the strengths of the IRP process. It gives a range of participants a voice about energy choices and costs. When conducted most successfully, the public participation process can lead to a consensus which results in both the desired economic outcome as well as a shared sense of public and utility commitment. In theory, an accepted plan, built upon on a broadly recognized understanding of the issues involved, reduces the chances that there will be litigation over the costs incurred by a utility as the plan is implemented.

Profitability Of IRP (Commission role)

In considering IRP profitability, calculations must take into consideration income which is lost when sales are reduced as a result of energy conservation and efficiency investments. When approving an IRP plan, commissions must adopt cost recovery policies as well as positive incentives for demand-side activities.

Plan Implementation (Utility role)

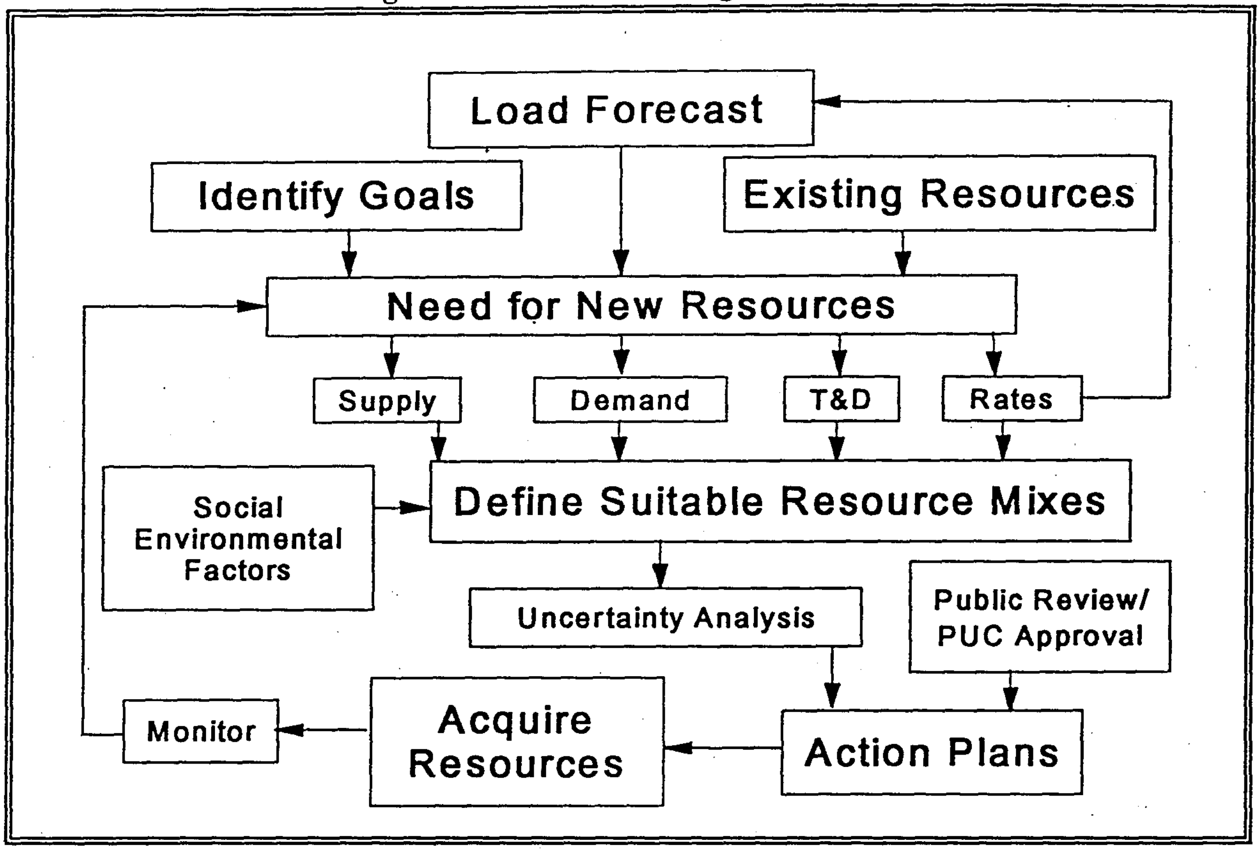
Least-cost planning only makes sense when it leads to least-cost **doing**. Cost savings are only achieved when a utility, on an ongoing basis, implements its plan.

PLANNING INTO THE FUTURE: KEEPING AN EYE ON THE BALL

To keep plans current in terms of resource availability and technological advances, most jurisdictions require a utility to update and file a new plan every two, three or five years. Several jurisdictions also require including a specific, short-term action plan coinciding with the length of time between filed plans. Short of changing circumstances, the utility should be expected to proceed in accordance with its short term action plan. The burden always remains with the utility to engage in the continuous process of re-analyzing the future and re-optimizing the mix of resources and to stay abreast of the future as it unfolds.

Chart 1, developed by Eric Hirst of the Oak Ridge National Laboratory, illustrates the flow of the IRP process. First the initial load forecast identifies the energy demand, a demand which can be met from a mix of resources. The actual selection of resources

Chart 1: Integrated Resource Planning Flow Chart, Hirst 1992



results in a rate outcome. Rates, then, influence the demand which impact the load forecast. This new load forecast, in turn, influences the energy resource options which affect rate outcome, etc. These constant feedback loops mean that the process is never finalized and is conducted on a continuous and iterative basis.

DIFFERENCES BETWEEN INTEGRATED RESOURCE PLANNING AND TRADITIONAL UTILITY RESOURCE PLANNING

Load forecasting has become increasingly important over the past twenty years. This change reflects the transition from the era of constant and steady growth that characterized the 1950s and 60s to the more volatile and generally slower growth period of the 1970s and 80s. To accommodate this shift, the forecast techniques used for electricity planning have become increasingly sophisticated.

Traditionally, planners only considered meeting consumers needs by providing electricity. IRP forecasting adds a new wrinkle by recognizing that customers do not want electricity for its own sake. Rather, customers want the end uses that electricity provides. They want light when it is dark, heat when it is cold, cold when it is hot and electric motors which do the work demanded of them. Customers are largely indifferent to whether their end-use, electric needs are met through increased investment in energy efficiency or through increased investment in generation. Most customers neither know nor care about the source of their electricity as long as they have, for example, the light they want when they turn on the switch.

Thus, the goals of load forecasting under traditional planning are different from those under IRP. Under traditional planning, planners really need to know only how much electricity will be used. Under IRP, it is also important to know how much electricity will be used for each individual end use — for heating, lighting, air conditioning, refrigeration etc. This finer level of detail is necessary so that planners can investigate the demand-side potential.

In recent years, planning has relied on two techniques for demand forecasting. One approach, econometric forecasting, generally focuses on total electricity usage. Here, a traditional utility planner looks at historic trends and predicts future trends by analyzing general economic indicators, such as disposal income, housing starts and new investments by industrial and commercial firms. These forecasts are not designed to yield specific information about how electricity is used, but if the specific end use of a utility's energy service is not understood, a utility is not well positioned to best use demand-side resources.

The other forecasting approach which has been developed to serve the needs of utility planners is the end-use forecast. Here, the utility estimates the number and types of the electrical appliances and equipment in use by its customers — the refrigerators, the lighting systems, the motors, the heating and air conditioning systems — and then predicts how many more will be installed during the planning period based on population and similar economic forecasts. This information, combined with estimates of the existing and projected energy use per appliance and turnover rates, produces a forecast of energy use for each end use. These are then added together to provide an estimate of total electrical use. End-use forecasts of this nature are not only more precise than econometric forecasts, but they also give the utility detailed information about where the demand-side opportunities exist.

For example, knowing how much electricity is required to provide commercial lighting and the size of the lighting demand gives a utility the information it needs to determine how much energy could be saved with an efficient lighting program. The more information available, the more options there are for a utility to make wise resource investments.

End-use forecasting also requires a working, and continuously updated knowledge of the relevant federal, state and local laws on building standards, appliance efficiency standards, etc. Planners must also keep current on the amount of electricity or energy likely to be used to power each of the end uses. Finally, good end-use forecasting understands and in some way accounts for the price elasticity feedback illustrated in Chart 1. There will be a cost with any particular mix of resources, and these costs will affect the demand. In general, higher costs will result in lower demand, and lower costs will raise the demand.

DETERMINING THE TOTAL COST OF SUPPLY AND DEMAND-SIDE OPTIONS

As utilities compare the cost of each supply- and demand-side option, they need to capture the entire life-cycle cost. This life-cycle cost means the fixed and variable costs incurred over the life of the investments: construction, operation, maintenance and fuel costs. In addition to these expenses, some states require that utilities take environmental and other external costs into account to fully compare resources during the planning process and generate the least-cost plan.

Utilities incur two types of environmental costs. First, there are the direct costs of complying with existing environmental laws, such as the cost of scrubbers required at many fossil fuel plants by the Clean Air Act. These costs are directly incurred during the construction and operation of a facility and are included in an ordinary costing procedure. The second type of environmental cost is less obvious because it does not show up as a direct cost incurred as a result of a regulation. These "costs" are the environmental impacts resulting from the production of electricity and delivery of energy services. Because these costs have not been explicitly identified, neither the utility nor the customer is directly paying for the impact.

To begin to address this, many states are requiring utilities to analyze the external, environmental costs during their resource planning process. This means identifying and quantifying the impacts of a particular energy resource choice on air, water, land and wildlife habitat.

In the analysis undertaken in several states, the externality which has had the single, largest impact on resource costs and choices is the emission of carbon dioxide into the air during the burning of fossil fuel. No federal, and few state, regulations exist to regulate carbon emissions. Yet, carbon dioxide is recognized as a major contributor to global climate change. The risk being faced by utilities is not only whether or not there will be global climate change, but whether, in the future, there will be laws regulating carbon dioxide emissions. If such regulations are enacted in the next decade (and many people anticipate that they will be), there will be a cost of compliance for facilities which are operating or being purchased **today**. If this is the case, in looking at the environmental costs, the future cost of that anticipated compliance should be included in today's analyses to adequately and prudently compare the full costs of selected resources.

RESOURCE OPTIONS

Supply-side

Conventional Plants, often utility-owned facilities

Oil, coal and natural gas plants
Nuclear
Small combustion turbines
Life extensions of existing combined cycle gas or oiled fired plants

Non-utility owned generation

Cogeneration
Self-generation
Independent power producers

Purchases from other systems

Transmission expansions or upgrades

Distributed Placement

Renewables

Hydropower
Geothermal
Solar thermal
Photovoltaics
Wind
Wood wastes
Agricultural wastes
Tidal power

Other supply resources

Fuel cells
Municipal solid waste

Demand-side

Energy efficiency options to reduce the customer's energy demand

High efficiency motors and variable speed drives
Industrial process improvements and controls
Heat recovery
High efficiency lighting technology and design
Building insulation and high efficiency windows
Energy management systems
High efficiency heat pumps
High efficiency office equipment
High efficiency water heaters (heat pumps, solar)
Super efficient appliances
High efficiency cooling (chillers, air conditioning, cool storage, evaporative cooling, outside air economizers)

Energy efficiency options to increase the utility's efficiency in generating and supplying energy

Reduced transmission and distribution losses
Advanced transformers
Load management
Utility control of appliances

Passive solar modifications

Day lighting
Design, siting and orientation of buildings
Space heat and cooling

Rates

Real time pricing
Time of use rates
Seasonal rates
Inclining block rates
Interruptible rates
Incentive rates

IRP AND CHANGING CORPORATE ATTITUDES

Utilities that want to seriously embrace IRP have to be willing to consider a major shift in corporate attitudes and infrastructure. While the commission's role is very important, it only provides oversight and assigns costs after the fact. It is up to the utility to make sure that IRP succeeds, and therefore utilities must be sure that they have the skills to:

- do integrated analyses
- identify and use demand-side resources
- design efficiency programs
- market and deliver programs
- analyze and factor in externality costs
- operate and maintain different types of facilities
- solicit, negotiate and purchase resources effectively in a competitive, wholesale market

Doing this well requires a new planning paradigm for the utility. If new skills and attitudes are not acquired, the practice and implementation of IRP will simply not go well.

Corporations can improve their chances for success in several ways. First, salaries and promotions for managers and other employees should be pegged to successfully locating and acquiring the lowest-cost resources.

Incentives should be provided to company shareholders for those utilities who do least-cost planning well. The better a company does IRP, the more profitable it should be as a utility.

Finally, there must be public recognition and praise for utilities who are good at IRP, who effectively use low-cost energy resources and who achieve substantial economic efficiency. This well-deserved praise benefits the utility as well as offers as a model for other utilities striving to master IRP.

IRP Policy Questions That Regulators Must Address

The successful development and implementation of an integrated resource plan requires each commission to articulate clearly and right from the start the goals to achieve. It is asking the impossible to expect a utility to optimize its investment activities without providing the criteria by which the success of the optimization will be judged. By addressing in advance the following six key policy areas, commissions will be positioned to better understand and communicate to the utility and other stakeholders what the IRP process should accomplish.

Other chapters in this book describe each of these areas in significantly more detail. The intent in presenting them here, in this shortened version, is to give commissions a check list of key items to cover during their initial IRP deliberations.

WHAT IS THE OBJECTIVE YOU SEEK TO ACHIEVE WITH INTEGRATED RESOURCE PLANNING?

The overarching goal and objective of IRP should be straightforward. IRP is an economic efficiency model that provides a framework for conducting analysis and comparison of a wide variety of resources, in the context of a wide range of possible futures in order to find the most efficient, reliable and least cost combination of energy resources.

The critical issue for commissions in defining the objective they seek to achieve through IRP is the need to define efficiency. What is "most efficient?" What will "most economic outcome" mean in each state? Historically, the test for efficiency was simply to minimize the utility's revenue requirements for a given level of demand for electricity. This analysis consisted of a resource portfolio that depended 100 percent on supply-side resources. The level of demand was considered a given.

IRP takes a different perspective by distinguishing between electricity, kilowatts, kilowatt hours and energy services such as heat, light, motor drives etc. This energy service perspective recognizes that the costs customers face are the combination of the price of kWhs that drive a motor or refrigerator and the number of kWhs needed to produce the desired motor drive or cooling. This means how efficiently the motor or refrigerator in converts kWh to motor drive or cooling is important. IRP, therefore, requires consideration of demand-side management (DSM) options in the resource mix.

Most commissions strive to minimize the total costs of energy services, including the costs borne by the utility, the customer and, in some cases, society at large. For example, there are frequently costs to customers associated with their participation in demand-side programs. It is important to consider these costs in order to achieve a complete and fair comparison of all costs associated with one resource to that of another.

There are two ways of measuring efficiency that look beyond a utility's cost alone. Minimizing the Total Resource Cost (TRC) has been the most commonly adopted method. This measure considers both the utility's direct expenditures and the cost borne by consumers who participate in a utility DSM program. Several states have expanded upon the TRC objective by requiring utilities to optimize resource choices based upon total societal costs (SC). This approach demands consideration not only of the direct costs incurred by the utility and its customers but also the indirect, social costs and benefits placed on society. Most often these indirect, or external, costs are those associated with environmental damage, but sometimes they include other external impacts as well such as economic growth and job development.

In general, IRP focuses **on minimizing customers' bills rather than their rates**. An overall reduction in total resource cost achieved through the efficient use of energy will lower average bills. At the same time, as sunk costs shift to a smaller pool of kWh sales, higher rates may result. Commissions need to keep an eye on both bills and rates. Bill savings greatly outstrip any rate increases.

All customers benefit from lower system costs achieved through IRP, but customers who actually receive DSM programs get an additional benefit through the lower use. As utilities implement their DSM programs, what happens to the customers who do not or cannot participate in any program? Their use does not decrease, but their prices may increase as fixed costs are spread over fewer kWhs. Commissions must pay attention to this effect, both by reviewing bill impacts and by making sure that the utility offers programs that will turn non-DSM participants into participants.

WHEN DOES A UTILITY NEED NEW RESOURCES?

For years, the answer to this question was simple. A utility needed a new resource when customer demand exceeded reliable supply.

By the early 1970s, as the economic approaches which ultimately led to IRP developed, the answer shifted to: A utility needs a new resource **whenever acquiring a new resource reduces total costs.** Stated another way, a utility "needs" any resource that costs less than the avoided cost. Need, then, becomes an economic question in addition to a reliability question. This shift in thinking means that sometimes new resources will be acquired to keep the lights on, and sometimes they will be acquired to lower overall costs. Even utilities with "excess capacity" can lower their costs by using resources that are cheaper than their current operating costs.

An understanding of avoided cost has been very important for analysis. For instance, some conservation programs can be implemented for less than 2¢ per kWh. This cost falls below the price most utilities pay for fuel at a typical power plant. By opting for a DSM program, a utility runs existing units less. The cost of DSM is less than the fuel cost savings, thus reducing the overall cost of providing energy services.

At the heart of IRP is the question: **As compared to what?** What existing and planned utility resource would a new resource displace? What time of day or year would the new resource provide energy services? Would the overall costs be lowered or raised if the new resource were added? To develop an accurate assessment and comparison of costs, all relevant costs for alternative and existing options must be included in an analysis.

In implementing IRP, some utilities have used the cost of the next planned unit as the avoided cost for acquiring any new supply- or demand-side resource. This approach, however, misstates the value of many resources. To fully exploit the IRP process, the full value of the resources displaced by the alternative resource option should be calculated and compared to the full cost of the alternative resource.

Transmission and distribution savings should also be looked at when determining what resource choice makes most sense. Acquisition of demand-side alternatives or dispersed small-scale supply alternatives can mean that costly line upgrades could be postponed or avoided altogether. Similarly, renewable resources, such as photovoltaics or wind turbines, offer the possibility of avoiding more costly line extensions into remote settings.

Finally, there are the external costs. Renewable resources and DSM programs generally cause less environmental damage than most traditional supply-side resources. Attributing costs to environmental damage generally improves the economic attractiveness of non-traditional resources.

HOW CAN MARKET FORCES BE CAPTURED IN THE IRP PROCESS?

Incorporating competitive market forces can improve IRP outcomes and lower energy costs.

How can the utility capture the economies offered in the competitive wholesale generation market? The utility must develop some systematic way to quiz the market to find out what resource options are available.

One effective method is for the utility to devise and circulate its optimal plan describing the most efficient resource mix it can produce. Then, through a competitive bidding and/or negotiation process, the utility can create the opportunity for competitive wholesale providers to step forward and show whether they can provide more attractive resources at a lower cost. Often the negotiation process, following up on the market response is key to acquiring resources at the lowest possible cost.

Requiring the utility to optimize first and others to bid second allows accurate measurement of the value of the resource offered. This approach is sensitive to the highly competitive, fast moving market environment in which Independent Power Producers operate. (The term used to refer to all types of competitive wholesale providers.) When an Independent Power Producer (IPP) can respond to a specific plan, the value of its offered resources will be clearer, the bid review and/or negotiation process moves more quickly as does issuing and financing of purchase contracts. In recognition of the need to work within the realities of the competitive market place, regulators must carefully ba lance the need for oversight with the need for flexibility and speed.

HOW CAN REGULATORS ALIGN THE INTERESTS OF CONSUMERS AND SHAREHOLDERS?

In the words of 1989 NARUC resolution, "a utility's successful implementation of its least cost plan should be its most profitable course of action." (See full resolution in the Appendix at the end of the book.) The most powerful way to help a utility move towards least-cost planning is to make sure that the interests of the consumers are aligned with those of the shareholders.

At first glance, the interests of consumers and shareholders may seem to be in natural conflict. Customers seek the lowest cost, and shareholders want the highest profit. In actuality, the conflict materializes only when the old rules of regulation still apply. The key is to identify and remove the financial disincentives to the utility for pursuing IRP.

Traditional regulation, albeit unintentional, rewards utilities primarily for making sales. In a rate case, prices are established by setting the revenue requirement and dividing it by the level of sales. The more the utility sells, the more revenue it takes in. The less it sells, the less it earns. Meanwhile, the only utility costs that change as sales go up are fuel costs which are both quite low relative to retail prices and subject to automatic adjustment through the fuel adjustment clauses. The result is increased sales which translates to increased profits. Conversely, when IRP is implemented and utilities begin investing in conservation and load management programs, the better the programs are, the more money a utility will lose. That is a clear disincentive to succeeding at DSM.

It is here that commissions hold their most powerful tool in getting utilities to be good at implementing IRP. By establishing regulatory incentives and cost recovery policies that reward utilities that successfully lower costs and penalize utilities that do not, commissions are sending a clear message that IRP is important. Such policies, together with an effective IRP process, mean that the lowest practical cost for consumers is also the most profitable course for the utility to pursue. Ratepayers' and shareholders' interests are thus aligned, and the utility manager does not have to choose between what is best for the customer and what is best for the company's owners.

In addition to removing disincentives to conservation investments, regulators should also consider positive financial incentives that reward utilities for successful demand-side activities. The incentives can be structured to reward managers and/or shareholders. This kind of incentive recognizes that developing and implementing successful DSM programs is not easy. Utilities need to think about such programs in a new way and develop new sets of skills. A financial incentive calls attention to successful programs and provides a tangible reward that reflects the regulators' seriousness and commitment to this effort.

An important, related policy issue is recovery of direct expenses for demand-side programs. Commissions need to pay careful attention to how direct costs for DSM programs are recovered, particularly where DSM investment is expected to increase significantly.

Direct DSM costs can be either expensed and recovered in one year or ratebased and amortized over a period of years. Expensing allows a utility quick recovery. Utilities often want such quick recovery, especially when they first take up conservation investments in a serious way because they are insecure about future recovery of their conservation investment. However, expensing does result in a mismatch between costs and services because most conservation measures are expected to last a number of years. For example, if energy efficient lights with a ten-year life are installed and the cost of the installation is recovered up front, today's ratepayer will be, in effect, paying for services that will be delivered over a ten-year period. Generally, regulators have tried to avoid this kind of mismatch in the timing of benefits received and costs paid.

Amortization avoids the timing mismatch and reduces the level of rate impact by spreading cost potential over the useful life of the conservation program. Where a sustained level of DSM activity is expected, amortization might be the preferred approach. However, once DSM costs reach an ongoing and constant level, the difference in rate impact between expensing as compared to ratebasing is diminished and the intergenerational effects become less important.

Some state PUCs have allowed deferred accounting or other adjustments which permit a full dollar-for-dollar recovery of conservation costs. The thought here is that any cost not incurred between rate cases goes straight to the utility's bottom line. This can be counterproductive to DSM, especially if a utility is not keen to make the cost-effective DSM investments in the first place. A deferred accounting system which allows all DSM dollars to be fully recovered, similar to most fuel-cost adjustment clauses, can effectively counter the tendency to underinvest in conservation.

SHOULD THE COMMISSION APPROVE A UTILITIES PLAN IN ADVANCE?

Whether a commission should pre-approve a utility's IRP plan has been a matter of controversy in some states. Utilities, unsure of how to proceed given new rules, have asked for pre-approval, but commissions, reluctant to have such approval be interpreted as a prior prudence review, have resisted.

There is plenty of room for a happy, or at least comfortable, median. Clearly, commissions can not and should not provide a carte blanche blessing. Yet, by approving a plan, they can approve the process and assumptions that were used in its development, and they can indicate that the utility is pursuing a reasonable investment strategy. To offer this level of approval, the commission needs to be convinced that the analysis was conducted in a sound manner, that the utility considered an appropriate breadth of resources and that the method for determining and comparing costs was reasonable. The commission will also want to be assured that public input, reflecting the opinions of many interests, was included. The burden of updating assumptions and making final resource selection, however, always remains with the utility which means that prudence remains an after-the-fact determination. However, if the utility's planning process is sound and ongoing, the opportunities for prudence disputes will diminish.

How state commissions have chosen to respond to filed utility plans has varied. For instance, commissions in Maine and New York review and approve the utilities' plans to be certain that avoided cost calculations are reasonable. But neither commission explicitly approves the filed plan per se. On the other hand, the Wisconsin Commission approves a consolidated, statewide plan for all its activities at one time.

Whether or not the commission formally approves the utility's filed IRP, it should provide for public participation and for detailed comment and analysis on the proposed plan. Public participation can take many forms including an adjudicated hearing, a series of technical workshops or a collaboration. Whatever the means, the opportunity for participation by all customer groups and other stakeholders is key to the successful implementation of the plan. Public participation can strengthen the plan by challenging a utility's predictions and offering alternatives that may improve the IRP process. Parties who work together reviewing and building the plan generally will understand it better and, as a result, support actions which take place as a result of it.

HOW CAN COMMISSIONS SHAPE AN EFFECTIVE PROCESS FOR INTEGRATED RESOURCE PLANNING?

Critical to the success of any regulatory policy is that it be consistently implemented by the regulators. Commissions must take care that their decisions and actions in ratemaking, rate design, certificates of need, prudence, fuel cost adjustment and other decisions are consistent with their articulated IRP policies. All staff who work on any electric utility issue should understand how their work fits in with IRP.

For many commissions, this means better internal organization to allow information and ideas to flow among staff members who may not otherwise see how their work interrelates. Coordinating rate design with the long-run marginal costs flowing out of the IRP plan is an example of this needed information exchange.

CONCLUSION

Exploration of these key policy areas is fundamental to successful IRP implementation. However, customers should not be denied the benefits of DSM benefits or even minimal investment in DSM while the details of these policies are being worked out. It is not necessary to complete the full discussion of these policy areas to start benefiting from the products of a completed Integrated Resource Plan. Utilities can, and should, be encouraged to start adding low-cost DSM to their resource mix without fearing that they are putting themselves or their customers at risk.

Avoided Cost Calculations: Analyzing New Resource Acquisition

The introduction of IRP into utility decision-making has charged utilities to acquire least-cost energy resources using a strategy that establishes a common framework for comparing very disparate resources. Avoided cost analysis is the common framework that establishes a mechanism for comparing conventional and unconventional supply-side resources and demand-side resources. It provides the means to compare the costs of alternative energy resources and decide which are cost effective and which are not. Yet like many features of IRP, avoided costs can be misunderstood and consequently misapplied. This chapter describes avoided cost methods and the most common errors that occur when calculating these costs.

CONCEPTS TO UNDERSTAND

Utilities must constantly balance the need to provide electricity to all customers, at every instant in time, with the need to minimize costs. While seeking least-cost options, a utility cannot compromise its ability to provide reliable service, its obligation to serve and its need to avoid unacceptable risks. Decisions confront utilities not just in terms of what resources to acquire but in terms of what resources at their disposal should be operated at any point in time.

Avoided cost analysis helps utilities assemble their least-cost plan by identifying what a resource is worth to a utility. Looking at it another way, the most a utility would be willing to pay for a resource. This is best done by looking at the specific operating characteristics and location of an actual resource under consideration and asking a number of questions. What existing or planned utility resources would the new resource displace? What time of day or year would the new resource provide energy services? Will the resource raise or lower the reserve margins? Will the resource increase or decrease transmission or distribution costs? Would overall costs be lowered or raised if the new resource were substituted for a planned resource?

To accurately assess and compare costs, all relevant expenses for existing and new resource options are included in the analysis. These include transmission and distribution savings, risk and reliability effects and often costs of environmental externalities. For instance, acquisition of demand-side alternatives can mean that costly transmission and distribution system upgrades could be postponed or avoided altogether. Similarly, renewable resources, such as photovoltaics or wind turbines, may offer the possibility of avoiding more costly line extensions into remote settings. In addition, allocating full environmental costs to resource choices generally improves the economic attractiveness of non-traditional resources.

CALCULATING AVOIDED COST

To find out what electricity is worth, avoided cost calculations ideally look at the cost of electricity (capacity and energy) over every hour of every year. Any resource not already in the resource plan can be evaluated by comparing its actual cost to the cost it would avoid were it to come on the system at no (zero) cost. This calculation is called the avoided cost. A resource that provides electricity at a cost (or price) lower than its avoided cost is, by definition, cost effective and worth acquiring.

How do utilities make this calculation? Avoided cost can be calculated in a generic or customized, resource-specific fashion. In either case, utilities begin the same way which is to undertake the IRP steps to determine the optimal, least-cost resource mix. These steps include:

- **Load Forecast**
  This first step uses historical trends, econometric analyses or preferably end-use forecasts to construct a load forecast for each hour of the year.

- **Consideration of Possible Resource Options**
  The utility constructs a list of options to consider. This list needs to be as comprehensive as possible by including central and dispersed supply-side resources, renewable resources, demand-side resources, power purchases etc.

- **Development of an Optimal, Least-cost Resource Plan**
  Developing an optimal plan which chooses among a broad range of options is complex, but the theory can be illustrated with a simple example.

Suppose a utility is developing a resource plan using two dispatchable resources.

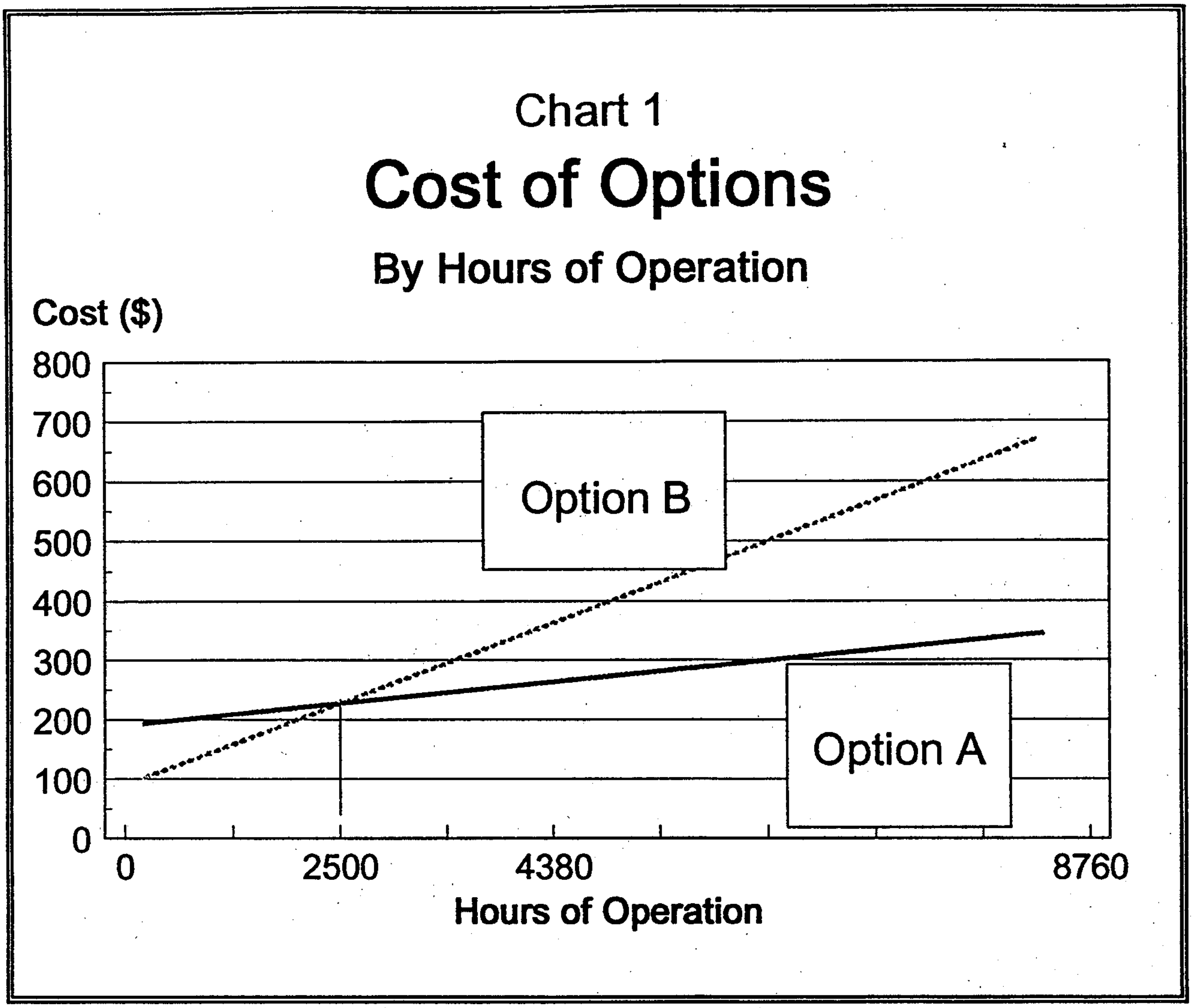
Option	Investment	Annualized Capital Cost	Fuel Cost
1	$1000/kW	$200/kW	2¢/kWh
2	$ 500/kW	$100/kW	6¢/kWh

Option 1 has the characteristics of a baseload resource — high capital costs and low fuel costs. Option 2 is similar to a peaking unit with low capital costs but higher fuel costs. How does a utility choose how much of each of these options to buy in order to have the least-cost mix? Where is the break even point where the higher capital cost of a base-load unit is balanced by its lower fuel cost? The answer lies in looking at the 8760 hours in the year and finding the point at which it costs less to operate Option 1 with lower operating costs and at which point does it becomes cheaper to operate the lower capital cost Option 2.

This number is found using the graph on Chart 1 which plots costs of both options across the entire year.

Chart 1 shows that Option 1 is cheaper when in operation over 2500 hours each year. Option 2 is cheaper when in operation less than 2500 hours throughout the year.

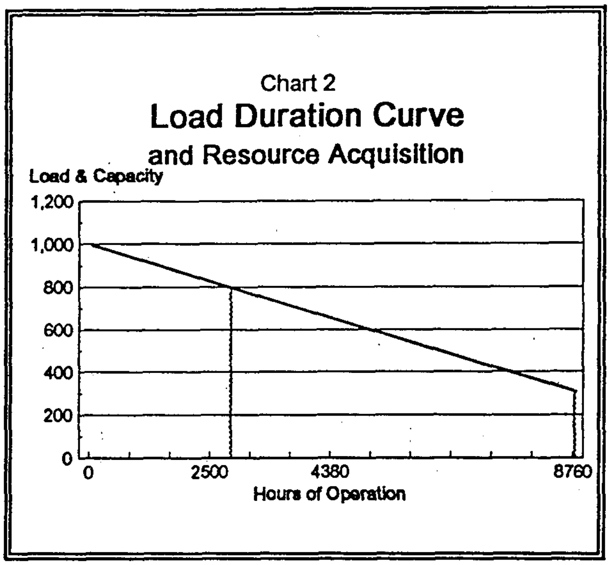
Having derived this number, the next question is how much capacity must be operated for more than 2500 hours, and how much will run for less than 2500 hours? This is answered by taking the information found in



a utility's load duration curve.[1] The illustration in Chart 2 represents a simplified load duration curve.

This shows that the highest demand required in a given year is 1000 MW, and the lowest demand is 300 MW. The first graph shows that Option 1 is the cheapest resource for load in excess of 2500 hours. By drawing a line from 2500 hours until it intercepts the load duration curve, the least-cost, optimal resource mix can be determined. This graphing shows that any MW of capacity which will be operated for 2500 hours or more should be the Option 1 plant. Any MW of capacity which will run for less than 2500 hours should be the Option 2 plant. With this guidance, a utility is most economically served by acquiring 200 MW from Option 2 and 800 MW from Option 1. Taking into account cost for both plants, the total cost to the utility turns out to be $303.9 million.

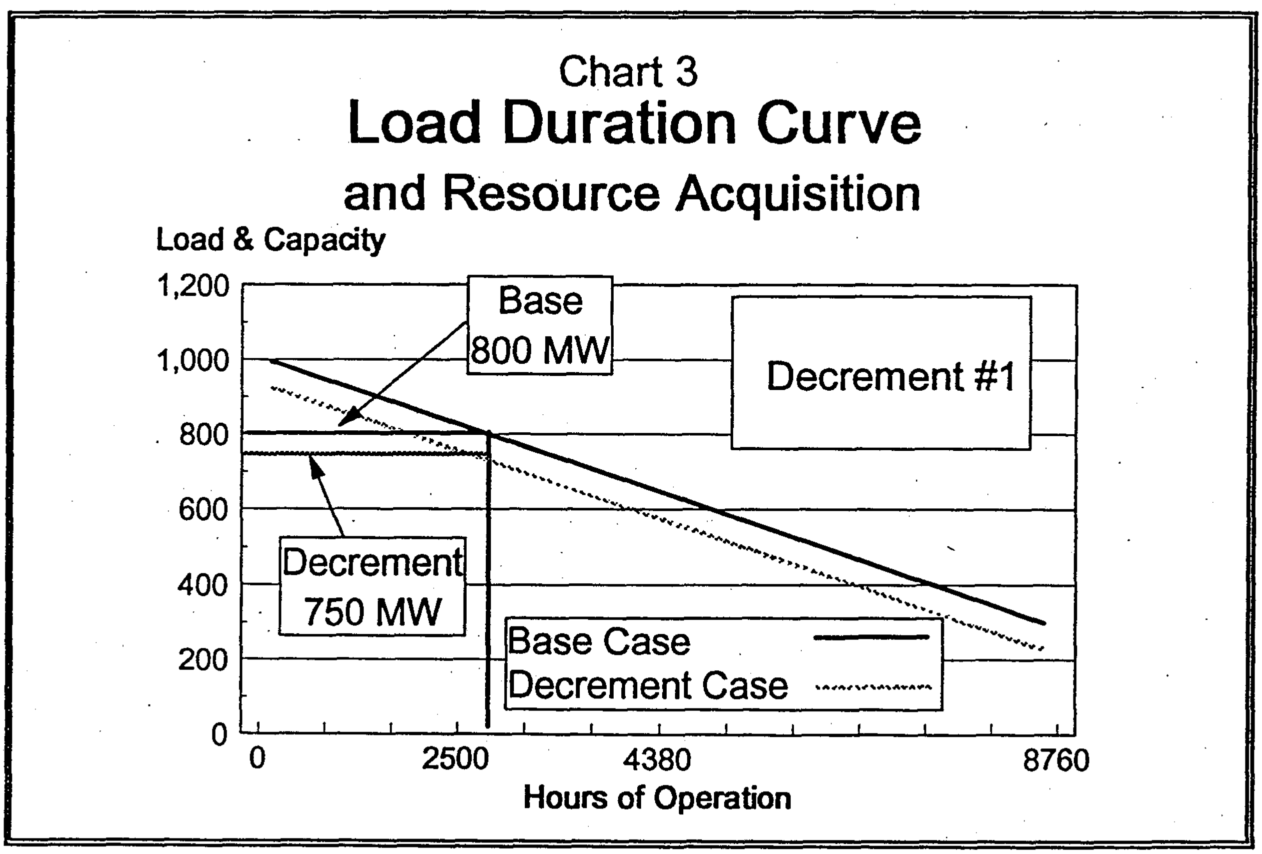
[1] A load duration curve is a utility's hourly load (or skyline) which is reordered so that highest demand is hour one, the second highest demand is hour two and so on.



Standardized Decrement Approach

What is a utility's avoided cost? A way to derive this cost is to suppose that the utility obtains a free, around-the-clock resource which provides 50 MW every hour of the year. This 50 MW decrement will affect the resource mix as shown in Chart 3.

Now the peak load requirement for the utility is 950 MW, and the minimum load requirement is 250 MW. Again, by drawing a line from 2500 hours to intercept the new load curve, it can be seen that, despite the free MW, 200 MW must still be acquired to meet the load requirements for 2500 hours of the year. On the other hand, now only 750, not 800 MW are needed to meet the baseload requirements.



The cost for purchasing 750 MW of Option 1 and 200 MW of Option 2 is $285.1 million. The cost savings from 50 free MW is the difference between the total revenue requirements of the two plans or

$303.9 - 285.1 = $18.8 million

The avoided cost is calculated by dividing the savings ($18.8 million) by the energy which no longer needs to be acquired (438 million kWh). The avoided cost is 4.3¢ per kWh. This means that the value to this utility of a 50 MW, 100 percent load factor resource is 4.3¢ per kWh.

This example is purposely constructed very simply to illustrate how to calculate a standardized avoided cost. A more "real life" situation would define a slice of the resource requirement in order to meet specific energy needs of the utility and match the operating characteristics of the types of resources that a utility believes are available. Size, capacity factor, starting year and duration are characteristics considered by utilities when defining this standardized decrement.[2]

When using this standardized approach to acquire resources, the decrement is then filled by resources whose characteristics match the characteristics defined in the decrement and whose costs fall below the computed avoided cost. Resources, at or below avoided cost, are added in ascending order beginning with the least expensive. This could mean that even though a resource falls below avoided cost, it will not be acquired if there are enough options to fill the decrement that cost even less.

In addition to using the standardized approach as the tool to actually acquire resources, it can also be used to inform the market place of an approximate price a utility is willing to pay for a resource. In turn, the utility can quickly test the market place and assess what resources are available. This survey is followed by a resource-specific, customized avoided cost.

<u>Customized Avoided Cost Calculations</u>

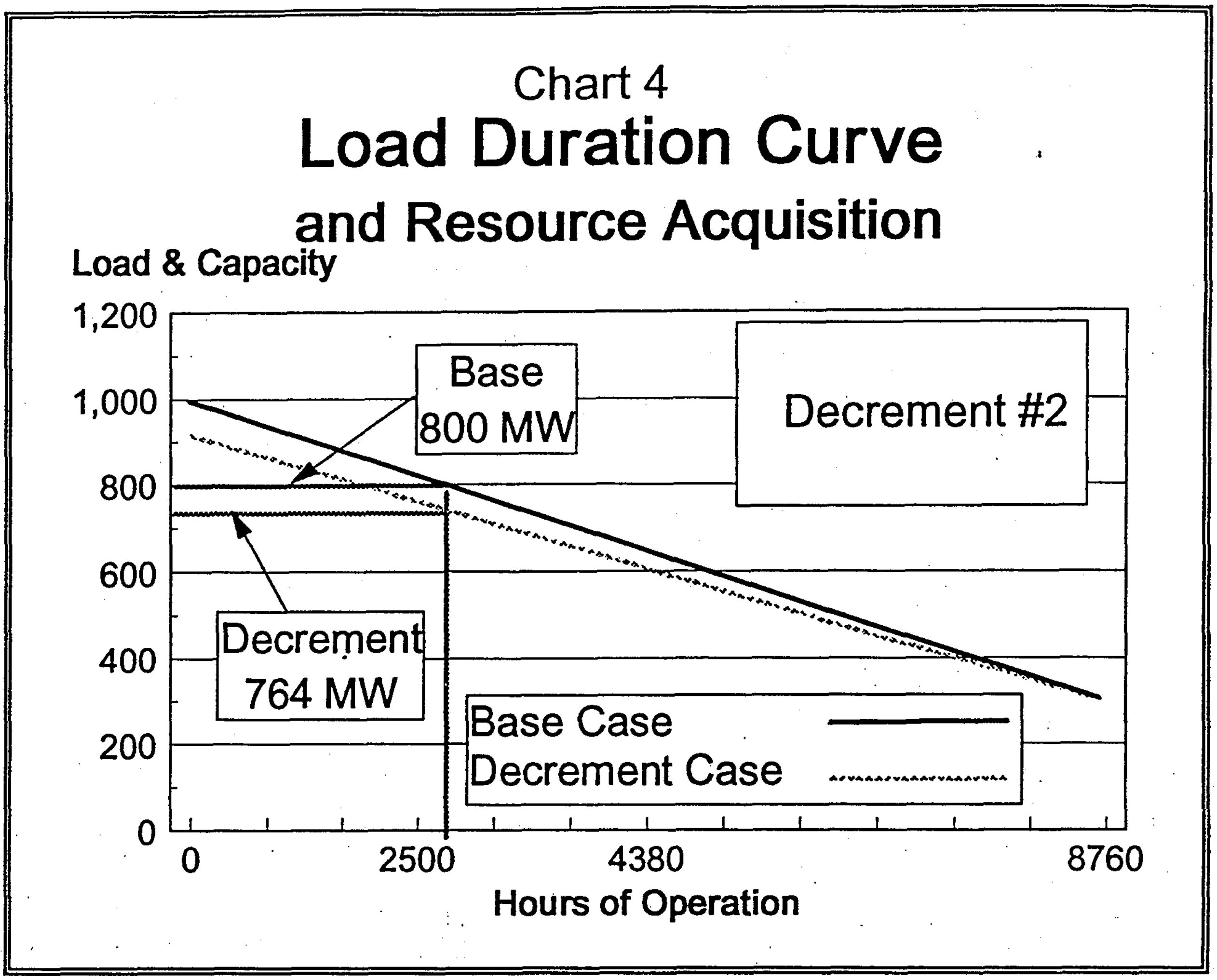
The example above can be built upon to illustrate how to derive a customized avoided cost. In this case, shown in Chart 4, suppose a DSM measure that would reduce peak demand by 50 MW and have no impact on the lowest demand. Further suppose that intermediate demand levels are reduced by less than 50 MW.

This free resource affects both the baseload and the peaking requirements. Now, 764 MW are needed for 2500 hours or more and 186 MW are needed for less than 2500 hours. The total cost of this resource mix is $290.2 million. The cost savings from this resource is:

$303.9 - 290.2 = $13.7 million

While the total dollar savings is smaller in this example, because the actual amount of energy saved is also smaller (219 million

[2]The size of a decrement is decided by considering how sensitive avoided costs are to load levels. If avoided costs change rapidly, then accurate costs can only be assured with smaller decrements. If avoided costs are slow to change, then larger decrements are acceptable. A reasonable decrement size for an electric utility might include two years of peak demand growth or five percent, whichever is lower. In other situations, decrements are sized according to the next resource to be acquired.



kWh), the avoided cost now, at 6.3¢ per kWh, is about 50 percent higher than the 4.3¢ for the around-the-clock displacement resource. The value to the utility for this partial resource is 6.3¢ per kWh. This occurs because the alternative resource provides its capacity and energy in the time periods that costs are highest. This 50 percent avoided cost differential between baseload and peaking units is not uncommon.

This illustrates that the best way to come up with accurate avoided costs is to consider the specific operating characteristics of a replacement resource including MW, capacity factor and time period of operation. The technique requires a specific answer to the question of how the resource plan would change were a specific, new resource added to the mix? By re-optimizing the resource plan to accommodate the addition of a specific resource, an exact, customized avoided cost of an individual resource can be calculated.

The avoided cost is what the utility should be willing to pay to purchase an energy resource. Any cost, at or below what a utility already expected to pay, is a cost-effective decision on the part of utility. This technique determines what it is worth to the utility to acquire this resource. Whoever is offering the resource must then decide whether the calculated avoided cost is an acceptable price for the option.

Avoided Cost Shortcuts To Consider

Because customized avoided cost calculations can be time consuming, shortcuts have been developed which allow utilities to calculate the avoided cost for a specific re source without re-optimizing the resource mix each time.

Peaker Method
A simple shortcut that has been derived calculates avoided cost based on the cost of a peaking unit. Here, the two units from the example above are used to compare the results from this technique to those derived from a customized avoided cost calculation. In this case, to determine the avoided costs, the capacity costs solely from the peaking unit are used in the calculation. Avoided costs are taken to be the operating costs of the most expensive unit which is actually in operation during each hour. In this example, capacity costs are assigned to the ten percent of the hours when the load is highest.

The cost is determined by assigning costs to different time periods of operation in the following manner:

	10% operation or 876 hours	876-2500 hours	over 2500 hours
Marginal Energy Costs	6¢	6¢	2¢
Capacity Costs	11.4¢ [3]	0¢	0¢
Avoided Cost	**17.4¢**	**6¢**	**2¢**

After a decrement has been established, the number of kWh that each decrement has in each of the three time periods is tallied up to derive an avoided cost. Applying this calculation to the second decrement example where there is a 50 MW reduction in the peak period and no load reduction at the lowest load, the avoided cost is 6.1¢, not 6.3¢. The difference is attributable to the fact that capacity costs, in fact, vary by time. If you reduce loads year round, you build less baseload, but if you reduce loads mainly on peak, you build fewer peaking units. Customized accounting can take this into account, while the peaker method cannot.

This cost, though, is fairly close to the answer derived from the more accurate customized approach. And the cost will be close the more the replacement resource resembles a peaking unit.[4] But is close good enough?

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[3] The cost of the sample peaker is $100 per KW per year. This is spread over the ten percent of the year, 876 hours, when load is highest. Thus $100/876 hours = 11.4¢ per kWh

[4] Where a utility is building primarily baseload resources, using a peaker shortcut may introduce fairly large errors.

Can a utility live with it? Here the tradeoff arises between how critical it is to have the avoided cost calculation be precise. If there is a lot of money at stake, it may be in a utility's best interest to re-optimize its resource plan rather than rely upon the peaker method. Also the utility may be interested in getting other information from the re-optimization exercise that it cannot otherwise obtain, such as the impact of a specific resource on reliability, unit size requirements and unit forced outages.

Shortcuts With Limited Application

Allocating Costs To Time Of Day

It is tempting to undertake a shortcut in which a single avoided cost calculation for a utility's resource mix is computed for every hour of the year. A resource-specific avoided cost could then be determined by figuring out the resource's hour-by-hour operating characteristics and tallying up the respective avoided costs. This is attempted in some states. But in actuality, it is difficult, if not impossible to do. Many schemes have been proposed to assign costs to different hours. However, because no scheme goes back to the fundamental structure of how electricity is used, the allocations of cost are fundamentally arbitrary. This suggests that, when using this analysis, special care must be taken when evaluating resources which are disproportionately on peak.

The Next Plant Approach

A very common, but mistaken shortcut, uses the next planned unit as the avoided cost for acquiring any new supply or demand resource. Here a utility might say "we are planning on building a gas turbine, and therefore, any resource option that is cheaper than that falls below avoided cost." In doing this, they are able to calculate a single number, say 6¢ per kWh as the cost of a gas turbine and say that they should acquire any resource that is cheaper than this price and reject any resource that is more expensive. This only works in situations where the new resource resembles a gas-fired turbine.

However, if the proposed resource is very different in the way it provides an energy service, the 6¢ per kWh will end up having very little validity. Take, for example, a weatherization program which saves energy during peak winter months. Earlier calculations and intuitive knowledge confirm that peak power replacement has a higher avoided cost than baseload power replacements. In addition, a demand-side program is provided directly on-site which eliminates transmission and distribution costs. Given these factors, a weatherization program can end up being worth more than 6¢ per kWh to the utility. Yet by using the next-plant approach, this alternative might be immediately, and mistakenly, rejected.

WHAT KEEPS GOOD AVOIDED COST CALCULATIONS FROM OCCURRING?

As part of the IRP process, the purpose of avoided cost calculations are to ensure that a utility locate and acquire the lowest cost mix of energy resources. The following constraints hamper the IRP process in many states and can mean that customers are not receiving the most economical mix of resources.

- Demand-side management is not treated as an equal player. When this occurs the environmental and potential financial benefits are sacrificed.

- Some utilities have been reluctant to turn to the market place to obtain either supply- or demand-side resources.

- Potential savings in transmission and distribution investments are frequently overlooked. Renewables and demand-side resources have a better chance of emerging as cost-effective options when the costs associated with transmission and distribution are included in the calculation of avoided cost.

- Surplus capacity does not mean that the avoided cost is zero. There are always avoided fuel costs and often avoided transmission and distribution costs.

- While dispatchability is a good characteristic, it is not a necessary characteristic for every resource choice. There are non-dispatchable resources that, if acquired, would lower a utility's cost without diminishing its ability to provide electricity. Utilities need to determine just what dispatchability is worth and how dispatchability should influence cost.

- Many resources, particularly DSM and dispersed generation, will result in lower losses on the transmission and distribution system. Any marginal reduction in losses should be taken into account.

- Some resources, particularly smaller resources, may increase reliability and therefore allow the utility to carry lower reserves. The associated savings should be captured in the analysis.

- Occasionally the argument is advanced that intermittent resources like wind and solar should have no capacity value because they may not be available at peak times. This is wrong. Instead, the capacity value of intermittent resources should be determined by looking at how they reduce the capacity needed to maintain reliable service.

Until now, this discussion has focused on the more technical aspects of avoided costs and in doing this takes as a given a variety of assumptions about the future. These assumptions include fuel price forecasts, load growth and the remaining life of a nuclear plant. In reality, these uncertainties can have a major impact on the analysis (in some cases a far greater impact than the impact of the issues presented in this paper). This suggests that forecasts used in the avoided cost analysis require careful scrutiny because the risk from forecasting errors can be great.[5]

CONCLUSION

Understanding and correctly calculating avoided cost will go a long way toward making sure that utilities locate and acquire the least-cost energy resources. However, when avoided costs are poorly done, the cost of electricity will rise. Poor avoided cost calculations result in acquisitions of resources that are too expensive while, at the same time, overlook cost-effective resources.

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[5] Risk and uncertainty are discussed more fully in a later chapter.

Customized avoided cost calculations are the most reliable way to compute what a resource is worth. Standardized avoided costs are particularly useful to let providers of energy services know roughly what a utility is willing to pay to acquire a new resource and to let the utility test the market and see what resources may be available. Shortcuts should be used selectively, with a full knowledge of their built-in biases or limitations.

Dealing with Risk and Uncertainty

Uncertainty is a key issue affecting IRP. Yet incorporating uncertainty into IRP is difficult. This chapter describes what risk is, why we need to care about risk and uncertainty, tools available to planners and strategies to reduce risk.

WHAT ARE RISK AND UNCERTAINTY?

The terms **risk** and **uncertainty** are widely used but frequently confused with one another. They are not, however, interchangeable. Uncertainty describes the unknowns of the future. Risks are the consequences of those decisions — the best guesses — made in the face of uncertainty. If there are no negative consequences resulting from the decisions, there is risk and thus no problem. Problem only occur when consequences of guessing wrong are high costs, failed investments or environmental damage, there are problems. Utilities and consumers face this risk of guessing wrong.

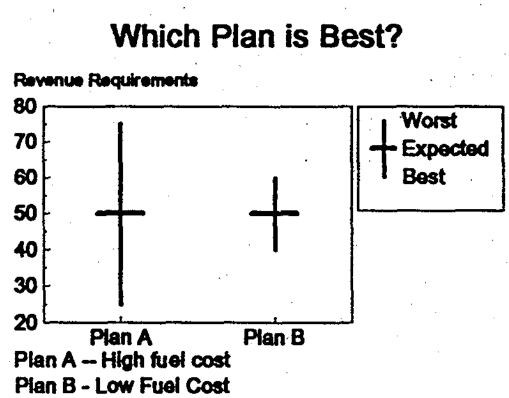
WHY DO COMMISSIONS CARE ABOUT RISK?

Risks Are Big

Commissions care about risk because the stakes are large. Customers have faced rate increases of 50 percent from a single bad decision. Although the source of uncertainties may be changing, risks are not getting any smaller.

Risk Preferences Differ Among Stakeholders

Utilities, stockholders and ratepayers often favor projects with very different risk profiles. With the utility looking out primarily for its management and stockholders, it is left to commissions to think first of the interests of ratepayers. For example, compare the risks of two alternative projects a utility might consider in Figure 1. Plan A is a low cost capacity, high fuel cost facility, such as a gas combustion turbine. Plan B as found at a wind or hydro facility has just the opposite characteristics.



Both projects have the same expected cost over the life of the plant. However, because fuel prices for Plan A are very uncertain, they have a significantly wider cost range than the potential fuel price variation for Plan B. While there is a chance that Plan A will have very high fuel prices, it is also possible that the fuel price will fall very low. Plan B with a smaller and more predictable price range offers the lower overall cost risk.

The risk associated with Plan A is obvious — that fuel costs will be high. The risk associated with Plan B, on the other hand, is much less apparent.

On first blush, one would guess that customers and utilities both would prefer the greater fuel price certainty associated with Plan B. After all, it is well known that fuel costs are a key uncertainty facing utilities, and therefore an opportunity to predict these costs with relative accuracy should be attractive to all stakeholders. However, this is not the case. While customers would likely opt for the reduced price volatility of Plan B, more frequently than not utilities choose Plan A. There are three reasons for this preference:

1. If gas prices end up at the low end of the scale and the utility has selected Plan B, then the utility can lose customers to other fuels.

2. If the utility has selected Plan A, it is very likely to have the company of other utilities who are making similar decisions. This means that the risk associated with exposure to high fuel costs is similarly shared and thus minimized.

3. Fuel clause provisions mean that volatile fuel costs are not really a high risk for utilities. Commissions rarely disallow fuel cost increases and when they do, it is never based upon the argument that a plant which burns a particular fuel should not have been built in the first place. By being reasonably confident that high fuel prices can be passed on to the customers, Plan A is, in fact, a low risk for the utility even though it is a high risk for customers.

Because risk profiles appeal to utilities and customers in different ways, the utility management will advocate for its risk preference in IRP proceedings, certificate cases etc. Commissions, therefore, need to understand where customer and utility interests diverge, and in these identified areas, they need to represent consumer preferences and interests.

<u>Risk Decisions Demand Good Judgment</u>

Allocating ample time to considering uncertainty is important because there are no easy tools, no simple yardsticks to measure and analyze it. In the absence of a ready tool, good, subjective judgment is a critical component.

<u>Categorizing Risk</u>

Energy resource planners face different types of planning risks: exogenous, supply-side system and resource specific and DSM specific.

Exogenous Risks are those a utility faces regardless of the resource choice they make.

- economic growth
- interest rates
- inflation rates
- capacity and energy demand
- purchased power availability and costs
- future environmental taxes and/or regulations
- future industry structure
- regulatory risk
- market risk

Supply-side system and resource-specific risks are unique to the fuel choice and the technology and include:

- project financing and O&M costs
- siting and permitting
- construction time
- costs and permitting associated with transmission
- forced outages
- future operation of existing units
- technological changes /improvements
- future fuel costs
- contract enforcement

DSM-specific risks are faced in both conservation and load management programs and include:

- lower than expected participation
- technology performance and persistence
- changes in customer behavior
- technology costs
- marketing and administrative costs

GIVING SPECIAL ATTENTION TO ENVIRONMENTAL UNCERTAINTY

Environmental uncertainties are among the greatest uncertainties facing utilities. Not only must utilities face the day-to-day work of complying with current regulations, but they need also to keep an eye on the future and consider what additional regulations may emerge. The reason for this is simple. A power plant built today will operate for 30 years or so. The lifetime economics of the plant will be greatly affected by future environmental requirements.

- There is considerable concern about CO_2 emissions, particularly regarding global climate change but also in terms of its impact on crop and forest growth. The Clinton Administration has already adopted a voluntary Climate Change Action Plan that is designed to reduce global warming gases to their 1990 level by the year 2000. This plan calls for considerable voluntary actions from electric utilities. Future regulatory action is a reasonable possibility and would certainly have an impact on utilities that are heavily dependent on fossil fuels, particularly coal.

- Mercury is now showing up in concentrations which greatly exceed background levels in both the Great Lakes and in "pristine" lakes in northern New England. High levels of mercury found in freshwater lakes and streams throughout the country has prompted over 30 states to issue health advisories warning women and children to limit and in some cases refrain from eating fish.

  Eagles and osprey in the northeast have been found to carry such a high body burden of mercury that there is a possibility that reproductive success is being diminished. Mercury has been documented to cause neurological and kidney damage in humans and has an adverse impact on fetal development. Fossil fuel consumption, particularly coal consumption, may account for as much as 25 percent of U.S. anthropogenic sources.

Technologies to capture and control mercury at the stack are in their infancy, are expensive and may not be effective.

- The Clean Air Act Amendments (CAAA) of 1990 already strictly control emissions of sulfur dioxide. The Act currently includes some provisions to reduce nitrous oxides but additional regulations aimed at improving air quality in ozone non-attainment areas are also anticipated.

Utilities need to anticipate these scientific uncertainties, keeping in mind that future regulatory demands may be placed on them. The challenge they face is deciding how to factor these unknowns into their decision making — today.

MEETING THE CHALLENGE FOR UNCERTAINTY PLANNING

Utility planners must figure out how to undertake analyses looking at the future that are comprehensive and useful without losing sight of the fact that the wildest and scariest range of potential events might not be wild and scary enough. The trick is to come up with reasonably likely values without ignoring boundary conditions. For instance, in the early 1980s, nobody imagined that oil and natural gas prices would fall, much less return to 1960s levels, adjusting for inflation. The repercussions of being blind-sided by low fuel prices meant that more expensive power contracts than might otherwise have been the case were negotiated. Identifying the range of futures that could occur gives the utility the flexibility it needs to respond quickly and effectively to changes from baseline projections.

Key areas to consider in effective analysis are:

<u>Interaction Of Key Uncertainties</u>

The need to try to capture the interaction of key uncertainties cannot be overstated. Many of the uncertain variables are understood to be related, but the exact nature of the relationships is not obvious. For instance, the relationship between fuel prices and electric load growth is unclear. Low fuel prices generally encourage switching from electricity to another fuel, thereby depressing electric load growth. On the other hand, low fuel prices may stimulate the economy, thus encouraging electric load growth.

<u>Recognizing Data Limitations</u>

Lack of information is a universal constraint to all analyses, but it is a particular problem for risk analysis. Ideally one needs to know not only the most likely load forecast, but each possible load forecast and its probability of occurring. To even try to do this, assumptions need to be made. These assumptions are at best "good guesses," and accordingly, it should be understood right from the start that they are arbitrary.

To make matters more complicated, even if all the necessary information was readily available from objective sources, the Herculean challenge of analyzing a resource plan for many levels of demand still persists.

These problems suggest that risk analysis is part art, part science. The key is to consider an adequate range of possible futures and to focus on flexible and diverse resource acquisition strategies.

TOOLS FOR UNCERTAINTY ANALYSIS

The techniques, listed below, are available to model and analyze uncertainty.

Sensitivity Analysis
Scenario Analysis
Portfolio Analysis
Risk Adjusted Discount Rates
Options Theory
Probabilistic Analysis
Monte Carlo Simulation
Decision Analysis

Sensitivity Analysis and Scenario Analysis are considered the most useful and are probably the most practical for a utility to employ. They are discussed here. The other tools are described in more detail in Appendix A at the end of this chapter.

Sensitivity Analysis

In this technique, a preferred plan is defined, after which key variables are altered to see how the plan responds to different assumptions. The analysis sets up a game of "what if." First, an IRP plan is analyzed on a best estimate basis, and its revenue requirements and performance are determined. Analysts then pose a variety of alternative scenario questions — What if load grows at twice the predicted level? What if fuel prices are lower than projected? — and learn about the implications of these possibilities.

As an example of how sensitivity analysis is best used, assume that a new 280 MW plant planned for 1996 is under consideration. If growth occurs as expected, what are the costs and how do these costs compare to other reasonable options? Suppose, instead, that high (or low) load growth occurs. How would the utility respond? What is the cost of that response, and are the response costs lower if some other option is chosen today?

The technique is useful in understanding what uncertainties matter the most. It is capable of isolating the impacts of uncertainty and associated risks for a single parameter, allowing consideration of flexibility and providing additional information on the robustness of different resource strategies.

Scenario Analysis

Here a range of alternative, internally consistent and logical futures are constructed by considering those exogenous uncertainties that make sense to worry about. Resource strategies are identified to meet each future, and the best options are combined into a single plan. This form of analysis can be very useful when looking carefully at one resource strategy at a time.

PacifiCorp, for example, developed different, scenario-specific mixes of combined-cycle turbines, renewable resources, DSM programs, cogeneration and coal plants. The scenarios considered medium-high load forecasts, electrification, loss of major generating resources, high natural gas prices and a CO_2 tax. For each scenario, results included the amount of each resource acquired, utility operating revenues, average electricity prices and emissions of SO_2, CO_2 and NOX.

The strength of this type of analysis is that it recognizes that different variables are linked. However, because it is not always clear what the linkages are (do low fuel prices raise or lower load?), a problem that arises is that different scenarios are constructed using assumptions that are not always consistent with each other. In addition, scenario analyses may not ferret out the broadest range of possible outcomes and therefore, the future could unfold in unanticipated ways.

GUIDING UTILITIES THROUGH UNCERTAINTY: THE ROLE OF THE COMMISSION

There is no simple formula for dealing with uncertainty; no single tool that can decide how much more someone should pay to be assured a lower risk. Computer models do not exist which are capable of evaluating the risk profile of a given energy plan and deriving an answer that says something like "It is worth paying two percent more to lower the risk" of a particular mix of energy resource choices. Computers can be used to generate a list of things to worry about and to frame the questions that should be posed by energy planners, but they cannot answer the questions.

Given this situation, what guidance should commissions offer utilities to ensure that good planning and decision making takes place in the face of uncertainty? There are approaches that commissions can recommend that will benefit utilities and their ratepayers. These approaches rely upon good sense and careful thinking and call upon commissions to require that their utilities

- Not prematurely rule out any alternative resources or strategies in the IRP process. This is particularly true of resources that are different from both an economic and environmental point of view, such as renewable resources. A list options should be as varied as possible and in particular should favor resources that have a different set of risk characteristics from other resources currently in the portfolio.

- Consider all the possible uncertainty outcomes even those that might seem ridiculous. Nobody thought in the early 1980s that oil prices would remain stable, much less fall. These perceived impossibilities kept these options from being seriously considered. This step cannot be underrated and a lot of time should be designated to it.

- Anticipate what the future might hold. For instance, it is prudent to expect that environmental regulations will get stronger, not weaker. With fuel prices at an historic low, there is little probability that prices will fall lower. There is probably more room for error on the high side.

- Undertake sensitivity analyses on possible plans to decide which of the uncertainties are most important.

- Develop a resource acquisition strategy that is flexible and diverse at the lowest possible cost. Low-cost planning acknowledges that the optimal resource choices may cost more than the least-cost options because, by paying a little bit more, the level of risk a utility faces is reduced. A slightly higher cost plan might better protect utilities and ratepayers from volatile fuel prices, unexpected changes in load and future environmental regulations.

CONCLUSION

Uncertainty analysis is undertaken to minimize expensive mistakes. But there is no magic wand, no simple, reliable method to consider and evaluate risk. The best tool is good, subjective judgment and an ability to think broadly about the range of possible outcomes. Perhaps the most common mistake is to assume that the future will look like today, only more so — that fuel prices will stay low and that environmental regulations will remain invariant. An equally important mistake treats today's forecasters as being smarter than their forbearers.

APPENDIX A
ANALYTICAL TOOLS FOR UNCERTAINTY PLANNING

Portfolio Analysis is a variation and extension of scenario analysis. It is based upon the idea that costs of generation alternatives generally do not move in isolation. It strengthens scenario analysis by selecting different acquisition strategies and testing which ones will do best given different possible futures. It recognizes that portfolio diversity means more than simply including multiple technologies in the resource mix but also includes a variety of risks. When appropriately applied, it offers the potential for utility planners to create efficient resource plans that minimize costs commensurate with acceptable levels of risk.

In undertaking these analyses, multiple resource plans are developed, each of which meets different corporate goals for resource and risk diversity. These plans are then subjected to sensitivity analyses. The technique acknowledges the analytical limitations of uncertainty analysis by depending upon subjective judgments to make the final decision as to what the most robust portfolio is.

The Northwest Power Planning Council tested five, alternative conservation-acquisition portfolios before selecting a strategy that increased cost only slightly but substantially reduced future risk.

Risk Adjusted Discount Rates, borrowed from financial theory, apply different discount rates to the benefits of a given resource investment, depending on the risk that those benefits will occur as expected. It is the approach that the Colorado Commission requires utilities to present in their IRP filings. This tool, which is still evolving (Awerbuch, 1993), begins with the reasonable premise that more risky investments should be discounted compared to more certain alternatives. To develop as a useful tool, there remain areas where further refinement would be helpful. As currently structured, the model looks at the risk of individual projects in isolation. This means that a natural gas project's risk would not depend on whether the utility was already heavily dependent on gas. Such a view is inconsistent with the generally held belief that diverse resource portfolios possess lower risks.

Options Theory, which was developed by commodity traders, allows utilities to evaluate the value of delaying an investment until more information on how the future might unfold is available. There are some features for which a delay will not be particularly useful, such as the price of fuel over the next 20 years. In other cases, though, it has more application. A year later more information may be known about a specific technology or the direction of a particular environmental regulation. Options theory offers a method of calculating the cost of waiting a year to build a facility less shrouded in regulatory or technological uncertainty.

Theoretically, the same tool can be used to evaluate whether it is worth paying more for modularity, multi-fuel capacity and contract reversibility. New England Electric Systems (NEES) used this tool when they issued a RFP to IPPs and required respondents to include in their proposal the cost of an option to cancel the contract at future points in time. Options theory has been adopted in NEES' their most recent Plan.

Probabilistic Analysis. There are a broad class of probabilistic analyses that function by attempting to look at the impacts from different combinations of probabilities. Analysts assign probability values to key uncertain variables. Outcomes are then derived by combining the values of the key factors. Computer models have been developed to undertake these probabilistic analyses and pare down the millions of possible outcomes to a number that can be useful to a planner. The two most common of these, Monte Carlo Simulation and Decision Tree Analysis, are described briefly below.[1]

> **Monte Carlo Simulation** begins by assigning probabilities to different exogenous uncertainties (future economic activity levels, oil prices and weather), then lets a computer randomly combine these possible outcomes, using a technique that can be compared to a "roll of the dice." Probabilities are assigned using a combination of historical data, informed judgment from people familiar with the issues and discussions about what changes in the utility planning environment might affect variability in the future. The output values from a given run are assembled into probability distributions which are typically further distilled into a smaller number of possible futures that can be applied usefully in further analyses.

Decision Tree Analysis (DA) is another method for analyzing a combination of uncertainties using a process that mimics typical decision making. It recognizes that choices are made in the face of uncertainty and that after a few years, when the implications of decisions made have had a chance to play themselves out, utilities confront what actually occurred and must once again make decisions about the future using past performance and future predictions. In undertaking a DA, forecasters list key uncertainties, assign each uncertainty a "chance node", predict the probabilities that a particular outcome might occur and offer decision possibilities capable of responding to chance outcomes. For instance, in evaluating load, a utility may predict the following:

- 20 percent chance of a high case load forecast
- 60 percent chance of base case load forecast
- 20 percent chance of low case load forecast

Resource alternatives can then be tested to see how well they cover the probability of handling high, low or base case forecasts. For instance, in 1995 the same utility can decide whether to build a gas-fired plant for 1998 completion, build a coal plant for 2000 completion or accelerate or slow down DSM acquisition. Each resource acquisition strategy is evaluated against the impacts and costs of future chronic surpluses (low case load forecast) and future chronic deficits (high case load forecast).

Three years later, in 1998, there is another chance node to again evaluate load

[1] More detailed information about how to consider and undertake Monte Carlo Simulations and Decision Analyses is offered in Logan (1993).

forecast. Planners face another decision which may include the same or different set of resource options. DA helps in choosing resource plans in which adjustments can occur in a manner that is consistent with both the time it would take for the utility to recognize a trend and a reasonable project lead time needed to respond.

Probabilistic techniques force explicit recognition of probabilities associated with future states of the world and allow an examination of how multiple, small uncertainties can combine to create big risks. The tools are important in their ability to capture the relationship between variables, their requirements to specify the probabilities of all outcomes and their ability to provide an apparently definitive answer.

This same ability to give a definitive answer is also one of the tool's most serious drawbacks. In reality, the analysis is "data free" because it is made in the absence of actual information. The subjective assumptions made early on in the analysis are submerged, so that a final outcome's appearance of objectivity is false. For instance, if the probability of high demand is set too high, then it would be easy for the tool to be used to justify overbuilding. In addition, this form of analysis does not relieve the tension that arises between the need to focus on likely outcomes without ignoring boundary conditions.

IRP And Competition

The passage of the Energy Policy Act of 1992 (EPAct), which embraces both increased competition and greater reliance on IRP, has fueled a discussion on whether IRP and competition are compatible. This question is not new. It has been before regulators and utility planners since Congress increased competition in the electric industry through passage of the Public Utility Regulatory Policies Act of 1978 (PURPA). In the 15 years since PURPA was enacted, utilities across the country have lowered the cost of providing energy services by successfully combining the elements of IRP and competition. EPAct now codifies this synergy.

Where effectively pursued, IRP has provided the structure for considering the broadest range of energy resource alternatives and finding the least costly mix of options to meet energy service needs. Competition has provided the mechanism to ensure that the options considered in IRP are as inexpensive and varied as possible. This chapter examines how IRP and competition have evolved in the wholesale competition arena, presents examples of existing retail competition and offers a framework for considering what some see as the next step for retail competition — retail wheeling.[1]

[1]A fuller discussion on IRP and Competition is found in Cavanagh (1993), Cohen (1993) and Moskovitz (December 1993).

PUTTING THE IRP PRINCIPLE TO WORK

In exploring the relationship between IRP and competition, consider first that the fundamental principle of IRP is to identify, analyze and acquire cost-effective resources, namely resources which lower the long-term cost of energy services. The process is not simple. If it were, all that would be necessary would be to compare prices of different resources and to acquire those with the lowest price tag.

Prices, however, tell what a resource costs, not what it is worth. For example, compare a photovoltaic (PV) system that produces power at the cost of 10¢ per kWh to a coal plant that produces power for 5¢ per kWh. Clearly one source of power costs twice as much as the other, but given the operating characteristics of the two resources the 10¢ per kWh PV may be more valuable to the utility than the 5¢ per kWh coal plant. This could occur if the PV's output were largely on-peak or if installation of the PV also reduced transmission and distribution (T&D) costs. IRP is the analytical tool which can determine whether the advantages associated with the PV facility are sufficient to overcome the 5¢ price premium.

IRP, when properly implemented, identifies what a resource is worth and compares it to what it costs. A resource is desirable to acquire (build or buy) whenever its cost (or price) is less than it is worth to the utility. The worth of a particular resource is equal to the utility's avoided cost, taking the specific characteristics of the resource in question into account. IRP considers all feasible supply- and demand-side resource options and selects a mix that minimizes overall costs.

The benefit of IRP is that it allows very different resources — from lighting retrofits to photovoltaic units to a utility-owned and operated gas fired turbine to a non-utility biomass facility — to be compared in order to decide which are most cost-effective for a given utility at a given time. Because of the disparate nature of these resources, an analysis must include all related costs for each potential alternative. When conducted in this manner, an IRP analysis reveals which resources offer the greatest value, net of costs, to a utility and its customer.

Under current cost-of-service regulation, once a resource is acquired, consumers pay the cost of the resource which, if IRP is done right, should be less than the worth. Of course, even when IRP is done right if the future unfolds differently than expected, some resources may end up costing more, not less, than they are worth. To prepare for this possibility, good IRP should include a thorough risk analysis to try to minimize the likelihood and magnitude of such undesirable outcomes.

IRP AND UTILITY COMPETITION

Evaluating competing resources has always been at the heart of the IRP process. In the absence of broader market competition, the utility conducts an IRP analysis of the demand and supply resources it views as being available and produces a plan that optimizes those resources at the lowest total cost. Unfortunately, focusing only on those resources within the utility's control precludes other viable and potentially valuable resource options that may further reduce costs.

Adding Wholesale Competition

The addition of wholesale market competition then is quite compatible with the IRP framework. In fact, 36 states have already benefitted from the expanded number of resource options provided when market forces are brought into the IRP process.

When considering market competition, the utility first conducts its in-house analysis and develops an optimal mix of cost-effective, utility-initiated energy resources. However, instead of immediately acquiring those resources, the utility adds a step; it turns to the market and asks if anyone can offer a project that lowers the utility's costs. Here, using competitive bidding, negotiation or both, the marketplace is used to see whether resources are available that can reduce costs. In other words, the market is used to see if anyone can beat the utility's avoided cost.[2] A market system that offers resources more cheaply than the utility produces a lower overall cost which is then reflected in retail rates.

Competition at the wholesale level was introduced into the electric industry at about the same time as IRP when it became clear that economies of scale no longer favored utility

[2]Avoided cost analysis must be done carefully. Avoided cost does not mean the cost of the next utility plant or even a single figure such as 5¢ per kWh. Avoided cost, instead, reflects the cost savings associated with the specific characteristics of the resource being considered for acquisition.

construction and environmental impacts of large, centralized plants. Non-utility generators (NUGs) have offered economic and environmental alternatives to large, centralized facilities as well as a keen interest in participating in the competitive process. Utilities have frequently been overwhelmed by the response they have received to their solicitations. It has not been unusual for a utility to issue a request for proposals and receive bids for projects totalling 10-20 times the needed resources. Competition has brought more players into the energy service business and in doing this, has tapped both expertise and capital. It has driven innovation and increased diversity into an industry that was ripe for it, while offering consumers and utilities new ways to spread the risks inherent in resource acquisition.

States which have successfully incorporated this wholesale competition have seen:

- Lower utility and consumer costs
- Greater diversity of resources
- Reduced consumer risk

EPAct attempts to expand upon this successful experience. This is done by giving wholesale power providers broad access to the transmission grid and, in effect, designating the Federal Energy Regulatory Commission (FERC) as the enforcement agency for open transmission.

Market Competition At The Retail Level

Retail competition already exists. Electricity directly competes with natural gas, oil and other fuels for a broad variety of customer end uses. Customers will and do switch from one fuel source to another for heating or cooking to lower their energy bills. Utility-supplied electricity also competes with power produced directly by customers on site. Industrial customers and even some commercial customers have long had the choice of meeting all or some of their electrical needs through self-generation at power plants, large and small, that they own and operate themselves. Electricity supply also competes with energy efficiency on the customer's side of the meter. Customers can and do choose to conserve electricity by installing their own, more efficient office or production equipment or by improving the efficiency of their buildings. Most of these retail choices have existed for a long time, but in an increasingly competitive economy customers have become more aware and, willing to act on these choices.

Retail Competition Through Retail Wheeling

Retail wheeling is a form of retail competition which has received increased attention. Under retail wheeling, rather than pay the existing retail prices for electricity, customers have the option of shopping around for the best deal for themselves. In doing this, they pay the local utility a retail wheeling rate for transmission and distribution services and buy unbundled electricity generation service (capacity and energy) from a different supplier. The supplier could be a neighboring electric utility, a NUG, an electricity broker or an industrial firm's own cogeneration facility located at a different site.

The clamor for retail wheeling is driven by retail rates, not marginal supply costs. As a result, retail wheeling discussions are most heated in regions where retail power costs are high, and the market costs of wholesale power are low. This situation has occurred in many parts of the country for a variety of reasons. Chiefly:

- Cost overruns at utility-constructed (generally nuclear) plants
- Costs associated with abandoned plants (again generally nuclear)
- Excess capacity caused by the recession and lower than expected demand for power
- Low oil and natural gas prices, resulting in low wholesale market prices

While these are the cost conditions that frequently make retail wheeling attractive to large customers, they are the same conditions that often make retail wheeling economically undesirable.

If wholesale competition is functioning well, the utility will already be acquiring all cost-effective supplies, and there is very little chance that retail customers will find resources that offer additional system cost savings under a retail wheeling framework. If the utility is taking advantage of wholesale competition for new resources, then it is unlikely that new supplies identified by customers will beat the utility's marginal supply costs very often or by very much, and as a result retail wheeling will yield little, if any, economic benefit.

Retail wheeling has raised a number of concerns, one of the most prominent being that it is a pretext to shift costs from large electricity customers to smaller users, without producing any benefit to customers as a whole. Given that large electricity users have generally been the primary proponent of retail wheeling, this concern is a reasonable one. Retail wheeling is clearly undesirable unless it is structured in a way that reduces, not simply shifts, costs. Cost reductions can only occur when the wheeling customer is able to acquire power more cheaply than the utility could acquire it.

ADDITIONAL PROBLEMS WITH RETAIL WHEELING

Policy makers considering retail wheeling need also to resolve the following issues and questions:

- The conflict between retail wheeling and good environmental policy.
- The conflict between retail wheeling and utility investments in DSM.
- How will cost recovery be configured?
- Will retail wheeling really broaden resources choices?
- Can the local utility avoid an obligation to serve a customer who returns to the system. If not, will other customers bear this cost?

One key to constructing a rational retail wheeling framework that is consistent with IRP lies with the retail wheeling rate (RWR). Too often, retail wheeling discussions assume that the charges for the retail wheeling services are set by looking only at the cost of the unbundled T&D services and do not consider other unavoidable utility costs. Limiting wheeling costs to the cost of T&D services almost always leads to retail wheeling charges that are quite low relative to the overall retail rate. Typically, these rates encourage uneconomical power-purchase decisions because the combination of these low wheeling rates and short-term market prices for electricity will probably be less than either retail rates or long-term avoided costs of electricity.

Instead retail wheeling rates should be priced to encourage wise economic decisions and discourage poor ones by including all of the unavoidable utility costs. This is the same rationale used when setting cogeneration deferral rates. To do this, the RWR should equal the prevailing retail rate (RR) minus the utility's relevant marginal supply costs (MSC), as follows:

$$RWR = RR - MSC$$

Relevant marginal supply costs are the incremental, out-of-pocket costs needed to provide energy and capacity to a particular customer over the time period that the customer seeks retail wheeling services.

The purpose of this approach is to encourage retail wheeling when it lowers total costs and to discourage it when it merely reduces the customer's current rate but does not lower total system costs. In setting the retail wheeling rate in this manner, the customer faces two separate charges. The local distribution utility charges the RWR described above, and the new supplier of kilowatts and kilowatt hours imposes separate charges for their services (SSC). The customer's new retail rates (NRR) can be expressed in the following formula:

$$NRR = RWR + SSC$$

The question becomes, under what conditions will the customer's NRR be less than his original retail rate? After all, it is only when the new rate is less than the old rate that the customer would have a financial interest in pursuing retail wheeling options.

Rearranging the formulas shows that NRR is less than the old retail rate **only** when SSC is less than MSC. In other words, using this retail wheeling framework results in an economic benefit to customers engaging in retail wheeling services **if, and only if**, their new supply-side cost is less than the local utility's marginal supply cost.

CONCLUSION

Competition at the wholesale level has already proven to be a powerful and efficient way of lowering energy service costs. Expanding wholesale competition with well thought out systems can continue to provide substantial benefits to consumers and should eliminate most of the need to consider retail wheeling. IRP offers a dynamic and economically sound means of adapting to these changes in a way that assures a viable, competitive industry and protects the interests of customers.

Regulatory Reform: Removing the Disincentives

Every regulatory system creates a set of incentives and disincentives. Some are deliberate, and others are unintended but just as effective. Traditional ratemaking results in some strong disincentives to acquiring demand-side resources. These include:

1. Utilities are restricted in how they can recover DSM program expenses.
2. Utilities by devoting resources to DSM programs rather than to other profit-making activities forego earning opportunities.
3. Utilities can lose revenues and profits from sales not made as a result of successful energy efficiency programs.

It is incumbent upon regulators to recognize what disincentives in the traditional ratemaking process make DSM investments financially objectionable to utilities and decide whether incentives should be instituted. Regulators cannot police every decision utility management makes. Aligning a utility's financial interest with articulated public policy objectives is a powerful means of encouraging utilities to make decisions in a manner that is consistent with policy objectives.

This chapter examines mechanisms for recovering lost revenues resulting from DSM investments. The following chapter looks at options for direct cost recovery and DSM incentives.

HOW LOST REVENUES OCCUR

The traditional regulatory system produces very powerful incentives for utilities to increase electricity sales and correspondingly large disincentives to the pursue energy efficiency. On a national average, each additional kWh a utility sells contributes 5¢ to its bottom line profit (before income taxes). Thus, if the current ratesetting process is viewed as an incentive plan, the "incentive" or "reward" for each kilowatt hour the utility sells is a nickel. Likewise, a nickel comes off a utility's bottom line each time a kilowatt hour is conserved. To put the magnitude of this incentive in perspective, a one percent change in a utility's sales has about a 100 basis point impact on its return on equity.

The reason for this is that traditional rate setting is based on the following formula:

Revenue Requirements = Expenses + (Rate Base * Rate of Revenue)

The utility's revenue requirement is the total dollar amount the utility needs to operate, including a fair return on shareholders' investment. In effect, this is the amount of money regulators determine the utility needs. The next step in a rate case is to set rates. This is done by dividing revenue requirements by sales.

$$\text{Rates} = \frac{\text{Revenue Requirement}}{\text{Sales}}$$

This derives a price per kWh which customers are charged. Regardless of what level of revenues the commission decides was needed, once rates are set, the utility's actual revenues are linked to and driven by sales until the next case. The more sales a utility makes, the more revenue it receives. Every lost sale means less revenue.

Profits and revenue, however, are not the same. Profits are the difference between revenues and costs. Thus to know how increased sales affect profits, one needs to know how increased sales affect costs. The answer is simple. The only costs that significantly increase with increased sales, at least in the period between rate cases, are fuel and purchased power costs. In most states, fuel and purchased power costs are subject to fully reconciled, automatic adjustment clauses. These adjustment clauses have the effect of making fuel costs the customer's, not the utility's, responsibility. This means that higher fuel costs have no impact on utility earnings.

This concept can be distilled into two formulas, one for states with fuel clauses and one for states without them.

States with fuel clause: Increased Profit = Retail Rate - Average Fuel Cost

States without fuel clause: Increased Profit = Retail Rate - Marginal Fuel Cost

If utilities profit by increasing sales, successful DSM programs that result in a customer using fewer kWhs cause the utility to lose profit that it would have otherwise received. That is hardly an encouragement to do DSM. Even when DSM is factored into the expected sales, it is still not in the utility's real financial interest to pursue vigorously DSM programs which decrease customer usage. These lost revenues inevitably undermine a commission's best efforts to compel a utility to use all cost-effective DSM as a viable alternative to new generation.

In 1989, The National Association of Regulatory Utility Commissioner (NARUC) adopted a resolution that expressly recognized the fact that utilities lose revenues and profits when they or their customers invest in cost-effective energy efficiency. (Resolution is included in the Appendix at the end of the book.) NARUC's response was simple and unequivocal — reform regulation so that the successful implementation of a utility's least-cost plan is its most profitable course of action. In other words, align the utility's financial interest with the interests of its customers.

DECOUPLING VS. LOST REVENUES: REGULATORY CONSIDERATIONS

Lost Base Revenue Adjustments (LRAs) and revenue decoupling are the two approaches generally used to eliminate the disincentives and address the issue of demand-side profitability. Using a lost base revenue adjustment[1], one calculates how many dollars a utility has lost due to its DSM programs, then increases revenues by that amount. For example, suppose a utility has a program to replace existing electric motors with more

[1] The phrase lost-base revenues is used to distinguish fuel revenues from base revenues. Fuel revenues comprise nearly all of a utility's variable costs. In most states, fuel revenues are fully recovered on a reconciled basis in fuel adjustment factors. Fuel revenues are not lost as a result of energy efficiency investments.

efficient ones. The utility estimates that its electricity sales will fall by 100 million kWh by pursuing this replacement effort. If each kWh produced 2¢ in revenue net of fuel and any other variable costs, the utility would lose $2 million in net revenue to this program. Under a LRA approach, this amount would be subsequently recovered.

A revenue decoupling approach operates differently by severing a utility's allowed revenue from its sales. To do this, the commission determines during a normal rate case how much revenue a utility needs to cover its expenses and sets an electric rate which is expected to produce that level. Later, perhaps at the end of a year, the commission and the utility see whether, in fact, that revenue has been generated or whether, due to fluctuations in sales from the expected level, some greater or lesser amount has been realized. When the utility has received too little, the error is corrected through a surcharge. If the utility has received too much, the error is corrected through a rebate.

In principle, both approaches address the existing disincentive to utility DSM, but in fact the results from the two approaches are quite different. LRA limits itself to changes in revenues resulting from specific DSM measures. The decoupling approach is applied to all changes in utility sales and therefore removes the utilities' incentive to promote new sales. LRAs are not capable of removing existing incentives to increase sales.

Because decoupling separates profits from fluctuating sales levels **regardless** of the cause of the changed sales volumes, it addresses efficiency impacts resulting from **all** effects including:

- rate design
- all utility-sponsored DSM activities
- energy efficiency achieved through standards and other means
- energy efficiency measures undertaken by consumers directly, without any utility involvement.

Thus far, seven states, California, New York, Washington, Kentucky, Oregon, Montana and Maine[2] have adopted decoupling mechanisms. Other states are now considering decoupling mechanisms. In contrast, the apparent simplicity and perceived effectiveness of the more narrowly circumscribed LRAs has led many more states (including Massachusetts, Rhode Island, Michigan, Ohio and Indiana) to implement LRAs.

Table 1 summarizes the characteristics of each of the approaches.

[2] Maine no longer uses decoupling for reasons presented later in this paper.

Table 1. Decoupling v. Lost Revenues

	Decoupling	Lost Revenues
SALES	Removes sales incentive and all DSM disincentives	Removes some DSM disincentives, does not remove sales incentives.
M&E	Does not require sophisticated measurement and/or estimation	Requires sophisticated measurement and/or estimation.
	Utility does not profit from DSM which does not actually produce savings.	Utility may profit from DSM which does not actually produce savings.
SCOPE	Addresses revenues lost due to: Rate design All DSM programs Customer DSM Efficiency standards	Addresses revenues lost due to utility DSM programs only.
OTHER	Eliminates load forecast gaming.	No direct effect on subsequent rate cases.
	Low litigation potential, low administrative cost.	Cost recovery uncertainty, litigation prone, high administrative cost.
	Reduces volatility of utility revenue resulting from many causes.	No effect on the volatility of utility earnings.

Rate Design

Getting prices "right" is an important element of IRP. Inverted block rates and time-of-use (TOU) rates may provide better price signals to consumers than declining block or flat rates. But utilities oppose these price structures because of the risk that customer response to the price signals will significantly reduce utility revenues and earnings. With TOU rates, for example, customers respond to high on-peak rates by investing more heavily in energy efficiency or shifting electricity use from on-peak to off-peak periods. These responses to better price signals result in substantially diminished utility earnings (for example, an on-peak kWh price of 10¢ produces two and a half times the incremental earnings as an off-peak kWh priced at 5¢).

Utilities have had TOU rates imposed against their wills and have experienced large revenue and earnings losses. Boston Edison, for example, recently suffered a substantial loss of earnings due to the imposition of steeply differentiated TOU rates. To a utility rate department, the first priority of "getting prices right" is to assure stable revenue flows. Rates which signal customers to reduce use during high cost periods jeopardize stable revenues.

Decoupling holds utilities harmless from revenue losses resulting from consumer response to better prices and as a result aids in the effort to improve pricing. LRAs, on the other hand, do not address revenue losses associated with implementation of rate design changes.

<u>Measurement And Evaluation Issues</u>

Verifying the performance of energy efficiency investments is as important a responsibility of regulators as verifying power plant performance. Measurement and program evaluation techniques for DSM activity have been steadily improving, but the field is developing, and many uncertainties persist.

LRAs rely heavily on accurately measuring the savings actually produced by DSM measures. In order to estimate lost revenues, one must first determine how many kilowatt-hours of energy and kilowatts of peak demand were actually saved. While these saving estimates are typically made as part of the ongoing evaluation of DSM programs, a LRA greatly increases the burden placed on measurement because so many additional dollars depend on the measurement outcomes. Adding LRAs to program cost can at very least double and possibly quadruple the total dollars at risk in measurement (Compare a 2¢ program costs with 5¢ of lost revenues.).

Under a LRA regime, DSM savings must be separately determined for practically every different rate a utility charges. At a minimum, kWh and kW savings must be separately established for each participating customer class. In addition, depending on the utility's rate structure, separate measurements must be made for the TOU periods, seasons of the year and/or voltage levels at which customers take service. In other words, measurement must be expanded dramatically from what is required for DSM program purposes alone.

Other questions also arise:

- How does one determine the effect of lost revenues resulting from an industrial energy efficiency program which, on the one hand, achieves the desired level of energy efficiency improvement? On the other hand, these savings are more than offset by increased levels of industrial production now made possible by the increased competitiveness of the industrial consumer.

- How much revenue is lost to a DSM program when sales exceed forecasted sales due to weather or other factors?

- Do LRAs create an incentive to subsidize customer-initiated DSM so that the utility will be able to recover lost revenues?

While the LRA approach increases the reliance on measurement, it presents the utility with a new set of perverse incentives. After all, utility profits will increase under a LRA in direct proportion to the measured or estimated DSM savings, so the goal will be to maximize the **measured** savings. But revenues are lost only to the extent savings actually occur. For the utility, then, the way to play the LRA game is to maximize **measured** savings but not to actually save anything at all. In principle, such abuse can be policed. In practice, DSM program design and administration result from a large number of small decisions which makes regulatory oversight difficult. While regulation does a reasonably good job of reviewing the once-in-a-decade, multi-billion dollar decision, it does an inadequate job of overseeing the thousands of daily decisions of utility managers or the tens of thousands of daily customer contacts.

Decoupling does not rely upon measurement of DSM program effectiveness. An effective DSM program will not result in a loss of revenues under decoupling.

Scope Of DSM Programs

Decoupling also addresses efficiency gains from the full array of utility-sponsored DSM programs. Energy savings from some utility DSM programs, such as educational programs stressing the importance of energy efficiency are, for practical purposes, difficult or impossible to quantify. Because LRAs are limited to measured energy efficiency improvements, they offer no incentives to provide these programs.

More importantly, customers may undertake energy efficiency directly or energy efficiency may result from legislation adopted at the state or federal level. Efficiency improvements originating from activities such as these are automatically covered by decoupling. Because LRAs are limited to quantifiable, utility-sponsored DSM programs, they do not address these types of activities.

The implications of the limited scope of LRAs are wide ranging. A wide array of efficiency opportunities can be achieved in a very cost-effective manner through efficiency standards, improved customer education and development of energy efficiency infrastructures. In the absence of decoupling, the implementation of energy efficiency in any of these arenas penalizes the utilities. As a result, utilities will frequently oppose legislation and other activities aimed at substantially improving the energy efficiency of their customers.

Decoupling is important even if one believes that utility investment in DSM should be limited by the no-losers test or that utility-sponsored DSM is an interim step along the way to an effective and fully competitive energy efficiency market. Improved information, capital availability and better marketing approaches may lead to an expansion of energy service companies displacing or at least reducing the need for utility involvement. But the transition to a more competitive market will be impeded by a conflict between utility interests and the interests of the would-be competitors. Without decoupling, the success of energy service providers hurts the utility. Will utilities want to help create an energy efficiency industry if that industries' success is adverse to the utilities' interests? LRAs, because they are limited to utility-sponsored DSM, do not address energy efficiency implemented by private vendors.

Other Attributes

Controversy In Rate Cases

One of the more controversial questions raised during traditional rate cases in jurisdictions which use future test years or an historical test year with an attrition adjustment is: What level of utility sales is forecasted during the year the new rates will be in effect? Because lower loads mean higher prices and higher loads mean lower prices, typically, utilities will argue that sales are growing slowly, if at all, and rates must be raised to provide additional revenues. Ratepayer representatives counter this by arguing that sales will increase sharply and therefore, the rate increase can be reduced or eliminated because the new sales will provide ample, additional revenue.

Depending on how it is implemented, decoupling can reduce or eliminate these load forecasting controversies. If the total revenue level is set directly, as in the California ERAM approach, load forecasting debates become largely irrelevant because any errors are trued up the next year. If a revenue level-per-customer approach to decoupling is used, then the controversy shifts from forecasting energy sales to forecasting the number of customers. Since forecasting energy sales is often a matter of forecasting both the use-per-customer and the number of customers, decoupling is likely to reduce, but not eliminate, controversy over forecasting.

LRAs, on the other hand, will increase the level of controversy. The LRA approach does nothing to the forecasting controversy except to introduce a new round of litigation over the kWh savings of the DSM projects.

Cost Recovery/Litigation/Administrative Cost

The complexity of measurement and evaluation and the need to address new policy issues raised by LRAs may lead to litigation and related high administrative costs. This increased uncertainty and risk of DSM cost (lost revenue) recovery may make DSM a less attractive resource.

Decoupling imposes administrative costs and risks at the outset but, once implemented, decoupling mechanisms are generally easy to administer, and cost recovery is very predictable.

Revenue Volatility

Under traditional regulation, a utility's revenue fluctuates roughly in proportion to its sales. Anything that affects sales – weather, economic cycles, appliance efficiency standards or DSM programs – will simultaneously affect revenue. An LRA approach will, if it works well, restore revenue lost to DSM programs but will not reduce earnings volatility. A decoupling approach, because it is more comprehensive, reduces the volatility in utility revenues. This may result in lower capital costs to utility customers.

DECOUPLING AS THE FAVORED ALTERNATIVE

For the reasons presented above, decoupling does a better job than the LRA approach in addressing some of the frailties of traditional utility regulation. It is not, however, a panacea. By its nature, decoupling removes an existing disincentive to least-cost planning. It does not take the next step and provide a positive incentive for good planning. In addition, decoupling only focuses on the short-term (between rate use) disincentive.
But decoupling does provides a relatively simple mechanism to remove a variety of short-term, perverse incentives which prevail in the existing regulatory structure. LRAs, on the other hand, are much more limited in scope, cumbersome in application and open to abuse.

DECOUPLING: ADDRESSING RISKS AND PRICE VOLATILITY ISSUES

Assuming, then, that decoupling is the preferred regulatory reform to support DSM, there remain a number of concerns which are often raised. These fall into three general categories:[3]

1. Decoupling shifts weather and business cycle risks from the utility to customers.

2. The potential price changes resulting from decoupling are too great.[4]

3. Decoupling removes a utility's incentive to promote the economic development of its service area and/or to attract new customers.

The remainder of this chapter looks at these concerns and addresses a number of related questions as well. These include:

- Does decoupling shift risks?
- Is a shift in risk desirable if consumers are compensated for it?
- Is it necessary that decoupling shift risks?
- What options are available to modify decoupling plans to shift less risk?
- What effect does decoupling have upon a utility's incentives to attract new customers or keep existing customers?

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[3] Some utilities have been concerned that if they are owed a significant amount of money as a result of decoupling, regulators will refuse to provide it. These risks are not discussed in this chapter. However, the concern provides another reason to minimize any deferred balances.

[4] The term "price" is used in the context of price volatility. When discussing volatility, both the total price (bill) for electric service and the rate paid per kWh or per kW are relevant. Decoupling affects bills and prices equally. However, where decoupling is effective at encouraging good IRP, the overall result will reduce electric bills as supply sources are replaced with less expensive DSM. On the other hand, with good IRP electricity rates may rise as the utility's revenue requirement is spread over fewer kWh sales.

Shifts In Risks

While the existing decoupling mechanisms shift weather and economic risks from the utility to customers, this is not necessarily undesirable. Both weather and business cycles cause sales, and hence revenue and earning levels, to fluctuate. This earning volatility in turn is one of the factors that determines a utility's cost of capital[5]. The more volatile a utility's earnings, the higher its cost of capital.

Because utility rates include a rate-of-return based on the company's cost of capital, customers of utilities without decoupling mechanisms pay for increased utility volatility through higher, although more stable, electricity prices.

Thus, the question is not who pays but how the payments are made. Do customers take the weather risk in the form of a small amount of price volatility or in the form of higher utility rates of return?

Framework For Assessing Volatility
Price volatility can cause problems for customers. For residential and commercial customers, the unpredictability of electricity bills generally cause concern. For others, particularly for manufacturers, the volatility in electric rates can make production decisions more difficult. But while a particular decoupling mechanism may produce some volatility, it will also have beneficial effects, such as lower overall resource costs and lower cost of capital to the utility.

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[5] More formally, where a utility's earnings are relatively volatile, its common stock price will generally be lower and more volatile. The standard methods of setting a utility's allowed cost of capital rely heavily on the market performance of the utility's common stock.

The decision of whether to shift some, all or none of the weather- or business-cycle risks is a judgment each commission should address in an orderly, and thoughtful manner using the following framework:

1. Answer the primary question: Should profits and sales should be coupled?
2. Analyze a simple decoupling mechanism which allows risks to be shifted.
3. Assess the maximum, annual price change, with weather-business cycle volatility shifted to customers.
4. If the maximum price change is too great, consider simple methods to reduce volatility, including adjustments that shift only part of the weather or business cycle risks.

Taking into account the effectiveness of various options and beginning with the simplest measures first, possible modifications to the decoupling mechanisms should be analyzed in the following sequence:

1. Two year averaging of decoupling accruals
2. Weather adjustments
3. Economic adjustments
   a. Customer growth
   b. General business adjustments
   c. Adjustments based on one or a few key industries

After each step, but particularly after the first, a commission should assess the remaining price volatility. Because each adjustment adds to the complexity of the mechanism, modifications should only be made in those cases where the commission believes the remaining price volatility is too great.

State Regulatory Responses To Shifting Risks

Decoupling plans in Washington, Maine, New York and California shift weather and to varying degrees economic risks away from the utility to customers. The shift in risk was a deliberate decision on the part of regulators. For example, the Washington Commission stated:

Commission staff and WICFUR both accurately note that the decoupling mechanism is broad; it not only insulates the company from deviations in sales caused by conservation efforts, but also from deviations in sales caused by other factors, for example, temperature and customer-initiated conservation. The Commission views this as a virtue, not a drawback, of the decoupling mechanism.[6]

Similarly, the Maine Commission stated:

Under existing rate of return regulation, risks faced by the utility such as variation in profit due to weather or economic cycles are reflected in the utility's cost of capital. If the utility is no longer subject to profit variation due to weather and economic cycles, the cost of capital should be less.

Since weather and the economy are not within the control of the utility, there are practical limits to the amount of efficiencies that can be squeezed out by the utility in response to these factors. For these reasons, requiring the utilities to remain exposed to these risks does not really save the ratepayer any money in either capital costs or sig-

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[6] Docket Nos. UE-901183-T and UE-901184-P, April 1, 1991.

nificant management efficiencies. The issue is who pays for the costs of these risks.[7]

These decisions are based on two factors. First, no important regulatory purpose is served by placing these risks on the utility. Risk should be thought of as a finite resource. There are limits to the amount of risk regulators should place on utilities. Does it make sense to place weather risks on the utility even though it has no ability to change the weather and usually only a limited capability to respond to its effects? Would it be better to put utilities at risk for the consequences of their own actions, for example, power plant performance, purchased power practices, customer service or other areas where increased exposure to risk may produce better performance?

Second, customers can expect lower costs if they accept the risks of revenue volatility. For example, data for Central Maine Power Company (CMP) suggested that shifting weather and economic risks to customers produces price increases or decreases which could run as high as two to three percent in a year with extreme conditions. Meanwhile, one analyst estimates that CMP's reduced earnings volatility has lowered the utility's cost of equity capital by 100 basis points.[8] This translates into a permanent price decrease of about one percent.

Arguments For Maintaining The Status Quo

Still, several arguments have been advanced in support of leaving the current level of weather and economic risks with the utility. These are:

- The status quo should be maintained for its own sake. This reduces the need for rate changes, particularly increases, which will not be well received by customers.
- Utilities may not control the weather or the economy, but they do have some control over the effect of both on their sales and revenues. For example, a utility could intensify its marketing in sectors which are relatively insensitive to weather and economic conditions but not encourage sales in more risky sectors.[9]
- Customers are particularly ill-equipped to shoulder more economic risks, beyond those to which they are already subject. Residential customers, for instance, already risk lower incomes or unemployment while most business customers see their own earnings rise and fall with the economy. Decoupling further increases customer exposure to risks.

Each of these points is valid, though their importance varies considerably from state to state and from utility to utility. This suggests a need for a careful utility-specific assessment of price volatility.

Quantifying Price Swings

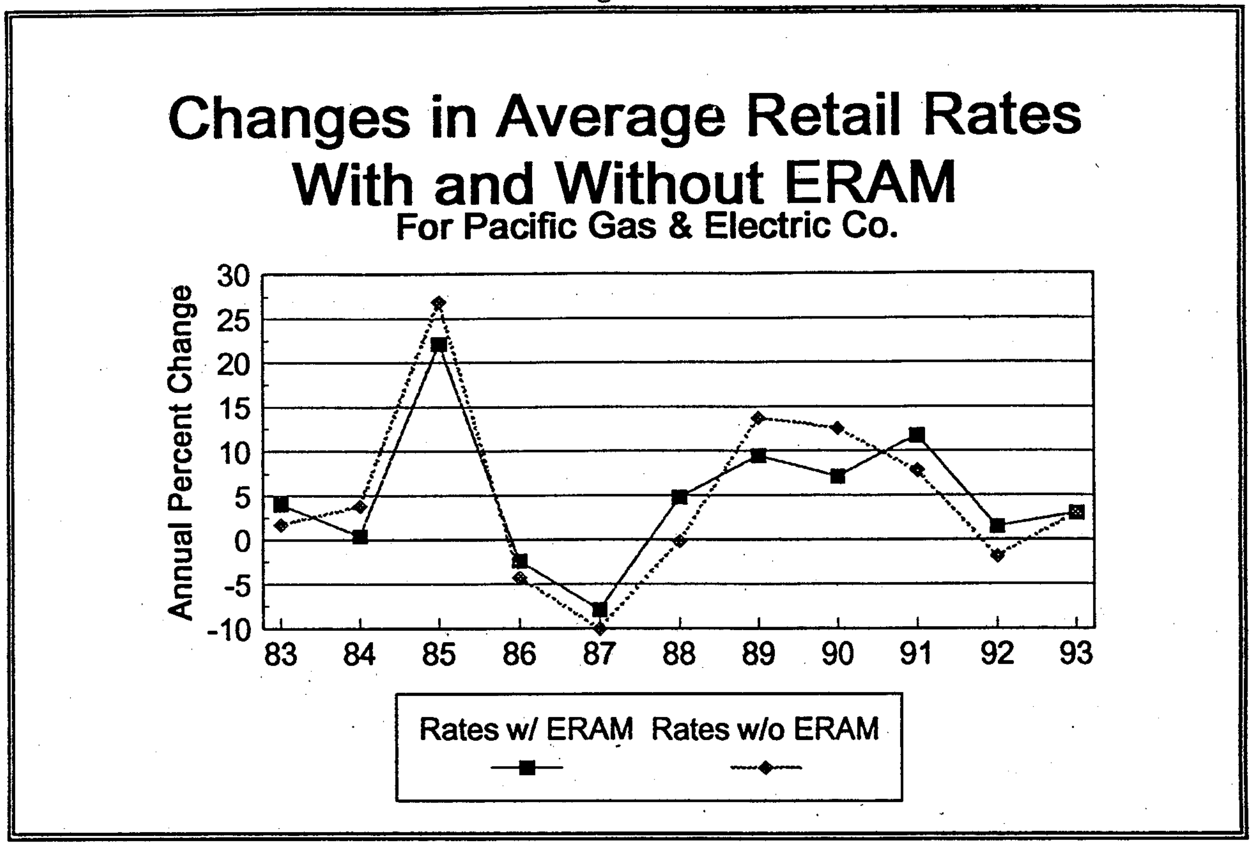
The presence of potential price volatility depends on many factors, including the characteristics of a utility's customer base, the

[7] Docket No. 90-085, May 7, 1991.

[8] Direct testimony of Steven Hill in Docket No. 90-085.

[9] While this discussion is, in theory, correct, utilities do not appear to discourage new sales in risky markets.

Figure 1



degree of weather and business cycle fluctua tion and the utility's rate design. Some utili ties will be more sensitive to changes in wea ther or economic conditions than others. Quantifying the maximum price swings that a particular decoupling plan will produce is a simple task that should be performed.

A study of the historical price volatility in California's ten-year ERAM history (Eto 1994) is of particular interest. Figure 1 be low shows the impact of decoupling on prices for Pacific Gas & Electric Company from 1983 through 1993. Although de coupling created small price changes (the average being one tenth of percent), the net effect was a reduction in price volatility.

Historical data comparing sales, weather and economic conditions can reveal the maximum and average amount of volatility. Alternatively, most utilities use short-term sales forecasting models which explicitly adjust for weather and economic conditions. The forecasting equations provide a direct measure of potential price volatility. Whatever method is used, the maximum exposure should be identified. If the maximum exposure is acceptable, it is unnecessary to make any special effort to adjust the decoupling mechanism.

<u>Mechanisms For Sharing Risk</u>

After looking at the likely range of price swings which could occur under decoupling, the next step is to compare these to the price swings that would result under traditional regulation. For example, decoupling will generally result in symmetric price changes due to economic cycles. Expansionary periods produce a rebate; recessions produce a surcharge. Under traditional regulation, these cycles influence the timing of rate cases. A recession, for example, is likely to induce a rate case. Economic expansion, on the other hand, directly benefits customers under traditional regulation only if the commission initiates a rate decrease. Such a decrease or rebate occurs automatically with decoupling.

Price

If a commission concludes that the maximum price swings are still too great, the following adjustments can be made.

A simple first step to take is to reflect accruals in rates based on a two-year rolling average. This reduces volatility by averaging periods of over- and under-collection without violating current accounting rules[10]. The time period can be extended beyond two years if the utility and regulators are willing to forego the benefits of reporting revenues, and hence earnings, in a fashion that is consistent with a decoupling plan. Under current accounting rules, utilities receiving (or refunding) a shortfall (surplus) in revenues within a two-year period are allowed to reflect that revenue in earnings immediately. But under SEC rules, if the recovery of revenue undercollection/overcollection takes more than two years, the revenue must be booked according to when it is received, not when it is accrued. This means that if sales are low in a given year, earnings will also be low, though earnings will be higher at some future time when the cash is received.

If, after multi-year averaging, regulators still believe that the level of price volatility is too great, they should consider the next two adjustments.

- Every six months adjust rates to reflect the prior six months of accruals, amortized over the next 18 months. Once this approach has been in place for a while, rates will reflect the four most recent six-month periods.

- Adjust rates annually, with each year's activity collected or recovered over the following 12 months. Where rate change becomes too large, lengthen the period using a first-in-first-out (FIFO) accounting approach. The effect of FIFO is to treat each dollar received as offsetting the oldest dollar in the deferred revenue account. This extends the averaging period to the maximum extent without violating the accounting rules.

Weather

Without decoupling, weather-related risks fall on the company. When the weather is mild, sales and earnings are low and vice versa. With decoupling, weather-related risks are shifted from the company to the customers, which trades earnings volatility for price volatility. It is possible to develop a fairly simple weather-adjusted decoupling mecha-

[10] Under current accounting rules, where a utility will receive (or refund) a shortfall (surplus) in revenues within two years, it is allowed to reflect that revenue in earnings immediately.

The Mechanics of Weather and Economic Adjustments

It is quite simple to modify a decoupling mechanism to remove the effects of weather and/or the economy on sales. Decoupling mechanisms operate by allowing a utility to book and ultimately collect deferred revenues where

Deferred Revenues = Allowed Revenues - Actual Revenues

Two options are available to remove weather and/or economic effect on profit. They differ in form, not substance.

1. Deferred Revenues = Allowed Revenues - Adjusted Actual Revenues

Where Adjusted Actual Revenues are the revenues which would have been collected if weather and/or the economy had been normal.

2. Deferred Revenues = Adjusted Allowed Revenues - Actual Revenues

Where Adjusted Allowed Revenues are the revenues which would have been allowed if the actual weather and/or the economy had been used instead of normal.

nism that shifts all or part of the weather-related risk back to the company.

For example, weather normalization techniques are already familiar to many regulators. Where regulators, utilities and other parties have developed acceptable weather normalization methods, the same techniques can be used to "normalize" actual revenues. Price changes occur under decoupling when there is a difference between actual and allowed revenues. Weather normalizing actual revenues eliminates differences between actual and allowed revenues caused by weather. In this fashion, it is possible to develop a decoupling plan that assigns weather-related risks to the utility.

Simpler methods are available for states that have not developed agreed upon weather normalization procedures. For example, a utility might estimate that each additional degree day results in 100 megawatt hours of added sales. Other parties might differ with this estimate. The range is likely somewhere between 80 and 120 megawatt hours of sales for each additional degree day. To get the exact number might prove to be difficult and contentious. A precise derivation of weather impacts would also needlessly complicate what could and should remain a simple process.

The controversy associated with trying to obtain a precise estimate can be avoided by realizing that it is not necessary to shift 100 percent of the weather-related risk back to the company to address price volatility concerns. Regulators might reasonably decide to implement a weather adjustment that is based on, say, 50 megawatt hours per degree day. In this fashion about half of the weather-related risk is shifted from customers back to the company. The purpose of the adjustment is to reduce price volatility to an acceptable level, not to obtain some scientific correlation between degree-days and electricity sales.

Economy

Under traditional regulation, a utility's earnings are also at risk if economic conditions cause sales to change. Under an Energy Rate Adjustment Mechanism (ERAM) style decoupling mechanism, such as that used in California and New York, this risk is fully shifted to customers.

The revenue-per-customer (RPC) decoupling mechanism used in Washington inherently shifts some, but not all, of the economic risks to customers. With RPC decoupling, rates are set in the traditional fashion, but the revenue the utility gets to keep is determined by the number of customers. Revenue requirements are divided by the amount of customers in a given test year to set an allowed RPC amount. This amount is then multiplied by the number of customers the utility actually served in the rate period to determine the total revenue the utility is allowed to keep. The difference between the revenue the utility is allowed to keep, and the revenue the utility received is reconciled, then rolled into rates for the next period. This reconciliation can be positive or negative and is equally likely to be either if the customer calculation and count has been done fairly.

When RPC is employed, not all of the economic risks are shifted because customer growth, like sales growth, is influenced by economic conditions. It is likely that customer growth is less susceptible to economic changes than sales growth, and hence only a portion of the economic-related risk would be shifted to customers.

The degree of the risk shifted depends in part on how customers are counted. For example, one result of a poor economy is that vacancy rates, both residential and commercial, tend to increase. This means that many houses may be vacant and commercial space not actively occupied. Under the way utilities in Washington count customers, these vacant buildings count as customers unless they disconnect from the grid and terminate service. In most situations the buildings remain connected so lights can be turned on when a real estate broker shows the property or to keep pipes from freezing.[11]

An alternative approach normalizes for general economic conditions in much the same manner as for weather. One important determinant of a utility's sales forecast, particularly its near-term sales forecast, is the level of economic activity in the service area. The utility might believe that each one percent change in gross state product results in a 100,000 megawatt-hour change in sales. Again, other parties might differ and provide a range around this estimate. But if a commission wants to limit price volatility, it could adopt a simple economic adjustment similar in approach to the weather adjustment described earlier. A third alternative might be developed if a utility's service area were heavily dependent on one, or a few, major industries. Here, the adjustment would

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[11] It appears that during the recent and ongoing recession in the Northeast CMP has experienced a substantial net increase in these "zero-use customers." They can be identified from bill frequency data.

If regulators wished to reduce the potential for price changes by shifting more of the economic-related risks to the utility than is currently the case, it could require that the definition of customers be changed so that zero-use customers, i.e. customers with between zero and 100 kilowatt hours per month, are not counted as customers.

be developed based on some measure of the economic activity of those industries.

Weather, The Economy And Loads

Load forecasters have long been aware of the effect of weather and the economy on electricity sales. Reviewing load forecasts is a convenient way to analyze the sensitivity of a given utility's sales to weather and the economy. One utility, when undertaking its short-term load forecast, uses a statistical (econometric) approach to estimate revenue-per-customer for both residential and commercial customers. For residential customers, it finds several statistically valid predictors – per capita incomes, the penetration of electric space heat, heating degree days, the price of electricity and historic usage levels. The resulting forecasting equation shows that the addition of 100 heating degree days above normal causes use-per-residential-customer to rise by about 35 kWh. If there are 500,000 customers, this translates into 17,500 mWh. The forecast for the industrial and commercial sectors provides similar information on weather for those sectors. (Typically, there is no relationship between industrial sales and the weather.)

The impact of economic activity can also be obtained from econometric forecasts. For the same utility, the equation shows that each one percent increase in per capita income causes use-per-residential customer to rise by two tenths of one percent. Identifying the impact of abnormal economic conditions, however, is more complicated than the weather adjustment because normal or expected economic conditions are harder to define. Forecasting expected economic conditions is an ordinary part of the ratesetting process in states using future-test-year approaches, but it may be entirely absent in historical test year states.

Once the effects of weather and the economy on sales are established, a final step analyzes for the effect of these sales variations on utility profits. The effect of sales variation on utility revenue can be developed using a conventional utility revenue model. The effect of sales variations on costs are developed using the same approach to marginal (or variable) costs used elsewhere in the decoupling adjustment.

Utility's Incentives To Promote Desirable Sales

Another concern suggests that decoupling might diminish a utility's incentive to make economically efficient sales of electricity. The concern is that the current incentive to sell more electricity should not be removed because some of the sales may be desirable. A related issue is that decoupling may eliminate the utility's incentive to engage in economic development activities. With respect to the latter concern, the design of the decoupling plan will dictate the extent to which the short-term incentive to promote economic development is reduced. For example, the revenue-per-customer approach can continue to reward economic development activities, especially if new customers are highly efficient. The ERAM-type mechanism in use in California and New York can also be adjusted to take account of new customer additions.

The next question to consider is whether economical sales can be promoted in the absence of decoupling. One of the primary, albeit not the only, that traditional regulation provides strong incentives to increase sales, is that short-term profits are associated with increased sales.[12] The incentive is entirely blind to whether the additional sales are economically efficient or inefficient. All sales add to profit. All conservation hurts profits. Decoupling, on the other hand, is sales neutral. Neither additional sales nor additional conservation affect the utility's income.

The short-term profit incentive is not the only incentive utilities face. Utilities generally believe it is in their interest to have low rates, a high market share and a strong, economically healthy service territory. Each of these goals is furthered when a utility pursues economically efficient new sales.[13] The incentive effects of any single program cannot be viewed in isolation.

The choice, then, is between the traditional system with its serious, perverse incentives versus efficiency and decoupling which support incentives operate in the right direction. Commissions believing that additional incentives are necessary for economically efficient new sales (or, for that matter, for cost-effective DSM or for low-cost power generation), can design structured and targeted incentive mechanisms. When this has been done, regulators have been careful to construct DSM incentive plans that reward utilities that do a good job of acquiring cost-effective DSM and penalize utilities that acquire too little cost-effective DSM or any amount of non-cost-effective DSM. Rejecting decoupling leaves the utility with the traditional incentive to increase all sales indiscriminately, without regard to their economic effects.

What Happened To The Maine Decoupling Experiment?

It should be noted, that very recently the Maine decoupling experiment came to a close. Initially, it was adopted as a three year experiment and for all practical purposes, it had run its course. Two factors were central to the program expiration.

First, after decoupling was put into place, CMP filed for increased rates, in large part because sales were low. Shortly thereafter, CMP petitioned to the PUC to withdraw the requested rate increase. The commission agreed. At the time, both parties were aware that the effect of the withdrawal was to use the decoupling mechanisms for an unintended purpose – rate deferral. The result was that the deferred balances became quite large. The large balances, in turn, became troublesome politically.

When decoupling was allowed to expire, the Maine PUC expressed interest in developing a broad-based incentive regulation approach and directed CMP and other parties to attempt to develop a proposal. As part of this process, the parties will consider what approach to the lost revenue issue should be adopted.

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[12] The incentive is short -term for two reasons. First, in the short-term, utilities typically have adequate capacity available to meet additional demands so that rates, for the most part, exceed short-term marginal costs. This may not be true in the long run as new capacity costs force marginal costs higher. Second, utilities only receive additional profits until the next rate case.

[13] The utilities that have instituted decoupling appear to be no less vigorous in their desire to have new businesses locate in their service territory.

DSM Potential

One of the main contributions of IRP has been its ability to evaluate supply- and demand-side resources on an equal footing. Toward this end, a principal goal of IRP is to identify and pursue those demand-side management (DSM) opportunities that can meet customers needs at a cost that is lower than other resources. But adding DSM to the list of available resources is, for some, a major step. For many, DSM is a novel, and in some respects, an alien concept.

This chapter addresses the concerns of skeptics by outlining, in broad terms, the potential of DSM as a low cost resource. It is not intended to propose which DSM measures should be undertaken by a particular utility. Rather its aim is to illustrate the large role DSM can have in resource planning and why a focused and careful attempt to seek out and acquire cost-effective DSM is a worthwhile effort for utilities and ratepayers. This chapter first looks at the size of the DSM resource, addresses the question of why market forces have not been able to capture this potential and looks at utilities that have successfully obtained cost-effective DSM resources.

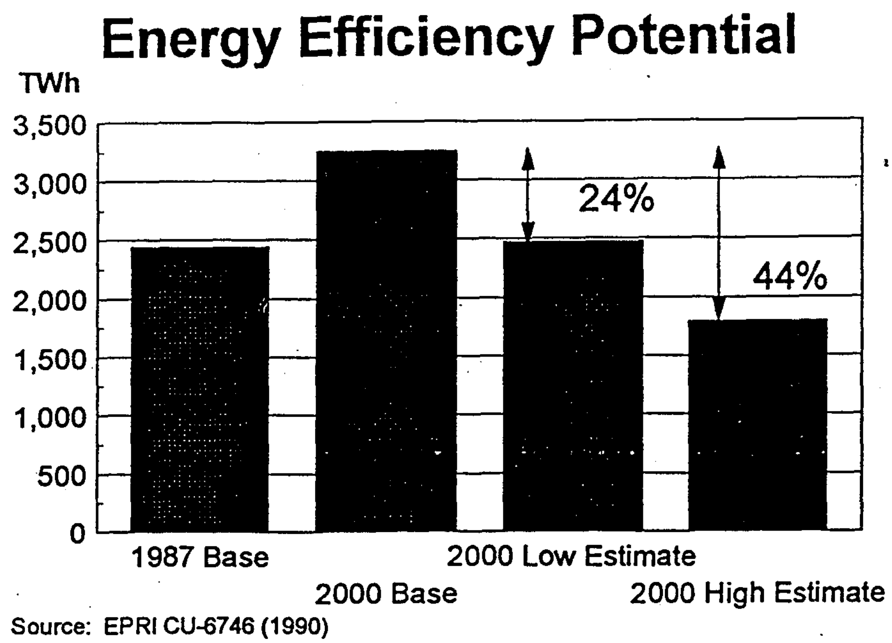
WHAT IS THE DSM POTENTIAL?

The utility industry and energy efficiency advocates surprisingly agree that DSM, conservation and load management could meet a major portion of electricity needs. The Electric Power Research Institute (EPRI), the research and development wing of the electric utility industry, issued a report (EPRI 1990) quantifying the technical potential of DSM in the U.S.[1]

The study looked at potential savings from all major customer groups (residential, commercial and industrial) and concluded that in the absence of conservation measures, electricity demand would increase at about two percent per year. The study showed that even with pessimistic assumptions of MTP, the growth in electricity demand could be entirely eliminated. More aggressive assumptions of DSM potential yielded demand reductions of two percent per year over the study period. This is a 24 percent savings in electricity consumption by 2000 using the low conservation level scenario, and a 44 percent savings using the high conservation level scenario (See Figure 1). Savings of these magnitudes are equivalent to the out-

[1]The study first estimated how much U.S. demand for energy would grow between 1987 and 2000. It then calculated the extent to which usage would be reduced if the "maximum technical potential" (MTP) for energy efficiency were achieved. In estimating MTP, the study assumed that the most efficient conservation measures commercially available in 1987 would be installed by 2000. MTP in this case was not limited to cost-effective measures but included all measures that were available 1987. On the other hand, the study made no allowance for new, more efficient measures becoming available after 1987. It is possible that these two study limitations offset one another, but in any case the results of the study provide a rough estimate of DSM potential.

Figure 1



put of between 100 and 200 of the largest nuclear or coal-fired power plants in the country.[2]

The location of these savings is also of interest. Figure 2a shows a very similar savings potential for all customer classes. This is important because if conservation programs are distributed equally among customers and customer classes, equity concerns about the effects of conservation on non-participants are not as important. Figures 2b through 2d also indicate that savings are greatest in three areas: lighting, space conditioning (heating, ventilation, and cooling) and, for the industrial sector, motor drives.

While this study suggests an enormous technical potential for DSM, there remains a question of how much of it is cost effective. To consider this question, EPRI teamed up with an unlikely collaborator — Amory Lovins of the Rocky Mountain Institute (RMI).

Lovins is undoubtedly the world's most outspoken advocate of energy efficiency. In a now famous Scientific American article (Fickett 1990), the team of researchers posed the question: At different price levels, how much conservation can be expected to occur? Even though consensus was not reached between the two parties regarding the maximum amount of energy savings that could be realistically realized, they did agree that there was a large amount of savings at 4¢ per kWh or less.

EPRI found that there was enough conservation available at 4¢ per kWh or less to reduce energy use by almost 30 percent.

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[2] The EPRI savings estimates are 800 to 1,436 billion kWh annually. The output of a large plant is assumed to be seven billion kWh per year (one million kW capacity operating 80 percent of the time).

Figure 2a
Potential Savings by Sector

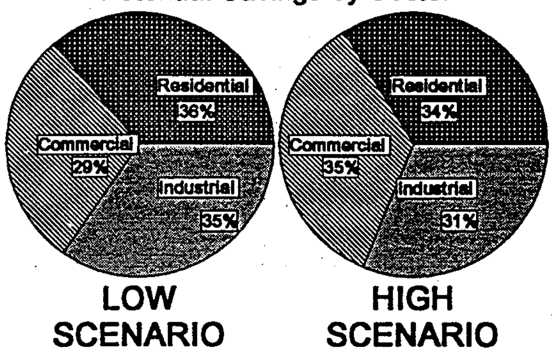


Figure 2b
Residential Savings by End Use

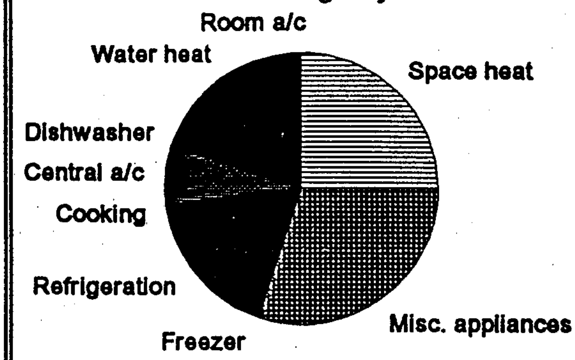


Figure 2c
Commercial Savings by End Use

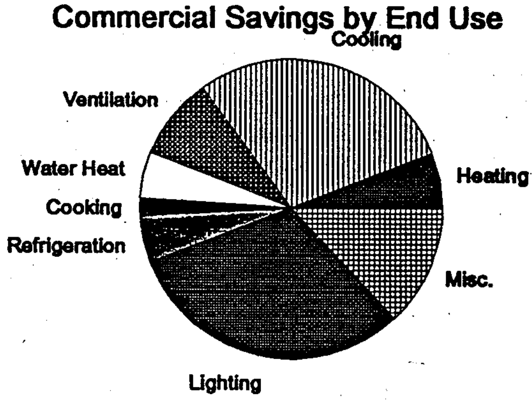
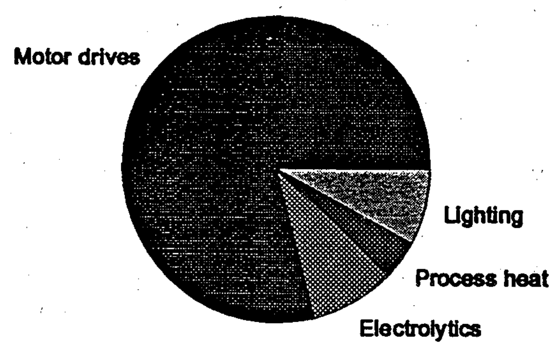


Figure 2d
Industrial Savings by End Use



RMI was more optimistic and found that there could be a 70 percent cut in electrical consumption using the same 4¢ cut off for the cost of conservation. What is most remarkable though is not the differences between the two projections but the similarities. Both EPRI and RMI recognized that savings in at least the 30 percent range were available at or below typical costs for new supply resources. To begin to tap a significant portion of this potential, attention is best focused where all parties agree that savings can be achieved. There will be time to argue at a later date whether even more potential is available. The lesson for now is to realize that there is a great deal of unrealized and cheap conservation potential that is waiting to be tapped.

WHY THE MARKET HAS LEFT COST-EFFECTIVE DSM POTENTIAL UNTAPPED

The market economy generally does a good job of using prices to induce consumers to make reasonable choices. Why then does the market for electricity leave a substantial amount of cost-effective conservation potential untapped? The answer lies in many places.

Electric Rates Do Not Reflect Costs

Electric rates are administratively set by public utility commissions, not by market forces. This is a major reason why electric rates do not track the marginal costs of producing electricity. Only when the price of a product is set reasonably close to the marginal cost are customers able to make good, economic decisions.

There are a number of reasons why electric rates reflect costs poorly. First, rates set by commissions allow utilities an adequate level of profit but not the higher level of profit that would presumably occur without regulation. For some utilities, this results in rates being set below marginal costs. Consequently, customers are not given good price cues and do not make optimal choices.[3]

Even if the overall level of rates is reasonable, typical electric rates often do not match costs very closely. For example, relatively few customers pay higher rates for more expensive on-peak service even though the cost to the utility of providing this service is frequently substantially higher than the average cost.

Utilities And Customers Use Different Decision-Making Criteria

Most utilities have access to large amounts of low-cost capital. Typically, a utility will invest in a plant that will earn an overall return of, perhaps, 10 to 12 percent. Another way of saying this is that utilities generally will invest in a long-lived — say 20 year — asset so long as it has a nine year payback (i.e. the annual operating cost savings are at least one-ninth the amount of the utility's investment).

Customers generally require a much faster payback period. Many utilities have found that unless an energy efficiency investment offers a payback of around two years, customers will not make the investment. As

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[3] This problem was probably more important ten years ago, when high fuel prices resulted in high marginal costs, than it is today.

Table1 shows, this means customers require a much higher rate of return than utilities in order to invest in conservation. This lower investment threshold for utilities means that there are many investments which are cost effective for utilities but not for customers.

The Nature Of Electricity Purchase Decisions

Electricity is an unusual product and one about which it is difficult to make rational purchase decisions. Customers, with very few exceptions, have no direct use for it. Instead, they want warm (or cool) buildings, light to read by, unspoiled milk and for business customers, production of their own output.

In this sense, electricity is a little like gasoline. But with gas, the link between the decision to drive and the cost to the customer is easy to follow. Consumers generally know

Table 1: Implicit Real Discount Rates (Plunkett 1988)

Payback (Y)	**Investment Lifetime (Y)**							
	3	**5**	**7**	**10**	**15**	**20**	**25**	**30**
1	146.5	159.8	161.5	161.8	161.8	161.8	161.8	161.8
1.5	68.4	87.3	91.2	92.3	92.5	92.5	92.5	92.5
2	33.5	55.5	61.3	63.5	64	64	64	64
2.5	13.3	37.2	44.4	47.6	48.6	48.8	48.8	48.8
3	0	25.1	33.4	37.5	39	39.3	39.3	39.3
4		**9.7**	19.4	24.9	27.5	28.1	28.3	28.3
5		0	**10.7**	17.2	20.7	21.6	21.9	22
6			4.6	**11.9**	16	17.3	17.8	18
7			0	7.9	**12.6**	14.2	14.8	15
8				4.7	9.9	**11.8**	**12.6**	**12.9**
9				2.2	7.8	9.9	10.8	11.2
10				0	6	8.3	9.3	9.9
12					3.1	5.8	7.1	7.7
15					0	3.1	4.6	5.5
20						0	1.9	3

Shaded area = Customer cost of capital; **Bold** figures = Utility cost of capital what a gallon of gasoline is and that their car can go 20 miles for every gallon.

The link between electricity use and cost is not as obvious. Consumers generally do not know what a kWh is, how much one costs or how many their refrigerator needs to operate. The additional usage from deciding to turn on an extra light today will not show up on a bill for weeks, long after the decision to use the light is forgotten. Worse still, the effect of flicking the light switch will be aggregated into a bill that includes every other decision made by the household during the month (including a five-year-old's non-decision about a snack after staring into an open refrigerator for 30 minutes). The point is, it is difficult for customers to understand their electricity purchase decisions as clearly as they do most other purchase decisions. For these reasons, customers often have only a poor idea as to how much electricity each of their end uses require. This makes rational purchase decisions difficult.

Lack Of Sophisticated Knowledge

For utilities, buying a new resource requires a very sophisticated analysis conducted by well-trained personnel. Decisions are reached after comparing the capital and operating costs of a number of alternatives, often taking into account several forecasts of future fuel prices, load growth, interest rates and other variables. In principle, customers should also compare the future costs of various alternatives. In fact, customers seldom have the tools or skills to do this. The typical homeowner or owner of a small commercial business is rarely in a position to make equipment purchase decisions today that take long-term implications of energy costs into consideration.

Energy-Efficient Products Are Often Not Readily Available

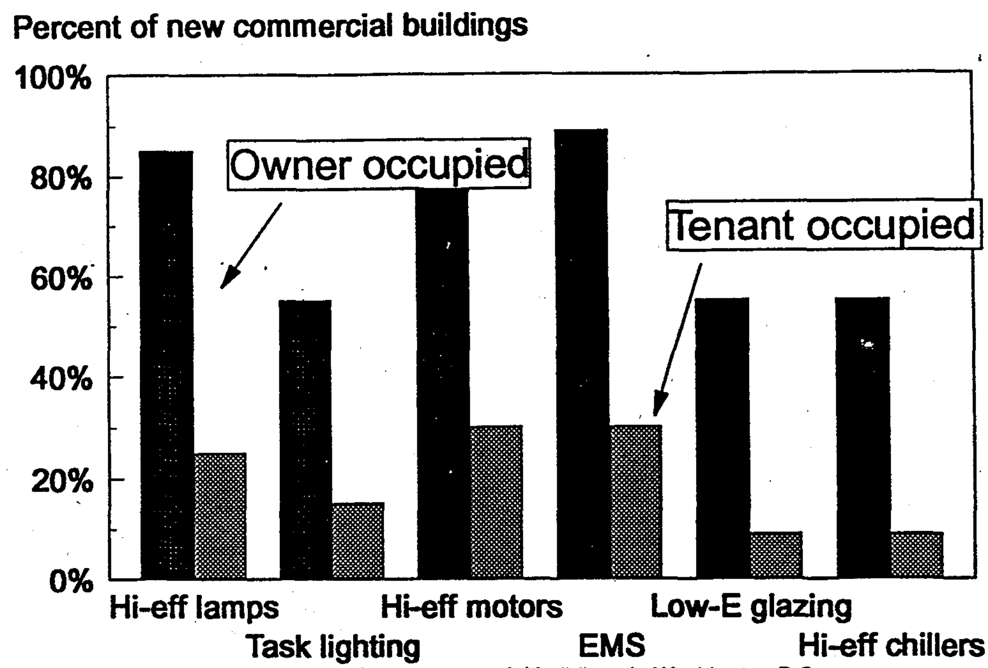
Even when customers want energy-efficient products, they are often unable to find them. In some cases, stores do not stock them. In other situations, designers and contractors are unfamiliar with efficient options and prefer to stick with products they have sold in the past.

Tenant Issues

Tenant-occupied businesses and residences are often much less energy efficient than other buildings. While the landlord makes the decisions involving capital expenditures, it is the tenant who pays the electric bill. This gives the landlord little incentive to choose efficient equipment since he or she is not paying the electric bill. In cases where the tenant has the option of installing efficient equipment, there is often little reason to do so since a higher capital investment may not be worth the associated energy savings. This is particularly true of tenants who frequently move.

The problem of energy inefficiency in tenant-occupied buildings was reported in an article in Energy User News (Hines 1990). As summarized in Figure 3, the tenant-occupied commercial buildings in the study were several times less likely to have high efficiency measures.

Figure 3 Percent of new D.C. commercial buildings with various energy-efficiency measures, by building efficiency



Percentages of new commercial buildings in Washington D.C. with various energy-efficiency measures, by building occupancy (Hines 1990).

ARE UTILITIES ABLE TO GET DSM IN A COST-EFFECTIVE MANNER?

Program evaluations have been conducted for individual DSM programs since the early 1980s. Although initial results sometimes showed evaluated savings to be lower than the original planning estimates, most pro grams were, nevertheless, cost effective.

In recent years, with the advent of DSM per formance incentives for utilities, greater at tention has been placed on evaluation meth ods. This is especially true in states such as Massachusetts, New York and California, where there has been a sizeable commitment to DSM.

Some preliminary results summarizing eval uations of programs operated during 1990-1992 by the Massachusetts Electric Com pany are shown in Table 2.[4]

These results illustrate that utilities are get ting the low-cost energy resource that they had banked on receiving and demonstrate that utility commitment to DSM is very worthwhile.

[4] This preliminary summary information was provided by Susan Coakley immediately prior to publication of this workbook. A full report is expected by early summer 1994.

Table 2: Summary of Massachusetts DSM Evaluation

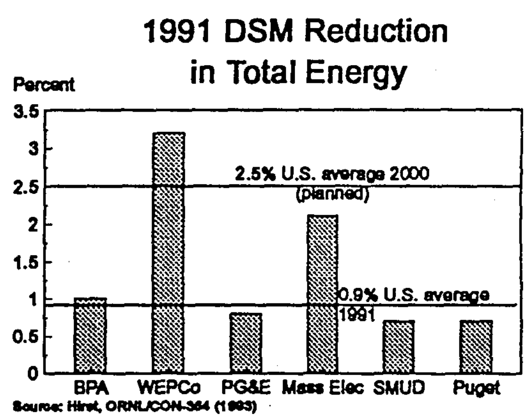
Level of Savings	% of Planning Estimate
Planning Estimate	124%
Lifetime Energy*	138%
Annual Capacity	90%
Lifetime Capacity	95%
Program Costs**	75%
Measured Lifetime*	110%
Cost of Savings**	
Lifetime kWh	54% (2.5¢/kWh)
Lifetime KW	95% ($84.09/KW-Yr)

*Re-estimated based on actual mix of measures installed
**Includes both utility and customer costs

CAN EVEN MORE DSM BE UNDERTAKEN?

Even for those utilities reputed to have conducted aggressive DSM efforts, it is fair to ask how close they have come to capturing the full cost-effective potential. Evidence suggests that these utilities still have a long way to go. Data from utilities reporting their DSM programs to the U.S. Energy Information Administration for 1991 has been aggregated and summarized (Hirst 1993). The data shows that New England utilities saved 2.3 percent of the 1991 sales and planned to achieve savings of 6.4 percent of sales from the year 2000. Similar figures for the western states (California, Nevada, Arizona and Hawaii) were 0.7 percent and 3.6 percent respectively. The average U.S. savings from 1991 was 0.9 percent for all reporting utilities, and projected 2.5 percent for the year 2000. Results for selected, individual utilities are shown in Figure 4 and illustrate that there is a great deal more cost-effective DSM potential, even in some of the most DSM-active regions and utilities.

Figure 4



CONCLUSION

Clearly a substantial amount of cost-effective DSM is available to benefit all ratepayers at most or all utilities. Whether the potential savings is ten or 50 percent is immaterial. Most importantly, there are unexploited and cost-effective opportunities, and there should be no excuse not to pursue programs that can be shown to cost less than the benefits they provide from the point of view of avoided fuel, T&D expansion, new electric generation and external environmental costs.

How To Judge A Utility's DSM Effort

A role of many Public Utilities Commissions is to assess how serious and committed the utilities they regulate are about DSM. At first glance, utility commitment to DSM appears great; every day one can read or hear about successful programs. However, there are many examples where utilities claim to be doing DSM, but the results from their efforts are questionable. In still other places, utilities persist in doing very little with DSM. To ensure that DSM programs are undertaken in earnest and result in significant savings, how should a commission guide their utilities?

This chapter looks at how a commission can judge, using qualitative and quantitative measures, a utility's DSM effort. Its purpose is not to offer tools to measure a particular DSM program or argue whether the utility should be awarded an incentive based on a previous commission ruling. Instead it poses a series of questions that commissions should ask to learn about a utility's DSM effort. Each question is followed by a discussion describing what constitutes a serious effort.

The questions are divided into two groups. The first set relates to the **scope** of the DSM effort and raises questions about program breadth and depth and specific program characteristics. The second group of questions address how to evaluate the **quality** of an effort. A utility can have a lot of programs and spend a good deal of money on DSM, but it does not necessarily follow that they are acquiring meaningful energy savings. [1]

Within each of the two groups, the questions are posed roughly in order of priority beginning with the most important question. Questions preceded by an asterisk are the most critical and represent the bare minimum that commissions should ask. The list is not intended to be all inclusive. Useful, but less pressing, questions have been omitted to keep the process manageable.

SCOPE OF DSM PROGRAMS

***Has The Utility (Or Anyone Else) Made An Assessment Of The Technical And Achievable Amounts Of Energy Conservation? Is This Assessment Guiding The Size And Targets Of The DSM Program?**

An assessment of conservation potential, undertaken as part of the IRP effort, identifies those cost-effective, energy efficiency resources that are available to meet energy needs. When done well, this assessment demands systematic thinking about energy savings potential and serves as the basis for

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[1] Quality is a hard concept to nail down, of course, and some aspects that are important are undoubtedly omitted from this discussion. Nevertheless, the questions and answers presented should be useful for commissions to evaluate whether or not the utility DSM programs are performing well.

guiding the utility's conservation effort. The existence of a conservation assessment is not meant to suggest that all energy efficiency options have been considered but rather that some thought and effort have gone into identifying the potential savings.

***What Are Energy Efficiency Goals?**

Savings goals should be derived from the long-range IRP Plan and should indicate in MW and annual GWh the extent to which the utility will rely on energy efficiency over the planning horizon. This is the first measure by which the utility's annual performance should be judged.

A simple test to determine whether the savings goals are bold enough compares the savings figures both to forecasted growth in loads and to existing loads. If utility loads are growing, what percent of load growth is being met by conservation? The potential to meet load growth through conservation is great. There are examples of high-growth utilities reducing their forecasted load growth by one-third to two-thirds through energy efficiency programs, and some low-growth utilities expect to meet all load growth with conservation. Even no growth or negative-growth utilities can target energy savings if the cost is less than the utility's avoided fuel cost. All of this, of course, is predicated on commissions removing the disincentives to conservation.

Are Programs Targeted To The Biggest End Uses And Market Segments?

The conservation assessment will identify market segments and end uses with the largest potential for savings. Utilities targeting their programs to these areas will generally get more bang for the buck.

If most residences, for example, heat with fuel oil or bottled gas, and fewer than five percent heat with electricity, then a home weatherization program may not be the highest priority program. On the other hand, if the service territory contains significant urban areas, the utility is probably missing a good bet if it does not have a commercial lighting program. If ten or 20 industrial customers account for 75 percent of the utility's industrial load, a DSM program comprised of technical assistance and financial incentives coupled with a direct, targeted marketing effort will likely achieve a high percentage participation and probably yield high savings. The conservation assessment should illustrate the cost-effectiveness of these targeted programs and help in program sizing.

Are Programs Offered To All Customer Classes?

Cost-effective DSM opportunities are available for all customer classes — residential, commercial and industrial (and irrigation if applicable), and accordingly customer equity demands that programs be offered to each class. This is true not only because all customers can benefit from DSM programs but also because all customers will pay for the programs.

The number of programs should not be a criterion for success or seriousness of effort. A utility offering a large range of programs may or may not be doing a good job. Fewer, more comprehensive programs may be just as good and have lower administrative costs. Further, the number of programs can be misleading if every demonstration, pilot, research project or education-only activity is counted as a "program."

Careful consideration should be given to which programs should be offered. A serious DSM effort will devote a significant portion of the budget to programs which give customers financial incentives. In general, education programs should be used to create awareness, understanding and support for the more aggressive and higher budget programs. The savings from education programs alone can be hard to measure and as a result, most utilities do not rely on them to supply resources.

Some typical DSM programs are listed in the box to the right.

DSM Programs Available to Customer Classes

RESIDENTIAL

- Low Cost Measures Direct Installation
- Home Weatherization Financing or Rebates
- Low Income Weatherization Grants
- Rental Property Weatherization Financing or Rebates
- New Construction Minimum Efficiency Standards
- Manufactured Housing Incentives
- Water Heating Efficient Equipment Rebates
- Air Conditioner Rebates
- Used Refrigerator Buy Back and Recycling
- Compact Fluorescent Lighting Incentives

COMMERCIAL

- Efficient Lighting Incentives (including design, for both commercial and industrial applications)
- New Construction Design Assistance
- New Construction Installation Financing
- New Construction Building Commissioning
- Existing Buildings Recommissioning
- HVAC Replacement Rebates
- Small Commercial Direct Installation

INDUSTRIAL

- High Efficiency Motors and Adjustable Speed Drives Rebates (for both commercial and industrial applications)
- Custom Process Improvement Incentives

***Are Programs Targeting Lost Opportunities?**

When customers change how they use energy, by, for example, remodeling a commercial space or building a new manufacturing facility, they create opportunities to make energy use more efficient. Utilities need to identify these opportunities and make sure that programs dovetail with customer action. If programs do not match the changes that customers are prepared or expect to make, cost-effective efficiency opportunities are lost. Going back to install efficiency measures at a later date can be expensive and even physically impossible. Avoiding lost opportunities by targeting programs to them is a policy that most DSM-oriented utilities have adopted.

The most obvious example illustrating why program timing is so important can be seen in new construction. It is usually easier and cheaper to bring energy efficient design of new homes or commercial buildings into the construction phase than it is to make changes at a later time. Utilities should offer educa-

Lost Opportunity Program Case Study

High Efficiency Motors

Puget Sound Power and Light, Tacoma City Light, Seattle City Light and the Bonneville Power Administration have joined together to promote the purchase and installation of high efficiency motors by offering rebates for the purchase of motors that exceed an efficiency threshold. The challenge these utilities faced was how to market this cost-effective program. Typically, when a motor burns out, most businesses, and industry in particular, require an immediate replacement which they get by calling their electrical supplier or motor dealer. The utility is by-passed altogether.

To link the market opportunity with purchasing patterns, the four utilities jointly hired a marketing agent to visit motor vendors in the area and enlist them in the program. Consequently, when a customer of any of the utilities calls one of these vendors, the customer is encouraged to purchase a qualifying motor, with the utility rebate and operating cost savings being used as part of the sales pitch. Customers who make this choice do not have to fill out paperwork or wait for approval before purchase. Forms are completed by the vendor who in turn receives a payment which varies depending upon the size of the motor sold.

The marketing agent periodically visits all vendors to keep them up-to-date about the program, answer questions and handle utility billing. Servicing the vendors in this way helps the utilities capture savings opportunities they would otherwise miss. As long as the vendors believe that the utilities will support this relationship and maintain the program for several years, they will continue to stock the high efficiency motors so they are available as needed. Vendors also appreciate the fact that a combined program frees them from having to know the program rules and procedures of four different utilities.

tion and design assistance for new construction, coupled with financial incentives for the implementation of cost-effective measures. While new construction is an obvious example of a customer purchase or investment affecting energy use, there are many other situations where the lost opportunity principle applies. When energy using equipment fails or nears the end of its service life, customers want to replace it, sometimes with great urgency. Examples include HVAC equipment (heat pumps, air conditioners, chillers) in commercial buildings, appliances (water heaters, refrigerators, air conditioners) in homes, and motors in industry. Because the equipment will have a long life, usually exceeding ten years, the replacement decision creates an opportunity for long lasting savings.

In commercial buildings, before a new tenant moves in, the owner frequently makes improvements to suit the tenant's needs. These improvements often include updating the lighting systems which means that there are excellent opportunities to install fixtures that reduce energy use.

Are Utility Goals And Organization In Harmony With DSM?

Most utilities have mission statements and annual performance goals which should be examined. Mission statements containing language about increasing sales are inimical to DSM.

DSM may raise rates even though it will lower customers' bills compared to what they would have paid in the absence of DSM. Most utilities persist in focusing on rates because they think they are selling a commodity — kilowatt-hours. Customers, on the other hand, react to the rhetoric of rates, but, in fact, are more knowledgeable about and motivated by their overall electric bills. Utilities that recognize that their customers are more interested in bills than rates are more likely to focus on providing value through energy services (lighting, cooling, or motive power) because they see DSM as an important part of the energy services they provide.

Annual management goals (or performance goals or corporate objectives) give insight to what is important to top management. Do these goals include DSM performance? Are managers, or all employees, rewarded based on performance relative to these goals? Aligning self and corporate interest with DSM success is a powerful motivator.

If DSM is important, it will be represented near the top of the organization chart, not buried under several layers, nor made one of 17 departments that report to a single vice president. Also, while there is no clear preferred organizational model, a DSM department that is close to resource planning and load forecasting will receive better support than one that is removed from these critical functions.

What Percent Of Operating Revenues Are Spent On DSM?

This statistic has emerged as a quick way to gauge utility DSM activity and commitment. Among the highest performers using this statistic is the Sacramento Municipal Utility District, which in 1991 had a DSM budget of 6.4 percent of its operating revenues. A good effort lies in the range of two to four percent of operating revenues. Setting a percentage target for utilities is not advisable because the target tends to become a ceiling. Also, commissions should be careful not to confuse spending with program success.

QUALITY OF DSM PROGRAMS

*What Are The Program Participation Rates?

The percent of eligible customers who participate in a program should be tracked and reported. The participation rate, sometimes called market penetration, should be measured in both annual and cumulative terms, such as five percent per year, and 70 percent over the life of the program.

The American Council for an Energy Efficient Economy (Nadel 1994) has reviewed participation rates for some of the best, or at least best documented, programs offered by North American utilities to all customer

Highest Reported Participation Rates

Program Type	Highest Participation Rate
RESIDENTIAL	
Low Cost Measures	68%
Comprehensive Weatherization	87%
Low-Cost Hot Water Retrofits	98%
Air Conditioner and Heat Pump Rebates	60%
Refrigerator Rebates	80%
Compact Fluorescent Lamps	60%
New Construction	100%
Appliance Labeling	23%
New Construction Labeling	39%
COMMERCIAL	
Lighting Rebates	21%
HVAC Rebates	90-100%
Multiple Measure Rebates	17-23%
Lighting Direct Installation	>85%
Performance Contracting Retrofits	15%
Comprehensive Retrofits	74%
New Construction	70%
INDUSTRIAL	
Motors	64%
Multiple Measure Rebates	36-48%
Custom Rebates	51%

Source: Nadel, et. al., 1994

classes. Their work, which looks at many programs still in progress, can help DSM planners understand what is achievable over the life of a program. However, because these programs are still in operation, the ultimate participation rates remain unknown.

When judging participation rates, it is important to know how the eligible population is determined and the number of eligible customers. A small number of narrowly-defined eligible, customers may make it easy to achieve high participation rates through targeted, one-on-one marketing. It is also important to know how participants are counted. Are customers participants if they receive only an audit? Are customers counted once or multiple times if they receive several different rebates? Commissions should develop standard definitions of participants and participation so that utility results are comparable. The 1994 ACEEE report is a useful guide for developing these definitions.

***Do The Programs Have Management Information Systems For Program Tracking And Monitoring?**

Utilities with a good system for tracking and reporting information gain early insights to program operation and cost effectiveness and find out how well program goals are being met and how complete the data is for program evaluations. There is a cost, sometimes significant, for system design, system maintenance and data entry, but for programs that are expected to deliver significant savings, the cost is well worth it.

Commissions should ask about tracking systems to see that they are in place and to ensure that program summary information can be produced in management reports on a regular and ad hoc basis (Care should be taken not to micro manage the development of tracking systems. The point is not to direct the utility as to what data must be collected or reported but to assure commissions that the utility has the capability at least of managing their programs well.) The information collected via tracking systems is critical for program evaluations and to easily track levelized cost.

Tracking systems need not be large and complex computer databases. Many programs can be easily tracked using a simple spreadsheet program. Finally, tracking systems should be flexible enough to accommodate program modifications.

What Is The Levelized Cost Of Each Program?

The levelized cost should be less than the utility's avoided cost, which by definition would make the DSM program cost-effective. Many DSM programs have proven to be cost effective, with many costing the utility less than 2¢ per kWh. Many more fall into the 2 to 5¢ per kWh range.

When comparing costs from one utility to another, it is very important that the assumptions be standardized, and at a minimum be explicit. Different assumptions about the expected life of DSM measures, the discount rate used and what costs are included can cause big variations in results. Commissions should specify acceptable assumptions, or specify how these assumptions should be made, to ensure comparability.

***Are Evaluation Reports Being Produced For Major Programs?**

Program evaluations are an essential part of a DSM effort. There are two types of evaluations. Process evaluations evaluate how well the program is being run, and impact evaluations attempt to measure the energy savings achieved. Programs that are projected to supply the most energy savings and those with the largest budgets should be periodically evaluated.

An evaluation plan should be developed as part of the program plan which allows everyone to know in advance program goals, the purpose of the evaluation and the data that must be collected to support the evaluation. When the utility is new to program evaluation or if the proposed evaluation methodology is new or innovative, other evaluation professionals should review the proposed plan.

After the evaluation is actually undertaken, comments to the draft report should be solicited from the affected program staff and by evaluation professionals unrelated to the program prior to completing the final report. Evaluation reports should be made available for public review.

Evaluation budgets, according to a 1993 survey of 13 active DSM utilities, represent from 1.3 to 7.9 percent of utility DSM budgets, with a 4.5 percent average (Evaluation Exchange, 1993).

Are Customer Advisory Groups Being Used To Plan, Review And Revise Major Programs?

The success of DSM programs depends on understanding the targeted market, understanding the needs of the trade allies that serve that market and staying close to that market for feedback on program operations. For some programs, this information can be gathered via surveys, focus groups or other types of formal market research. But if the utility wants significant participation, it will test program ideas and approaches on the affected and interested parties to predict how well they will be received.

To accomplish this, some utilities establish ongoing program advisory groups. The purpose of these groups is to solicit input and feedback about program operations and to help work out the inevitable program bugs. It is important that discussions with these groups support a dialogue and that comments are considered seriously. This type of outreach activity demonstrates a real commitment to and desire for successful programs. Commissions or advocacy staff may want to ask the utility for a list of program advisory groups, names of members and telephone numbers, then contact the members and ask if they feel the utility is listening to them and acting on their advice.

What Effort Is Being Made To Develop The Market And Work With Trade Allies?

Trade allies are the private businesses that are critical to the delivery of quality energy efficiency services and DSM programs. Trade allies are manufacturers of energy efficient products, manufacturers' reps, suppliers and distributors, dealers and retailers, designers of energy efficient systems and buildings, product specifiers and installation contractors. Most strong utility programs have enlisted the support of trade allies in program planning, delivery and modification.

Trade allies market DSM programs best when the program is designed to work alongside the normal business relationship. Trade allies who see DSM programs as an opportunity to expand their markets will view utilities as partners rather than competitors.

In most DSM programs, utilities will be trying to make trade allies more aggressive advocates of energy efficiency. To accomplish this, utilities should continue to work with trade allies to educate them about better methods and tools for analyzing alternatives, different design practices, more efficient products and utility needs and motives. This education can take the form of seminars and workshops, reading material and program requirements or standards.

CONCLUSIONS

There are many factors that illustrate whether a utility is serious about its DSM effort and doing it well. Looking at one factor in isolation will not provide an adequate assessment of the utility DSM effort. Elements most critical to a successful and serious DSM effort include:

- a conservation potential assessment or IRP that guides DSM planning and investment

- explicit, numerical energy savings goals for each year
- programs that target lost opportunities
- program participation targets and participation rates that ultimately seek high market penetration
- program tracking systems that collect and report essential performance information
- evaluations for major programs.

Cost-Effectiveness Testing Of Demand-Side Management Programs

There is wide agreement that cost-effective DSM is desirable. Yet what does cost effective mean? This is an important question to ask because DSM programs often affect different parties in different ways. A program may be very attractive for customers who participate but less so for those who do not. Fully evaluating a DSM program requires understanding the impacts from more than one perspective. This chapter explains cost-effectiveness and describes the tests used to evaluate programs.

COST-EFFECTIVENESS TESTS[1]

There is no single tool or cost-effectiveness test which tells a utility or commission everything that is needed to decide whether or how best to undertake a DSM program. What is available to planners and policy makers is a group of tests, each of which is designed to examine the costs and benefits of a DSM program from a particular perspective. Because each test says something unique about the program, the tests are meant to be used in parallel to understand the full impacts of a program and to design (or re-design) a program. The use of these tests, along with a flexible process for program approval and modification, will enhance the acceptability and value of a DSM program.

The results of each test are expressed as a Net Present Value (NPV) of DSM benefits and costs. A positive NPV, regardless of its magnitude, signifies a cost-effective investment. Test results are also represented as a ratio of present value benefits divided by present value costs. Any benefit/cost ratio of 1.0 or more means that a program is cost effective from the point of view of that particular test.

Five pieces of information are used in the five tests. These are:

- energy or demand savings
- avoided costs
- DSM costs
- retail prices
- environmental costs

The cost-effectiveness tests mix and match these key inputs. The five tests are described below together with the perspective they represent, a description of the benefits and costs they consider and how each test is best used.

Total Resource Cost (TRC)

This test measures the net benefits of a program, exclusive of externalities, from the point of view of the utility and its ratepayers as a whole. With the addition of externalities,

[1] This paper briefly describes each cost-effectiveness test. Details on how to run these tests can be found in the California Standard Practices Manual (1987).

this test is called the societal cost test (see below).

Costs Measured

- Utility program costs (including incentives paid to participants)
- Participant costs (net of any financial incentive paid by the utility)
- Increased supply cost (load building)

Benefits Measured

- Avoided supply costs of utilities and participants, including generation, transmission, distribution and non-electric costs

Best Use

States face a policy decision in choosing which test — the TRC or the SC — should be used to determine from the outset whether or not a program makes economic sense. For states that do not consider externalities, this test determines whether a program makes economic sense by identifying whether it increases or decreases the total direct cost of meeting energy service needs. If a program fails this test, it should not be pursued. Programs that pass this test, if implemented, will result in a lower total cost.

Societal Cost (SC)

This test is the same as the TRC, except that it includes environmental externalities and other external, societal costs. It measures the net benefits of a program from the point of view of the utility and its ratepayers as a whole.

Costs Measured

- Utility program costs (including incentives paid to participants)
- Participant costs (net of any financial incentive paid by the utility)
- Increased supply cost (load building)
- Environmental and other societal costs

Benefits Measured

- Avoided utility and participant supply costs, including generation, transmission, distribution and non-electric costs
- Environmental and other societal savings

Best Use

For states that consider externalities, this test determines whether the program being evaluated makes economic sense by identifying whether it increases or decreases the total social cost of meeting energy service needs. A program that fails this test should not be pursued.

Rate Impact Measure Test (RIM)

This test measures the impact on the utility's average retail prices over the lifetime of a DSM program.

Costs Measured

- Utility program costs (including incentives paid to participants)
- Decreased revenues resulting from load reductions
- Increased supply cost (load building)

Benefits Measured

- Avoided utility and participant costs, including fuel, generation, transmission, distribution and non-electric costs
- Increased revenues (load building)

Best Use

This test is used to assess the average cost impacts to non-participant ratepayers over the life of the program. The test serves as a warning. If a program fails, it needs to be looked at more closely to see what modifications, if any, can be made. Two observations about this test deserve special note. First, the test provides information on **average** lifetime price impact and not the price impacts in a given year to a specific customer class which is often of particular interest. Second, even in the best situation, where DSM costs are zero, this test will show that costs exceed benefits whenever retail prices exceed avoided cost, as occurs in most places in the country today. This test will show that at 0¢ DSM fails when compared to a 5¢ power supply.

<u>Participants Test (PT)</u>

This measures the quantifiable benefits and costs to a participating customer.

Costs Measured
- Participants' incremental costs[2]
- Bill increases (load building)

Benefits measured
- Participant bill reduction
- Incentive paid by utility or third party
- Federal, state and local tax benefits, if any
- Operations and maintenance savings

Best Use
The purpose of the test is not to determine whether or not a program is worthwhile. Instead, it is used to evaluate and adapt program design, market the program and set a contribution level for participants. For instance, a high benefit/cost ratio means higher customer contributions can be asked for with out sacrificing market penetration.

[2] Incremental costs are the difference between the cost of the efficient option chosen and the less efficient option not selected.

<u>Utility Test (UT)</u>

By measuring the impact of the program on utility revenue requirements, this test reveals how the program will affect electric bills and, therefore, how it will impact utility revenues.

Costs Measured
- Utility program costs (including any incentives paid to participants)
- Increased supply costs (load building)

Benefits Measured
- Avoided supply costs, including generation, transmission and distribution costs

Best Use
Like the PT, this test is not meant to serve as a tool to decide whether or not to go forward with a program. Instead, it is valuable in identifying what incentives should be made available to the utility in order for the program to be attractive to them.

USING TEST RESULTS FOR PROGRAM ACQUISITION AND MODIFICATION

Utilities should run all five tests in order to get as clear a view as possible of the costs and benefits. Often state commissions will designate in their IRP Rules or Orders which tests should be conducted and which tests should be given precedence. For most states, the results from the TRC or the SC test are a threshold because these look at whether the program reduces costs in a manner that is consistent with the utility's overall IRP objective. If these tests indicate that a program makes sense economically, the results of the RIM may be examined to determine the rate impact on non-participants, and the UT will indicate the revenue impact on the utility.

Because these tests are designed to look at the impact from a single program, it is important not to lose sight of the total distribution of costs and benefits from the entire DSM effort. When looking at the DSM effort as a whole, there may be reasons to run programs with relatively low benefit/cost ratios. For instance, a low income program might look marginal on its own but in a larger context, when trying to distribute benefits evenly among ratepayers, it may make sense.

There are options for programs that while attractive from an all ratepayer or societal perspective, expose non-participants to unacceptable rate impacts. Tailored program adjustments should be made to relieve whatever features place an unfair burden on the non-participant. The results of the tests can be used to think about what modifications make sense to make a program (or programs) more cost effective from all perspectives. Adaptation strategies to consider include the following:

Additional Programs

A look at all DSM programs may show that only certain customers and customer classes are being served. Offering programs to all customer classes more evenly distributes the cost and benefits faced by all customers.

Program Redesign

Redesigning the program to streamline administration can reduce costs and improve cost effectiveness. Marketing costs can be cut when trade allies are involved in program marketing. Benefits will increase if ways can be found to increase energy savings. For single measure programs, additional energy efficiency measures can be offered with only minimal impacts on program administration costs.

Cost Recovery

If a large rate impact on customers is anticipated, cost recovery can be re-configured or extended over a greater number of years (the expected life of the installed measures) to lessen the financial hardship.

Cost Allocation

Rate design can be changed so that the targeted rate class pays a larger share of the actual program costs. This is equitable for participants in a particular customer class, but non-participants in the same rate class may be even worse off.[3]

Participant Pays

By having participants cover a portion of the DSM costs, the cost to the utility and in turn to the non-participating ratepayer is smaller. When this is done, however, the possibility that there will be fewer participants and less savings should be recognized right from the start.

Budget Adjustments

If utility avoided costs are low in the early years of a DSM program but rise in later years, the program can initially be throttled

[3] For a complete discussion on DSM cost allocation see Centolella (1993).

back, then steadily accelerated to reach full size at some later date.

EVALUATING A COMMERCIAL LIGHTING PROGRAM

Tables 1 and 2 below, adapted from an actual case, shows how a utility used the five tests to evaluate a commercial lighting program.

Running the five tests using this data illustrates how the benefit/cost ratios vary depending upon one's economic perspective. This example shows that while the lighting program is cost-effective, it does not pass the rate impact test. To reduce the rate impact, a utility could consider lowering the incentives paid to participants. To minimize the impact on non-participants without altering the average rate impact, more of the program cost could be recovered from participants.

On the positive side, the impact from this decision would lower program costs, improve the already positive cost-effectiveness from the UT perspective and make the RIM test less negative. Such a shift would not change the value of the program from either the TRC or SC perspective. On the negative side, such a move could reduce the numbers of participating customers which, in turn, would reduce savings. It is up to the utility, with guidance from the commission, to decide what final balance should be struck.

In balancing cost and rate impacts, one commission took the position that after program modifications were made to minimize rate impacts to non-participants, a DSM program that satisfied the TRC test and failed the RIM test could be continued or implemented without commission approval provided that the utility's present value of revenue requirement per kWh did not increase by more than one percent over the duration of the program.

Table 1

Commercial Lighting Program Costs and Benefits

Code	What Code Represents	Present Value (PV) Millions $
A	Program costs (planning, design, administration, customer incentives, evaluation)	10.0
B	Customer share of costs	4.0
C	Lost revenue, net of avoided fuel costs	44.0
	Benefits	
D	Customer bill savings	44.0
E	Avoided cost of alternatives	28.0
F	Avoided environmental externalities (≈10% of avoided cost)	3.0

Table 2

Test Conducted	PV Cost	Inputs Used	PV Benefits	Inputs Used	Net PV	Benefit/ Cost Ratio
Participants (PT)	-4	b	+44	d	+40	11.0
Ratepayers (RIM)	-54	a,c	+28	e	-26	0.5
Utility (UT)	-10	a	+28	e	+18	2.8
Total Revenue Cost (TRC)	-14	a,b	+28	e	+14	2.0
Society Cost (SC)	-14	a,b	+31	e,f	+17	2.2

WHAT ELSE IS IMPORTANT TO KNOW ABOUT COST-EFFECTIVENESS TESTS?

There remain some other aspects that require further discussion.

Constant End Use

All tests assume a constant end use, amenity level and production level. The tests can be applied to situations where these assumptions are not a given but to do so requires special attention.

Non-Energy Benefits

Cost-effectiveness tests do not capture the non-energy benefits offered by DSM programs, including improvements in quality and increased amenities. Again, special care needs to be applied to programs that have significant non-energy benefits. One approach makes sure that direct customer contributions cover the program costs that are not energy related.

Load Building And Fuel Switching

These tests when carefully applied can be used to calculate the impact of load building and fuel switching. This is done by first identifying an energy service need, such as space heating, then identifying the full cost (capital and operating) and benefits of each space heating technology.

CONCLUSION

Cost-effective DSM lowers costs, improves the environment and reduces risk and uncertainty. Although cost-effective DSM always lowers bills, it may or may not lower unit prices. Is, then, a DSM program that raises rates but lowers bills a good idea? When the program offers customers energy services at the lowest possible cost, the answer is most often yes. Toward this end, Eric Hirst (1991) urges that "the large reductions in total costs not be foregone because of small increases in electricity prices." But there is no single formula that says that a five percent decrease in electricity costs over the next 20 years justifies a one percent increase in electricity prices. It is up to every commission to consider these questions and offer policy guidance.

To make sure, though, that there are not big winners and big losers, programs can be modified so that one set of customers does not benefit at the expense of the utility and non-participating customers. This flexibility will enable DSM programs to provide cost-effective energy services while minimizing the impact on rates.

Direct DSM Cost Recovery And Incentives

Utility resistance to DSM programs has two origins. In the first place, there is general skepticism about and unfamiliarity with DSM. Added to this is the fact that because traditional ratemaking does not accommodate utility investment in DSM, utilities that pursue DSM incur financial losses. These two disincentives are closely connected because any cultural resistance to DSM cannot be expected to diminish until the financial disincentives associated with traditional ratemaking are removed.

A previous chapter of this book looked at lost revenues caused by utility investment in DSM and presented methods to make DSM more profitable for utilities. This chapter looks at the issues surrounding the recovery of the direct dollars spent on DSM and considers both accounting methods and incentive/penalty schemes to encourage DSM performance. Fair treatment of expenses combined with active incentives can offer a powerful way to overcome cultural resistance and accelerate utility acceptance of DSM programs.

ARE DSM COSTS DIFFERENT?

In looking at DSM costs, the first questions to ask are: How should a utility recover the direct costs associated with DSM? Are DSM program cost expenditures different from other expenses? One way to answer these questions is to look at the ratemaking system and find out what outcomes are encouraged when DSM expenses are treated the same as other expenses. Rate cases, whether based on historic or future-test years, set prices. They do **not** set expenses or revenues. Utility revenues are simply the prices set in a rate case times the level of sales. Profits are the difference between revenues and costs.

Between rate cases (practically speaking utilities are always between rate cases), profits can be increased by either increasing revenues or decreasing costs. However, not all categories of costs are equal in their effect on utility profits. Some costs, such as the marketing and labor costs associated with new customer services, lead directly to increased revenues. Were these expenditures reduced or eliminated, the utility would also experience lower revenues. Therefore, as long as the incremental revenues exceed the incremental costs, the utility has no reason to cut these costs.

Other cost reductions may have no immediate impact on revenues or quality of service, but a negative impact would likely occur over time. Tree trimming and power plant maintenance are typical examples of this relationship of expense to revenue. Costs can be cut on a temporary basis to increase profits without adversely affecting overall service, but if these costs are cut too deeply or for too long, service will suffer. At some point, customers and regulators will notice the decline in service quality and will undoubtably take action.

Finally, there are the costs which neither contribute to increased revenue nor negatively impact service quality. Federal taxes and DSM expenditures are two examples. If the utility can cut its federal tax expense, its profits go up and service quality is unchanged. No matter what level of federal taxes are "allowed" in a rate case, the utility has an incentive to reduce this expenditure to zero if it can. Similarly, if "allowed" DSM expenditures are not made, the utility is better off. No profit-making opportunities are lost, and the quality of delivered power does not suffer in either the short or long run. Were the utility to spend more on DSM than what was "allowed" in rates, it would reduce reserves and profits, and the direct expenditures themselves would never be recovered. Such an expenditure would be a loser on all fronts.

Under current regulation, utilities have an incentive to add supply-side power plants because they make a profit on their investment. Investment in DSM not only does not yield a net profit, but profits can go up by cutting DSM. Returning then to the question: are DSM expenses different from other utility expenses? The answer is an unqualified yes, and accordingly these expenses should be treated differently. Realizing this is only the first step. The larger question is what kind of treatment is best or most reasonable.

There are accounting methods and incentives both of which handle DSM expenditures differently from other expenditures and in doing so help to promote, rather than discourage, DSM.

ACCOUNTING ADJUSTMENTS

Many of the costs of DSM programs fall at the beginning of a program, while the savings are achieved over time. Cost arising from the initial marketing, installation and testing of DSM usually fall in the first year of a program's life. In addition, there is a certain amount of expected loss that will occur as the utility gains the knowledge and skills it needs to design and administer a DSM program. But once DSM measures are in place, benefits will occur over the lifetime of the measure, which in some cases is 20 years or more. The question before regulators is: How can these expenses be treated so that costs are borne fairly by all recipients — today's and those in the future? There are accounting techniques that can be applied to fairly share DSM costs, but there are also regulatory obstacles that must be understood.

As a general principle, General Accounting Principles (GAP) and the Federal Energy Regulatory Commission (FERC) accounting rules do not permit expenses, including DSM expenses, to be capitalized. Unlike a supply resource, a million dollar DSM investment cannot be capitalized and, therefore, cannot be depreciated. This means that most DSM expenses must be reflected in the first year's income statement, and recovery must occur based on the single year. There is no option to ask for recovery in any future rate cases. This is a strong disincentive.

Deferred Accounts

There are, however, exceptions to this principle. If regulatory policy is set out prior to the incurrence, some expenses can be capitalized, allowing the utility to earn a profit on them. A common way to do this is for commissions to issue an order stating that expenses incurred at one date can be deferred to a future rate cases. In this situation, a special, deferral account holds DSM expenses. At a later date, the expenditures are reviewed, and those which the commission considers prudent are allowed to be recovered in rates. This method allows adequate time for review, with reviews occurring with enough frequency to keep accumulated balances from getting too large.

The commission must carefully define what expenses can qualify for this deferred treatment. For example, would an advertising campaign explaining a utility's desire to help customers conserve be properly considered institutional or DSM advertising? Regulatory oversight needs to ensure that there are no "hidden" costs. These are expenses the utility would have incurred whether or not they had implemented the DSM or expenses that are simply not allowable, such as the purchase of tickets to sporting events.

Ratebased Or Expensed

At the time of the next rate case, DSM costs accumulated in the deferred account have the option of being expensed (recovered in a single year) or ratebased (recovered over more than one year, like a mortgage). Either approach can be designed to allow reasonable recovery of costs. Some utilities and regulators prefer expensing and the immediate cash flow it provides. Others prefer the slightly slower impact on rates which comes with ratebasing. Ratebasing can ease the impact of DSM expenditures on rates as DSM builds up and arguably provide greater intergenerational ratepayer equity. However, once a steady level of expenditures is reached, there is little difference in the rate impact of ratebasing and expensing.

Massachusetts and Iowa are two states which allow all direct DSM costs to be held in a deferred account which is periodically added to rates by amortizing the deferred costs over five years with an allowed return. Wisconsin defers, then ratebases, with the amortization period lasting up to ten years.

INCENTIVES [1]

Before outlining some options for incentives, it is worth asking, why should commissions create incentives when they can **mandate** DSM programs? First, DSM incentives should not be confused automatically with "giving the utility more money." Penalties, too, are part of a symmetrical, overall incentive approach which rewards positive performance and penalizes poor and costly efforts. Incentives give the utility a stake in successful DSM programs. For a DSM investment to reach anything near its cost-saving potential, the entire utility, in all its many parts, must believe that efficiency is a legitimate resource and one which increases personal and corporate profit.

The most successful utility DSM investments have occurred where the utility, both shareholders **and** employees, have been given the opportunity to share in the savings realized by the DSM programs.[2] Utility employees working with customers are in the best position to understand what works for their cus-

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1 A full discussion of DSM incentives is found in Nadel (1992).

[2]There are excellent examples in Wisconsin, California, Washington and Massachusetts.

tomers, where the DSM opportunities reside and how opportunities can best be captured. Commission-mandated programs, on the other hand, may simply be too rigid and generally require time-consuming oversight to ensure that the utility is following all the rules.

Common Incentive Programs[3]

The following three types of incentives programs are commonly offered to utilities.

Shared Savings

This approach begins with an estimate of the net dollar savings produced by a utility's DSM programs. Next, as the name implies, the utility is allowed to keep a share of the savings and thus has an incentive to maximize the amount of money saved. This approach is the most popular, but it must be treated cautiously to keep cream skimming — only installing DSM measures with the highest savings — from occurring. Shared savings, instituted together with other mechanisms, such as oversight by a DSM collaborative[4] will generally not result in cream skimming.

Bounty

Here a utility is rewarded with a specified amount of money for every kWh it saves, with the actual amount usually reflecting the expected shared savings. Bounties reward specific accomplishments, are the simplest to administer and maximize the number of kWh saved. They can also be used in reverse by penalizing utilities that fall short of specified goals.

Rate Of Earning (ROE) Adjustment

Utilities achieving a preset target level of activity or savings are given a higher ROE.

Key Design Principles To Market Incentives For Utilities

Choosing the right incentives program requires balancing many interests. Designing incentive plans that work will be easier if the following principles are used.

Keep it simple.

The message needs to be simple and clear, like a headline. If utility managers do X, they will get Y. It is not enough to say they have the opportunity to argue for Y. That kind of language carries with it an uncertainty that will cause utility managers not to hear, or at least not to believe, the message.

Get their attention.

The amount of money involved, whether a penalty or reward, needs to be enough to get the attention of the utility's board of directors. A range of 50-100 basis points commonly will spark utility interest. Incentives for managers and line workers who successfully install DSM should also be large enough to capture their attention.

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[3] For a general discussion of DSM incentive options see Moskovitz (1989). For a review of the variety of incentives state commissions have provided for DSM investments see Reid (1993).

[4] Collaboratives which typically consist of the utility, environmental groups, the state's consumer advocate and representatives of customer groups have been used in several jurisdictions, sometimes initiated by the commission and sometimes by the utility. They generally discuss and try to reach consensus on a range of DSM issues such as the size of investment, the design, implementation and evaluation of programs and cost recovery. For more information, see J. Raab (1992).

Don't overdo it.
The rewards offered to utilities must pass the front-page test. While directing a slice of the savings back to the utility offers a serious corporate incentive, it is the customers who must be the largest beneficiaries and receive the lion's share of the achieved savings.

Do Incentives Work?

In nearly a dozen states where incentives are in place, the DSM activities of the utilities have been analyzed before and after incentives were instituted. Comparisons of DSM activities of utilities with state incentives and those in neighboring states without them have concluded that incentives make a difference (Nadel 1992 and Wisconsin Energy Conservation Corporation 1993).

A good example of how a well-designed incentive structure can stimulate and support managerial interest in DSM can be found at the New England Electric System (NEES) which serves customers in Western Massachusetts and Rhode Island. NEES has both a shared savings and a bounty plus cost incentives. The earnings resulting from these plans were enough in 1992 to put them over an earnings threshold which then triggered the management bonus system. Such a structure creates a powerful internal motivating force for successful DSM.

CONCLUSION

Removing accounting biases by allowing DSM expenses in a fashion that reflects the nature of these costs. Also offering utility incentives to support DSM will go a long way toward making DSM an attractive energy service for utilities to pursue seriously.

How to Acquire Renewable Resources

INTRODUCTION

A recent Department of Energy survey indicates that renewables represent roughly 8.5 percent of the country's energy mix, a percentage which would be far smaller but for large-scale hydro projects. This is disturbing because there are many more proven, cost-competitive renewables available in the marketplace than are being used. Estimates as to the percentage of renewables that could reasonably be included in the country's energy mix by the first quarter of the 21st century range from as low as 18 percent to as high as 53 percent. Even using the most conservative projection, it is clear that renewable energy should play a much larger role in the nation's supply than it does.

By not exploiting cost-effective renewable opportunities, most utilities are not locating their least-cost energy option and as a result the energy mix in many states is more expensive than it needs to be. The value of renewables also extends beyond the easily quantified, direct cost of supplying energy. Their supply is sustainable. Environmental impacts are typically much lower than impacts from fossil fuel plants. Production units can be built in smaller, modular increments, with significantly shorter construction lead times than required for conventional fuel plants. Finally, renewables increase the diversity of a utility's fuel mix.

While most states have very little recent development of renewables, there are some notable exceptions. Since the late 1970s both Maine and Vermont have substantially added to their electric power resource base, and virtually all the resource additions have come from renewables, mostly in the form of biomass energy. California has developed a great deal of wind power and leads the nation in the use of solar energy. These advances are particularly striking because while these states are endowed with the renewable resources that they are exploiting, there are other states with an equal or richer resource base where very little development has taken place. A reliable wind resource is most available in the Great Plain States from North Dakota to Texas. While Maine may be timber rich, the same can be said for Washington, Oregon, Louisiana and Georgia. Solar resources could be most fully exploited in New Mexico, Arizona and parts of Texas.

What then are the characteristics that allow one state to actively pursue an available renewable resource, while another state opts to ignore a similar or better resource? The answer is a complex one which will vary from state to state, but at the heart of the answer is a regulatory environment which expects utilities to aggressively and accurately pursue IRP.

This chapter describes ways to increase the portion of renewables in the energy mix. It looks at the opportunities and barriers which exist during policy setting, planning, acquisition and contracting. Then, it describes initiatives which, if pursued, could be useful in persuading more utilities and regulators of the viability of renewables.

USING INTEGRATED RESOURCE PLANNING PRINCIPLES [1]

The concept of IRP has been well established as an economic resource optimization model which serves as a means of conducting analysis and comparison to find the most efficient, reliable and least-cost combination of energy resources. Key to understanding IRP is to appreciate the distinction between what a resource costs and what a resource is worth. The back-of-the-envelope calculation, a competitive bid or a simple spreadsheet can tell you what a resource costs. IRP goes farther and tells you what a resource is worth. This distinction is very important when considering renewables or comparing renewables to a diverse set of energy resources. The reason is simple. In choosing between two very **similar** resources, where the timing, location and load duration is the same, it is safe to say that the "right choice" is the resource that costs less. Because similar resources are worth the same amount, the less costly one is clearly the better value.

When resources are **markedly dissimilar,** the calculations are not so simple. Yet if IRP is adopted and implemented well, cost-effective renewables will fare well. For this to be the case, regulators and utilities need to have up-to-date information about the cost, availability and the performance of renewables. This is particularly important because early experiences with wind, solar and other renewable technologies (when costs were high and reliability unpredictable) continue to color regulators', utilities' and customers' views about renewables. Without reliable and recent information, decision makers will not be able to make good choices about which resources should receive serious consideration during the IRP process.

Such information is critical to perform the sophisticated analysis needed to adequately compare the worth of a resource. Unfortunately, many states, including those with fully implemented IRPs, continue to view acquisition of resources as commodity-driven. The lower the cost, the better the deal. Yet, there are many situations where the higher priced resource is actually worth more to a utility. When the total value of the resource is considered, assessment of the true cost can only be identified when performing the type of analysis demanded by the IRP process. These analyses go beyond just looking at the cost of the resource and factor in one or all of the following components:

- operating requirements
- distribution, transmission and reliability benefits
- environmental impacts
- location on the utility grid
- a methodology that reflects comparative risks, including technological, fuel cost, environmental, contractual and performance.

Take, for instance, a company choosing between two very different resources, such as a wind farm and a coal-fired plant. Knowing the cost of each resource cannot by itself tell you which resource is the right choice. The wind resource might cost 6¢ per kWh and the coal plant 5¢ per kWh. The answer, while appearing obvious, is not. Other factors taken into consideration might show that the wind farm plant is worth 6.1¢ and coal

[1] Three papers prepared in 1992 and 1993 by Moskovitz provide a more detailed discussion on the issues associated with renewables and on specific initiatives which can be taken.

plant is worth 4.9¢ per kWh. In this calculation, the wind farm is cost effective and the coal plant is not.

Line extensions into remote areas provide another good example of incorporating these concepts into a decision-making process. In these areas, the avoided cost is the combination of capacity and energy-related savings, labor and material costs of placing poles and transformers, and transmission and distribution costs caused by the extension of services. When this full range of costs is factored into the equation, renewables have a better chance of emerging as the most cost-effective option.

Giving Value To The Unquantifiable: From Good Tools To Supportive Policies

A planning tool, no matter how good, cannot do it all. While tools are getting better all the time, there are factors that are simply not easy to quantify. What is the value of diversity and short lead time? How can we quantify environmental considerations? How much is it worth to develop new technologies at a higher price today in return for a lower price tomorrow?

An IRP process would be easier to undertake were these values easily quantified and plugged into a calculation. But this is not the case, and it is altogether possible that quantifiable values can never be attributed to these considerations. To remedy this problem, judgment calls also need to play a role in the planning process. A stated policy eliminates the need to either ignore important values because they cannot be quantified or spend a huge amount of intellectual capital on trying to determine numerically what diversity is worth or what a reduction in fuel risk is worth. Once a policy is adopted, a value for the combined features can be calculated by looking at the policy decision, determining its financial impact and coming up with a numerical value of worth.

California, for example, said half of its new energy resources would come from renewable resources. By calculating backwards from this decision and determining how much more California will pay if renewables constitute half the anticipated resources, it would be possible to say that the value of renewables is worth X amount to California legislators. New York has taken a slightly different tack. They said that they want to get up to 300 MW of renewables provided that it does not cost too much. New York is currently trying to determine how much is too much and will likely come up with a number that says "We are willing to have our rates go up by X amount in order for renewables to make up a larger fraction of our energy mix."

Another policy technique adopted by some states is "tie breaker" legislation. Michigan, Minnesota, Maine and New Jersey all have statutes which express a preference for conservation and renewables. In effect, these laws direct utilities to favor renewables and conservation if all other factors are equal. Other states simply have statutory language that encourages renewables.

ACQUISITION

Once an IRP plan has been developed in which some portion of renewables are included in the energy mix, the next step is to be sure that the acquisition process is designed to support implementation of the IRP. The primary areas where the transition from planning to acquisition requires attention are:

- price
- acquisition methods
- contract details
- transmission
- regulatory support for renewable acquisition

Price

The price used in the planning process must be similar to that reflected during acquisition. If a policy on what a renewable is **worth** is included in the planning process, it must also apply during the acquisition process.

Acquisition Methods

Approximately one-third of the planned renewable additions are expected to be owned and operated by regulated utilities. The remaining two-thirds are likely to be provided by qualifying facilities and non-utility generators (NUGs). While there are barriers to acquisition of renewables for both utility and non-utility sources, barriers facing the NUG are the greatest.

Utilities will obtain renewables from the non-utility sector via competitive bidding, contract negotiation or a hybrid of the two. No matter how the resource is acquired, care must be taken to assure that all resources are able to enter into unbiased competition. Problems arise when certain provisions are adopted which preclude the ability of some resources to fairly enter into the competition. For example, in their negotiations, some utilities make it clear that contract payments will be lowered when avoided cost falls below a certain level. Other terms call for canceling a contract if regulators prohibit the utility from full cost recovery at a later date. The cash flow uncertainties created by these provisions make it nearly impossible to obtain financing for what might otherwise be a cost-effective, renewable resource project. Allocating the risks in this way means that the utility imposes very different standards on a NUG than they might impose on themselves or another utility. Excessive demands placed upon NUGs that in essence bar them from the competition can be described as **show stoppers**.

A commission or utility needs to understand the potential impact of these show stoppers on the acquisition process by asking themselves whether certain provisions simply eliminate some resources from the competition. If the answer is yes, if provisions are designed with the sole intention of eliminating certain competitors from the acquisition process, then it is better to state right from the start that certain resources — i.e. municipal solid waste incinerators or coal-fired plants — are not wanted.

More commonly, however, this explicit desire to rule out a competitor is not the case. Instead provisions, which are established for one purpose or for traditional supply technologies, end up having unforeseen and expensive consequences. One of the worst mistakes that a utility can make is to impose a cost inadvertently on some projects and not on others. As a consequence the analysis is skewed because the provision raises the cost of the project, making it appear too expensive for a utility to acquire.

An understanding of the risks and how they are allocated before the competitive bidding or negotiation process begins can help avoid this trap. The Massachusetts's Commission attempted to address this when first getting involved in competitive bidding . At that time, they expressly undertook a decision-making process where they identified each potential risk and decided, right from the start, who would bear it. When allocating a risk to a developer, it did not matter whether the developer was a utility or a non-utility developer. By being conscious and clear about this from the beginning, they were able to compare options with equal risk profiles.

Contracts Details

Failure to negotiate a contract has been noted as the primary reason that successfully bid renewable projects fail to become operational. One reason is the tendency of both utilities and regulators to tilt the playing field with regards to risks and write contracts with NUGs which get the maximum possible amount of security, assurance and guarantee. It is important to understand that while this can be done and some of what will be included in the contract will come virtually without cost, other items, such as security requirements, will have a price tag attached to them.

Standard Contracts

Standard contracts which specify the general terms and conditions under which power is to be purchased offer ways to keep the playing field fair. At a minimum, they serve as a point of reference making it easier to consider how to incorporate into a contract those provisions which differ from standard terms. By beginning with the same terms and expectations in all contracts, there is a better chance of treating sellers of all types of energy resources equally. Standard contracts can reduce transaction costs and provide a convenient, efficient and direct way to examine acquisition issues and fairly convey state and utility policies to developers and financiers.

Front-end Loaded Contracts

Front-end loaded contracts provide power contract payments which exceed utility avoided cost during the initial years of the agreement, then decline in subsequent years. In general, the more capital intensive a technology (as is frequently the case with renewables) the greater the need for a front-end loaded type of contract. Front-end loading matches the types and timing of costs incurred by facilities whose initial construction costs are significantly higher than their long-term operating costs. However, because front-end loaded contracts mean that early payments will be high (despite the fact that later payments will be low), some states prohibit or, at minimum, discourage front-end loaded contracts. Outright prohibitions on front-end loaded contracts eliminate some renewable resources from further consideration, even when a renewable option is, in fact, the least costly. When this happens, it is important for utilities and regulators to consider carefully the advantages of renewables and determine the expected full life cycle cost and savings of many of these options. Instead of simple prohibitions, regulators and utilities should adopt contract practices that consider each project's total, lifetime costs together with the cost characteristics. This issue is discussed further in the next section.

Security

Another contract consideration is how utilities handle security. At issue is the need to protect ratepayers from projects which, for one reason or another, fail. To address this concern, utilities frequently add security provisions to contracts. These provisions serve as insurance policies to guarantee that a facility will be built on time, perform as expected and operate for the full term of the contract. As with any insurance policy, the more extensive the required coverage, the greater the cost to the resource developer. Therefore, when too many security requirements are placed on a resource developer, the cost of the project can become so expensive that it may no longer be cost effective.

The risk of demanding too much security is especially great for facilities with front-end loaded contracts. In the early years of such projects, customers pay higher prices in anticipation of receiving the benefit of lower prices in later years. Security provisions aimed at assuring reliable performance in the later years of operation can negate some of the financial advantages afforded by front-end loading.

This question of cost-competitiveness is of particular concern because the security requirements imposed on NUGs have no parallel to similar projects constructed by utilities. In the case of utilities, the risk of expensive failures or long-term expected benefits that never materialize is borne directly by consumers and is not included as a cost of power plant development.

It is possible, though, to address the need to insure without placing an undue financial hardship on a developer. Perhaps the least costly and most effective way is to carefully construct the price pattern to provide security. This can be done by tailoring a contract payment mechanism to reflect the cost of the technology that is being bought, not the technology that is being avoided. In the case of renewables, this means that the energy payments over the term of the contract must cover more than the operating cost of the facility. Pricing schemes with this basic element have been adopted in New Jersey, California and Vermont in order to make sure that security be provided without imposing additional costs on the contract acquisition process itself. This pricing pattern means that it is always in the best interest of a NUG to operate its plant. The more reliable the plant and the more it operates, the more profitable the plant will be. Such a pricing scheme is also a useful way to judge when and to what degree front-end loaded contracts may be necessary for capital-intensive, renewable projects.

Transmission

The issues associated with transmission can both support and hamper development of renewables. On the positive side, there are situations where a stand alone photovoltaic system can be placed in a remote area thereby eliminating the need for a new transmission line. In other instances, renewable technologies can be located strategically on the existing grid to avoid or delay needed upgrades to the transmission and distribution system.

Yet other renewables, because of where they are located geographically, do not offer the same advantage. In these cases, rather than eliminating the need for a transmission upgrade, these renewables require transmission lines to wheel the power into the grid. The question that arises is how should the cost of these system upgrades be handled. Four states, Michigan, Maine, Wisconsin and New Jersey require that transmission upgrade costs be reasonably allocated between the utility (actually its customers) and the developer. Other states place nearly the entire expense on the developer. California, for example, runs the **but for** test. If the transmission system would not have been upgraded, **but for** the addition of this project, then the developer must bear the full cost of the upgrade.

Regulatory Support For Renewable Acquisition

The process in place by PUCs can be a hindrance or a benefit to renewable resources. On the positive side, the presence of a simple and efficient regulatory process can help resolve disputes that arise during negotiations. Commission rules which clearly articulate state policies toward renewable resources can specify what is expected of utilities and what consequences will fall on parties who do not comply. Clearly articulated policies can promote an efficient competitive acquisition system where there is a place for renewables.

On the other hand, commission proceedings can be time consuming, expensive and necessitate the personal involvement of the developer. This can be a serious barrier to developers of renewable resources who neither have experience with such proceedings nor have the resources needed to participate fully. As a result, developers of renewables will focus activities in states where they believe they can best get a project permitted and built and will shy away from states with time-consuming, expensive or unfamiliar processes. To remedy this, regulatory practices designed to minimize the amount of regulatory involvement required by non-utility developers should be adopted.

The relationship between a developer and commission is also strongly influenced by the temperament and attitude of the regulated utility. Some utilities are committed to innovation while others have much more narrow and self-serving views about resource acquisition. When deciding how to treat utilities, commissions must judge and decide just how prescriptive or how flexible they should be when considering mechanisms to encourage the acquisition of renewables. In doing this, regulators need to be sure that the mechanism they adopt matches the nature of the utilities they are regulating. Ideally, consumers are best served by a flexible approach because it is through this flexibility that utilities can maximize the value they offer their customers. With less cooperative utilities, however, this approach can backfire because flexibility also gives utilities the option of simply ignoring cost-effective resources. When this is the case, it is better for commissions to design a prescriptive approach where acquisition of cost-effective resources are required rather than to assume that a utility will, on its own, locate and acquire these types of resources.

Utilities with no obvious conflicts and a history of being supportive of renewable acquisition should be given a loose enough rein so that they have the flexibility to be innovative. Regulation of more resistant utilities, on the other hand, will have to be more prescriptive to assure that cost-effective renewables are acquired.

SUPPORT OF RESEARCH AND DEVELOPMENT

Any new technologies raise the question of how to support and pay for the learning curve appropriately associated with the research and development stages needed to bring a new system on-line. There are a number of strategies and ideas which can be implemented to support development of renewable technologies; technologies that are currently priced above the avoided cost but, with more operational experience and production efficiencies, could become cost competitive.

Revisiting The DSM Model

Utilities and commissions can rely on experience from DSM pilot programs when looking for models to support the development of renewables. A review of these programs shows that utilities supporting DSM programs have faced relatively little risk during the start-up of DSM activities. By following certain guidelines, cost recovery was nearly always assured during a reasonable learning period. This is typically the case even when a pilot program ultimately proves not to be cost-effective and therefore is not pursued further.

The reason for assurance at the outset of new programs and activities was that commissions anticipated that there would be expenses, perhaps above avoided cost, associated with the learning curve for energy conservation projects *for which detailed cost-effectiveness analyses had not yet been performed.* It was understood from the beginning that there would be some pilot programs that would not be successful and that continuation of such a program, at least without modifications, might not be a very good idea after all. Commissions around the country recognized this "start up" risk and decided it was one worth encouraging utilities to take. Commissions, in general, allowed for cost recovery of prudent expenditures associated with these projects.

This is really no different from pursuing a renewable pilot project to learn more about a technology, to improve a technology and/or to determine situations where the technology is cost effective. As with DSM, there is always the possibility of failure. Commissions exercise their leadership and commitment by making policy decisions based upon judgement calls. These give utilities the direction they need on the size, cost and timing of the risk they can reasonably expect to assume.

Market Pull Or Sustainable Orderly Development

Here the question is should utilities spend above their avoided cost today with the expectation that by buying now the market will be pulled along and the cost of the technologies will fall; fall so much that the aggregate of the early and late purchases will be cost effective. Take for example, photovoltaics. It may be reasonable to believe that if utilities start buying small amounts today, say ten MW for the next five to ten years, that the future cost of photovoltaics will be low enough to be cost effective. However, the only way that future costs will be low enough to be cost effective, is to spend some money today. These early purchases give the learning curve a chance to move to a point of improved production efficiencies and operational effectiveness.

There is precedent for precisely this kind of approach. The Sacramento Municipal Utilities District (SMUD) made a decision to purchase renewables that were not cost effective because they predicted that as a result of investments such as theirs, prices would go down. Today, prices are monitored and if SMUD's prediction does not hold true, they have the option of stopping the purchases.

Here again, there is a DSM precedent for this approach. In the golden carrot program for energy efficient refrigerator development, utilities offered a cash prize and marketing support for the company who could manufacture the best, energy efficient refrigerator. This program accelerated the development of the highly efficient refrigerator, and today there are three on the market — three, because in addition to the winner, two other contestants are also marketing the prototypes they developed during the competition. This program gave manufacturers enough incentive to support the development of energy efficient, but expensive, refrigerators under the assumption that there would be consumer interest once the product was commercially available. This approach recognizes that consumers would not have access to certain technologies today but for the willingness of some to take risks and make investments five years earlier.

This philosophy has driven technology development in this country in many fields for many years, and it is wholly appropriate to consider it an effective approach for renewable development. However, translating this sound notion into regulatory policy can be difficult. Ideas for spurring on costeffective applications of renewable resources are discussed below.

INITIATIVES TO IMPROVE OF ACQUISITION RENEWABLES

Most of the initiatives discussed here are interim in nature. Yet by implementing them now a broader range of interests will be able to see the value of an increased role for renewables. Through this showcasing venture, there is a greater likelihood that efforts will be made to identify and remove the planning, acquisition and regulatory barriers to renewable acquisition.

Green Pricing

These are optional rates in which consumers agree to pay a little more, between five to ten percent above their existing retail bill, in order to support the utility's acquisition of renewable energy resources that may be slightly higher than the avoided costs. Consumers have already demonstrated their willingness to purchase more expensive products precisely because they are better for the environment. Green pricing provides customers with a means to accelerate renewable development beyond the level that is justified using least-cost planning. This support should result in more development and acquisition of renewables and will likely lead to increased production and technology improvements which will further lower the cost of renewables.

Utility Shareholder Incentives To Encourage Acquisition Of Renewables

For the most part, any incentives for renewable development have been given to developers in the form of tax credits and additional tax benefits. Incentives aimed at developers are useful particularly if renewable resources are not yet competitive with conventional resources. On the other hand, if renewables are already cost effective, as many are, the overall impact would improve if the incentive were shifted and used to en courage utilities to purchase power from an operating renewable.

Wisconsin is the only state in the country that has a purchased power incentive solely for renewables. Put in effect in May of 1993, an incentive of 1/4 to 3/4¢ per kWh, depending on the type of renewable acquired, should improve the interest in and success of renewable projects in Wisconsin. Even a smaller incentive in which a utility is able to earn one mill per kWh for each kWh purchased from a new renewable resource (provided that the purchase price is at least one mill below the utility's avoided cost) will encourage utility managers to overcome perceived obstacles in purchasing renewables.

Green RFP

Carefully written competitive bids can and should be designed to avoid problems that discourage participation by renewable developers and bias utility decisions against renewables. One way that this is accomplished is by issuing a RFP in which only renewable energy resources are allowed to compete to fill an allocated portion of new capacity needs. By separating solicitations for renewable and non-renewable resources, the bidding documents and the evaluation procedures can focus on the unique characteristics of each resource. In addition, it sends a clear signal to developers of renewable energy resources that their projects are welcome.

In 1992, New England Electric Systems (NEES) issued such a RFP to solicit proposals solely from developers of renewables. The response to this Green RFP convinced them that the cost and availability of renewables were much better than they would have predicted. NEES received 41 bids and selected seven projects to provide 200,000 mWh annually. Energy sources for the seven projects include wind, municipal solid waste, waste heat and landfill gas.

Safe Harbor Rules

Safe harbor rules offer a chance to balance a utility's desire for certainty on the one hand with its need to improve its learning curve about renewables through research, development and demonstration programs. The concept recognizes that while some risk is okay, if utilities feel that the risk they are being asked to assume is too large, then good programs may not be implemented because utilities feel cost recovery might be in jeopardy.

Utility uncertainty can be reduced through regulatory rules which encourage the use of demonstration programs for renewable resources. These are activities that a utility can safely invest in without unduly risking cost recovery. These "safe harbors" establish boundaries for utilities which quantify how much or what kind of risks can be taken without sacrificing cost recovery. Safe harbor rules give regulators a means of expressing policy preferences relating to renewable research and development activities, as well as establishing research and development expenditure budget levels that protect both the customer and the utility interests.

The concept of safe harbors is not new and has been used by the Securities and Exchange Commission (SEC) in many areas.

Maine and Iowa adopted safe harbor rules on conservation programs in which utilities were authorized to implement any cost-effective conservation program, without prior commission approval, provided that the rate impact was less than one percent. In promulgating this rule, regulators let utilities know that they should only seek pre-approval on those conservation programs that would have a meaningful impact on overall rates. New York's safe harbor rule states that one percent of utility revenues could be invested in research and development expenditures without prior approval of the commission.

Safe harbor differs from pre-approval in its specificity. Pre-approval is contract-specific. Regulators give permission to sign a specific contract. Safe harbor is much broader in its purpose. It sets guidelines that give a utility flexibility to learn about and experiment with new technologies without jeopardizing a utility's chance to recover the costs associated with the learning experience. While utilities are still subject to prudence reviews, safe harbor rules outline what the commission believes is a reasonable course of action.

Stand-Alone Service

Regulators and utilities should recognize the potential benefits of stand-alone service by adopting rules that encourage the use of cost-effective, renewable-based customer stand-alone services.

The Colorado PUC is the first commission to amend its electric line extension rules by requiring utilities to present customers with a cost comparison between stand-alone photovoltaic systems and conventional line extensions. The calculation takes into consideration energy use and distance from existing transmission lines to determine whether a stand-alone photovoltaic system would be cheaper than a line extension. While cost considerations do not single handedly affect whether or not a customer will ultimately choose a stand-alone system over a line extension, they do go a long way toward increasing the utilities' and public's awareness about a photovoltaic alternative. Cost comparisons leave open how the responsibilities and risks for these systems are best shared between the customer and the utility.

Restructuring Taxes To Encourage Use Of Renewables

Resource acquisition decisions could be influenced by changing how utilities are taxed. Currently, taxes are collected based upon gross receipts, sales, property and income. Taxes are unaffected by the resource used to produce energy.

If, for example, sales or income taxes were replaced by emissions taxes, decisions regarding utility operation and resource acquisition would be different. If taxes declined as air emissions declined, utilities would be more likely to favor investments in cleaner fuels, air pollution reduction systems, conservation and renewables. While this initiative is in its infancy and needs fine tuning before being implemented, it shows promise when considering truly effective ways of encouraging the development and use of energy resources that are less harmful to the environment.

CONCLUSION

Renewable energy can play a much larger role in the nation's electrical supply than it currently does. One reason that renewables have thus far failed to gain the prominence they deserve is that current planning and resource evaluation methods do not measure the actual value of these resources. Yet aggressive and creative actions by regulators, utilities and other policy makers can make a substantive difference in bringing renewables on-line in the twenty-first century.

Energy Policy Act Of 1992

The Energy Policy Act (EPAct) of 1992, the most significant Federal energy policy in a decade, has the potential, if fully implemented, to reduce electricity bills significantly for consumers, to improve the nation's energy efficiency and to reduce the emission of global warming gases.

EPAct creates both new opportunities and new obligations for regulated electric utilities and for state regulators. They promote IRP for regulated electric utilities and increase the resource choices available for consideration in a utility's IRP process. This broader range of choices is encouraged in three ways. First, new production tax credits and subsidies will make renewable resources cost competitive. Secondly, demand-side investments will become more financially attractive to utilities. Finally, the potential number of competitive providers of all resources will increase as a result of changes in the Public Utility Holding Company Act and FERC-regulated transmission access.

The Act is a large and comprehensive piece of legislation that impacts nearly every producer and user of energy in the United States. This chapter examines the two sections of the Act that concern IRP for electric utilities and that create new duties for state public utility regulators: Conservation and Energy Efficiency by Electric Utilities (Sec. 111) and Long Term Wholesale Purchase Standards (Sec. 712).

In their review of the regulated utility provisions of EPAct, the American Council for an Energy Efficient Economy (ACEEE) and the Alliance to Save Energy (ASE), made the following energy saving estimates for the years 1993-2010.

Saves:	**4.6 Quads of Energy (mostly coal and gas)**
Saves:	**275 billion kWh**
Avoids:	**Construction of 104 (500 MW) coal plants**
Reduces:	**20% of the projected electricity growth**
Reduces:	**by 34% carbon emission growth**

WHAT DOES EPACT COVER?

The new obligations created for state public utility regulators are contained in amendments to the Public Utility Regulatory Policies Act of 1978 (PURPA)[1]. Four new ratemaking standards are set out for commission consideration, all of which directly impact the electric utility IRP processes. State regulatory authorities **must consider** each of these new standards for each electric utility

[1] 16 USC§2601-2648.

over which it has rate authority. However, **adoption is voluntary** and left to the discretion of each commission.[2]

In considering each standard, commissions must determine whether its adoption will advance the three original purposes of PURPA:

1. Conserve energy supplied by electric utilities

2. Make more efficient use of the utilities' facilities and resources

3. Establish equitable rates for electric consumers

Conservation and Energy Efficiency By Electric Utilities Title I, Sec. 111

Three of the Act's four standards for regulatory consideration fall under this section. If enacted into state laws, these standards offer the greatest promise for the country's utilities to improve their energy resource selection and use. These three standards are:

1. Integrated Resource Planning

2. Investments In Conservation and Demand Management (Demand-side Profitability)

3. Energy Efficiency Investments in Power Generation and Supply (Supply-side Efficiency)

Integrated Resource Planning Sec. 111(a)(7)

All state commissions must consider the adoption of an IRP process that requires utilities to develop an analytical framework to compare equitably and systematically supply- and demand-side resources. Through the development of such a framework, a fair evaluation of the full range of resource alternatives can be undertaken to determine what mix of resources will best provide customers with the lowest cost service that is also reliable, diverse and capable of being effectively dispatched to meet load. This analytical framework must include a methodology to evaluate and verify savings from energy conservation and demand-side investments and to monitor the durability of the savings over time.

Electric utilities employing IRP are required to provide opportunities for public participation and comment during the planning process. Further, the Integrated Resource Plan must be regularly updated, and finally it must be implemented.

Investments In Demand Management (Demand-side Profitability) Sec. 111(a)(8)

This standard requires that utilities' investments in energy conservation and demand-side management be as profitable as supply-side investments. This is an issue that was addressed in a resolution adopted by NARUC in 1989. At that time, NARUC concluded that regulatory reform was needed to remove the disincentive to IRP and to make

[2] PURPA originally required consideration of five ratemaking standards: cost of service, time of day rates, load management techniques, no master metering, automatic fuel adjustments, only with incentives for efficiency and information to consumers about rate schedules. These all work to promote efficiency and are worth revisiting if not yet in place. 26 USC§2625.

the successful implementation of a utility's least-cost plan its most profitable course of action. In considering demand-side profitability, calculations must take into consideration income which is lost when sales are reduced as a result of energy conservation and efficiency investments. Cost recovery policies together with the need for a positive incentive for demand- side activities should also be included when implementing this standard.[3]

While it is important for the signals to be clear to the utility that there is no penalty for vigorous pursuit of demand-side options, EPAct recognizes that care must be taken to document conservation and energy efficiency savings so that the utility does not improperly benefit from overly ambitious predictions of savings. The Act therefore specifies that investments made in conservation and efficiency must be monitored and evaluated to determine if the savings that were expected were, in fact, achieved so that neither the utility nor its customers is penalized by, or benefits from inaccurate estimates.

Energy Efficiency Investments In Power Generation And Supply Sec. 111(a)(9)

The focus of this standard is to improve generation, transmission and distribution efficiency. In adopting this standard, commissions would review ratemaking policies, identify those which pose disincentives to efficiency and adopt new approaches that reward improved supply-side efficiency.

One place a state commission might first look to identify disincentives to efficiency is in the fuel cost adjustment practices. Fully reconciled fuel adjustment clauses are a disincentive to efficiency, as efficiency gains do not reward the utility (nor does the utility suffer loss) for inefficient operations which result in a greater use of fuel. For example, a power plant in need of maintenance will often consume more fuel to meet its required energy output. Because fuel costs are fully recovered from customers and repair costs are not, the utility is better off delaying maintenance and using more fuel.

Protection for Small Businesses

Although not a new PURPA standard in and of itself, Section III of the Act recognizes the impact the adoption of the IRP standards could have on small energy service-related businesses. In response to this concern, when a state commission adopts either the IRP or the demand-side profitability standard, it must also consider the impact of these standards on small businesses engaged in the design, sale, supply, installation or servicing of energy conservation, energy efficiency or other demand-side management equipment. This requirement stems from a concern that a utility, by design or inadvertently, may exert its monopoly power to squeeze out competitors who are or could provide energy conservation services.

Utility energy conservation programs can encourage, as well as discourage, market opportunities for small businesses. A utility which provides all energy conservation through the use of in-house programs and direct purchase from select vendors effectively cuts out the small competitors. On the other hand, utilities such as New England Electric Systems (NEES) and Pacific Gas and Electricity (PG&E) have relied extensively on local businesses to supply and in-

[3] Mechanisms for recovering lost revenues are described in an earlier chapter.

stall efficiency products. This practice has created new business opportunities for the private sector and has improved inventories of energy-efficient equipment such as motors, lights and windows at many wholesale and retail outlets.

Competitive bidding for DSM services uses market forces to identify providers of demand-side services. Such programs create markets where they did not exist previously and can expand opportunities for small business providers.

<u>Long-term Power Purchase Standard</u>
<u>Title VII, Sec. 712</u>

This fourth standard of EPAct which also relates to the IRP process describes four issues which must be looked at by a state commission when considering utility purchases of long-term power contracts from wholesale generators.

If this standard is adopted, a state commission would ask the following four questions when reviewing wholesale power purchases.

1. What are the utility's capital costs and retail rates when power is purchased from a long-term, wholesale power supplier and how do these compare to the capital costs and retail rates that would occur if the utility constructed its own generating facility?

2. Does the financing structure of exempt wholesale generators, which can carry a higher level of debt than equivalent facilities built by utilities, threaten the reliability of power purchased from the wholesale generator or provide an unfair advantage for the wholesale generator when compared to the utility?

3. Does it make sense to implement a mechanism for advanced approval or disapproval for a specific wholesale power purchase?

4. Should a reasonable assurance of adequate fuel supply be a condition of pre-approval of purchased power?

In general, most state commissions examine these questions as a matter of course when reviewing wholesale power purchases. Adoption of this standard simply assures that the proper questions will be asked.

CRITERIA, PROCEDURES AND TIMETABLES FOR CONSIDERATION OF THE FOUR STANDARDS

<u>Criteria</u>

Each state commission is required to consider the four standards and determine whether or not they are appropriate to adopt in light of the objectives of the 1978 PURPA law.

State commissions have the latitude to reject a standard if it is contrary to state law. They can also elect to implement partially or phase-in the standards in cases when immediate and full implementation would impose a hardship on ratepayers.

<u>Procedures</u>

State commissions are required to review the standards for all rate-regulated electric utili ties, including investor-owned utilities, municipal utilities and cooperatives. In states where commissions have already considered the three conservation and energy efficiency standards, the prior proceedings will suffice in meeting EPAct's standard of consideration, providing that the written record ably reflects both what was considered and the final decision. This same grandfathering option does not apply to the wholesale purchase standard.

For all standards which require consideration, commissions must provide public notice and conduct a public hearing designed to allow all interested parties to communicate their views. A commission's final decision as to whether a standard will or will not be

QUESTIONS ARISING FROM EPACT

EPAct raises some very important questions regarding the structure of the electric utility industry.

Does EPAct's increased emphasis on IRP conflict with the increased emphasis on competition in the electric industry?

While this question is raised frequently by both regulators and utilities, IRP and competition are wholly compatible and, in fact, can strengthen one another. The goal of IRP is to reduce the cost of resource acquisition over a given period, and the purpose of competition is to use the market place to see what resources are available in order to find those with the lowest cost. As with any policy, if not properly implemented, conflicts can occur. Conceptually, these two activities work well together.

The IRP process provides an analytical framework to feed market-based information into a company's own internal planning and cost analysis. Using the IRP process, a utility will first conduct its own analysis to identify its energy needs and to select resources it believes can meet those needs at the lowest total resource cost. After this analysis is done, market information can be collected and scrutinized to see whether there are resources that can meet the utility's demand for power at a cost lower than the utility believed it could achieve itself.

Used in this manner, IRP and wholesale competition go hand in hand to achieve the lowest cost/optimal resource mix. The IRP process establishes a framework for comparing a wide range of disparate resources and allows the selection of the ones which are truly the best value when taking into consideration such factors as cost, reliability and variety. The more diverse the resources a utility examines, the more the IRP process is needed, precisely because it provides a common framework to compare a broad array of supply- and demand-side resources with vastly different operating and cost characteristics — from attic insulation to power from a gas-fired generator to photovoltaics to wind — and decide which are the best value for a utility and its customers. The outcome of IRP will be improved as the number of options increases. Wholesale competition is a powerful way of adding choices to the process.

How does the Act treat retail wheeling?

The Act leaves the legality of retail wheeling up to each individual state. However, where the IRP process includes an opportunity for competitive wholesale market participation, it is unlikely that an individual retail customer would be able to attain supply-side resources below a utility's avoided cost. Those resources would already have been offered to and acquired by the utility.

Commissions need to approach retail wheeling with great caution. The retail wheeling sought in states in the past year has been antithetical to economic efficiency. Independent resources were offered at costs which were, in fact, greater than the utility's own avoided costs though lower than existing retail rates. Retail wheeling of resources which are more costly than the utilities' avoided cost increases the total cost of electricity resources.

What is the relationship between EPAct and the Clean Air Act?

The passage of EPAct means that there will be a greater need than ever for cooperation between the DOE and the EPA. The Clean Air Act Amendments of 1990 provides utilities the opportunity to earn credits by reducing SO_2 emissions with energy conservation investments **when done under an IRP framework.** The definition of IRP in the Clean Air Act is nearly identical to the definition found in EPAct. Yet despite this apparent similarity, there is still latitude as to how the Acts are interpreted and implemented at the state and federal levels. The Clean Air Act requires that the savings from energy conservation investments by regulated utilities be measured, verified and persist over time. State activity that meets this standard should also comply with Section 111 of EPAct. It is in the interest of state commissions for EPA and DOE to coordinate their views of IRP in an effort to minimize any confusion that could result from state regulatory implementation of the two Acts.

adopted, must be in writing and must be based upon the record and evidence presented at the hearing.

Timetables

Consideration of the wholesale purchase standard must be completed within one year of the adoption of the Act, by October 24, 1993.

Consideration of the conservation and energy efficiency standards must begin within two years of the enactment of the Act, by October 24, 1994 and be completed by October 24, 1995.

RESOURCES AVAILABLE FROM FEDERAL AGENCIES

The DOE has been authorized to provide grants of up to $250,000 for each state to support the consideration and implementation of the conservation and energy ef ficiency standards. The first grants are e-xpected to be available by September 1994.

OTHER PROVISIONS OF EPACT

While the major thrust of EPAct is to set up a framework to bring the four standards before state commissions, the Act also includes a number of related provisions.

The Act mandates a form of IRP for the Tennessee Valley Authority and the Western Area Power Authority.

It requires that commissions consider the IRP and demand-side profitability standards for gas utilities.

DOE must, within two years, conduct two surveys. The first surveys state policies resulting from the consideration of the conservation and energy efficiency standards. The second is a survey of IRP policies in effect by electric cooperatives.

In order to encourage the development of renewables, the Act offers the following monetary incentives which are included in the Act, but not yet appropriated:

- A production tax credit of 1.5 ¢ per kWh for wind and closed-loop biomass facilities. Closed-loop biomass facilities are those in which the trees are grown expressly for fuel at a specific plant.
- A production payment of up to 1.5¢ per kWh for new solar, wind, geothermal or biomass (not limited to closed-loop) facilities owned by either state or political subdivisions or by non-profit cooperatives.
- Permanent extension of a ten percent investment tax credit for solar and geothermal energy.

ENERGY EFFICIENCY PROVISIONS

The Act limits the extent to which utility rebates for energy conservation are taxed. By tax year 1993, 100 percent of the rebate received by residential customers will be excluded from taxable income. For industrial and commercial customers, beginning 1995, 40 percent of the rebate is excluded from taxable and by 1996, 65 percent of the rebate will be excluded from taxable income.

States are required to update their residential building energy codes regularly.

New energy efficiency standards are to be adopted for:

- Commercial and industrial heating, ventilation and air conditioning
- Industrial and small motors
- Distribution transformers
- Water heaters
- Incandescent and fluorescent lamps.

These higher efficiency standards mean that, over time, the amount of savings achieved by conservation programs may be less than was anticipated prior to enactment of the Act. The turnover of appliances, motors and other equipment when it occurs will automatically be at a higher level of efficiency than was earlier predicted.

Energy efficiency labeling is required for lamps, small motors, office equipment and utility transformers.

To help states and industry associations figure out how industries can achieve greater efficiencies for their operations, small DOE grants are available.

DOE must issue voluntary guidelines establishing energy efficiency ratings for residential buildings.

The Department of Housing and Urban Development must establish a program promoting energy efficiency mortgages which includes working with lenders to develop a lower mortgage rate for homes that meet an established standard of energy efficiency.

ENERGY MANAGEMENT BY FEDERAL AGENCIES

By 2005, all federal agencies must install to the maximum extent practicable, all energy and water conservation measures with a payback of less than ten years. Agencies can retain 50 percent of their bill savings to fund additional DSM investments.

A federal energy efficiency fund of up to $50 million annually will support energy-efficiency investments by federal agencies.

Federal agencies are elevated to the position of customers of utilities by encouraging and authorizing them to participate fully in utility demand-side management programs and to accept financial incentives offered by utilities.

Energy managers of federal facilities are eligible for bonuses if they achieve high levels of energy efficiency within their agency.

DOE must create energy efficiency standards for all federal buildings.

POTENTIAL ENERGY SAVINGS

In their review of this section of EPACT the ACEEE and ASE itemized the following, estimated savings between 1993-2010, shown in Table 2.

Table 2

Potential Savings in Quads	
Utility Rebate Tax Exclusion	1.15
State Residential Building Energy Codes	.57
Energy Efficiency Standards	1.16
Energy Efficiency Labeling	1.93
DOE Grants to Improve Industry Efficiency	1.75
Energy Efficient Mortgages	.78
Federal Energy Management	1.93
Total Possible Savings	**9.27**

OTHER PROVISIONS OF INTEREST

Every two years the DOE must prepare a new, least-cost energy strategy for the President to submit to Congress as part of a National Energy Policy Plan. By requiring the submission of the least-cost strategy, energy efficiency and conservation will be weighted equally with supply-side resources.

DOE must establish guidelines for the voluntary reporting of the emission of greenhouse gases and for emission reductions achieved

through measures such as improved energy efficiency. This means that for the first time, DOE will track greenhouse gases emitted from each of the energy-producing sectors. The collected record should show who is emitting which gases, at what quantities and how emissions of gases are reduced as a result of energy conservation programs. While this provision does not set emission standards, it does provide a first step toward determining which utilities and facilities are releasing greenhouse gases and what they are doing to curb these emissions.
Funds are authorized for research, development and demonstration on the more efficient use of coal, and funds are extended for DOE's Clean Coal Program.

A partial exemption from the Alternative Minimum Tax is provided to oil and gas drillers which reduces their tax liability by an estimated $1 billion over the next five years.

Demonstration programs, together with infrastructure and support systems, are created for the development of electric and gas-fired vehicles. Electric vehicles are eligible for a ten percent investment tax credit. This provision is particularly important in cases where electric vehicles are powered with renewables, non-fossil fuels and natural gas. Using these fuels will lower the emissions of greenhouse gases, which will in turn lead to environmental improvement.

IMPLICATIONS OF THE ENERGY POLICY ACT

To fully comply with EPAct, state regulatory commissions will have an increased need for both technical assistance and resource materials. Commissions should not hesitate to make their needs known to the DOE, to Congress or to the White House in order to insure that the implementation of the Plan does not fail due to a lack of assistance and resources.

The DOE has been authorized to provide grants of up to $250,000 for each state to support the consideration and implementation of the conservation and energy efficiency standards. Beginning in fiscal year 1994, $5 million dollars has been authorized, but not appropriated, for the next three years. However, at this writing, roughly $3 million is available, via transfers from other accounts, for fiscal year 1994. There is $8 million dollars in the proposed 1995 budget. The DOE is now considering rule making to describe the criteria it will use to allot grants to state commissions. The first grants are expected to be available by September 1994.

TRAINING REQUIREMENTS

There is a need to include energy efficiency training in the education of planners, architects, engineers and implementors. There are simply not enough people who know how to install technologies or who understand the correct application of effective technologies. There is a scarcity of college or vocational institute programs providing technical training in energy conservation technologies.

The Clean Air Act Amendments Of 1990

Congress has moved to incorporate IRP into Federal law with some frequency.[1] The Clean Air Act Amendments of 1990 (CAAA) feature IRP as an important tool for states and utilities to use in building a compliance strategy.

This chapter reviews the CAAA by looking at how it affects electric utilities and what opportunities it offers that can be met through IRP. Because the Acid Rain Program Title IV of the CAAA[2] focuses explicitly on IRP and supports serious consideration of DSM and increased use of renewables, the body of the chapter is focused on this section of the Act.

WHAT DOES THE ACT COVER?

The CAAA is one of the most comprehensive pieces of environmental legislation to be passed by Congress in the past 20 years. The CAAA updates the 1970 Clean Air Act through 75 initiatives. Included in these provisions are regulations covering sulfur dioxide, nitrogen oxides, ozone non-attainment areas, vehicular emissions, air toxics and particulates. The Act handles different pollutants in different ways. Some, such as SO_2 are regulated explicitly. The air toxics section, on the other hand, expands the air toxics program, lists 189 chemicals to be regulated and includes a procedure for the EPA to add and delete from the list.

While there are utility implications for many of the provisions in the Act, Title IV, the Acid Rain Program most directly promotes IRP, energy conservation and increased use of renewables.

TITLE IV: THE ACID RAIN PROGRAM

Title IV of the CAAA, the Acid Rain Program, was promulgated to:

- Achieve significant environmental benefits by reducing emissions of sulfur dioxide and nitrogen oxide
- Reduce these emissions at the lowest cost to society
- Encourage pollution prevention through efficiency and renewable energy

It sets as its primary goals the reduction of annual SO_2 emissions by ten million tons below 1980 levels and reduction of annual NO_2 emissions by two million tons below 1980 levels. Under this regulatory approach, the EPA is looking to reduce total loading of these pollutants across the country, in lieu of revising ambient air standards. Regulating in this manner gives each utility more latitude

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[1] The Clean Air Act of 1990, Public Law No. 101-549, the Northwest Power Act of 1980, Public Law No. 96-501 and the Energy Policy Act of 1992.

[2] This paper excerpts sections from the EPA Handbook (1994). Copies of this handbook can be obtained from the EPA, Acid Rain Program, Washington D.C. 20560.

and flexibility to select strategies to implement the Act's goals.

Sulfur Dioxide Reduction

Sulfur dioxide reduction, the core of the Acid Rain Program, is designed to take place in two stages. Phase I, which begins in 1995, targets the 110 highest SO_2-emitting plants in the country. It affects mostly coal-burning electric utility plants, located in 21 eastern and midwestern states. These plants are required to reduce their emissions of SO_2 to a level equal to 2.5 pounds per million BTUs[3] multiplied by their average annual fuel consumption rate for the baseline years of 1985 to 1987. Phase II, which begins in 2000, tightens the Phase I limits and expands the scope of the program to include all additional electric utility plants producing over 25 MW. Power plants emitting SO_2 in excess of 1.2 pounds per million BTUs are required to reduce emissions to a level equal to 1.2 pounds per million BTUs multiplied by their average fuel consumption rate for the baseline years of 1985 to 1987.

The Allowance System

The most innovative feature of the Acid Rain Program is the creation of the SO_2 allowance. Each allowance represents authorization to emit one ton of SO_2, and utilities must have enough allowances to cover emissions from their units. For instance, a utility must hold 5,000 allowances for a unit emitting 5,000 tons of SO_2.

Every utility is allocated a specific number of allowances based upon past SO_2 emission rates and fuel utilization. Phase I units are allocated allowances equal to the average of the 1985-87 heat output times 2.5 pounds of SO_2 per million BTU emissions rate. Phase II allocations are derived from the same baseline year times a 1.2 pounds of SO_2 per million BTU emissions rate. To ensure fair opportunities for growth, additional allowances are granted to utilities that were low SO_2 emitters or whose plants operated at reduced capacity during the baseline years.

The allowances are allocated annually by the EPA to each utility on the basis of the allowed emission rate times the baseline emissions. Once allocated, allowances may be bought, sold, traded or banked for use in future years. This ability to buy and sell allowances gives utilities one more strategy to reduce SO_2 emissions at the lowest possible cost. Other options include

- switching to lower sulfur fuels
- installing scrubbers
- implementing energy efficiency
- acquiring power from renewables

At the end of each compliance year, a utility must retire one allowance for each ton of SO_2 emitted in the preceding year. Eventually, the total annual emissions will be capped at 8.95 million tons per year.

If a utility does not have adequate allowances, it must pay a non-compliance fee of $2000 per ton and acquire additional allowances for subsequent years.

IRP, described in more detail later in the chapter, is the tool utilities have at their disposal to determine how to comply with regulations as inexpensively as possible. Recognizing the important role of energy efficiency

[3] One million BTUs of fuel will produce roughly 100 kilowatt hours of electricity.

and renewables in reducing emissions, Congress included in the CAAA incentives to make these options as attractive as possible. These incentives offer three ways for utilities to earn additional allowances.

Reduced Utilization

This provision is designed to credit Phase I plants for curbing emissions below the 1985-87 baseline levels. A Reduced Utilization Plan is required from the utility to show how the reduction will occur. Options include

- reduction from energy conservation
- reduction from improved efficiency
- shifts to sulfur-free generators[4]
- shifts to designated, compensating units

Because these Phase I plants are high SO_2 emitters, the potential for reduction is very high (ten times higher than the potential reductions that can be achieved from CRER bonus allowances described below). Credits are given for all energy savings, and there is flexibility as to where the measures are placed or generation occurs. For instance, energy-efficiency measures may come from anywhere within the utility system, and energy generated from renewable sources can be purchased from outside the utility system. Again, the net value of the freed-up allowance over the cost of achieving the SO_2 offset can be of considerable worth to the utility.

Avoided Emissions

This program supports system-wide reductions in SO_2 emissions through energy conservation and use of renewables. Utilities that reduce SO_2 at any given unit below the compliance levels required by Title IV through the use of energy efficiency and renewable energy, free up one allowance for every ton of SO_2 avoided. The allowance can be used for current compliance elsewhere in the utility's system, banked for future use or sold.

Of the three ways utilities can earn additional allowances, this incentive is the easiest to implement because the utility receives the benefits of avoided emissions automatically without submitting an application. In most cases, the cost of offsetting energy conservation will be considerably less than the value of the allowance, thus creating value for the utility. This program, because it affects all units over an indefinite period of time, has the greatest SO_2 reduction potential.

Emissions reductions achieved through energy conservation begin in 1995 for Phase I units and 2000 for Phase II units.

Conservation And Renewable Energy Reserve (CRER)

This Reserve is a special bonus pool of 300,000 allowances, representing 150 billion kWh, which is awarded on a first come, first served basis to utilities undertaking new initiatives in demand-side efficiency and renewable energy. For every 500 mWh of energy saved through demand-side efficiency or generated through renewable energy brought into operation after January 1, 1992, a utility acquires one allowance from the Reserve.

The Reserve is an incentive for utilities to set up efficiency measures and renewable generation before the compliance deadlines. It gives utilities a head start to receive a return on efficiency and renewable investments.

[4] In general, these will be renewable energy resources, but in some cases geothermal and biomass production will qualify.

Phase I utilities may earn these allowances from January 1, 1992 to January 1, 1995. Phase II utilities may earn Reserve allowances on qualifying initiatives undertaken from January 1, 1992 to January 1, 2000.

A utility undertaking measures to earn bonus allowances through early conservation activities must prepare an IRP Plan that is approved and accepted by its state commission and must include provisions for net income neutrality, thus leaving utility profits unaffected by DSM investments. Any subsequent decision to acquire and /or install an energy conservation and renewable project must be consistent with the Plan.

The EPA began accepting applications for CRER allowances on July 1, 1993, and awards for the first 532 allowances were made in November 1993.

What Is An Allowance Worth?
Tradeable SO_2 emission allowances put a dollar value on pollution prevention. Utilities need to estimate the market price of the allowance to develop the least-cost compliance strategy.

To help establish a market price, the EPA sells a designated number of allowances annually. Every year, the EPA holds an auction and sells 2.8 percent of the allowances which have been reserved from the total allowance allocation. These auctions are intended both to help signal price information to the market early in the program and to provide a public source of allowances for utilities that are not allocated allowances. Utilities, environmental groups and allowance brokers can participate in the EPA auctions.[5]

The 1993 auction yielded the first recorded values for allowances. Prices for allowances to be put in use beginning in 1995 ranged from $131 to $450, with an average price of $156 per allowance. Prices for allowances to be placed in use beginning in 2000 ranged from $122 to $310, with an average price of $136 per allowance.

These initial prices are lower than what was originally expected and may not be representative of future market values. In the first place, the EPA was committed to selling its allowances no matter what the price. This probably depressed the selling price below that at which other allowance holders would be willing to sell. Secondly, allowance trading is new. Market activity and expertise will continue to evolve. Finally, the auction sales were paid in 1993 prices, while the allowances will be used in 1995 and 2000. Thus, the auction represents the net present value of some higher future allowance price.

A recent report issued by the Electric Power Research Institute (EPRI), based upon likely utility compliance actions, predicts that allowance prices could rise from $250 per allowance in 1995 to $480 per allowance in 2007 (These values are in 1992 dollars).

Price signals are entering the market through other means as well. A few private trades

[5] One interesting development to further reduce SO_2 emissions has been the creation of a non-profit business entity established to purchase allowances at auctions and elsewhere and remove them from circulation. This group also accepts charitable donations of allowances, thereby creating an income tax deduction for the donating utility.

have taken place. Several brokerage firms, trading exchanges and specialty consulting firms are offering services to support the buying and selling of allowances. As the compliance dates near, more information about allowance markets will emerge.

For planning purposes, the market price for allowances over various time periods can and should be treated similarly to fuel prices — as a variable cost related to the amount of energy generated. The risks associated with uncertainty in the future market prices can be viewed as one views the risks associated with future fuel prices.

Integrating Compliance And Resource Planning

The CAAA only requires utilities to submit an IRP when applying for CRER bonus allowances. Yet IRP is the tool that is uniquely designed to answer the two converging questions. "How do I provide least-cost service for my customers?" and "How do I provide low-cost reductions in SO_2?" Decisions not made under an IRP framework can be misleading. Low-cost options may be ignored, and more expensive alternatives may be selected.

In considering how to meet its environmental objective as cost-effectively as possible, a utility should not have any preconceptions on how to comply. Allowances, building scrubbers and switching fuels are all options which must be considered. Only by recognizing and considering all options can costs expect to be as low as possible. Consideration of SO_2 emissions reduction in an IRP framework requires that the following steps be undertaken:

- Develop a complete list of all compliance options.
- Determine the technical capability and market availability of each alternative.
- Evaluate options for cost and performance.
- Choose option(s) based upon costs, performance and risk considerations.
- Calculate total number of allowances freed up or consumed.

Considering these options via the IRP process allows for meaningful comparisons and final selection of the options that reduce SO_2 emissions at the lowest cost to a utility and its ratepayers.

What Are Some Additional Benefits Of Title IV?

While provisions to promote energy efficiency and renewables apply explicitly to curbing SO_2 emissions, reducing dependence on fossil fuels will decrease emissions of other pollutants — namely CO_2, NOX, particulates and certain air toxics — as well. This will produce additional environmental benefits.

HOW ELSE DOES THE CAAA SUPPORT IRP?

Because NO_2 is a precursor of ozone, Title I of the CAAA, will when fully implemented require electric utility reductions of NO_2 at a much higher level than in Title IV. This will have a substantial impact on IRP in many states — particularly those in the ozone non-attainment areas on the east and west coast. NO_2 rules are expected to be issued in 1995 and will probably affect more than 400 power plants. Because of this NO_2 compliance is a risk that must be taken into account in IRP, even though the CAAA does not speak directly to this point in Title I.

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APPENDIX

Resolution in Support of Incentives for Electric Utility Least-Cost Planning

WHEREAS, National and International economic and environmental conditions, long-term energy trends, regulatory policy, and technological innovations have intensified global interest in the environmentally benign sources and uses of energy; and

WHEREAS, The business strategy of many electric utilities has extended to advance efficiency of electricity end-use and to manage electric demand; and

WHEREAS, Long-range planning has demonstrated that utility acquisition of end-use efficiency, renewable resources, and cogeneration are often more responsible economically and environmentally than traditional generation expansion; and

WHEREAS, Improvements in end-use efficiency generally reduce incremental energy sales; and

WHEREAS, The ratemaking formulas used by most state commissions cause reductions in utility earnings and otherwise may discourage utilities from helping their customers to improve end-use efficiency; and

WHEREAS, Reduced earnings to utilities from relying more upon demand-side resources is a serious impediment to the implementation of least-cost planning and to the achievement of a more energy-efficient society; and

WHEREAS, Improvements in the energy efficiency of our society would result in lower utility bills, reduced carbon dioxide emissions, reduced acid rain, reduced oil imports leading to improved energy security and a lower trade deficit, and lower business costs leading to improved international competitiveness; and

WHEREAS, Impediments to least-cost strategies frustrate efforts to provide low-cost energy services for consumers and to protect the environment; and

WHEREAS, Ratemaking practices should align utilities pursuit of profits with least-cost planning; and

WHEREAS, Ratemaking practices exist which align utility practices with least-cost planning; now, therefore, be it

RESOLVED, That the Executive Committee of the National Association of Regulatory Utility Commissioners (NARUC) assembled in its 1989 Summer Committee Meeting in San Francisco, urges its member state commissions to:

1) consider the loss of earnings potential connected with the use of demand-side resources; and

2) adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and

3) otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action.

Sponsored by the Committee on Energy Conservation
Adopted by the NARUC Executive Committee, July 27, 1989