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PROFILES IN ELECTRICITY ISSUES:

INTEGRATED ♦ LEAST-COST RESOURCE PLANNING

SUMMARY

Many state regulatory commissions are requiring utilities to change the way they plan for new capacity or energy resources. This new approach, which often is called least-cost planning (LCP) or integrated resource planning (IRP), puts new emphasis on demand side management or DSM programs, especially conservation. Regulatory policies implementing LCP or IRP usually attempt to establish a "level playing field" in which utilities are required to evaluate DSM options on equal terms with traditional supply side options when planning for the future resource needs of their ratepayers.

ELCON strongly supports least-cost planning when the results of a utility's planning process minimizes its long-run revenue requirement necessary for an adequate, reliable and efficient electric supply. For reasons set forth in this *Profile*, ELCON has serious concerns regarding the development and implementation of least-cost resource plans that fail to meet this standard. In particular, ELCON opposes consideration of environmental externalities (or other so-called social costs) that are not required by law and which are not cost-effective.

ELCON is an association of large industrial consumers of electricity. Our members have facilities in most of the 50 states and many foreign countries. Our members produce a wide range of products, including steel, petroleum, chemicals, industrial gases, glass, motor vehicles, electronics, appliances, textiles and food. Our member companies consume over four percent of all of the electricity in the United States. Our members require an adequate and reliable supply of electricity at reasonable prices to produce competitive products. For a copy of other PROFILES, write or call ELCON at the above address.

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Profiles in Electricity Issues:

INTEGRATED ♦ LEAST-COST RESOURCE PLANNING

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SUMMARY OF ELCON'S POSITION

Many state regulatory commissions are requiring utilities to change the way they plan for new capacity or energy resources. This new approach, which often is called least-cost planning (LCP) or integrated resource planning (IRP), puts new emphasis on demand side management or DSM programs, especially conservation. ELCON considers the terms "least-cost planning" and "integrated resource planning" interchangeable. ELCON notes that it is less important what the planning process is called, but rather how the process is implemented to assure an adequate, reliable and efficient electric supply at cost-based rates. ELCON supports LCP or IRP that adhere to the following definition and principles:

ELCON's Definition of Integrated/Least-Cost Resource Planning

Integrated or least-cost resource planning is a utility's planning process that minimizes its long-run revenue requirement necessary for an adequate, reliable and efficient electric supply at rates based on actual costs. The least-cost plan should include cost-effective supply and demand side resources.

ELCON's Principles of Integrated/Least-Cost Resource Planning

1. The efficient use of all resources, including energy, is a prudent and environmentally responsible business practice.

2. The maximum use of competition -- on both the supply and demand sides -- should be encouraged to establish more efficient wholesale and retail electricity markets.

3. Selected social costs (such as environmental externalities) should not be internalized in least-cost plans. Resources should be compared using actual costs, including the costs required to comply with environmental laws.

4. A "level playing field" should be established for evaluating cost-effective supply and demand side options by minimizing market barriers and other restrictions on the efficient acquisition and utilization of any supply side or demand side resource.

   a. Market barriers on the supply side can be mitigated by increasing competition in bulk power markets, i.e., by allowing all buyers and sellers of bulk power nondiscriminatory access to transmission.

   b. Market barriers on the demand side can be mitigated if price signals are correctly set and end-users have adequate access to information on the costs and benefits of their choices. Customers will be able to minimize the total costs of their energy services only when prices are correctly set.

5. Utilities should offer a broad menu of embedded cost-of-service electricity rates and services, not highly bundled electricity services that restrict competition and result in the inefficient usage of electricity.

6. Both supply and demand side resources should be subject to prudence and "used and useful" standards. Costs of these resources should be expensed or rate-based as appropriate. Utilities should not be given financial incentives to implement least-cost planning.

7. Utility compliance strategies to address environmental legislation, such as the acid rain provisions in the Clean Air Act Amendments, should be developed as part of their least-cost planning effort. The same principles of least-cost planning that govern the acquisition of supply or demand side resources also should apply to pollution abatement costs.

8. Costs which are specifically assignable to a supplier, customer, or customer class should be borne by that supplier, customer, or customer class. Costs should be classified based on the actual operating characteristics of the resource. Energy related costs should be allocated to ratepayers in the energy or variable component of rates. Capacity related costs should be allocated in the demand or fixed component of rates.

9. Least-cost planning should be an on-going process. Utilities should continuously re-evaluate the plan's forecasts, assumptions, and resource options, and to alter the plan as needed. Utilities always have the burden to justify any changes in their least-cost plan.

10. Regulatory oversight should be provided. Regulators should carefully evaluate least-cost plans, including any subsequent modification to that plan, with particular emphasis on demonstrated energy or capacity impacts of DSM options. Opportunity should be provided for public comment on the least-cost plan, including the assumptions used in life cycle analysis, cost-benefit analysis, and other decision support methodologies. The least-cost plan should be a public document.

INTRODUCTION

Many state regulatory commissions are requiring utilities to change the way they plan for new capacity or energy resources. This new approach, which often is called least-cost planning (LCP) or integrated resource planning (IRP), puts new emphasis on demand side management or DSM programs, especially conservation. ELCON considers the terms "least-cost planning" and "integrated resource planning" interchangeable. ELCON notes that it is less important what the planning process is called, but rather how the process is implemented to assure an adequate, reliable and efficient electric supply at cost-based rates.

Regulatory policies implementing LCP or IRP usually attempt to establish a "level playing field" in which utilities are required to evaluate DSM options on equal terms with traditional supply side options when planning for the future resource needs of their ratepayers. However, some states are implementing LCP or IRP that clearly give preference to DSM programs. This reflects the fact that there is not widespread agreement on how LCP or IRP should be implemented by utilities. Some of the key points of disagreement are:

- *How should the need for new capacity and energy resources be determined in a least-cost plan?*
- *What environmental issues should be addressed in least-cost plans?*
- *How should supply side resources be acquired to achieve least-cost goals?*
- *How should demand side resources be acquired to achieve least-cost goals?*
- *Should utilities be given incentives to implement least-cost planning?*
- *How should costs be allocated to ratepayers?*
- *What regulatory oversight is necessary to assure that least-cost goals are met?*

ELCON supports least-cost or integrated resource planning when the results of a utility's planning process minimizes its long-run revenue requirement necessary for an adequate, reliable and efficient electric supply at rates based on actual costs. Utilities should only use cost-effective supply or demand side resources that meet this standard.

HOW SHOULD THE NEED FOR NEW CAPACITY AND ENERGY RESOURCES BE DETERMINED IN A LEAST-COST PLAN?

Utilities have the ultimate responsibility for determining the capacity and energy needs of its native load customers. The acquisition of any supply side or demand side resources to meet those needs should start with the development of an overall "least-cost" resource plan.

Regulatory commissions should establish broad guidelines for the design and implementation of these plans. The resource plan should include a determination of need and a description of the utility's next avoidable supply alternative and its avoided cost. The evaluation of the cost-effectiveness of other supply and demand side options, assuming those options can provide a comparable and verifiable resource, must be done in comparison with the avoided cost. The cost-effectiveness of demand side options must include recognition of any bill savings.

Commissions should establish filing requirements which subject utilities' least-cost resource plans to public review and comment. At a minimum, these filing requirements should document the utilities' projected needs and all relevant planning assumptions (See Figure 1).

WHAT ENVIRONMENTAL ISSUES SHOULD BE ADDRESSED IN LEAST-COST PLANS?

Utility compliance strategies to address any applicable environmental laws should be developed as part of their least-cost planning efforts. The same principles of least-cost planning that govern the acquisition of supply or demand side resources should apply to pollution abatement costs, such as the costs required to comply with the acid rain provisions of the Clean Air Act Amendments of 1990. However, a least-cost plan must not consider environmental externalities (or other so-called social costs) that are not required by law. The "internalization" of such externalities can artificially raise the costs of electricity to consumers and result in significant shifts of energy consumption and associated economic activities to utilities, states or countries where those externalities are not internalized. Such shifts may actually increase environmental impacts, which is conterproductive to the goals of enviromental protection.

For example, policies directed at reducing so-called greenhouse gases -- particularly, carbon dioxide -- could have profound implications on domestic and global energy markets. The secondary effects of such changes could be equally drastic impacts to industrial production and U.S. competitiveness in world markets. In light of these risks, the direct consideration of potential global climate change in least-cost planning would be highly premature. Any consideration should proceed only as scientific evidence is validated, and then only where cost justified, and required by law.

Environmental and Siting Restrictions on Specific Technologies

Conventional electrical generating technologies and fuels must be relied upon to provide the major share of our electrical needs well into the next century. The quantity of additional electricity that can be economically and reliably supplied from alternative energy and technological resources (e.g., solar, wind, biomass, and geothermal) is very limited. Although fossil fuels remain the key natural resource input for our electricity generation, other options must not be foreclosed. For example:

- The long-term energy interests of our country are clearly served by actions, such as improved licensing procedures and the standardization of design that would enhance the economics of the nuclear option. Standard design would overcome many safety and siting concerns and speed construction.

Figure 1

CONTENTS OF AN INTEGRATED/LEAST-COST RESOURCE PLAN

1. Energy (kWh) and capacity (kW) requirements, by major end-use, on a system-wide and customer class basis, for both historical and forecast periods.
2. Description of forecast methodologies, assumptions, and databases.
3. Cost of service studies by customer class.
4. Expected rate impacts of alternative resource options.
5. Description of candidate DSM options, including customer potential to cogenerate, self-generate or wheel-in own power from a distant QF.
6. Description of cost-effectiveness criteria, and screening and integration methodologies.
7. Description of utility's capacity expansion and unit retirement plan, disaggregated by:
   a. Generating source (e.g., ratebased generation, nonutility and affiliate generation, repowered units, and purchased power contracts).
   b. Generation type (e.g., baseloaded, cycling or peaking).
   c. Fuel type.
8. Identification of "benchmark" unit (i.e., the next avoidable unit for purposes of establishing the utility's avoided cost).
9. Identification of non-price factors used in selection of new sources of capacity and/or energy (e.g., reliability concerns).
10. Identification of relevant bulk power markets, including potential power purchases or sales, and build options available to the utility.
11. If competitive bidding is used, a description of the bid solicitation and the criteria used in bid selection.

- New environmental or siting restrictions on the use of any fuel, such as coal, must be balanced against any resulting increase in economic and national security costs. Coal, for example, is our Nation's most abundant energy resource. The development and use of Clean Coal Technologies (CCTs) should continue to be encouraged in order to maintain the viability of coal as an energy resource and to assure adequate protection of the environment.

The siting and construction of new transmission facilities must not be unduly impeded. Utilities should be required to build or upgrade facilities where the need for capacity is evident. State and Federal policies and regulations should allow for the expedited siting and licensing of new facilities, especially interstate facilities. The alleged health risks of electromagnetic fields (EMF) that emanate from transmission facilities -- and indeed, from all electrical and electronic equipment and devices -- must not be used as an excuse to inhibit the siting and construction of such facilities absent more definitive resolution of the true health risks of EMF.

Finally, new or upgraded transmission lines which facilitate broader intra- and interstate bulk power markets may be less costly and therefore more efficient than constructing new generation capacity or implementing energy or load reduction programs. Many regions of the country have and will continue to have surplus capacity.

HOW SHOULD SUPPLY SIDE RESOURCES BE ACQUIRED TO ACHIEVE LEAST-COST GOALS?

The electric utility industry is becoming more competitive. Yet, this industry is arguably one of the most regulated industries in the U.S. economy. Electricity is the only major energy resource that is still subject to regulatory controls from the point of production to the point of the retail sale. All other energy forms are largely unregulated at the production end, with wholesale prices set in competitive markets. Utility least-cost planning can achieve truly least-cost goals only where market barriers in existing bulk power markets are removed so that the efficiencies of competition can be fully realized.

Increased competition in bulk power markets will help assure the availability of the lowest cost power possible, consistent with an adequate and reliable supply. However, a workably competitive bulk power market requires both many sellers and many buyers seeking out each other for the lowest price transactions. This requires that any seller or buyer have guaranteed access to transmission (i.e., wheeling) if that market is to operate efficiently. Thus, truly competitive bulk power markets require the unbundling of generation and transmission services in bulk power transactions. Utilities should provide unbundled generation and transmission services on a nondiscriminatory basis to all buyers and sellers of bulk power, including qualifying facilities (QFs) and independent power producers (IPPs). Utilities should be required to maximize third-party use of all generation and transmission facilities in excess of native load requirements. While competition can and should be encouraged in generation, competition is not practical nor possible in transmission. The owner of transmission facilities necessarily must be a monopolist.[1]

Competitive Bidding

Utilities should competitively acquire all new capacity requirements through bidding or open competitive negotiation procedures. New sources of capacity should have no efficiency, technology or ownership limitations, including quantifiable capacity from DSM programs, as long as there is guaranteed access at cost-based rates to multiple markets for nonutility generators. If nondiscriminatory transmission access is not guaranteed by the bidding process, then bidding must be limited to qualifying facilities (QFs) with all other potential sources taken into account in determining the utility's avoided cost or benchmark.[2] The benchmark, as approved by the utility's regulatory authority, should be the ceiling either for direct purchases of electricity or for cost recovery from ratepayers if the utility decides to build.

Several states allow DSM programs to be submitted as bids in all-source competitive bid solicitations. In these cases, DSM programs would compete directly with supply side bids, and the bidding process itself determines the relative cost-effectiveness of the DSM or any other bidded resource. However, only measurable and verifiable DSM resources should be allowed to bid in competitive bid solicitations. Utilities always have the burden of proof to show that a DSM program provides capacity. DSM resources also should not be selected in competitive bid solicitations as a consequence of arbitrary quotas.

Finally, all economically justified demand side initiatives should be allowed the opportunity to bid in competitive bid solicitations, including the option of a customer to cogenerate or self-generate electricity and to use that power at more than one facility.

Non-Price Factors in Competitive Bidding

Competitive bid solicitations should give consideration to non-price factors. The most important non-price factors arguably are reliability and fuel availability. But these factors conflict with the need to minimize price. Increasing reliability or improving the security of fuel supply will, all else equal, increase cost, and therefore, the price paid for the capacity and energy from the supplier. The task at hand, to achieve least-cost goals, is how and where to make the tradeoff between price and non-price factors without sacrificing the potential efficiency gains of competition.

This problem can be solved by making a clear distinction between appropriate non-price factors and non-price factors that can cause subsidies. Appropriate factors directly address reliability and security of fuel supply, while minimizing cost. Non-price factors that cause subsidies do not

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[1]A more detailed description of ELCON's position on wheeling is available from ELCON upon request.

[2]Competitive bidding originally was conceived as a market-based approach for determining a utility's QF buyback rate, as an alternative to the administrative determination of avoided costs. For a more detailed discussion of ELCON's position on competitive bidding, see Profiles in Electricity Issues: Competitive Bidding.

(See Figure 2). This distinction assures all ratepayers that the best tradeoffs have been made between the needs of a reliable supply of power with secure fuel resources, at least-cost.

Advance articulation of all non-price criteria, with opportunity to comment in a public proceeding, is crucial. Non-price factors which can cause subsidies should not be considered in bidding programs. The use of non-price criteria represents an opportunity for self-dealing, manipulation of the bidding process, and other inefficiencies. Appropriate non-price factors should be recognized in bid selection, but price should be the dominant factor.

Utility Bids in Competitive Bid Solicitations

Consumers are very concerned that utility ownership of nonutility generation (QFs and IPPs) can lead to self-dealing and other abuses. Utilities or their affiliates must not be allowed to build non-ratebased generators inside their service territories without adequate regulatory oversight and demonstration that the utility's market power has been mitigated. As long as utilities have an exclusive franchise area, it does not make sense for them to either recover more than costs or earn more than a fair rate of return on investments inside the franchise area.

There may be reasons for utilities to be allowed to build outside their zone of economic influence. They may have a proven record of excellent construction or possess special resources

Figure 2

NON-PRICE CRITERIA IN COMPETITIVE BID SOLICITATIONS

Examples of Appropriate Non-Price Criteria

Reliability

Fuel Diversity/Stability

Dispatchability

Unit Commitment

Length & Terms of Contract

Financial Viability

Experience

Security

Examples of Non-Price Criteria That Can Cause Subsidies

Fuel Type (e.g., Renewable Resources)

Use of Local Resources

Economic Development Considerations

Environmental Benefits

or skills. However, if they voluntarily elect to participate in other utilities' competitive bid solicitations, they should not be allowed to block competition for their own needs. Thus, there must be a linkage between utility ownership of QFs and APPs ("affiliate power producers") and transmission access for other QFs and true IPPs.[3]

HOW SHOULD DEMAND SIDE RESOURCES BE ACQUIRED TO ACHIEVE LEAST-COST GOALS?

Preconditions to the Implementation of Utility DSM Programs

Utility DSM programs typically offer financial incentives to defray some or all of the cost of high efficiency appliances and end-use equipment, weatherization measures, and control technologies that help ratepayers utilize electricity more efficiently. These incentives may include cash rebates, low (or zero) interest loans, free installation or other services, and special rates. The financial incentives are sometimes deemed necessary to compensate for market imperfections or market barriers that allegedly prevent the adoption of energy efficiency improvements even though they already may be cost-effective for the ratepayer to implement.

However, the need to expand the role of utilities on the customer's side of the meter raises serious concerns. Prior to implementing any DSM programs, utilities first should assure that rates are set based on cost-of-service so as to send appropriate price signals. Only when rates are correctly set can customers efficiently minimize the total costs of their energy services. Rates should be established for a full range of services, including time-of-use, curtailable, and interruptible rates.[4]

Setting the Right Price Signal

Utilities should correct and improve the price signals sent to ratepayers, particularly by offering time-sensitive and other cost-based rates. Other ways to greatly improve price signals include the elimination of cross-class subsidies that often are promoted in rate designs and cost allocations procedures, prohibiting the recovery of nonfuel related expenses in the fuel adjustment clause, and the removal of front-end loading of capital cost recovery.

Ratepayers should be provided a broader range of options for electricity services and thus, greater opportunities for efficient energy usage. This allows the efficiencies of decentralized, competitive markets to be captured by consumers and stockholders. Where cost justified, a broad menu of rates and services should be offered by utilities to all customer classes. These would include, for example, rates based on system reliability and supply availability constraints such as interruptible or curtailable rates.

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[3]A more detailed description of ELCON's position on PUHCA reform is available from ELCON upon request.

[4]For a detailed discussion of ELCON's position on demand side management, see Profiles in Electricity Issues: Demand Side Management (DSM). The summary from that *Profile* is reproduced in Figure 3.

Time-Sensitive Rates

Rates to all consumers of electricity should be based on costs actually incurred by utilities in providing the service to the customer or customer class. Where economically justified, electricity rates should send time-sensitive price signals, reflecting the actual costs incurred by utilities at different times of day or season. Time-sensitive rates should be sent to residential and commercial class customers, as well as to industrial ratepayers where it is most commonly done. Cost-based, time-sensitive price signals would tell customers more accurately how their consumption impacts the utility and, more likely, would result in more efficient utilization of electrical energy. Examples of time-sensitive rates include: time-of-day (TOD) or time-of-use (TOU) rates; and seasonal rates. Utilities should offer only those rates which are consistent with its actual cost structure, are cost-effective to implement, and meet the diverse needs of its ratepayers.

Rates to each customer class should reflect the costs incurred in meeting their respective loads. Subsidizing one class at the expense of another is counterproductive to least-cost goals. For example, subsidized residential rates encourage those customers to consume more than they otherwise would consume absent the subsidy. This discourages cost-effective conservation behavior and purchases of energy-efficient appliances. Alternatively, artificially high industrial rates encourage industrial firms to relocate electricity-intensive operations or to explore the option to generate their own electricity.

It would be counterproductive to implement DSM programs involving cash incentives for end-use equipment or appliance purchases before rates are corrected to send cost-based price signals. Utility DSM programs will neither be efficient nor equitable without the establishment of appropriate price signals.

Information Progams

Informed customers are able to make better consumption and purchasing decisions than uninformed customers. In fact, information is essential if competitive markets are to operate efficiently. Utilities should increase the amount and quality of information in competitive end-use markets, where cost-justified.

Information programs must be carefully designed and implemented so as to avoid disrupting or distorting legitimate end-use appliance and equipment markets. For example, utility information programs must not favor one supplier over another, nor should one brand of appliance be promoted at the expense of another brand, all else equal. Consumers must always have the ability to fully exercise their choices, including the option to switch fuels, if competition is to be allowed to work.

Evaluating the Cost-Effectiveness of DSM Programs

Determining the cost-effectiveness of DSM programs requires: careful estimates of the actual success of each DSM program in meeting its stated objectives; consideration of any cash payments or financial incentives given to participating ratepayers; and estimates of the

Figure 3

SUMMARY OF ELCON'S POSITION ON DEMAND SIDE MANAGEMENT (DSM)

1. ELCON supports cost-effective demand side management (DSM) programs. A utility should only implement DSM programs that are consistent with the minimization of its long-term revenue requirements necessary for an adequate, reliable and efficient electric supply.

2. Prior to implementing DSM programs, utilities should set rates based on cost-of-service, and without subsidies, so as to send appropriate price signals. Rates should be established for a full range of services, including time-of-use, curtailable and interruptible rates.

3. Where "market barriers" exist that discourage end-use efficiency improvements, information programs should be directed to mitigate those barriers and encourage efficient demand side behavior.

4. The acquisition of demand side resources should start with the development of an overall resource plan. The resource plan should begin with a determination of need and include both demand and supply options.

5. Demand and supply options must be properly compared. The maximum payment a utility should make for a demand side resource is the avoided cost minus the bill savings. Financial incentives should not be paid for demand side resources which already are economic to implement under existing rates.

6. Competitive bid solicitations may be used for the acquisition of quantifiable DSM resources.

7. The energy and capacity savings and costs of DSM programs should be measured with the same standard of accuracy as estimates of capacity, energy output, losses, availability, reliability and economic life of supply side resources. In all cases, metered capacity and energy, whether provided by DSM or traditional supply, should be given preference in a utility's resource plan.

8. Selected social costs (such as environmental externalities) should not be internalized. Resources should be compared using actual costs, including the costs required to comply with environmental laws and regulations.

9. Embedded cost-of-service standards should be applied to the recovery of both demand and supply resource costs. Fixed costs should be recovered in the fixed (demand-related) component of rates and variable costs should be recovered in the variable (energy-related) component of rates.

10. DSM programs that target large industrial ratepayers should be carefully designed to minimize: (a) adverse impacts on the competitive markets in which industrial ratepayers operate; (b) the participation of so-called "free-riders;" and (c) subsidization of DSM participants by other industrial ratepayers who previously had implemented demand side programs at their own expense.

11. A utility's overall allowed rate of return should reflect the aggregate risk of all its supply and demand side investments. Utilities should not be given financial incentives to implement DSM programs.

12. Regulatory commissions must not require mandatory DSM programs. Utilities must always retain the responsibility and accountability to manage the use of their system resources whether demand side or supply side. All investments -- including DSM program investments -- should be subject to prudence and used-and-useful reviews.

This "Summary" is reproduced from ELCON's Profiles in Electricity Issues: Demand Side Management (DSM).

programs' impacts on the cost-of-service of both participating and non-participating ratepayers. Only DSM programs that are evaluated according to the following principles are cost-effective and therefore truly least-cost:

1. Supply and demand resources must be properly compared. A utility should only implement DSM programs that are consistent with the minimization of its long-term revenue requirements necessary for an adequate, reliable and efficient electric supply.
2. Utilities should not give financial incentives to ratepayers for demand side measures which already are economic to implement under existing rates.
3. The maximum payment a utility should make for any DSM resource is the avoided cost minus the bill savings that would occur due to the DSM program. Financial incentives that exceed that difference are ratepayer-to-ratepayer income transfers or subsidies. Subsidies result in inefficient price signals and should not be used.
4. Selected social costs (such as environmental externalities) should not be internalized in utility least-cost resource plans. Resources should be compared using actual costs, including the costs required to comply with environmental laws.

Monitoring and Verifying DSM Programs

DSM programs are not a valid substitute for supply side resources to the extent the aggregate operational characteristics of DSM measures have not been defined or demonstrated in comparable terms such as reliability and availability. Utilities must therefore carefully screen and select from the universe of DSM measures only those that are capable of achieving the intended results.

The following principles should be used to measure the actual impacts of DSM programs:

1. The effectiveness of DSM programs must be based on actual savings and costs and not solely on theoretical or the potential engineering estimates of savings or costs. Energy and/or capacity savings must be measured against actual baseline usage.
2. Customer usage behavior must be measured and validated before and after the implementation of any DSM program offering. Participating customer behavior should be compared to control group behavior over the same time period.
3. The end-use load shape impacts of DSM programs must be directly measured where incentives are given for capacity (kW) savings. Measurement costs should be allocated to DSM direct program costs.
4. In all cases, metered capacity and energy, whether provided by DSM or traditional supply, should be given preference in a utility's resource plan.

SHOULD UTILITIES BE GIVEN INCENTIVES TO IMPLEMENT LEAST-COST PLANNING?

The Regulatory Compact

Electric utilities are natural monopolies that are affected with the public interest. Regulatory authorities have statutory responsibilities to regulate this industry in a least-cost manner. Utilities are granted an exclusive franchise area to accomplish this objective. In return, they agree to provide adequate and reliable service in a nondiscriminatory manner at reasonable rates to all consumers in their franchise area. Utilities are granted an opportunity to recover all prudently incurred costs on assets that are used-and-useful in both a physical and economic sense. Utilities also are given an opportunity to earn a fair rate of return on investments required to provide service to customers. This allowed -- not guaranteed -- rate of return must reflect the aggregate risk of all the utility's investments. A primary objective of economic regulation is to limit cost recovery from ratepayers to prudently incurred costs, for investments that are used and useful, plus a fair rate of return.

Many advocates of DSM argue that the traditional regulatory compact creates a strong disincentive to the implementation of DSM programs which emphasize conservation. The "disincentive" is created by the perception that lost sales (conservation) do not contribute to earnings and may reduce utility profits. They have proposed a number of regulatory mechanisms for correcting the perceived disincentive. These include incentive rates of return, so-called "decoupling" procedures such as the <u>electric revenue adjustment mechanism</u> (ERAM), and cost recovery through the <u>fuel adjustment clause</u> (FAC) or other tariff riders.

The Appropriate Rate of Return for "Least-Cost" Investments

Only prudently incurred costs of regulated utility assets should be borne by ratepayers. These assets, which are used-and-useful, should be rolled into rate base, except costs that may be specifically assignable to an individual customer or customer class. A utility's overall allowed rate of return should reflect the aggregate risk of all its supply and demand side investments. Each category of investment, including DSM programs, should be allowed a rate of return that is commensurate with that investment's risk.

If regulators effectively reduce the risk of DSM program investments relative to other investments, they also should lower the allowed rate of return. A higher allowed rate of return (or "incentive" rate of return) is justified only if there is a commensurate increase in the utility's risk associated with those investments. An otherwise appropriate rate of return must be reduced if utilities are guaranteed recovery of DSM program costs (e.g., through the FAC) or they receive "bonus" payments for achieving targeted demand reduction goals. Such preferential treatment is counter to the principles of least-cost planning because it distorts the "level playing field" between demand side and supply side resources.

Recovery of "Lost Revenues"

Avoided net revenues resulting from DSM programs should be treated like the many other factors that are estimated as part of the utility's rate case filing to establish the sales estimate which forms the basis of the revenue requirement determination. Estimates of lost sales should be factored into the utility's total revenue requirements for the test year over which base rates are determined. Regulatory accounting procedures that "decouple" profits from kWh sales will distort a utility's motivation to efficiently plan and operate its business, and may result in cross-class or cross-customer subsidies. The use of procedures such as ERAM should not be allowed as a requisite of least-cost planning. However, if mechanisms such as ERAM are implemented, then the utility's allowed rate of return must be reduced commensurate with any reduction in the utility's risk.

The FAC or other tariff riders are totally inappropriate mechanisms for the recovery of avoided net revenues that result from DSM programs. If used at all, the FAC should only adjust rates for rapid changes in the costs of fuels.

HOW SHOULD COSTS BE ALLOCATED TO RATEPAYERS?

The allocation to ratepayers of the costs of any utility demand or supply side investment or expense should be based on detailed and accurate cost-of-service studies. These studies should be used by Commissions, routinely updated (e.g., as often as the utility files for new rate changes), and subject to public review and comment.

Rates should be designed to recover the cost of providing service and to reflect the manner in which those costs occur. Whether provided by supply side or demand side resources, or both, the costs of providing electric service should be classified into three categories:

1. Capacity costs are the costs associated with facilities necessary to respond to each customer's kilowatt demand on the system, including a reserve margin necessary to maintain an acceptable level of service reliability. Capacity costs include the cost of DSM programs that effect customer kW demand but which may or may not effect customer energy (kWh) consumption. The costs of DSM programs designed to reduce summer peak loads by offering customer rebates for energy efficient air conditioners is an example of capacity costs on the demand side. The costs of gas-fired turbines installed for the same purpose is an example of capacity costs on the supply side.

2. Customer costs are the costs incurred in servicing customer accounts, including a portion of distribution costs, hookup, metering and meter reading, bill preparation, customer accounting, and certain demand side program costs such as marketing expenses.

3. Energy costs are the costs incurred in the production of the kilowatthours (kWh) used by a system's customers, including the costs of energy conservation programs which effect only kWh consumption. For most supply side resources, the primary energy cost is fuel costs.

Once appropriately classified, these costs should be allocated to customer classes. This allocation should use an appropriate cost allocation method that recognizes the actual peak demand and energy consumption of each customer class.

Costs also are referred to as being either fixed or variable. Fixed costs are those that, in total, do not vary with output, where output is equal to total sales plus losses. Variable costs are those that change in total as output changes. Total variable costs increase as output increases and decrease as output decreases. Any rate structure used to recover the costs of providing service should reflect the fact that some costs are fixed and some are variable. Fixed costs should be recovered in the fixed, demand-related component of rates and variable costs should be recovered in the variable, energy-related component of rates.

WHAT REGULATORY OVERSIGHT IS NECESSARY TO ASSURE THAT LEAST-COST GOALS ARE MET?

Certain regulatory safeguards are necessary to minimize the potential abuse of market power if, as a result of least-cost planning, utilities are required to expand their reach to the customer side of the meter. The basic safeguards include:

1. Commissions must establish broad guidelines for the implementation of least-cost (or integrated resource) plans. Utilities must always retain the responsibility and accountability to manage the use of all their resources whether demand side or supply side.
2. Filing requirements should be established that subject utilities' least-cost resource plans and basic planning assumptions and methodologies to public review.
3. The acquisition of any supply or demand side resource should start with the development of an overall resource plan. The resource plan should begin with a determination of need and include consideration of both demand and supply options.
4. Commissions should require utilities to set rates based on cost-of-service so as to send appropriate price signals. Rates should include a full range of rates and services, including time-of-use, curtailable, and interruptible rates.
5. Utilities should not be allowed a return on DSM, supply side or pollution abatement investments that are not both physically and economically used-and-useful.
6. All utility investments should be subject to prudence and used-and-useful reviews.
7. The opportunity for public comment and review, including assured participation in the hearing process, must be guaranteed to all interested parties.