CONF-9104196--

PROCEEDINGS

NATIONAL CONFERENCE ON INTEGRATED RESOURCE PLANNING

Santa Fe, New Mexico
April 8-10, 1991

National Association of Regulatory Utility Commissioners
Room 1102 ICC Building; P.O. Box 684
Washington, D.C. 20044-0648

Telephone No. (202) 898-2200

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NARUC THIRD NATIONAL
INTEGRATED RESOURCE PLANNING CONFERENCE
SANTE FE, NEW MEXICO
APRIL 8-10, 1991

CONF-9104196--

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Survey and Analysis of Gas Utility IRP Efforts

Chuck Goldman
Lawrence Berkeley Laboratory
415-486-4637

Mary Ellen F. Hopkins
The Fleming Group
202-347-9500

FG01-89CE2830/

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Survey & Analysis of Gas Utility IRP Efforts

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EXECUTIVE SUMMARY

In collaboration with NARUC's Energy Conservation Committee, Lawrence Berkeley Laboratory (LBL) surveyed all state commissions (PUC) to assess the current status of gas planning and demand-side management and to identify significant regulatory issues faced by commissions during the next several years. A telephone survey of designated contacts in each PUC was conducted by The Fleming Group (a sub-contractor to LBL), between September-November 1990. Written summaries were then prepared and sent to respondents and Commission chairmen for verification and revision.

The major findings from this survey include:

Status of Gas LCP Regulations and Practices

- Efforts by state commissions to develop and implement integrated resource planning for local gas distribution companies (LDC) are expanding rapidly in about 15 states. Among this "most active" group, seven PUCs have in place or are implementing state-wide least-cost planning (LCP) rules or regulations. In four states, a least-cost planning (LCP) process has been established with utility IRP plans submitted (but not approved); initial utility plans are expected by the end of 1991 in three other states. Formal gas LCP regulations have not been adopted in several of these states, but many of the elements are in place and LCP practices are being developed through other regulatory mechanisms (e.g., rate cases). Six states have some active initiative related to gas LCP under development.

- Thirty PUCs report that gas LCP is not actively being considered. Eighteen of these states indicated that utilities develop gas conservation programs on a voluntary basis. About one-third of these states indicated that integrated resource planning processes for electric utilities are in various stages of development and that IRP for gas utilities will be considered only after experience has been gained from electric utilities.

- Rankings of state PUC activities with respect to gas IRP should be viewed as providing a snapshot of regulatory developments in an area that is evolving quickly, particularly in light of the fact that experience with gas IRP is limited in even the most active states.

Demand-side Management (DSM) Planning and Programs

- DSM programs are initiated and developed by gas utilities through various methods (number of states given in parentheses): because of PUC requirements (10) or suggestions (6), by the utility on a voluntary basis (29), and through collaborative working groups (9).

- About 85% of the states reported that some or all gas utilities offer energy audits to residential or multifamily customers. Various types of weatherization measures (e.g., insulation, caulking/weatherstripping) are offered by some or all utilities in about half of

the states, while heating equipment replacement or retrofit programs are being implemented in about 18-20 states.

- Thirty-two PUCs report that all gas utilities offer interruptible rates for commercial/industrial (C/I) customers, while nine other PUCs indicated that some gas utilities have this rate. DSM programs designed to improve equipment efficiency, the thermal performance of the envelope, or efficiency of industrial processes are much less common. Only about 20-25% of the states report that some or all gas utilities offer these type of C/I programs.

- Almost all PUCs indicated that the DSM programs of even the most active gas utilities could not be characterized as comprehensive, particularly in comparison to efforts of electric utilities in their state.

- Several regulatory and institutional factors tend to be correlated with those gas utilities that have more sophisticated DSM planning processes and aggressive energy efficiency programs. These factors include the existence of LCP regulatory requirements, combination utility (electric and gas), and the relative size of the utility, although these findings are somewhat speculative given data limitations and the limited scope of the survey.

- Gas utilities in ten of the 15 "most active" states evaluate the cost-effectiveness of DSM programs using economic tests that reflect various perspectives (e.g., program participants, non-participating ratepayers, the utility, and society). A number of PUCs indicated that gas utilities often prefered to focus on rate impacts of proposed programs and relied mainly on the non-participants test. PUCs in these most active states believe that various quantitative and qualitative criteria should be considered in screening and developing DSM programs, while several PUCs consider the total resource or societal cost test as the primary economic test.

- A number of PUCs commented that interim (and proxy) methods are currently being used to value the benefits of gas DSM programs, while more sophisticated analytic techniques are under discussion. Determination of avoided gas supply costs may be the most difficult DSM planning issue confronting utilities and regulators, as no consensus exists on a standard method to calculate gas avoided costs. Moreover, there are significant disagreements among various parties on gas supply costs that can be avoided because of DSM programs. Currently, only six states indicated that gas utilities or the PUC had developed a method to estimate avoided costs of new gas supplies.

- Seven PUCs reported that their state offers or has proposed some type of incentive mechanism for gas utilities that aggressively implement energy efficiency programs. Innovative approaches, such as "shared savings" as well as an increased rate of return for

conservation investments have been approved for gas utilities by PUCs in California and Massachusetts and are under consideration in Iowa, New Jersey, and District of Columbia.

- Fuel substitution programs and policies have often been quite controversial. In at least eight states, competing utilities had intervened or opposed DSM programs that offered financial incentives to customers for high-efficiency equipment. Several PUCs are currently involved in investigations on fuel substitution (Massachusetts, Vermont, and Wisconsin) or the related issue of promotional practices (Georgia).

Regulatory Review of Gas Supply Purchase Practices

- PUCs in 39 states indicated that they conduct prudency reviews of gas purchases. Fourteen of these states have some form of least-cost purchasing rules, either because of state statute, PUC order or rulemaking, or implicitly through practice.

- With a few exceptions, PUCs generally indicated that there was no relationship between prudency review procedures and LCP initiatives.

Key Regulatory Issues

- We found that the dominant regulatory issues tend to be different in states with more active gas LCP processes compared to the less active states. Development of LCP regulations and increased focus on DSM planning and programs were mentioned by about three-quarters of the 15 "most active" PUCs. Supply-related issues such as transportation and procurement policies, bypass and obligation to serve, and prudence review of gas purchase decisions were mentioned relatively frequently by PUCs in the other 36 states.

INTRODUCTION

Until recently, state regulators have focused most of their attention on the development of least-cost or integrated resource planning (IRP) processes for electric utilities. A number of commissions are beginning to scrutinize the planning processes of local gas distribution companies (LDCs) because of the increased control that LDCs have over their purchased gas costs (as well as the associated risks) and because of questions surrounding the role and potential of gas end-use efficiency options. Traditionally, resource planning at local gas distribution companies (LDCs) has concentrated on options for purchasing and storing gas (Hopkins 1990). Integrated resource planning involves the creation of a process in which supply-side and demand-side options are integrated to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest cost. As applied to gas utilities, an integrated resource plan seeks to balance cost and reliability, and should not be interpreted simply as the search for lowest commodity costs (Munts 1990).

The National Association of Regulatory Utility Commissioners' (NARUC) Energy Conservation committee asked Lawrence Berkeley Laboratory (LBL) to survey state PUCs to determine the extent to which they have undertaken least cost planning for gas utilities. The survey included the following topics:

- status of state PUC least-cost planning regulations and practices for gas utilities,
- type and scope of natural gas DSM programs in effect, including fuel substitution,
- economic tests and analysis methods used to evaluate DSM programs,
- relationship between prudency reviews of gas utility purchasing practices and integrated resource planning,
- key regulatory issues facing gas utilities during the next five years.

The remaining sections of this report discuss the results for each of these topics. The primary objective of the survey was to provide NARUC, state PUCs, the Department of Energy (which provided LBL with funding), and gas utilities with an initial assessment of state regulatory activities related to resource planning and demand-side management programs and planning processes of local gas distribution companies (Goldman and Hopkins 1991).

APPROACH

In this section, we discuss the approach used to design and conduct the survey of state PUCs on the status of least-cost planning for gas utilities.

Organization and Administration of the Survey

An initial list of contacts in each state commission was developed from several sources: NARUC's Energy Conservation and Gas committees, and previous survey work conducted by The Fleming Group (TFG). NARUC then sent a letter to all commissions announcing the study, accompanied by a list of contacts for each state. Commissioners were asked to designate appropriate staff contacts for various aspects of the study. The initial telephone survey was conducted by TFG and consisted of an extensive list of open-ended and multiple choice questions on various topics. Based on responses from contacts, LBL/TFG prepared written summaries for each state, which were then sent back for verification and revisions.

Assessing the Status of LCP regulation and IRP practices for gas utilities

Categorization of LCP practices necessarily involves some degree of subjectivity and judgment. In our survey, we attempted to adapt a ranking system used by EPRI for assessing LCP regulatory practices for electric utilities to the specific issues that arise in state regulation of gas utilities. We asked PUC respondents several open-ended questions: Does your state require least-cost planning or integrated resource planning for natural gas utilities? For all responses, describe the current situation in more detail with respect to IRP for gas utilities? Table 1 summarizes the criteria which were used to categorize PUC responses into one of five categories: (1) LCP not actively considered or rejected, (2) LCP under consideration, 3) LCP under development, (4) LCP under implementation, and (5) LCP in practice. Generally, we view states that are in groups three to five as being among the "most active" states with respect to gas LCP.

In our view, given that even the most active states are at the initial stages of gas LCP and that the situation can change relatively quickly in individual states, any ranking of state PUC activities should be viewed as providing a "snapshot" of regulatory developments in an area that is evolving rapidly. It would be a mistake to interpret rankings in a rigid fashion, particularly since there is no broadly shared consensus on what constitutes a mature integrated resource planning process for gas local distribution companies (LDC).

STATUS OF GAS LEAST-COST PLANNING REGULATIONS AND PRACTICES

Thirty PUCs report that LCP is not being actively considered in their states (see Figure 1). Among this group, two PUCs (Nebraska and Texas) noted that they do not regulate gas utilities at the state level. Nine states indicated that they were currently

Table 1. Status of Least-Cost Planning (LCP) Regulations for Gas Utilities

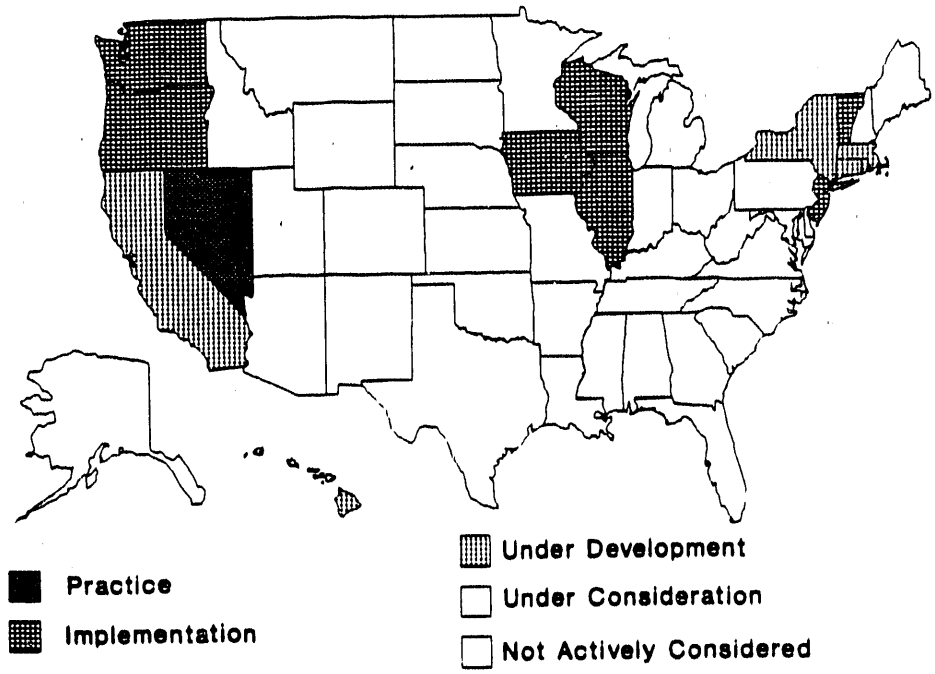
Status	*Definition*
In Practice	Indicates that LCP occurs by means of PUC rules or legislation, that practice includes regulatory mechanisms that could potentially be used for enforcement, and that utilities have submitted IRP plans.
In Implementation	Indicates that formal LCP rules or legislation are in effect; that a likely regulatory enforcement mechanism exists, or that LCP informal practices are relatively advanced and that most elements of LCP process are in place.
Under Development	Indicates active consideration of least-cost planning issues (through workshops, studies, or more formal legislative processes) with the intent of developing methods to implement LCP.
Under Consideration	Signifies that gas LCP issues are being discussed within the state by PUC or legislation, with the possibility that formal LCP development may follow.
Not Actively Considered	Indicates that LCP is not actively being considered by PUC and development is not imminent.
Rejected	Indicates that PUC has formally rejected LCP requirements for gas utilities.

Source: Adapted from EPRI, "Status of Least-Cost Planning in the United States," 1988.

considering or developing LCP requirements for electric utilities and that they wanted to gain experience with these utilities first before adapting LCP for gas utilities.[1] In almost all of these states, there is no PUC requirement to implement gas DSM programs; 18 PUCs reported that DSM programs are developed by utilities on a voluntary basis.

[1] PUCs include: Arizona, Delaware, Georgia, Kansas, Kentucky, Missouri, Pennsylvania, Utah, and Virginia.

Figure 1
Status of Gas LCP Regulations and Practices



We categorized six states as having gas LCP under consideration.[2] There is no requirement for gas LCP in these states, although the topic has been discussed by PUC staff or commissioners. Four of these states indicated that LCP activity is progressing on electric LCP first and that gas LCP may be considered next.

Based on PUC responses, the remaining 15 states appear to be "most active" in either developing or implementing least-cost planning regulations and practices for gas utilities. There are significant gas LCP initiatives underway in many of these states and a variety of approaches are being explored. We discuss efforts in these states in more detail to give an indication of the scope and range of activities. Among this group, about half of the PUCs have made substantial progress in terms of developing a formal regulatory framework (i.e., regulations, orders). In a few of these states, formal gas LCP regulations have not been adopted, but many of the elements are in place and practices are relatively advanced. In some cases, gas LCP practices are being developed and implemented in a rather ad hoc

[2] States are Alabama, Colorado, Michigan, Montana, New Hampshire, and Ohio.

fashion often through individual rate cases and other regulatory forums (e.g., investigations on interfuel substitution).

We categorized six PUCs in this group as having gas LCP under development[3]. In most of these states, there is some active initiative related to gas LCP. Examples include:

- **California** - Many of the ingredients of a least cost planning process for natural gas utilities are fairly well developed, although there is no formal or regular proceeding specifically concerning gas LCP. Long-range gas supply and demand-side options are included in the Biennial Fuels Report prepared by the California Energy Commission (CEC), which is responsible for long-term energy planning. The long-term demand forecast includes the effects of existing gas DSM programs and state building standards for new construction. DSM programs are typically proposed by gas and electric utilities in general rate cases, which occur every three years, and are evaluated for cost-effectiveness using the California Standard Practice Manual (1987). However, gas utilities are not required to evaluate all cost-effective options, only those implemented. Gas utilities are currently implementing a broad set of full-scale efficiency programs, some of which emerged out of a recently completed collaborative process (California Statewide Collaborative Process 1990). PUC staff also indicated that, at the present time, potential gas energy efficiency programs ("uncommitted" DSM) are not compared as an alternative to various supply options, which is an important shortcoming of the current process compared to electric resource planning in the state.

- **Connecticut** - The legislature recently enacted a statute which requires all gas utilities to file a ten-year supply and demand forecast on an annual basis. The Act requires that gas utilities identify "specific measures to control load growth and promote conservation (Connecticut Public Act 1989)." In addition, the DPUC has developed a process that includes significant public input and review by a "Conservation Collaborative Group" of the conservation plans and programs proposed by gas utilities in rate cases.

- **Massachusetts** - The Department of Public Utilities (DPU) is developing LCP processes for gas utilities on an ad hoc basis as companies file rate cases; no statewide rule is planned at this time for gas LCP. During these rate cases, the DPU approves conservation plans submitted by the gas utility. Boston Gas has submitted an ambitious conservation plan, parts of which have been approved, which includes a budget of up to $60 million over the next five years.

[3] States are California, Connecticut, Massachusetts, New York, Rhode Island, and Hawaii.

- **Rhode Island** - The Commission is also addressing gas LCP issues in the context of current rate cases of gas utilities (e.g., Providence Gas). Gas utilities already file long-range (five year) plans which detail projected supply options.

- **New York** - LCP for gas utilities is being discussed as part of the State Energy Planning Process by three energy agencies (State Energy Office, Public Service Commission, and Department of Environmental Conservation).

- **Hawaii** - The PUC is currently involved in a proceeding to establish a LCP framework for both electric utilities and GASCO, which produces and distributes synthetic gas to the Hawaiian islands[4].

Table 2 summarizes the current regulatory framework/process as well as the status of utility IRP (or long-range DSM) plans and programs in the nine states that are categorized as having either implemented or have gas LCP in practice.[5] Seven of these nine states developed LCP regulations jointly for gas and electric utilities or gas LCP requirements were adapted with very minor changes from existing electric LCP regulations.[6] In many of these states, implementation of LCP regulations for electric utilities was the initial driving force, although inclusion of gas LDCs was clearly a conscious choice made by PUCs. The gas LCP regulatory framework and process varies by state and PUC orders are not final in some states (see Table 2). In some cases, state legislation may have provided the impetus and mandate for a PUC to develop LCP regulations (Nevada, Illinois, Iowa), while in the District of Columbia, rules were promulgated as a result of a PUC order (i.e., regulations in effect). In some states (e.g., Iowa and New Jersey), development of gas energy efficiency programs has been a principal focus of the LCP regulations, which shapes the type and scope of plan that utilities are required to produce (i.e., long-range DSM vs. IRP plan). Until gas utilities in more states actually file IRP and/or DSM plans, it is too early to determine if these differences in emphasis are significant. Finally, it is worth noting that IRP plans have been submitted by gas utilities in four states, although no PUC has yet approved a plan as of February 1991.

Development of a gas LCP process is clearly a high priority in these states as evidenced by the level and pace of activity:

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[4] Because of the small quantities of gas sold in Hawaii, the focus of the proceedings is on electric utility IRP issues.

[5] Nevada and the District of Columbia are classified as having gas LCP in practice, while the other seven states are currently implementing a least-cost planning process for gas utilities.

[6] PUCs that developed LCP regulations jointly for electric and gas are District of Columbia, Illinois, Iowa, and Vermont. Gas IRP regulations in Nevada, Washington, and Oregon were adapted with minor changes from electric IRP regulations.

Table 2. Progress Toward Least-Cost Planning for Gas Utilities

State	Regulatory Framework/Process				Utility Practice	
	Legislation in Effect	PUC Requirements in Effect	Regulations in Effect	Other Regulatory Mechanisms	IRP Plan Submitted	IRP Plan Approved
Nevada	X	X			yes	no
Washington, DC		X			yes	Under consideration by staff [a]
Illinois	X	X			Due early 1991	
Iowa	X	Proposed			Mid- to late 1991 (DSM Plan)	
New Jersey				State Energy Master Plan (Draft)	1st DSM Plans in 1991	
Oregon		X			yes	no
Vermont		X			no	
Washington		X	X		yes	no
Wisconsin				Some elements in place; rate case		

[a] Twenty-two DSM pilot programs have been implemented and will be evaluated over the next two years.

• **Nevada** - Least-cost planning requirements developed as a result of electric LCP/IRP requirements, and a legislative initiative authorizing the PSC to develop a subsequent order (see Table 2). The Nevada Administrative Code (1990) requires "a summary of the plan to reduce consumption and demand, listing each program and its effectiveness in terms of costs and showing the forecast reduction of demand and the contribution of each program to this forecast." The Southern Division of Southwest Gas Corporation filed its first LCP on July 1, 1990. The Commission rejected the initial DSM program proposed by Southwest Gas and asked the utility to go back, and 1) list all technically feasible DSM options; 2) use the total resource cost test to evaluate the DSM programs; and, 3) prepare an implementation plan.[7] Other gas utilities serving northern Nevada are required to file a LCP in 1992. Nevada's LCP regulation requires gas utility's to develop a ten-year forecast, a three year action plan, and to include a detailed assessment of the technical and market potential of conservation by end use, a description of proposed programs, and a detailed cost/benefit analysis.

• **District of Columbia** - In March 1988, the District of Columbia (D.C.) Public Service Commission issued an order that requires District of Columbia Natural Gas (DCNG) to implement an integrated least-cost plan. In September 1990, DCNG filed its plan which includes the following steps:

1. Estimate baseline DCNG gas requirements without conservation programs;
2. Establish the lowest cost gas supply mix;
3. Identify cost effective demand side management options;
4. Integrate demand and supply options;
5. Develop an Integrated Least Cost Plan (DCNG 1990).

DCNG's integrated least cost plan considers multiple quantitative and qualitative planning criteria. Quantitative criteria include meeting future design day and annual sales requirements at the lowest possible costs; ensuring operational reliability; and, pursuing DSM programs that successfully pass the All Ratepayers Test, and meet the Commission conservation goals. Qualitative criteria includes: flexibility of DSM programs to meet the needs of the market, and reducing environmental impacts (DCNG 1990). Currently, DCNG is implementing 22 pilot DSM programs that are available to all customers, which are being evaluated during the next two years.

• **Illinois** - Illinois has a LCP rule in effect for natural gas utilities that is based on the Public Utility Act of 1987 which mandated that the Illinois Commerce Commission (PUC) promulgate a rulemaking procedure (this ended in January

[7] Docket No. 90-701, currently open.

1989), and that the Illinois Department of Energy & Natural Resources prepare a state-wide plan by January 1990. The state-wide plan stipulates that individual utility plans must be consistent with the state plan.[8]

The LCP requirements are applicable to about 95% of the gas sold in Illinois and individual utility plans are due in January 1991.[9] Gas utility resource plans are to include a 10-year demand forecast as well as an initial two year period featuring pilot DSM program implementation. The PUC expects utilities to prepare an estimate of the conservation impact of DSM programs (technical and market potential), which will be used to develop a modified peak day and sales forecast. Next, gas supply requirements are revised, along with any revisions in the cost of service and any change in sales. All variables are then combined to result in the goal of an integrated plan.

- **Iowa** - The Iowa Utility Board (i.e. the Commission) has proposed specific guidelines and requirements for the implementation of energy efficiency programs that apply to both electric and gas utilities which meets goals articulated in recent legislation passed by the Iowa General Assembly (Iowa Utility Board, 1990a and 1990b). In addition to enunciating broad policy goals related to the efficient use of energy, the legislation requires the state's gas utilities to devote 1.5% of their revenues to energy efficiency. The legislation was based on the recommendations of a working group composed of PUC and utility staff, Department of Natural Resources, and members of the Consumer Advocate Division of the Department of Justice (Smith 1990). Under the Commission's proposed rules, gas utilities would be required to forecast future energy capacity needs compared with existing supplies; assess the future capacity availability and cost of these supplies; identify and assess the potential and cost of demand-side options; and describe implementation procedures for selected programs, including budget requirements, and monitoring and evaluation procedures. After a utility files a plan which meets the Board's requirements, it is docketed as a contested case. The PUC expects gas utilities to file their first DSM plans by mid-1991.

- **New Jersey** - New Jersey has no direct regulation covering gas LCP, however, the proposed Energy Master Plan (NJEMP) contains guidelines on "Least Cost Planning Strategies for LDCs."(NJBPU 1990a) The proposed guidelines state that LDCs need to more fully incorporate conservation into the planning process and must employ a planning model that integrates supply-side and demand-side options. The final NJEMP is expected in early 1991. In addition, the New Jersey Board of Public

[8] Hearings on the PUC rules on the state plan were completed in September 1990 and the PUC Commissioners voted on a final order on LCP/IRP on October 3, 1990.

[9] Gas utilities are subject to the same LCP/IRP requirements unless they have less than 25,000 jurisdictional customers, in which case they may apply for an exemption to the order.

Utilities (BPU) has also proposed regulations that would require electric and gas utilities to file a Demand Side Management Resource Plan biennially for review and approval by the BPU and would also establish incentives for electric and gas utility participation in DSM activities (NJBPU 1990b). The first plan for each utility is due in 1991.

• **Oregon** - In April 1989, the Oregon PUC (1989) implemented electric and natural gas least-cost planning after a formal investigation. IRP plans have recently been submitted by two gas utilities, Northwest Natural Gas and Cascade Natural Gas, but have not been approved by the PUC (see Table 2). Initial resource plans have generally focused on least-cost purchasing for supply requirements. The PUC would like utilities to thoroughly evaluate DSM options in order to develop an acceptable least-cost plan.

• **Vermont** - In April 1990, the Public Service Board issued an order that outlined the Commissions LCP requirements for all major electric and gas utilities (Vermont Department of Public Service 1990). The Commission has mandated that all utilities submit three filings to the Board: (1) a work plan for the development of comprehensive DSM programs, which must be submitted within 90 days, (2) a DSM implementation plan which includes incentives, budgets and targets, within 180 days, and 3) a fully integrated resource plan which provides for annual summary reviews. The IRP is to be refiled and reviewed every three years thereafter. Vermont Gas Systems has one year to submit its third filing. Fuel substitution issues have been quite prominent as Vermont Gas System has proposed a pilot DSM program that promotes cost effective electric heat conversions to natural gas in this winter-peaking region. The Board states that Vermont Gas is free to offer rebates to equipment dealers and installers and/or cash incentives directly to customers for gas heat conversions. The Board recommends that an incentive program to promote high-efficiency space heating should be designed cooperatively in areas where electric and gas services overlap.

• **Washington** - Based on an October 1987 PUC order, Washington's regulations stipulate that gas utilities must prepare a least-cost plan in consultation with commission staff, and that the utility provide for public involvement in the plan preparation. The least-cost plan is defined as "a plan describing the strategies for purchasing gas and improving the efficiencies of gas use that will meet current and future needs at the lowest cost to the utility and its ratepayers consistent with the needs for security of supply." (Washington 1987). Washington's regulations are stated quite concisely, yet require gas utilities to perform a thorough and comprehensive integrated resource analysis. The utility's plan must be submitted on a biennial basis and shall include:

a) one, five and twenty year forecasts of future gas demand in firm and interruptible markets for each customer class;

b) an assessment of the technically feasible improvements in the efficient use of gas as well as the policies and programs needed to obtain the efficiency improvements;

c) an analysis of gas supply options including (e.g., projection of spot market versus long-term purchases for both firm and interruptible markets; evaluation of opportunities for company-owned or contracted storage or production; assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers;

d) a comparative evaluation of gas purchasing options and improvements in the efficient use of gas based on a consistent method, developed in consultation with commission staff, for calculating cost-effectiveness;

e) integration of demand forecasts and resource evaluations into a long-range (e.g. twenty-year) least-cost plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers.

f) a short-term (e.g. two-year) plan outlining the specific actions to be taken by the utility in implementing the long-range least-cost plan." (Washington 1987)

One gas utility has submitted a least-cost plan to the commission, but the commission staff have a number of questions concerning the submission which must be answered before the staff can recommend acceptance of the plan to the commissioners.

- **Wisconsin** - Wisconsin does not have a specific regulation requiring least cost planning for gas utilities, but key elements are in place based on current practices that have been established in rate cases and other regulatory proceedings. For example, gas utility DSM plans, programs and budgets are evaluated and set during rate cases, which occur on a regular basis. Utilities are required to estimate the technical and market potential of DSM programs and the impact of sales changes resulting from conservation, although the time horizon is typically short-term. In Wisconsin, DSM goals are set according to net benefits by end-use and the PUC is currently going through the first round of goal setting for natural gas DSM programs. Changes in the regulatory treatment of conservation goals are expected as gas utilities and the Commission gain more experience. The PSC staff are also currently conducting an investigation into interfuel substitution, which will provide a forum for additional discussions on the economic tests that are useful in gas planning (WPSC 1990.)

DEMAND-SIDE MANAGEMENT PLANNING AND PROGRAMS

In the next sections, we discuss the impetus for gas utility DSM programs in various states (i.e., state statute, PUC requirements, voluntary), summarize PUC respondents assessment of DSM planning and program activities at gas utilities, describe the economic tests and analysis methods used to evaluate gas DSM programs, and discuss current ratemaking and financial treatment of DSM program costs in various states.

Gas Utility DSM Programs: How Are They Developed?

We asked PUCs for their assessment and perspectives on the demand-side management planning process and programs of gas utilities. In general, the motivating forces causing gas utilities to develop DSM programs were strongly correlated to the level of activity with respect to gas LCP. For example, DSM programs are implemented by gas utilities in ten states as a result of PUC requirements. With four exceptions, these states tend to be among the most active in developing gas LCP (Figure 2).[10] In the 15 most active states, PUCs report that a variety of other methods are often used by gas utilities to initiate DSM programs (e.g., PUC suggestions, collaborative working groups, and at the utilities own initiative). Collaborative approaches and working groups, which have been successfully utilized by many electric utilities, are also becoming increasingly popular among gas utilities and their regulators. Nine PUCs reported that DSM programs are developed by working groups, although the approach, responsibility, and representation of stakeholders varies significantly among states.[11] Examples of these approaches include:

- **California** - The state's major electric and gas utilities jointly participated in a collaborative process with the PUC's Division of Ratepayer Advocates, the California Energy Commission and 14 other stakeholder groups which developed an expanded set of conservation programs and incentives for utility shareholders (California Statewide Collaborative Process 1990).

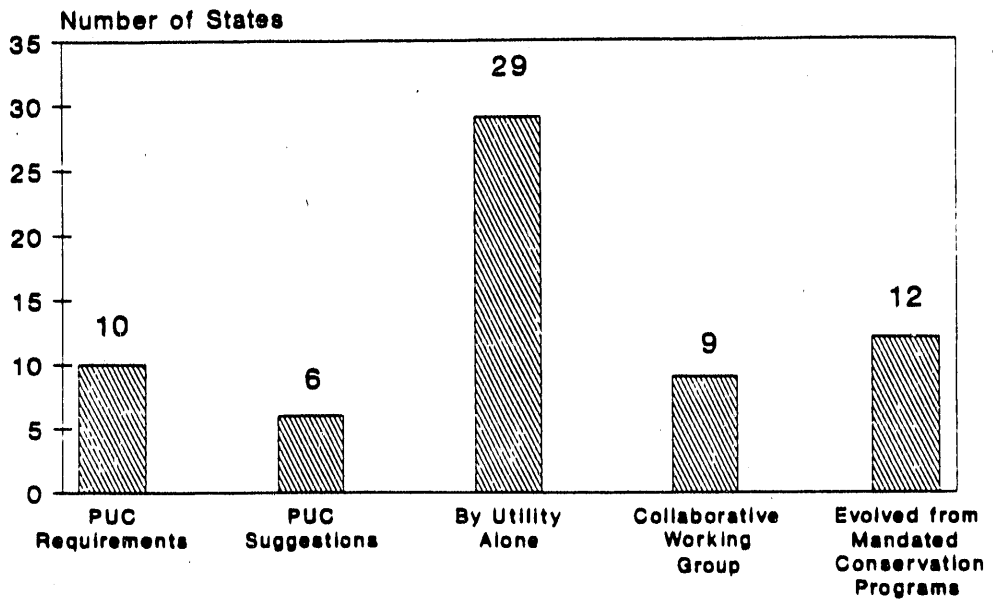
- **Connecticut** - Intervenor groups provide input and resolve differences on each gas utility's conservation plan and program through a "Conservation Collaborative Group" which includes representatives from the utility, Office of Policy and Management (OPM), the State Energy Office, Department of Public Utility Control, the Office of Consumer Council, CAP agencies and community groups.

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[10] States include District of Columbia, Florida, Illinois, Kansas, Massachusetts, Nevada, Oregon, Pennsylvania, Rhode Island, Tennessee.

[11] States include Alabama, California, Connecticut, Illinois, Massachusetts, Michigan, Rhode Island, and Washington, and the District of Columbia.

Figure 2
Gas Utility DSM Programs are Initiated
by Various Methods



- **District of Columbia** - A collaborative group composed of staff from District of Columbia Natural Gas, Commission staff, D.C. Energy Office, Office of People's Counsel, and consultants developed 22 pilot DSM programs encompassing all sectors, which are currently being implemented.

In contrast, in states that are not actively considering gas LCP, DSM programs that exist are typically initiated by gas utilities on a voluntary basis. Eighteen of the 30 states which stated that DSM programs are initiated solely at the utility's discretion also responded that they were not actively considering gas LCP. PUCs in 12 states reported that current gas utility DSM programs evolved from earlier conservation programs that were either federally-mandated (i.e., the Residential Conservation Service audit) or initiated as a result of state statutes.

Types of DSM Programs

PUCs were also asked to describe the type of DSM programs that have been implemented by gas utilities, whether these programs were offered by all or some utilities in the state, which gas utilities had the most comprehensive DSM programs, and at what general stage of development were the various programs (i.e., a few pilots, some pilot

programs/some full-scale, mostly full-scale). Energy audits appear to be offered most frequently to residential and multifamily customers, with about 85% of the states reporting that some or all gas utilities in their state conduct energy audits (see Figure 3). Various types of weatherization measures, ranging from infiltration reduction through caulking and weatherstripping to additional insulation were offered by some or all utilities in about half of the states. DSM programs that promote installation of high-efficiency equipment or retrofits to the existing heating system were being offered by some/all utilities in about 18-20 states.

Interruptible rates are the principal type of DSM program offered to commercial/industrial customers. Thirty-two PUCs reported that all gas utilities in their state offer interruptible rates, while nine other PUCs responded that some gas utilities have this rate (see Figure 4). However, DSM programs designed to improve equipment efficiency, or thermal performance of the building envelope, or programs that focus on improving the efficiency of industrial processes of commercial/industrial customers are much less common. Only about 20-25% of the states report that some or all of their utilities offer these type of programs.

There are some general trends related to the overall level of DSM activity that are worth noting. PUCs in virtually all states stated that even the most active gas utilities did not have comprehensive DSM programs in place at this time. In part, we believe this response was widespread because PUC staff tend to assess the DSM activities of gas utilities relative to accomplishments of electric utilities, which provides an implicit standard for defining comprehensiveness. Respondents did identify utilities that they consider most active in DSM, but this was not based on any pre-specified criteria.

It appears that a number of regulatory, institutional and structural factors tend to be correlated with those gas utilities that have more sophisticated DSM planning processes and ambitious energy efficiency programs. These factors include the existence of a formal LCP regulatory requirement or state energy planning goal or statute, combination utilities (electric and gas), the relative size of the utility, and geographic location (e.g. more severe heating climates). At this point, identification of those gas utilities that have the most active DSM programs is qualitative (based on assessments by PUC staff in each state) and somewhat speculative. This is the case because not all PUCs have access to the quantitative information (current and projected DSM expenditures, DSM expenditures as a percent of total revenue requirements, program participation rates, estimated gas savings, and savings and activity by customer class) that would allow for more meaningful comparisons of gas utility DSM efforts.[12] Again, most PUCs were able to provide only

[12] This type of information would typically be included in a long-range DSM or IRP plan.

Figure 3
DSM Programs Offered by Gas Utilities
(Residential Customers)

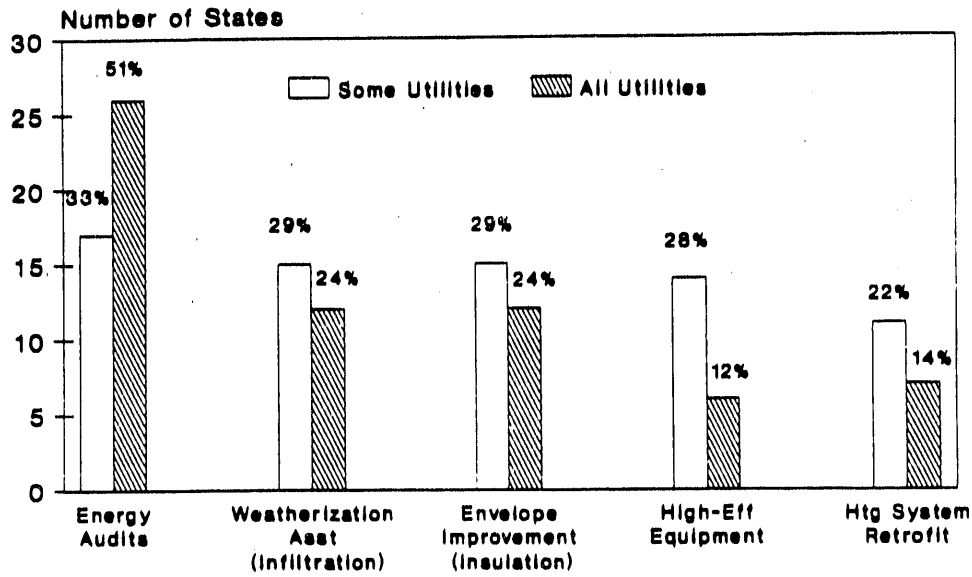
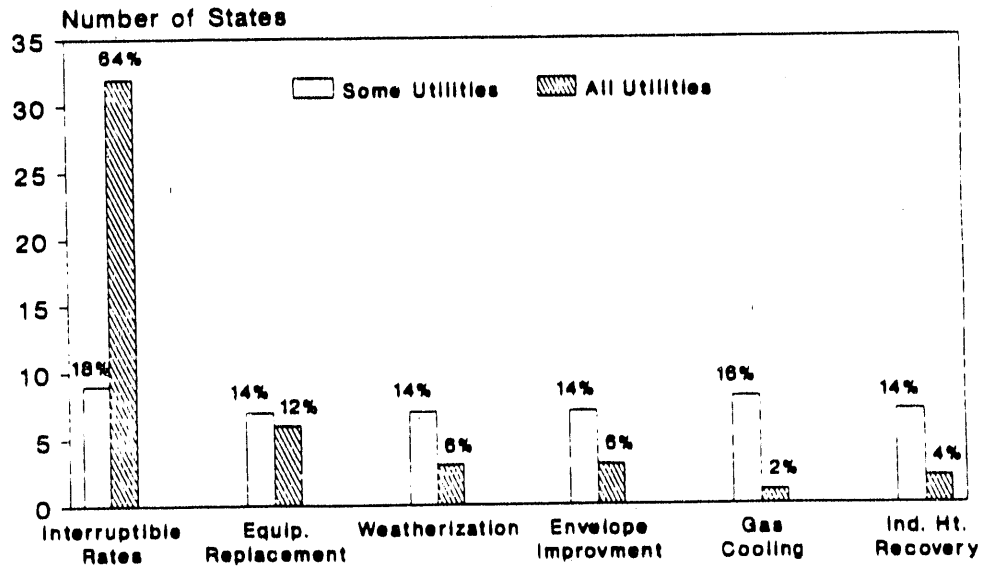


Figure 4
DSM Programs Offered by Gas Utilities
(Commercial/Industrial Customers)



a qualitative indication of the scope of DSM activity in terms of the number, type and scale of programs (pilot vs. full-scale). It would be useful to survey a sample of gas utilities and review gas utility IRP and DSM plans in detail (where available), and other DSM-related filings in order to collect this type of information.

With these caveats in mind, we make the following observations about factors that are correlated with gas utilities identified as having more active DSM programs. Within any state, larger gas utilities tended to have more sophisticated DSM programs and planning processes than smaller utilities. Some PUCs tend not to focus their limited resources on the smallest gas utilities and several PUCs in states with active gas LCP processes noted that the smallest gas utilities were exempt from LCP requirements. It also appears that gas utilities located in the coldest climates in the northern U.S. tend to offer a broader range of DSM programs (e.g., Wisconsin, Minnesota, Illinois, and Michigan) compared to utilities in the southern U.S., although this may just be coincidental because of other factors such as regulatory practice, existing state statutes, and presence of combined utilities.

Gas utilities that were identified by PUCs as active in demand-side management often were combined utilities (gas and electric). Interestingly, combination utilities represent a significantly larger share of all gas utilities in 15 states that are most active in gas LCP compared to the other states. Combination utilities (electric and gas) represent about 42% of the gas utilities in the 15 most active states (31 of 74) as shown in Table 3, while they account for only 20% of the utilities that sell gas in the other 35 states (38 combination utilities out of a total of 186 gas utilities). PUC staff in several states commented that the gas IRP and DSM planning processes of combination utilities tended to be more sophisticated than utilities that only sold gas, which they attributed to their electric IRP activities.

Economic Tests used to evaluate DSM Programs

A key objective of economic analysis is to provide a consistent framework for quantifying the benefits and costs of demand-side programs. Table 4 summarizes benefit and cost components that are considered in various economic perspectives: program participants, non-participating ratepayers, the utility, and society. The selection of cost-effectiveness tests directly impacts the mix of resources selected for a utility's resource plan and thus the choice of cost-effectiveness criteria has been a contentious issue between utilities, regulators, and intervenor groups (Berman and Logan 1990).

Table 3. Number of Gas Only and Combination Utilities in "More Active" States

State	Gas Only Utilities	Combination Utilities (Electric & Gas)
California	3	2
Connecticut	3	0
Hawaii	1	0
Iowa	2	5
Illinois	4	5
Massachusetts	8	2
New Jersey	3	1
Nevada	1	2
New York	4	7
Oregon	2	1
Rhode Island	3	0
Vermont	1	0
Washington	3	1
Washington, DC	1	0
Wisconsin	4	5
Totals	43	31

The debates on appropriate cost-effectiveness tests for DSM programs have at least resulted in much progress being made toward developing standardized procedures to evaluate the economics of electric (and gas) utility DSM programs.[13] Interpretations of the exact definition and usage of some of the components (e.g., cost definitions) of the various formulas used in the California Standard Practice Manual varies among PUCs and utilities. For example, different analytic techniques and methods have been used to value

[13] Readers are referred to the "Standard Practice Manual for Economic Analysis of Demand-side Management Programs" developed by the California Public Utilities Commission (CPUC) and Energy Commission (CEC), NARUC's "Least Cost Utility Planning: A Handbook for Public Utility Commissioners," and Electric Power Research Institute's (EPRI) "Technical Assessment Guide: Fundamentals and Methods, End Use" (volume 4).

Table 4. Summary of Economic Benefit-Cost Perspectives

Economic Perspective	Benefit Components			Cost Components		
	Utility Avoided Costs	Customer Bill Savings	Utility Incentive Payment	Utility Program Administration[1]	Customer Direct Costs	Customer Bill Savings
Participant		X	X		X	
Non-Participant	X			X		X
Utility	X			X		
Total Resource[2]	X			X	X	

[1] Includes incentive payments.

[2] Elements of the total resource are contained in the Societal Perspective, which also includes indirect economic and other non-quantifiable, difficult to quantify economic and non-economic impacts; and uses a different (societal) discount rate.

Source: F. Krause and J. Eto, *Least-Cost Utility Planning: A Handbook for Public Utility Commissioners*, NARUC, Volume 2, December 1988.

benefits of gas DSM programs and a consensus does not currently exist on the best method to use. A number of PUCs commented that interim and proxy methods are being used currently to value the benefits of DSM programs, while more sophisticated methods are under discussion and development. In part, the lack of consensus arises because there are significant disagreements among various parties on the components of future gas supply costs that can be avoided because of DSM programs (e.g., pipeline demand charges, take-or-pay charges in long-term contracts). Various names are sometimes associated with the different economic perspectives, although this is mostly a matter of convention.[14]

PUCs were asked to identify the economic tests used by gas utilities to measure DSM program cost-effectiveness. With a few exceptions, PUCs do not require specific economic tests in most states where gas LCP is not actively considered. Cost-effectiveness evaluation

[14] The utility perspective is described by the Utility Cost Test in the Standard Practice Manual and is referred to as the (Utility) Revenue Requirements Perspective in the EPRI TAG. The Ratepayers Impact Measure Test is commonly known as the "no-losers" test or non-participants perspective. The Total Resource Cost Test is similar to the "all-ratepayers" test.

of DSM programs is often not a major issue because gas DSM programs either do not exist or are quite small. In states that answered this question affirmatively (i.e., utilities use certain economic tests) a number of PUCs responded that gas utilities often favored the non-participant's perspective (i.e., Ratepayer Impact Measure test), but were either required to look at other economic perspectives (e.g., society) or that PUC staff considered these other perspectives in their economic evaluation of DSM programs. PUCs that are developing gas LCP often require utilities to perform a benefit/cost analysis in evaluating DSM programs that includes all the major perspectives. In some cases, PUCs rely more heavily on one or more of these tests. For example, in Connecticut, the primary economic test is the Utility Cost test, while, in the District of Columbia, the "all-ratepayers" (i.e. total resource cost) test is the predominant test in developing least cost plans. In Iowa, the Utility Board requires the Total Resource Cost and Societal tests (Table 5).

Several PUCs that are developing LCP regulations also require or suggest that gas utilities use various criteria in screening DSM options. These criteria typically include consideration of such factors as cost-effectiveness, energy conservation potential, required lead time, lifetime of option, free ridership, and cream-skimming.

Methods to Estimate Gas Avoided Costs

One important element in quantifying benefits of gas efficiency programs is a determination of the costs that are avoided by gas utilities by these type of programs. Only seven PUCs indicated that gas utilities or PUC had developed a method to estimate avoided costs of new gas supplies.[15] PUCs that responded typically gave brief descriptions of utility approaches because PUCs have rarely adopted a prescribed method to calculate avoided costs. Examples include:

- **California** - PG&E uses estimates of short-run marginal costs (SRMC) to value the benefits of gas DSM programs. The components of short-run costs include O&M expenses, administrative and general expenses, PG&E compression losses as well as the forecast commodity price of gas, which is the most significant element (PG&E 1990). Moreover, the CPUC has recently issued a decision which specifies costing guidelines that are to be used by gas utilities in developing long-run marginal cost-based rates (CPUC 1990).

- **Nevada** - Avoided cost methodology is under development by the PSC and gas utilities. Avoided capacity and energy costs are reviewed separately. Avoided capacity costs include the avoided cost of facilities, gas inventory charges, and pipeline contract capacity costs. Marginal avoided energy costs include variable costs (e.g., fuel) and gas inventory charge (which is a negative component when evaluated in this context).

[15] States were California, Connecticut, Iowa, Massachusetts, Nevada, Oregon, and Washington.

Table 5. Economic Tests Used by Gas Utilities to Evaluate DSM Programs

State	Utility Cost Test	Ratepayer Impact Measure	Total Resource Cost Test	Societal Test	Cost/Benefit Tests Required
Most Active States					
California	X	X	X	X	yes
Connecticut	X	X	X	X	yes (cost-effectiveness only)
District of Columbia	X	X	X	X	"All-ratepayers" test required
Iowa	X	X	X	X	
Illinois					Any cost/benefit test
Nevada		X	X		
New York	X	X	X		
Vermont				X	yes
Washington			X		
Wisconsin	X	X	X	X	yes
Other States					
Alabama		X			
Florida	X	X	X		
Maine					Cost/benefit evaluation
Michigan	X			X	
Minnesota	X	X			
Pennsylvania	X	X			Cost/benefit evaluation

- **Washington** - Pending development of a more sophisticated method, the Commission staff have recommended that gas utilities use a "proxy" avoided cost, consisting of the their weighted average cost of gas (WACOG), escalated at a combination of commodity and GNP escalation rates.

Financial Incentives to Utility Shareholders for Promoting Gas Energy Efficiency

In this survey PUCs were asked if financial incentives were offered to gas utilities to encourage energy efficiency programs. NARUC has recognized that traditional rate-setting regulation in most states discourages utility investments in DSM resource options because "each kWh a utility sells.. adds to earnings (and) each kWh saved or replaced with an energy efficiency measure... reduces utility profits" (Moskowitz 1989).

Seven PUCs reported that their states offer or have proposed some type of incentive mechanism for gas utilities that encourage conservation.

Three PUCs (Kansas, Washington, and Montana) have statutes or Commission rulings which allow for higher rates of return for conservation investments, but gas utilities have typically not taken advantage of these incentives.

- **Kansas** has a state statute that allows a gas utility's rate of return to be adjusted by 0.5-2.0% to allow cost recovery for specific conservation measures

- **Washington** - Legislation enacted in 1980 allows an incentive rate of return (ROR) rate base treatment for utility programs that improve efficiency, but the state's gas utilities have not requested cost recovery based on this approach.

- **Montana** - Has a state statute which gives the Commission the authority to allow gas utilities a higher return on equity (up to 2% on any retrofit program), but this has not been requested by any gas utility.

During the past year, PUCs in several other states reported that incentive mechanisms for aggressive implementation of DSM programs have been developed for gas utilities. Examples include:

- **Massachusetts** - The Department of Public Utilities (DPU) offers financial incentives to encourage conservation on a case-by-case basis. In September 1990, the DPU approved an incentive mechanism for Boston Gas that was linked to the company's ability to demonstrate (through a performance metering study) that it had achieved its estimated savings over a specified period (18 months). Boston Gas can earn an additional 0.5% premium on its allowed return on equity if it achieves the established conservation goal. In addition, the DPU has tried to eliminate disincentives to conservation by maintaining revenue for non-gas costs that would have been received by sales "lost" due to conservation.

• **California** - In August 1990, the California Public Utilities Commission approved an incentive/penalty mechanism to reward utility shareholders for vigorously and effectively managing energy-efficiency programs (CPUC 1990). Annual spending in 1991 by California's major gas utilities on energy efficiency programs is quite substantial: $40 million by Pacific Gas and Electric (PG&E) and $67 million by Southern California Gas (SoCal) Company, which represents about 1.4% and 2.0% of revenue requirements respectively (see Table 5). About 50-60% of these expenditures are subject to the adopted incentive/penalty mechanism. PG&E received a "shared savings" incentive in which utility shareholders will keep 15% of the net lifecycle benefits provided by its DSM programs that are classified as "resource programs."[16] For programs classified as customer equity and service programs, PG&E's shareholders will retain 5% of the actual program expenditures as an incentive.[17] PG&E received incentive treatment for both qualified electric and gas DSM programs. The PUC approved three separate incentive mechanisms for SoCal, which varied depending on the type of program. SoCal proposed a variable rate of return concept in which the utility would earn 14% of the program cost for energy efficiency programs that are categorized as "resource programs" provided that actual program costs do not exceed planned program costs.[18] A penalty mechanism that would reduce earnings for poor performance is also included (CPUC 1990).[19]

The PUC approved a cost-plus approach for SoCal's new construction programs and direct assistance and energy information/audit programs in which the utility would receive 10% and 5% of program costs respectively. If SoCal achieves its expected market penetration rates at planned cost levels, the utility's shareholders will earn an additional $3.7 million.

Incentives for gas utility shareholders are proposed or under consideration in Iowa, New Jersey, and the District of Columbia.

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[16] These programs are labelled resource programs because of their value as a resource to the utility system which can displace supply-side facilities (and provide energy and capacity savings at a cost that is less than the cost of generating electricity from building a new power plant or purchasing additional power). Resource programs include residential appliance efficiency rebate program, commercial/industrial (C/I) energy management rebate programs, and commercial and residential new construction programs.

[17] These programs include direct assistance to low-income customers, residential and C/I energy management services (audits), and super-efficient demonstration homes.

[18] SoCal's resource programs include residential appliance incentives and weatherization and high efficiency commercial/industrial equipment replacement, and industrial heat recovery.

[19] SoCal will break even if programs achieve between 70% and 80% of planned goals.

Table 6. DSM Incentives for Gas Utility Shareholders

	PG&E (Gas only)	SoCal Gas
	Millions of 1990$	
DSM Expenditures	$40.5	$67.6
Expenditures subject to incentives	$20.9	$39.0
Expenditures by Type of Incentive & Expected Earnings		
Variable Rate of Return	NA	$15.4
Expected Earnings	NA	$2.2
Shared Savings	-	NA
Expected Earnings	-	NA
Cost-Plus Programs	-	$23.6
Expected Earnings	-	$1.5
DSM Expenditures as % of Revenue Requirement	1.4%	2%
Estimated Annual Savings	Thousands of Therms (Mtherms)	
Resource Programs	5,500	12,084
New Construction	-	2,233
Direct Assistance & Energy Service	5,600	16,718
Total	11,100	31,035

Notes:

NA = Not Applicable

For PG&E, earnings for each type of incentive mechanism include electric and gas, so gas is not shown separately.

Fuel Substitution

Gas and electricity are substitutes in a number of residential and commercial end uses (e.g., space conditioning, hot water, and cooking).

For the purpose of classifying and evaluating DSM programs from a regulatory perspective, fuel substitution programs have the effect of increasing annual consumption of either electricity or gas relative to what would have happened in the absence of the program. In fuel substitution programs, this occurs by the utility inducing the choice of one fuel over another. Depending on the context and your perspective, these programs can either be viewed as promotional practices designed to increase sales or a least-cost approach to providing energy services.[20]

The survey revealed that a number of PUCs are currently grappling with this issue. At least three PUCs are involved in or beginning investigations or rulemakings on fuel substitution (Massachusetts, and Vermont) or promotional practices (Georgia). In other states, PUCs report that guidelines for promotional practices have been developed (although there typically is no formal policy regarding fuel substitution). For example, in Michigan, utilities have developed a procedure for notifying a competing energy utility of their opportunity to present an alternative proposal whenever fuel switching is recommended for customers. Oregon currently does not allow cost recovery for promotional programs. Eight PUCs reported that gas utilities in their states had intervened or opposed electric DSM programs that offer financial incentives for customers for heat pumps or that may have the effect of promoting all-electric houses.[21] Fuel substitution issues are often quite controversial. For example:

- In **Florida**, the PSC encourages natural gas be used for water heating and space heating (in the northern third of the state) in order to reduce the electric growth rate. The 1989 revision to the Florida Energy Efficiency and Conservation Act (FEECA) includes language to the effect that electric utilities encourage fuel efficient appliances. In 1989, the PSC attempted to require electric utilities to encourage gas use for commercial cooling, but the electric utilities immediately filed court action to stop the order, which caused the PSC to retract its order.

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[20] DSM programs can and should be evaluated in more than one category (e.g., conservation, fuel substitution) depending on the target market). Promoting electric heat pumps is a conservation program if the equipment replaces less efficient electric resistance heaters. In new construction, if a utility incentive induces builders to install heat pumps instead of gas space heating than the program may be considered a fuel substitution program. Unfortunately, in many cases, the boundaries between fuel substitution and conservation are often quite difficult to determine, and dependent on the perspective of respective gas or electric utility (See CPUC and CEC, "Standard Practice Manual",1987 for more discussion).

[21] Gas utilities in Alabama, Arizona, Nevada, Oklahoma, and Virginia, and the District of Columbia have opposed electric DSM programs promoting heat pumps; gas utilities are reported to have intervened in New York and Massachusetts as well.

- In **Massachusetts**, the PUC stated that Boston Gas may challenge a number of conservation measures proposed by Massachusetts Electric on the grounds that they are less cost-effective than electric to gas fuel switching. The DPU is expecting this to become a test case on fuel substitution.

States are also developing innovative approaches for addressing fuel substitution. Oregon has created a Fuel Substitution Investigation Group (FSIG), which is an advisory group that includes the PUC staff, the Oregon Department of Energy (ODOE), all gas and electric utilities, the Citizen's Utility Board, and consumer groups. The FSIG will be recommending guidelines on this issue and is developing an economic analysis of fuel substitution potential.

REGULATORY REVIEW OF GAS UTILITY SUPPLY PURCHASE PRACTICES

Prior to 1983, the gas purchase decisions of most local distribution companies were relatively straightforward because a spot market had scarcely begun to develop and interstate pipeline transportation was not readily available for spot gas (Means 1988). However, in recent years, gas purchase decisions of LDCs have become more complex, principally as a result of federal legislation (e.g., the Natural Gas Policy Act of 1978 which included phased deregulation of wellhead prices), FERC regulatory policies such as Orders 380, 436, and 500 which encouraged open access transportation by pipelines, and competition induced by the so-called "gas bubble" (Stalon 1986).[22] The ultimate effect of these changes was to transform LDCs into active managers of their own gas supply portfolios. Since the mid-1980s, LDCs have had to choose among different suppliers and develop the proper mix of short- and long-term supply contracts. Responsibility for purchasing gas now rests primarily with LDCs and large end-users that rely on pipeline transportation. Not surprisingly, one byproduct of LDCs increased control over and responsibility for gas supply costs has been increased regulatory oversight and involvement by many state PUCs in gas supply acquisition activities. PUCs have utilized two broad tools to mitigate ratepayer risk that is inherent in LDC gas supply decisions: prudence review of LDC gas purchase decisions, which is done retrospectively by PUCs based on general guidelines or state statutes, and advance review/approval of gas supply plans (Munts 1990).

In this survey, our intent was to followup on previous American Gas Association (AGA) and Interstate Natural Gas Association of America (INGAA) studies, but not attempt a comprehensive treatment of issues related to regulatory review of gas purchase

[22] Order 380 gave LDCs the freedom to purchase gas from non-traditional pipeline suppliers by removing gas costs from pipeline minimum bills. This reduction in minimum commodity bills allowed LDCs to rely on pipeline system supplies for peak use, and purchase interruptible and spot gas during off-peak periods. Orders 436 and 500 offered inducements to pipelines to carry gas purchased directly by end users and resulted in LDCs being free to purchase gas directly or indirectly (through marketers) from producers.

policies of LDCs. We asked respondents if PUCs conducted prudency reviews of gas utility purchasing practices, if states had adopted specific criteria or rules that are used in prudence reviews, and if states had adopted some form of "least-cost" or "best-cost" purchasing rules. We were particularly interested in determining what, if any, relationship existed between regulatory review of LDC gas purchase practices and integrated resource planning processes of gas utilities.

Key findings from this survey on these issues are:

- PUCs in 39 states indicated that they conduct prudency reviews of gas purchases. Among those states that conduct prudency reviews, Figure 5 shows that 12 states review gas purchases annually, typically in fuel cost adjustment hearings, three states do reviews on a contract by contract basis, and that 14 states review purchases in general rate cases.

- Four PUCs indicated that their states have adopted specific criteria, rules, or guidelines which were used in prudency reviews (Connecticut, Massachusetts, Michigan, Texas).

- Fourteen states indicated that they have adopted "least cost" purchasing rules, either because of state statute, PUC order or rulemaking, or implicitly through practice (see Table 7).

- With a few exceptions, PUCs generally indicated that there was no relationship between prudency review of gas purchases and the LCP process. In Washington, the staff reported that gas utilities can not recover costs unless they can demonstrate that purchase practices are linked with the utility's least-cost plan. Several states, such as Iowa, Oregon, and New Jersey, that are developing LCP processes indicated that they expect to forge better links in the future between gas supply purchasing practices and a utility's IRP plan, once utilities develop more aggressive conservation programs.

- Six PUCs reported that they require gas utilities in their states to file gas supply plans in advance of purchases (Alabama, California, Massachusetts, Nevada, Oregon, Rhode Island).

- In general, results of this survey show similar trends in the area of gas supply purchasing practices as the earlier AGA and INGAA studies. Not surprisingly, there are some differences from those earlier studies in the number and status of states with "least-cost" or "best-cost" purchasing practices (see Table 7). Discrepancies exist for obvious reasons (i.e., this survey was conducted 2-3 years after those studies and we used an expanded sample compared to the INGAA report) as well as methodological differences. We relied primarily on respondent answers and did not

Table 7. States with Least-Cost Purchasing Requirements

State	AGA Study (May 1987)	INGAA Survey[b] (Dec. 1988)	LBL/TFG/ NARUC Survey (Jan. 1991)
Alabama		X	
Arkansas		S	S
California	S[c]		
Connecticut		X	X
Dist. of Columbia			X
Illinois	S	S	S/X
Indiana			S
Iowa	S	S	S
Massachusetts		X	X
Michigan	S	S	S
Nevada			X
New York	S	S	S
Ohio	S	S	
Pennsylvania	S	S	S/X
Utah		X	
Virginia	X	X	
Washington	X	X	X
West Virginia	S	S	S/X

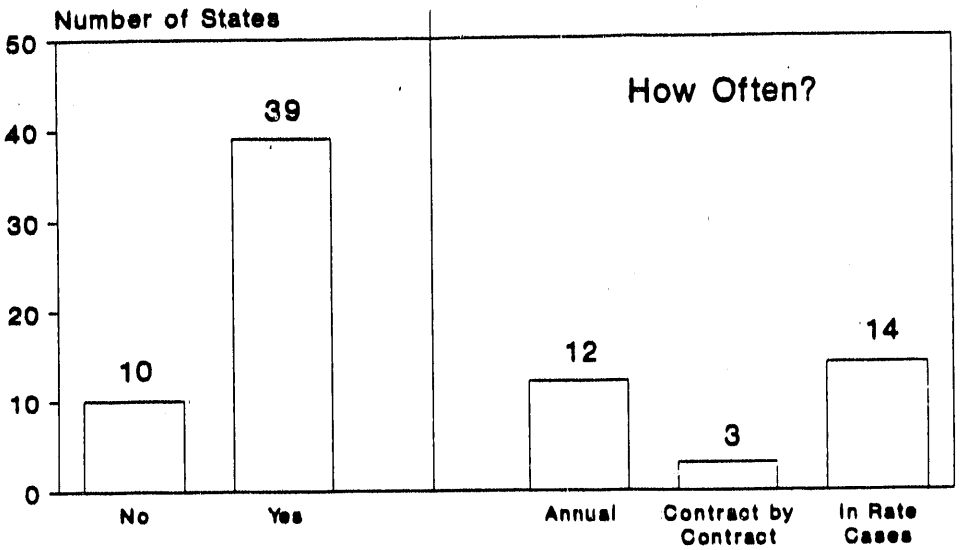
S = Mandated by State Legislation
X = PUC regulation or rules

[a] C.S. Smoots 1987, "Special Report on State Least-Cost Gas Purchasing Requirements," American Gas Association.

[b] Interstate Natural Gas Association of America (INGAA) 1988, "State Prudence Policies; Regulating the Gas Purchasing Practices of Local Distribution Companies," Table 1, December.

[c] The AGA study reported that: The California legislature enacted a statute in 1983 to encourage increased production of indigenous gas, which was amended in 1985 to require the use of a least-cost gas purchasing strategy (PUC Code, Section 785).

Figure 5
39 PUCs Conduct Prudency Reviews
of Gas Purchases



conduct a detailed and independent review of state statutes and case law as was done in the AGA study. Several state PUCs that have adopted least-cost purchasing requirements since the INGAA study (e.g., District of Columbia and Nevada) appeared to have done so in the context of an overall least-cost planning initiative.

KEY REGULATORY ISSUES

PUCs were asked to identify significant regulatory issues facing gas utilities in their states and discuss the likely direction of Commission activities during the next several years, section V of each state). Table 8 lists the issues identified by PUC staff in each state. Note that there is necessarily some degree of subjectivity in our translation of open-ended responses given by each state into a summary list of issues by state. A brief description of the type of topics mentioned and our categorization scheme will help in interpreting the issues identified by state:

Procurement includes issues related to supply options available to LDCs (e.g., choice of suppliers, portfolio mix),Transportation includes topics related to transportation customers, open access, obligation to serve these customers, re-entry and exit fees,

Table 8. Key Regulatory Issues Identified by PUCs

	SUPPLY ONLY									LCP AND DSM							
State	Procurement	Transportation	Supply Reliblty	Pipeline Addition	Bypass	Prudence Review	Deregulation	FERC/ Jurisd.	Rates	LCP	DSM	Load Forecast	Educ.	Promo Practices	Fuel Subst.	Electric Only	None
Most Active																	
California				X			X						X				
Connecticut		X							X			X			X		
Wash. DC									X	X	X						
Hawaii										X							
Iowa										X			X				
Illinois		X			X	X				X							
Mass.										X	X	X		X			
New Jersey						X			X	X	X						
Nevada				X				X		X	X	X					
New York				X						X	X						
Oregon										X	X				X		
Rhode Isl.						X				X	X						
Vermont										X	X				X		
Washington		X			X				X	X	X		X		X		
Wisconsin		X			X	X				X	X						
Other																	
Alabama			X											X			
Alaska		X			X												
Arkansas						X				X							
Arizona	X																
Colorado		X															
Delaware																X	
Florida						X	X		X								
Georgia										X							
Idaho		X	X		X												
Indiana																	X

	SUPPLY ONLY									LCP AND DSM							
State	Procurement	Transportation	Supply Reliblty	Pipeline Addition	Bypass	Prudence Review	Deregulation	FERC/ Jurisd.	Rates	LCP	DSM	Load Forecast	Elec.	Promo Practices	Fuel Subst.	Electric Only	None
Kansas					X	X	X		X								
Kentucky		X			X				X								
Louisiana																	X
Maryland	X																
Michigan		X	X													X	
Miami		X									X						
Minnesota						X		X									
Missouri		X			X	X		X									
Mississippi					X												
Montana			X													X	
N. Carolina				X		X											
N. Dakota	X				X												X
Nebraska										X	X						
New Hamp.		X															X
New Mex.																	
Ohio		X							X								X
Oklahoma											X						
Penn.																	
S. Carolina	X				X												X
S. Dakota																	
Tennessee	X					X											
Texas									X		X						
Utah	X							X									
Virginia				X								X					
W. Virginia																X	
Wyoming											X						X
Total	6	13	4	5	11	11	3	4	9	16	15	4	3	2	4	4	7

Supply reliability includes concerns about LDCs having access to and guaranteeing reliable gas supplies,

Pipeline Additions refers to issues that arise because of new pipeline capacity,

Bypass refers to policy issues related to large end users bypassing LDCs, also includes concerns about competitiveness of gas vs. alternate fuels (e.g., oil),

Prudence Review typically refers to policy guidelines and standards to be used,

Deregulation/Unbundling - refers to unbundling of gas rates and services for noncore customers,

Rates/Rate Design - includes marginal cost based pricing vs. embedded costs, cost of service issues, and innovative rates/pricing,

FERC/Jurisdiction - some states identified federal/state jurisdictional issues as key,

LCP - refers to least-cost planning regulations and implementation issues,

DSM - typically refers to getting utilities to devote more attention to gas DSM programs as well as DSM planning, market potential, and implementation issues,

Load growth/forecasting - includes states that are concerned about high demand growth as well as those that want to develop more sophisticated demand forecasting,

Environment - includes environmental effects of new pipeline additions as well as cleanup of manufactured gas plants.

Promotional Practices - refers to policy issues related to gas utilities attempting to increase market share by offering customers financial incentives to purchase gas equipment,

Fuel Substitution - includes issues and analysis methods to be used to examine end use fuel substitution.

Electric Only and None - means that PUC is focusing entirely on electric utilities or no key issue identified by PUC for gas utilities.

We found that the dominant regulatory issues tended to be different in the states with more active gas LCP processes compared to the less active states. Not surprisingly, development of least-cost planning regulations and processes and increased focus on demand-side management planning and programs were mentioned by 70-80% of the states that were classified as most active in gas LCP. Supply-related issues such as the need for new pipeline capacity, prudency review of gas purchase decisions, transportation rates and

design, and bypass were each mentioned by 3-4 states in this group. In contrast, only three of 36 states which are not actively developing gas IRP listed LCP as a key regulatory issue. The focus in these other states tended to be on a variety of supply-related issues. For example, issues that were mentioned relatively frequently by PUC staff in these 36 states include (number of PUCs in parentheses): transportation (9) and procurement (6) policies, bypass (8), and prudence review of gas purchase decisions (7) and reliability of gas supplies (4). In addition, issues related to gas utility demand-side management were mentioned by five of 36 states in this group. In several of these states, DSM-related issues are expected to be important, but often in terms of controversy over promotional practices and fuel substitution. Finally, the lack of activity (or controversy) related to regulation of gas LDCs is reflected in the fact that seven states did not identify a key regulatory issue and four other states indicated that, in terms of IRP, their PUCs would be addressing issues related only to electric utilities for the next several years.

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Illinois' Experience with Integrated Resource Planning for LDCs

Val R. Jensen
Manager, Strategic Planning
Illinois Department of Energy and Natural Resources

Presented to the Third NARUC National Conference on Integrated Resource Planning

April 8, 1991
Santa Fe, New Mexico

INTRODUCTION

Illinois is one of a handful of states to have established a formal and comprehensive planning process for natural gas utilities to accompany integrated planning for electric utilities. Although the process is still in its first cycle, the issues to be faced over the next several years are already apparent. To some extent these issues mirror those encountered in our electric utility planning process, while others are uniquely gas utility issues. In either case, they are proving to be at once more interesting and more frustrating than most parties had expected, and we have found quickly, that our experience with electric utility planning is of limited value.

This is not to suggest that integrated resource planning for natural gas utilities is necessarily more complicated or less appropriate. The same basic premise that gas service can be more efficient, equitable, and reliable, and can be provided at lower cost, if it is planned using an integrated approach still holds. It is still true that service costs can be lowered by employing demand-side resources. In between the premise and the result, however, is sea of difference.

THE ILLINOIS NATURAL GAS SYSTEM

Illinois ranks third in total natural gas consumption nationally. The State's 3.5 million customers are served by eight major investor-owned LDCs, the two largest of which are gas-only companies, with the rest being parts of combination utilities. Roughly seventy percent of total gas sales are to residential customers, although in terms of gas consumption, the residential sector accounts for only about forty-eight percent of the total. Twenty-six percent of all gas consumed in Illinois in 1989 was purchased directly by end-users and simply transported by LDCs.

Illinois is ideally situated with respect to both gas storage and transportation. The state ranks second in total underground gas storage capacity, and is served by nine pipelines.

However, given the discontinuities in service territories, and the lack of interconnections, a number of areas are served by only one or two pipelines.

Due in part to access to a variety of pipelines and huge storage capacity, Illinois enjoys fairly low gas prices. State wide, residential prices for space heating service averaged 46 cents per therm in 1989. Residential, commercial and industrial prices ranked 11th, 13th and 37th nationally. (Slide 1)

THE ILLINOIS LEAST-COST PLANNING PROCESS

Least-cost planning for electric and natural gas utilities is mandated by the Illinois Public Utilities Act. Each utility is required to prepare a plan every two years, which is to be consistent with the statewide plans prepared by the Department of Energy and Natural Resources. The statutory requirements are identical for electric and natural gas utilities, with the exception of the planning horizon. LDCs must plan over a ten year horizon, while electric utilities must prepare twenty-year plans. (Slide 2)

Statutory requirements aside, it became clear by 1987-88 when the task of writing administrative rules began, that gas and electric planning needed to be treated as two separate processes. The old ways of the gas industry rapidly were being discarded, increasing the need for administrative flexibility, a careful balancing of planning and gas purchasing reviews, and protection of proprietary gas purchasing information. Illinois' rule for electric utility planning is about thirty pages long, spelling out planing requirements in sometimes painful detail. The administrative rule for gas planning is about ten pages long, and by contrast is remarkable for its lack of detail. (Slide 3)

A distinction is made in the planning process between a two-year operational planning period and the longer ten-year "strategic" perspective. This distinction represents an attempt to reconcile the need for a long-term perspective on cost-minimization, with the increasingly short-term nature of gas supply decisions. The tension between the short- and the long-term views dominates gas resource planning. Without a long-term strategy, LDCs become victims of circumstance. At the same time, LDCs fear that failure to play the short-term market will subject them to penalties for imprudence, and in any case, rapidly changing circumstances make long-range planning an experience in speculation.

In January, 1990, the Department filed its first statewide natural gas plan. This plan contained forecasts of gas demand, an assessment of gas supply and prices, and twenty recommendations designed to promote the goals of efficiency, equity, and reliability, as well as the use of DSM as an initial and primary source of new supply. In keeping with our desire to make resource planning a collegial process, a Statewide Natural Gas Plan Advisory Group was convened, composed of representatives of the Commission staff, LDCs, public interest groups, pipelines and producers. This group was used to school Department staff in the fundamentals of the new gas industry, review drafts of the plan and help shape policy recommendations.

The use of this group, and a number of informal workshops held subsequent to filing of the plan, enabled parties to reach stipulations on virtually all of the recommendations contained in the plan ultimately adopted by the Commission. Perhaps more important, this cooperative process helped foster understanding of parties' respective interests and concerns, and helped to allay LDC fears that least-cost planning was an insidious plot to

manage their operations.

The next several slides summarize the statewide plan's policy recommendations, grouped according to the goal each is intended to promote. As you review these, keep in mind that the role of statewide plans in Illinois is to create a policy framework, and not to prescribe programs and actions. As with most policy statements, this one reflects the often conflicting impulses of the policy making process. (Slides 4,5,6 and 7)

Illinois' eight natural gas utilities filed their first integrated resource plans in January. These plans show a diversity across virtually every aspect of planning technique and result that makes generalization impossible. At one extreme are several plans that easily match or exceed the best plans of electric utilities in the state, and in fact were designed, I suspect, with that purpose in mind. At the other, are several plans proving the planning analog to the adage that you can lead a horse to water, but you can't make him drink.

While a comparative review of these plans would make an interesting study in gas integrated resource planning, I would like to focus more narrowly on three issues that I think for obvious reasons, will dominate discussions of gas least-cost planning. These are: Reliability; Interfuel competition; and Integration of DSM into the planning process and plans. The first is important, because it defines the essential business of every gas utility. The second is important, because it will in part define the future of the gas industry, and the third is important, because it is an essential component of least-cost service. My experience suggests that you will get little argument over the first two from anyone. And while no one will argue with the value of energy efficiency, you will get little agreement on its value to an LDC.

THE ISSUE OF RELIABILITY

The central objective of integrated resource planning is to find the least-cost or most appropriate mix of resources meeting some target level of reliability. In the electric utility industry, the meaning and derivation of this target are well-understood, and the utility's chosen target is rarely subject to debate.

The concept of gas system reliability, however, is not well understood within the context of least-cost planning, and it is not consistently defined. Some utilities view reliability in terms of meeting peak day design demand. Others view it in peak day and seasonal terms. No consistency is apparent in definitions of required reserves. Complicating matters further, very little work has been done to determine how different sources of supply contribute to reliability, although it is well-understood that some sources are much more dependable than others. For example, it is a given that direct purchases combined with interruptible transportation are less reliable than pipeline sales or storage.

Without some more specific idea of how different resource options affect reliability, it isn't possible to determine how much supply is enough, or how much pipeline supply versus firm sales versus storage is appropriate. Without some accepted reliability standard or measure of reliability, the role of DSM is complicated, and it isn't possible to determine what is least-cost.

Our approach to this issue in the first statewide plan was to suggest development of a

Delivery Assurance Ratio (DAR) that could account for the probabilities that various sources of gas supply would be unavailable at the time of peak demand. The DAR would be computed as the sum of the probabilities of failure of various supplies, multiplied by the amount of gas taken from each type of supply, divided by expected demand. The objective would then be to achieve a certain target DAR. Use of this type of measure, combined with the costs and supply constraints faced by each LDC, would allow an LDC to compute its least-cost mix of supply, and would be a valuable element of avoided cost calculations. (Slides 8 and 9)

The formal development of this type of reliability measure was rejected by every LDC for several reasons. First, LDCs believe they are not yet in a position to accurately assess the reliability of alternative sources of supply in any quantitative fashion. Second, each asserted that its service territory and supply characteristics were so unique as to preclude any type of uniform reliability measure or target.

The first complaint is reasonable, given that many supply options are relatively new, and untested by severe conditions. Nevertheless, experience will provide necessary support for some type of quantification.

The second complaint, while reasonable on its face, I think masks a much different concern. Until very recently, LDCs never had to confront the basic issue of how much supply is enough. Recognizing that they now are responsible for ensuring deliverability during peak periods, and having limited experience with the new gas market rules, LDCs are extremely cautious, and will resist any suggestion of a standard approach to reliability that might be perceived as reducing their flexibility.

Ultimately, parties agreed on a recommendation requiring LDCs to assess the reliability of various supply options, as well as to explain their reliability decision rules.

The information provided by LDCs in response to this recommendation, reinforces the concern that a better understanding of gas system reliability is needed if integrated planning for gas is to be effective. All LDCs emphasize that reliability, expressed in terms of ability to meet peak day, peak season and annual gas requirements, is their preeminent concern. However, each LDC defines these requirements in different terms. Most included some provision for a reserve margin to cover supply uncertainty, demand uncertainty or both, but some make no provision for reserve requirements.

For those LDCs using reserve margins, the target levels varied from five percent to 20 percent. Some companies made attempts to assess the reliability of individual supply sources, while others simply ascribe general levels of reliability to various sources. Most important from an integrated planning perspective, no utility examined formally the tradeoff between the costs and reliability of supply, or the optimal level of reliability. (Slide 10)

This is not to suggest that every LDC should approach reliability in the same way. The choices each has and the constraints faced will be a product of the pipeline and storage options open to each, and the composition of service territories. However, until a uniform method of expressing and assessing reliability is developed, we will have no way to determine how much supply is enough, and whether the supply mix is in fact optimal for a given utility.

It will be difficult to evaluate DSM economics consistently without some standard approach to reliability, since the value of avoided supply will change form LDC to LDC depending on the companies' reliability assessments. For example, LDC #1 assumes that

its firm purchase supply is 85 percent reliable. and therefore, needs to acquire roughly 1.17 dekatherms for each dekatherm of demand to be met by firm purchases (1.0 divided by 0.85). Every dekatherm of firm purchase supply avoided using DSM therefore, reduces the LDC's purchase requirements by 1.17 dekatherms. (Slide 11)

LDC #2 assumes firm purchase supply is 100 percent reliable; therefore, a one dekatherm decrease in demand equals a one dekatherm decrease in supply. It is easy to see that, given the same avoided and program costs, a DSM program will be roughly 17 percent more cost-effective when evaluated by LDC #1, than by LDC #2.

THE ISSUE OF GAS UTILITY DSM

That example provides a nice segway into the world of natural gas DSM, where, like in Alice's wonderland, nothing is quite as it seems. Looked at through the eyes of the grizzled DSM practitioner, the evaluation of natural gas utility DSM is straightforward; gas DSM energy conservation measures are identified, market potential is assessed, and avoided costs are calculated and multiplied by estimated DSM program savings to estimate cost-effectiveness. Given realistic assumptions about future natural gas costs, the analysis probably will uncover a number of potentially cost-effective programs from the societal and utility perspectives.

Stepping through the looking glass, however, reveals a more perplexing set of circumstances and perspectives that can turn many things on their head. First, the statute and administrative rule guiding least-cost gas planning in Illinois, require LDCs to use all economical means of DSM as initial sources of NEW supply. In support of these requirements, the first statewide plan required LDCs to undertake various DSM capability building activities that would enable utilities to defer the need for capital additions or increases in firm contracted supply or transportation. However, the plan also directed utilities to examine any DSM program that would improve load factors, including both off-peak load building programs and peak reduction actions. Statutory intent does not appear to support utility funding of DSM in cases where it may be cost-effective, but not needed to meet new resource needs.

Second, in contrast to the market conditions facing electric utilities, Illinois' LDCs see very little in the way of growth over the next decade. The sum of the eight LDC's growth projections show total demand growing at a rate of about 0.6 percent annually over the ten year planning horizon. When growth in transportation sales is removed, growth is even slower.

Given this outlook, LDCs are not facing a need for new resources to meet growing demand. Any capital additions that may be needed would be used to increase flexibility and lower costs. Slow to nonexistent growth juxtaposed on statutory obligation to provide DSM as an alternative to new supply clouds the role of DSM in our planning process.

Third, hidden within these aggregate trends, is perhaps a more compelling statistic. Average gas consumption per customer and has fallen by thirty to forty percent over the last fifteen years. This suggests that perhaps a large percentage of the relatively inexpensive and easy-to-get efficiency improvements has been captured. Our analyses of DSM potential indicate that efficiency improvements on the order of twenty percent remain possible, but are not necessarily economic.

Fourth, gas utility load factors are extremely low by electric utility standards, given that space heating is the predominant use of gas in the state. While replenishment of storage helps to balance LDC contract demands on pipelines and producers over the course of the year, much of the LDC's delivery capacity is underutilized much of the year. The simple economics of regulated utilities suggests that improvements in load factors can decrease the average cost of service. While improvements can be had by either peak reductions to valley filling, LDCs often view the financial rewards of increased sales as being much greater than those from reduced sales.

Fifth, while every utility is concerned with the effects of DSM on average costs or rates, gas companies tend to be much more adamant in their opposition to policies or programs that threaten to raises average costs. In part the concern stems from fear of the unknown as LDCs confront least-cost planning for the first time. More important in the eyes of the utilities, however, is the effect of increased average costs on the decisions of industrial customers regarding bypass. Although actual cases of bypass remain relatively few, the fact that most LDC territories are served by a number of pipelines, makes the concern legitimate. Thus, the contest between those who wish to minimize revenue requirements, and those who seek minimization of average rates is even more heated than it is in electric utility planning.

Finally, the analytics of gas DSM are hampered by inadequate data and experience. Much of the analysis still resembles back-of-envelop work, and even where LDCs have employed more sophisticated screening methods, the data used often is of speculative quality. Most LDCs in Illinois do not appear able to prepare a formal integration analysis, in some cases because the companies do not yet even have the tools to perform supply-side optimization. Specifically, information pertaining to DSM technology and program savings, program costs, and saturation and penetration rates is generally inferior to that used by electric utilities.

The combination of these circumstances and perspectives has led to a set of LDC integrated plans that by-and-large is lacking in attention to DSM. Most companies dismissed the prospects for DSM on the basis of little or no formal economic evaluation, being careful of course to proclaim their full support for the concepts of energy and economic efficiency. In fact, based on the DSM analyses performed to date, it is a stretch to even call these plans integrated.

Certainly, there are exceptions. Three LDCs (two of which happen to be affiliates and in direct competition with the state's largest electric utility) have presented DSM analyses that are akin to the textbook example: A wide variety of options is identified for each market sector; ECMs are bundled and then screened using clearly identified avoided costs; programs tentatively are selected using the societal and utility test; a reasonably thorough sensitivity analysis is prepared; and while effects on nonparticipants are acknowledged, the nonparticipant test results are not used to screen-out programs. In the end a healthy number of DSM programs is selected for piloting. These are shown on Slide 12 along with the programs proposed by the five recalcitrant LDCs. In short, these companies have prepared a plan that would gladden the heart of even the most sullen member of NARUC's Committee on Energy Conservation.

While the answer may seem obvious to many of you, I remain dogged by the question of who is right; the five recalcitrants or the three who are reborn? Unquestionably, the latter three companies have presented what most of us have come to regard as a legitimate integrated plan, and should be rewarded justly. And despite feeling as though the former are throwing down the gauntlet and challenging what has become the heart and soul of integrated planning, I nevertheless find myself sympathetic to some of their concerns.

Having the same arguments presented to me five or six times with varying degrees of eloquence, indeed has made me question whether in fact these companies have a point. Given no need to find new resources, slack or falling demand, declining levels of contract demand, low load factors and the prospect of rising average costs in the wake of DSM, does it really make sense to push hard on these companies?

I am slightly chagrined to say that in keeping with our reputation for paralysis by analysis, we don't yet have the answer in Illinois. However, I have reached two conclusions. First, those companies who do not wish to become involved in heavy promotion of DSM, have chosen this course for what they believe are very legitimate reasons. They have chosen not to spend a substantial amount of effort on DSM analysis because they believe the answer is obvious. They are not easily convinced of the benefits of DSM to them. More aggressive DSM action on their part will come more from regulatory and political persuasion than economic analysis.

Second, those LDCs who have decided to follow what many here believe is the better path, have not done so only because they believe in the doctrine of integrated planning. More important I believe, is the perception that if they are to achieve other aims (such as securing regulatory support for promotion of new gas technologies, or gaining a public relations advantage over their competition), they must act as though they believe the doctrine. This view is supported by the fact that total projected savings from their DSM programs is on the order of about one percent of gas sales after ten years.

THE ISSUE OF INTERFUEL COMPETITION

Finally, is the issue of interfuel competition. Potentially this is the most fascinating and perplexing issue to be faced in integrated resource planning. Taken to its logical extreme, interfuel competition, or more appropriately, the development of a formal policy on interfuel competition, requires that least-cost planning return to its origins as a method of determining the most efficient combination of energy and efficiency without regard to the source of energy. To do so, however, will require a major rethinking of the role of regulation in the planning process.

The issue is driven by two forces, one being primarily economic, and the other mostly financial. The economic force pushes interfuel competition, because by reallocating consumption between natural gas and electricity, resources can be more efficiently employed. A cursory look at the economics suggests that far too many resources are allocated to electricity consumption and too few to natural gas, although I'll admit cursory looks can often be deceiving. The financial force pushes interfuel competition as a way to shore-up sagging LDC revenues by increasing market share in traditional substitutable uses, and driving into markets traditionally held exclusively by electric utilities.

Like a bad dream, we have pushed the thought of confronting interfuel competition issues into a dark corner of the Illinois planning process. The Illinois Public Utilities Act actually suggests that the Statewide Plan is to be a joint gas/electric plan, but because we could not conceive of how we would resolve interfuel policy issues (or perhaps because we could perceive the resolution all too well), the planning process was bifurcated from the start based on arguments of administrative and methodological necessity.

While I continue to believe that a truly integrated planning process, incorporating both gas and electricity is methodologically and administratively complex, it is increasingly clear that soon the issues must be addressed. Complexities notwithstanding, the correct way to address them is through an integrated plan. However, for a variety of reasons, the correct way is not likely to be the way chosen, at least in the near-term.

First, a variety of policies and programs have been put in place in Illinois and elsewhere to protect electric utilities suffering from excess capacity. These include load retention or economic development rates, cogeneration deferral rates (and a host of other arguably discriminatory anti-cogeneration rates), and various other incentives for electric heating, the installation of all-electric commercial buildings and so forth. Head-to-head competition between LDCs and electric utilities, let alone policies promoting gas use are of limited value so long as these protective policies remain.

Second, policies supporting interfuel competition are not favored by all gas companies. LDCs that are part of combination utilities typically will promote gas use only in areas outside of their electric service territory. The obvious reason is that the majority of combination company profits are made by the electric utility.

Third, while a quick glance may suggest the issue is straightforward conceptually, a second look reveals complexity that seems to be due less to the analytics than to when the analytics should be applied. For example, if an LDC or a regulator wishes to promote, as an element of state policy, gas air conditioning as an efficient alternative to electricity consumption, clearly the policy should be supported by the economics as shown by total resource cost/societal and ratepayer impact tests.

However, how should we approach the case of the LDC simply acting like a business by trying to sell more of its product. For example, should we require an LDC attempting to promote gas air conditioning as a business strategy, to prove to regulators that gas air conditioning is societally beneficial, or that it minimizes gas and electric utility customer rate impacts? These are conditions that, at least in Illinois, we have never required an electric utility to meet. How do we reconcile the fact that increased use of gas may increase revenue requirements, but reduce customer bills? If consumption of gas rather than electricity is societally beneficial, should it be the policy of regulators to promote gas use, or should regulators be concerned with societal costs and benefits only when an LDC proposes to sell gas to electric utility customers?

Finally, the authority of state regulators, at least in Illinois, is unclear with respect to promotion of interfuel competition in any but the most benign form. For example, the ability of regulators to require customers to choose one fuel over another, except in periods of shortage, is severely constrained. It also is extremely unlikely that regulators will find it in their power to force electric utilities to promote sales of competitors' products. Certainly there is some precedence for such action in the PURPA requirements and in regulatory mandates for utilities to finance DSM. The difference, obviously, is that electric utilities typically are allowed to recover their costs and are even given incentives to promote DSM. Giving a customer to the local LDC represents dead loss to the electric company. Finally, and at least in Illinois, regulators cannot prevent a utility from promoting its own product with its own money if it so wishes.

As with most issues I've raised today, I don't have any real answers. The best that we

have been able to do to date in Illinois is formally encourage regulators to consider the effects of their actions on overall energy system efficiency, and to encourage LDCs to improve load factors by finding off-peak sales. These off-peak opportunities will most likely fall in the contested cogeneration and air conditioning markets. Gas-only LDCs, while clearly eager to be given clearance to more aggressively promote their service, have as yet only cautiously raised the general issue of regulatory policies favoring electric utilities. Beyond tinkering with existing promotional policies and programs it appears that the real issues of interfuel competition may have to be decided by state legislatures rather than regulators.

OTHER LESSONS OF ILLINOIS' EXPERIENCE

Beyond, finding that we have much to do before we resolve these three issues, we have learned some important and humbling lessons. First, as I suggested earlier, to say simply that the gas utility industry exhibits some differences from the electric utility industry, belies the fundamental character of these differences. It isn't just that the gas industry isn't vertically integrated, or that the certain segments of the industry are not regulated. The entire gestalt is different. The industries face very different challenges, are perceived very differently by customers and regulators, and are run by people from very different backgrounds. A productive gas resource planning process requires that these characteristics be understood and accepted from the start, and that LDCs are met on their own terms.

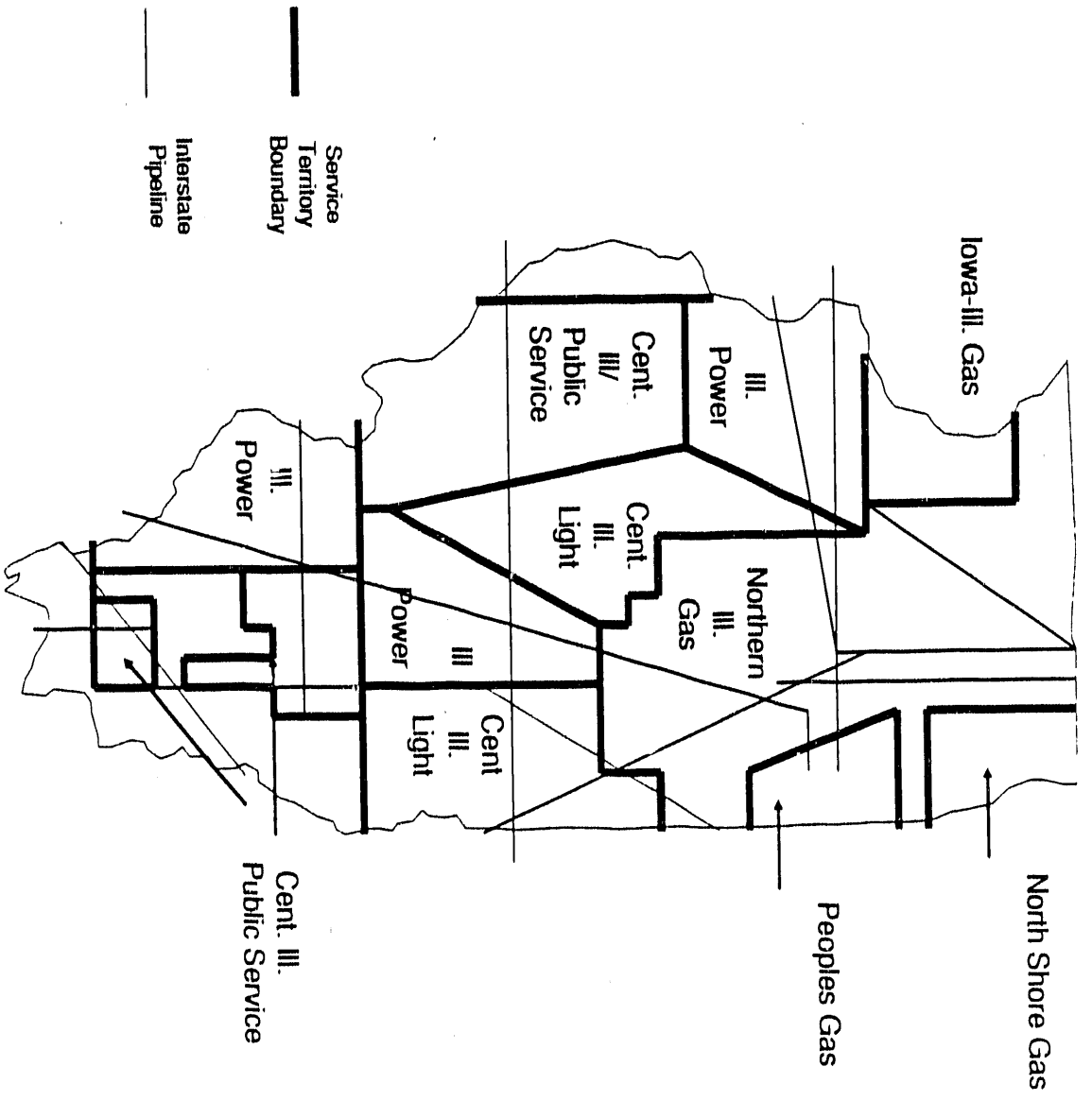
Second, as the gas industry moves increasingly towards competition, LDCs are much less willing than electric utilities to share information otherwise considered essential to an integrated planning process. This is due in part to a real concern for their bargaining position vis-a-vis suppliers and customers. I also suspect it is due to general suspicion of a planning process that is foreign to them.

Third, LDCs are not used to or comfortable with the long-range perspective common to resource planning. With contract lives of several months to several years, the action is in the short-run. They also face pressure from regulators who often put a premium on short-term prices. Privately and publicly LDCs have suggested to me that while they agreed it was important to consider long-run opportunities and consequences, they were more concerned with appearing prudent in the short-term.

Fourth, as gas-on-gas competition in certain end use markets has increased, LDCs increasingly are sensitive to policies that would reduce their marketing position relative to end user transportation or to bypass. The notion that LDCs are indifferent to end user transportation, is not shared by LDCs to a great extent, since rarely do rate structures compensate the companies for the cost of providing transportation, standby, balancing and storage services. LDCs with high bypass potential or inadequate rate structures, therefore, will be very wary of anything (and especially DSM) that threatens to increase average rates.

CONCLUSION

Well-intentioned as they may be, policies do not always translate well into practice. Whether the policies articulated in Illinois' planning statute, rules and statewide plan fulfill their purpose, clearly depends on the response of LDCs to these policies through their individual resource plans. And while it is too early to tell whether we have shown insight or simply hubris, the eight examples of LDC resource planning that we have to date in Illinois, suggest a process at once more interesting and more frustrating than anticipated. These plans also suggest that as with electric utility least-cost planning, the quality of the plans and planning process has more to do with the objectives chosen and payoffs perceived by each company, than with the all the rules, and policies we can imagine.


Iowa-Ill. Gas
Ill. Power
Cent. Ill/ Public Service
Cent. Ill. Light
Northern Ill. Gas
Ill. Power
Ill. Power
Cent Ill. Light
North Shore Gas
Peoples Gas
Cent. Ill. Public Service
Service Territory Boundary
Interstate Pipeline

Slide 2

ILLINOIS PUBLIC UTILITIES ACT
RESOURCE PLANNING REQUIREMENTS

Biennial Statewide Gas and Electric Plans Filed by DENR

Identify the programs and policies that promote Efficient, Equitable, Reliable, and Environmentally Safe energy service at the Lowest Possible Cost.

Biennial Plans filed by Gas and Electric Utilities

Annual forecasts of demand and supply for ten-year horizon.

Demonstration that plans fully utilize all economical DSM as initial sources of new supply.

Demonstration that plans are least-cost.

Formal Hearings on All Plans

Illinois Commerce Commission Modifies/Adopts Plans

DENR Required to evaluate Utility Plans.

Utility Plans Must Be Consistent With Most Recently Adopted Statewide Plan.

Approved Plans Provide Basis For Demonstration of Need in Certification Cases

Slide 3

ADMINISTRATIVE RULE REQUIREMENTS FOR LDC RESOURCE PLANNING

Annual Forecasts Of Peak And Annual Demand/10 Year Horizon

- Alternative projections and degree of uncertainty
- Demand for end user transportation
- Forecasted impact of conservation and cogeneration

Annual Assessment Of Supply

- Existing supplies
- Sources of future supply
- Impact of end user transportation
- Changes in reliability due to changes in sources of supply
- Description of decision making process

Demonstration That Plan Is Least-Cost (Based on PVRR)

Demonstration That Plan Incorporates All Economical DSM

Examination Of Long-Term Operating Environment

Slide 4

STATEWIDE PLAN RECOMMENDATIONS - PROMOTING EFFICIENCY

LDCs directed to prepare least-cost resource portfolios for alternative levels of demand as a hedge against uncertainty. LDCs required to describe relationship between short-run and long-run cost-minimization policies.

LDCs directed to identify appropriate set of unbundled services. Effects of unbundling on existing system to be identified.

If unbundling is expected to cause bottlenecks or shortages in any LDC services, utilities should develop a method for allocating constrained services - should examine auctions as one method.

LDCs directed to analyze costs and benefits of increased storage and pipeline interconnects.

Commission should consider whether existing policies and practices constitute barriers to technical efficiency.

LDCs required to estimate the potential for bypass.

All special contract prices should provide revenues sufficient to make a contribution to the recovery of fixed costs, in addition to covering the marginal cost of service.

Slide 5

STATEWIDE PLAN RECOMMENDATIONS - PROMOTING EQUITY

No utility shall be required to provide system supply gas to customers electing transportation service without a standby option.

The Commission shall consider in individual utility proceedings, mandatory backup provisions and/or effective penalties to prevent the unauthorized use of gas by transportation customers.

Slide 6

STATEWIDE PLAN RECOMMENDATIONS - PROMOTING RELIABILITY

LDCs to evaluate methods for determining service reliability as it relates to least-cost planning process. Specifically, each LDC should:

Describe its method for assessing reliability

Assess the relative reliability of alternative sources of supply

Discuss how reliability of various supply sources affects system reliability.

Gas utilities should have enough firm supply to meet peak day firm demand (accounting for most severe winter), plus some margin to cover non-weather contingencies.

Each LDC to describe how its supply acquisition policies address (1) security of supply, (2) balancing market responsive prices against short-term price volatility and (3) flexibility of supply.

Slide 7

STATEWIDE PLAN RECOMMENDATIONS - PROMOTING ECONOMICAL DSM

LDCs directed to investigate DSM programs designed to enable them to defer the need for capital additions or increases in firm contract demand or transportation, where these contracts include fixed charges based on utility nominations. Specific requirements:

Discussion of how LDCs have assessed DSM potential to improve load factors (including peak reduction and off-peak promotion).

Discussion of the effects of improved load factors on average system costs, amount and type of supply and system operation.

Discussion of load shape objectives.

Parties to participate in workshops to investigate end use data requirements, availability of data, and general guidelines for acquiring end use data to support least-cost planning for LDCs.

Parties to participate in workshops to investigate the costs and benefits of statewide programs to promote energy conservation in buildings.

Commission formally states its intention to provide for full recovery of prudently-incurred DSM-related costs. Each LDC directed to file a proposal for timely recovery of prudently-incurred costs associated with the analysis, design and implementation of DSM programs. Based on these proposals, the Commission shall determine appropriate method(s) of cost recovery.

Slide 8

MEASURING GAS RELIABILITY: THE CONCEPT OF A DELIVERY ASSURANCE RATIO

Delivery Assurance Ratio (DAR) = $\frac{a(FS) + b(NFS)}{\text{Expected Demand}}$

Where:

FS represents a source of firm supply

NFS represents a source of nonfirm supply, and

a and b are coefficients representing the probabilities that the stated level of supply will be delivered.

Slide 9

USING GAS SUPPLY RELIABILITY INFORMATION

Assume:

Incremental Gas Peak Day Demand of 200 MMCF

Target Delivery Assurance Ratio of 1.0

All Incremental Demand Met by One Source

Source	Reliability	Cost/MCF	Amount Needed to Equal Assured 200 MMCF	Total Cost ($000)
Pipeline Sales	.95	$4.00	210.526	842.1
Firm Trans	.90	$3.00	222.222	666.6
Storage	.97	$5.00	206.185	1030.9
Propane	.99	$7.00	202.020	1414.1

Firm transportation combined with direct purchases is less reliable, but even when a reserve margin is built in, it is less costly.

This example obviously oversimplifies the process, but highlights the value of supply reliability information.

Slide 10

COMPARISON OF LDC RELIABILITY ASSESSMENTS

LDC #1	LDC #2
Desired Reserve Margin - 10%	5-10%
Most-to-Least Reliable:	
Pipeline Sales	Owned Storage
Firm Transportation	Pipeline Sales
Owned Storage	Direct Purchases - Major Producers*
Leased Storage	Direct Purchases - Major Marketers
Propane	Interruptible/Spot
Interruptible Trans.	
	*Firm trans. 85% reliable

LDC #3	LDC #4
Desired Reserve Margin - 20%	None
Most-to-Least Reliable:	
Pipeline Sales	Pipeline Sales
Propane	Owned Storage
Storage	Firm Transportation
Direct Purchases	Propane
	Interruptible

LDC #5	LDC #6
Desired Reserve Margin*	10 %
Most-to-Least Reliable:	
Pipeline Sales (100%)**	SNG
Leased Storage (100%)	Pipeline Sales
Owned Storage (91%)	LNG,Propane, Owned Storage
Firm Transportation(85%)	Leased Storage
	Firm Transportation

* Equal to 1 Standard Deviation from predicted peak.
** Percent reliable

Slide 11

THE EFFECT OF RELIABILITY ON DSM

The Assumptions:

DSM program saves 9 DKT/year

Incremental societal costs = $447

Marginal cost/DKT = $4.00

CASE 1

100% Supply Reliability Assumed

Annual Benefit = 9.00 DKT * $4.00/DKT = $36.00
Total Cost = $447

Simple Payback = 12.41 years

CASE 2

85% Supply Reliability
(1.17 DKT required per 1.0 DKT of firm demand)

Annual Benefits = 10.53 DKT * $4.00/DKT = $42.12
Total Cost = $447

Simple Payback = 10.61 years

Slide 12

SUMMARY OF DSM PROGRAMS PROPOSED BY LDCS

The "Five Recalcitrants"

Furnace Maintenance
Ceiling Insulation Financing*
Weatherization Grants*
Incentives for Efficiency in New Construction**
Various Informational Programs

* Not a new program.
** Approved as part of electric least-cost plan.

The "Three Reborn"

Residential Audits*
Water Heater Weatherization Program*
Incentives for Attic Insulation(R-30)*
Incentives for Set-Back Thermostats*
Incentives for High Efficiency Space Heating(Residential)*
Residential Space Heat Rebates (Non-furnace)
Multifamily Loan Program
Incentives for Attic Insulation
Low-Income Weatherization**
Commercial Audits*
Incentives for Commercial Set-Back Thermostats/
Water Heater Retrofit
Commercial/Industrial Flex***
Incentives for High Efficiency Space Heating(Commercial)

* Offered by two companies.
** Existing program
*** Program options adjusted on a case-by-case basis

Pursuing Integrated Resource Planning for Gas Companies: The Massachusetts Experience

Linda D. Latham
Massachusetts Department of Public Utilities
NARUC Third Annual Integrated Resource Planning Conference
April 8-10, 1991

I. INTRODUCTION

The Massachusetts Department of Public Utilities ("DPU") has spent the last two years developing an integrated resource planning process for the electric companies in Massachusetts and, after issuing final regulations in 1990, will begin implementing the process this year.[1] The electric company process, called integrated resource management ("IRM"), will be implemented in conjunction with the Massachusetts Energy Facilities Siting Council ("EFSC"), which, as part of its legislative mandate, seeks to ensure that energy utilities in the state institute least cost planning techniques.[2]

As a result of knowledge gained during the development of our electric IRM process, and in response to significant changes in the natural gas market, (e.g., the increase in resource options available to natural gas local distribution companies ("LDCs") and the growth in market demands for natural gas), the DPU and EFSC have turned more attention to the planning procedures and conservation and load management ("C&LM") activities of Massachusetts gas companies. This paper will focus primarily on the actions of the DPU, but a brief description of the EFSC is included in order to provide a more complete overview of the state's least cost planning activities.

All gas and electric companies in Massachusetts must submit a supply plan to the EFSC every year for approval. The EFSC

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1 See for example, D.P.U. 89-239 (1990); D.P.U. 86-36-G (1989); and D.P.U. 86-36-F (1988).

2 There is currently a bill pending in the state legislature to incorporate the EFSC into the DPU.

reviews these plans to ensure that the utilities are providing reliable service to their customers at the lowest possible cost and with the least environmental impact. This entails analyzing the companies' demand forecasts, supply portfolios, and actual planning processes. In response to changes in the gas industry that provided LDCs with more resource options, the EFSC determined that it was more important to ensure that gas companies were effectively analyzing all possible alternatives. Accordingly, the EFSC began in 1989 to structure its gas company reviews to focus more on each company's actual planning process.

The EFSC's supply plan reviews are intensive, but are unfortunately not as effective in ensuring that companies practice least cost planning as we would like. First, these reviews are only conducted for each company once every two or three years due to staff limitations. Second, the EFSC is often forced to conduct its reviews in a retrospective rather than prospective fashion, because the LDCs do not need to obtain EFSC approval prior to acquiring a new supply source. As a result, the LDCs often present the EFSC with supply portfolios that contain supply sources for which the companies have already contracted.[3] Third, the EFSC has limited abilities to require changes to a company's supply plan or actual planning process. Under Massachusetts law, a company must have an approved supply plan before it can receive siting approval from the EFSC for a new energy facility such as a power generating plant or local pipeline. However, the EFSC can always request changes to a company's supply plan, but it can only enforce these changes for a utility that really needs an approval, i.e., one that is considering constructing a new facility or pipeline in the near future.

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3 The problems associated with these retrospective reviews should be mitigated for electric utilities once IRM is fully implemented, since IRM involves EFSC and DPU review of needs and resources prior to any resource acquisition. Some of these problems would be mitigated for gas companies with the proposed merger of the EFSC into the DPU, since our reviews could be coordinated more effectively.

The DPU is responsible for conducting rate case proceedings, reviewing supply contracts, evaluating C&LM programs, and approving various contracts between the LDCs and their customers. As a result of these responsibilities, the DPU has review authority over what costs can be recovered by a utility and how these costs will be collected from ratepayers.

The Commonwealth of Massachusetts currently does not have a formal IRP process for natural gas LDCs, but the DPU and EFSC have found ways to encourage gas integrated resource planning through our existing procedures and cases. As discussed above, the EFSC has begun to impose more stringent planning requirements on the natural gas LDCs, and it will soon apply these higher standards to each of our 10 regulated natural gas companies. The DPU has used several forums to encourage more efficient utility planning, including: rate cases, C&LM preapproval filings, and supply contract reviews. In this paper, I will first discuss the ways in which the DPU has used each of these forums to further the agency's general least cost planning goals. I will then describe the tools and incentives that have proved successful in encouraging increased IRP activities in the natural gas industry.

II. FACILITATING GAS COMPANY C&LM EFFORTS

Some basic historical facts about the gas industry made the introduction of C&LM to LDCs a difficult task. Gas companies have long operated under the premise that sales growth and marketing are good as long as supplies are available to meet the new loads. Electric companies in New England were faced with increasing marginal costs and capacity constraints during the 1980s, and some of these companies began to consider C&LM a viable tool for managing load growth. During this same period, however, Massachusetts gas companies faced declining marginal costs and they marketed actively in an effort to expand loads and lower their average costs.

In addition, Massachusetts gas companies are traditionally less concerned than electric companies about capacity constraints resulting from sudden increases in demand, because LDCs in Massachusetts are allowed to control their load growth. Based on DPU case precedent, LDCs do not have an "obligation to serve" new customers unless adding new load will help to lower

the average cost to serve existing customers. Therefore, if gas companies ever run into tight capacity situations -- such as the pipeline curtailments prevalent in the late 1970s -- they can simply decline to sign up any new customers. It is not surprising, then, that the idea of encouraging customers to conserve has historically appeared to many gas LDC executives as unnecessary at best and counterproductive at worst.

In the last decade, however, several factors led to significant changes in the New England gas market, and Massachusetts LDCs were forced to respond to a more competitive market. Demand for natural gas has recently increased in Massachusetts due to two factors: (1) strict emissions requirements imposed by the Massachusetts Department of Environmental Protection and the recent federal Clean Air Act Amendments have increased demand for gas as a fuel for electric generation; and (2) national security concerns and recent oil price volatility have encouraged more oil users to consider switching to gas. Fortunately, some of this new demand can be met with gas from new pipeline projects now in the works such as the Iroquois Pipeline. However, large-scale C&LM programs offer another attractive and cost-effective means of obtaining supplies of gas to serve new markets. In both theoretical dimensions and actual magnitude, large-scale C&LM programs offer New England a gas resource no less significant than the Iroquois project.

Several years ago the DPU began to encourage Massachusetts gas companies to investigate C&LM, and to invest in C&LM when the cost was less than the next avoidable source of supply. We began our efforts during gas company rate cases, and used these dockets to establish basic policy goals regarding gas C&LM and least cost planning. We relied heavily on precedent contained in electric company cases, and adopted for gas companies an electric company process known as preapproval. The process of preapproval, described in more detail below, allows the DPU to review a company's proposed C&LM program and approve it for cost recovery purposes before it is actually implemented.

A. How the DPU Used Rate Cases

The DPU had already developed a significant body of precedent on the subject of C&LM in electric cases, before we began to investigate C&LM for our gas companies. For example,

in a number of electric company cases the DPU delineated reasons why the market has failed to stimulate the optimal level of C&LM, and discussed why these "market failures" warrant utility involvement. We also developed a general cost-effectiveness standard based on avoided costs in electric cases, and ordered electric companies to proceed with the development of all cost-effective programs.[4]

In 1988 an intervenor in a Boston Gas Company rate case argued that Boston Gas should develop C&LM programs. Accordingly, the DPU began to investigate the appropriateness of gas C&LM, and used this first case to work through some of the basic issues such as avoided costs and program cost-effectiveness. See Boston Gas Company, D.P.U. 88-67, Phase I (1988); and D.P.U. 88-67, Phase II (1989). In subsequent gas company rate cases DPU staff used discovery questions and hearings to gather more information about other areas such as: gas C&LM potential, differences between gas and electric companies, and potential areas of gas company concern. We found hearings to be a very useful arena in which to have broad theoretical, as well as company-specific, discussions with company officials. The DPU also discovered that it was possible to incorporate existing electric precedent on the general subject of C&LM into gas company rate Orders, as many policy issues were directly transferrable. This enabled us to concentrate our efforts in later gas company rate cases on technical issues specific to the natural gas industry.

One important technical issue which the DPU addressed during a gas company rate case is the development of an avoided cost methodology appropriate for gas companies. We borrowed heavily from our existing electric regulations written in response to the Public Utility Regulatory Policy Act ("PURPA"), but also realized that there are some important differences between gas and electric companies. During a rate case with our largest LDC, we asked the company to conduct an avoided cost study based

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4 A good description of our general policies on C&LM is contained in our generic electric docket on integrated resource management ("IRM"), D.P.U. 86-36-F (1988).

on the PURPA regulations. The Company designated a "next unit" and used its dispatch model to calculate avoided costs over a twenty-year horizon. This case afforded us the opportunity to investigate the application of concepts such as "avoidable supply block" and "next unit" to gas companies. In subsequent rate cases, we reviewed avoided cost studies which deviated somewhat from the PURPA standard, but found that the new methods worked just as well.[5]

In our foray into avoided cost studies for gas companies, we found that several companies were uncomfortable with designating a new supply contract or pipeline project as their avoidable unit. The companies stated that they did not want to consider a future supply source "avoidable," as they did not want to worry their suppliers or jeopardize the viability of a proposed pipeline project. The DPU dealt with this concern by stating that a designated avoidable source was meant to serve as a proxy for the costs that a company could save through conservation, and that a company may not actually avoid that particular resource in the future even if C&LM programs were successful.

The DPU has used both gas and electric rate cases to continue forging our definition of cost-effectiveness. While the general idea of a "societal" or "total resource" benefit-cost test was first developed in our generic IRM case, many of the practical details regarding how to implement such a test have been clarified during rate cases. Because our initial definition of cost-effectiveness was somewhat vague -- and because new issues have continually arisen -- we have found that

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5 One company ran its dispatch model with and without its designated next unit, and calculated the resulting change in total costs over 20 years. That company then divided the total savings each year by the size of the supply block to determine an annual $/MCF value. For an example of our findings on avoided-cost studies see Boston Gas Company, D.P.U. 88-67, Phase II (19 ; Bay State Gas Company, D.P.U. 89-81 (1989); Essex unty Gas Company, D.P.U. 89-107 (1989).

the details are more easily dealt with when a specific program is being evaluated. (A detailed description of our cost-effectiveness standard is included in the following section.)

After the DPU had made some general findings on several avoided cost studies and included general directives regarding C&LM in several gas company rate cases, other gas companies began to include C&LM testimony in their rate case filings. Unfortunately, this early testimony referred almost exclusively to the companies' state-mandated residential conservation service programs. Thus, the DPU decided to try another tactic: we began to require companies to submit specific C&LM filings in compliance with the rate case Order. We ordered one utility to file an analysis of a load management program, and we ordered several companies to file semi-annual reports of their progress with respect to C&LM program development. We have also ordered two companies to submit full-scale C&LM programs for Department review under our C&LM preapproval process.

B. The Preapproval Process

In an effort to balance the risks and rewards for electric companies and their ratepayers, the DPU developed a process known as preapproval. Under this process -- originallydeveloped for electric generating plants -- a utility could petition for preapproved cost recovery of a power plant prior to construction. See D.P.U. 86-36-C. The preapproval process was designed to limit utility risk associated with the potential disallowance of a new power plant, and to protect ratepayers from cost overruns.

The DPU was aware that companies were wary about investing in C&LM for some of the same reasons that electric companies were wary about investing in power plants. From a utility executive's perspective, any C&LM expense not incurred during a test year represented an extra cost not recovered from ratepayers, plus reduced sales if the program was successful. In addition, companies knew that they were not necessarily guaranteed recovery of C&LM program costs incurred during a test year if the DPU did not eventually approve the program. Thus, the DPU decided to expand the idea of preapproval to C&LM programs as a way to make investment in C&LM less risky for a utility company. See D.P.U. 86-36-F (1988).

One gas company eventually tried to obtain cost recovery for a multifamily low-interest loan program during a rate case, and the Department encouraged the company to seek cost recovery for its program through a formal preapproval filing. (While a company can ask for preapproval during a rate case, a company can also file a request outside of a general rate proceeding.) Since that gas case, both gas and electric companies have taken advantage of the preapproval process, and preapproval cases have become a sizeable portion of the DPU's case load. Now all of our C&LM reviews are conducted as "preapproval cases" regardless of whether they occur during a rate case proceeding or between rate cases.

To date the DPU has reviewed the C&LM preapproval filings of four Massachusetts gas companies. The scope of current programs varies among companies, but we are working to expand the number of available programs so that each company has programs for all customer classes. We have approved three residential programs which offer measures such as attic insulation, wall insulation, clock thermostats, water heater wraps, and vent dampers. One company is even conducting individual audits of each participant's home in order to determine (and then subsidize) the best mix of measures for each participant. Both customer rebates and zero-interest loans are offered under these programs. We have also approved two programs for multifamily property owners that include full building audits and offer incentives or loans towards the cost of the recommended measures. We are currently reviewing a commercial and industrial program, a residential furnace replacement program, and a high-use residential audit program for one of our companies who already has basic residential programs in place. We also expect to receive three to four additional preapproval filings from gas companies this year.

Under the requirements established for preapproval, a company must support its request with the following items: (1) a complete description of the proposed C&LM program; (2) a detailed cost-recovery proposal; (3) a demonstration that the proposed program is cost-effective; and (4) the results of any requests for proposals issued to solicit program providers or administrators. A more complete description of the issues we investigate is included below.

1. Program Design Issues

The actual preapproval case entails a detailed review of a company's program design. The DPU tries to ensure that gas company C&LM programs are user-friendly and delivered in the most efficient manner. We also attempt to remove barriers that could deter customers from participating in utility C&LM programs, and we are hoping to learn what types of program designs and/or customer incentives work the best.[6] We are currently allowing our gas companies to implement different types of residential programs in order to learn which types are most effective.

The DPU is beginning to investigate ways that utility C&LM programs can be delivered in conjunction with audits provided under the state-mandated energy conservation service ("ECS") audit program. The potential for joint delivery with electric or water utilities has also been discussed, and the DPU is interested in pursuing this idea further. It appears that such joint delivery projects may help to increase the overall efficiency of providing C&LM services to Massachusetts residents, as well as allow utilities to lower their C&LM program costs by sharing fixed costs with other entities.

The DPU has also addressed several policy issues associated with program design. In an effort to reduce potential inequities between rate classes, the DPU has ordered gas companies to develop C&LM programs for all of its customer sectors (i.e., residential, multifamily, and C&I). In addition, the DPU investigates whether a company has taken steps in the design of its program to capture lost opportunities, limit free-riders, and target hard-to-reach sectors such as renters and low-income customers.

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6 For example, in an attempt to reach difficult market sectors, we have ordered companies to offer higher subsidies (usually 100 percent) to low-income customers. One company also offers C&LM measures to renters at no cost.

In an effort to reduce lost opportunities, the DPU has ordered companies to design programs that will ensure the installation of all cost-effective measures in a given building, rather than just measures with the highest benefit/cost ratios. One company evaluated a range of C&LM measures and determined what would be cost-effective for the "average-use" residential customer, and then designed a program that would deliver only those measures. Another company is implementing a residential C&LM program that offers individual audits in order to determine exactly what would be cost-effective in each house visited. After observing the results of these two types of residential conservation programs, we will be able to evaluate whether programs with an audit component actually produce greater savings or are more cost-effective than standardized programs targeted at average customers. Several gas companies are also investigating the benefits of instituting a residential new construction program that would help to prevent lost opportunities before they occur.

2. Program Cost-effectiveness

The DPU will only allow preapproved cost recovery for cost-effective C&LM programs, and thus a gas company must demonstrate during a preapproval case that its proposed program will be cost-effective. The DPU's cost-effectiveness standard has evolved over time, and is loosely based on what is often called a "societal" or total resource perspective. Thus, we include as costs all utility costs (e.g., subsidy costs, administrative costs, and program evaluation costs) and customer out-of-pocket costs (customer contribution to cost of measures plus any incremental increase in maintenance costs). Benefits are defined as the avoided costs accruing from the program plus avoided environmental externalities.[7] The net present value

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7 The DPU established values for the cost of various emissions during the course of its generic docket on IRM. We have adopted the externality values for gas companies and found the environmental benefits resulting from the conservation of one MMBtu of gas to be approximately $1.60. See D.P.U. 89-239, Table 1 (1990); and Boston Gas Company, D.P.U. 90-55, Schedule 12 (1990).

of the cost and benefit streams is calculated using the company's cost of capital as the discount rate. If the net present value is positive, the program is considered cost-effective.

The DPU has stated that companies should only encourage the installation of cost-effective measures, that companies should develop "bundles" of measures that provide the maximum net benefits, and that companies shall only receive cost recovery for programs that are cost-effective. Therefore, during a C&LM program review we analyze cost-effectiveness on three different levels: (1) the individual measure; (2) the "bundle" of measures to be offered; and (3) the overall program.

Utilities usually begin their program design by determining which measures will likely be cost-effective in their service territory. This process involves collecting data on the costs and expected savings of various measures. This is a difficult part of the cost-effectiveness analysis due to the limited data available on actual savings figures for gas C&LM measures. Therefore, we have allowed our gas companies to rely primarily on engineering calculations of savings. Because engineering estimates are based on theoretical conditions and not usually realized in actual practice, we have found it appropriate to "discount" the engineering savings estimates prior to analyzing the cost-effectiveness of measures.[8] By comparing the costs of each measure (including installation) to the stream of avoided-cost benefits (including externalities), a company can calculate the net present value for each measure. From these calculations, the company can determine which measures are

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8 One Massachusetts LDC developed discount factors for each measure it reviewed, based on how likely the savings would be affected by factors such as: customer behavior, improper equipment installation, and failure of materials. The company applied these discount factors to the engineering savings estimates for each measure to obtain a more realistic estimate of expected savings.

cost-effective on a "stand alone" basis and worthy of consideration for inclusion in a program.

The next stage of the analysis is to calculate the savings from measures assuming that they are installed in conjunction with other measures. This step is necessary because the total savings achievable from a group of measures is not equal to the sum of the savings from each individual measure, i.e., once energy use is reduced by installing a measure like attic insulation there is less to be saved by replacing an old heating system. To account for these "interactive effects" between measures a company must first determine which measures interact with each other. For example, wall insulation and clock thermostats interact, but wall insulation and attic insulation do not interact.[9]

To actually calculate which measures would still be cost-effective when installed as a group, one Massachusetts LDC performed an iterative analysis. The company began by ranking all cost-effective measures in order of net present value, and then it added measures one at a time recalculating the total interactive savings after the addition of each measure. See Boston Gas Company, D.P.U. 90-55 (1990). We found this approach appropriate, and stated that the ultimate goal of any interactive savings adjustment is to ensure that only cost-effective measures are installed. When calculating the cost-effectiveness of measures installed as a group, it is essential that the company determine which bundle of measures provides the greatest net benefits. Based on economic theory, it is possible to conclude that the bundle with maximum net benefits contains no non-cost-effective measures. As cost-effective measures are added to a bundle, the net benefits of the bundle will increase as long as each additional measure provides marginal savings benefits greater than its costs. If a measure is added that causes the bundle's net value to drop, the new measure is not incrementally cost-effective, i.e., its marginal costs are greater than its interactive marginal

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9 For a more complete discussion of interactivity see Oak Ridge National Laboratory publication ORNL/CON-228/P3.

benefits.[10] Variable program costs that are a function of the number of bundles installed -- such as customer audits or required site visits -- should also be added to the total cost of the bundle in order to determine if it is cost-effective to deliver the bundle to customers.

Once the optimal bundle of cost-effective measures is determined, the program-level analysis should be conducted. This level of analysis requires evaluating the total cost of implementing the program (fixed overhead as well as variable costs) as compared to the total benefits expected.[11] If sufficient net benefits exist to cover all fixed costs, then the program would be considered cost-effective. In the early years of a program participation may not be sufficient to render the overall program cost-effective. If the measures themselves are cost-effective, however, and sufficient market potential remains, the program may become cost-effective over its full life. Consequently, it is more useful to evaluate the cost-effectiveness of a program over several years, rather than the initial one or two year period.

3. Cost Recovery

If the DPU finds that a company's proposed C&LM program is well designed and cost-effective, we will consider allowing recovery of the costs associated with implementing the program.

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10 Economic theory dictates that it is inefficient to go beyond the point where marginal costs exceed marginal benefits, because such expansion reduces societal benefits. This was difficult to grasp at first, because often a bundle can still be cost-effective (have net benefits greater than zero), even though it contains non-cost-effective measures.

11 Several Massachusetts LDCs have conducted technical potential studies to determine the remaining C&LM potential in their service territories, and they have used these studies to help them establish their penetration targets, and total program savings.

A preapproval period is established -- usually one or two years -- and the DPU will allow companies to recover all program-related costs incurred over that period. Because the preapproval process is conducted every year or two, the DPU can perform regular reviews of individual programs to determine whether changes are necessary in order to improve program success.

In the first four gas company preapproval cases the DPU allowed each company to recover its program costs through the cost of gas adjustment clause ("CGAC"). We allow the companies to predict their program costs at the beginning of each six month period, and then reconcile actual with predicted costs every July. The Companies are ensured virtual dollar-for-dollar recovery of all C&LM program expenses incurred during the preapproval period.

In electric company preapproval cases which have occurred within the context of rate cases, the Department has included representative or forecasted C&LM program costs in base rates. In order to minimize inequity among rate classes resulting from C&LM expenditures, the DPU has required that utilities allocate program costs to each class based on the programs available to that class. As actual program costs are incurred they are compared to the level of program costs embedded in base rates, and the adjustable fuel clause is used to reconcile the costs. We foresee this type of cost recovery being employed in future gas cases as well, once our gas companies have programs available to all customer classes. In the future we would like to move to a completely performance based cost-recovery system, where cost recovery is linked to actual program success, i.e., actual savings obtained.

4. Lost Margins

The variable portion of a company's rate structure inevitably includes fixed as well as variable costs, and when C&LM programs lead to reduced sales companies suffer revenue shortfalls. The DPU has stated that companies can recover the portion of fixed costs included in base rates that are "lost" due to the success of a C&LM program. During a preapproval case, a company must calculate the fixed costs embedded in its rates for each customer class to which it will target a C&LM

program. Before a company can collect any lost margins, however, the company must calculate the level of its "loss" by determining actual savings obtained from its program. The DPU requires that program savings be measured through an extensive evaluation and monitoring study. We have approved the recovery of lost margins for one gas company, and are currently in the process of reviewing its evaluation and monitoring study.

5. Utility Incentives

While guaranteed recovery of program costs and lost margins effectively removes the major barriers for gas company investment in C&LM, these two factors do not actually give a utility an incentive to pursue C&LM aggressively. In order to reward gas and electric companies for superior C&LM performance, the DPU has allowed utilities to earn incentives on their C&LM programs. We have approved incentive mechanisms for several electric companies and for one gas company. As with the collection of lost margins, though, utilities cannot collect any incentives until the actual savings from their programs have been measured. The DPU considered several incentive mechanisms, and for various reasons decided to construct an incentive mechanism based on offering the company a premium on its return on equity ("ROE"). Instead of increasing a company's allowed ROE during a rate case, however, we determine a target bonus based on the company's test year equity and then establish a performance-based recovery.

For example, in the recent Boston Gas Company preapproval case the DPU approved a target incentive equal to 0.5 percent of the company's test year equity. Boston Gas proposed to divide the $2.0 million incentive by total projected MMBtu savings, and then to collect the resulting $/MMBtu incentive for each MMBtu saved. While the DPU found it appropriate to award an incentive in the form of $/MMBtu-saved, we were unwilling to allow the company to earn any incentive payments for an unsuccessful program that obtained very small savings. Accordingly, we imposed a 25 percent threshold beneath which the company would earn no bonus. Beyond the 25 percent threshold, the Company

would collect a fixed dollar incentive per MMBtu saved.[12] In addition, if the company exceeds its targeted MMBtu savings it will continue to earn incentive payments at the same $/MMBtu rate.

An incentive mechanism that divides the net benefits of a program between the utility and its customers is called a shared-savings approach. While we did not institute a shared-savings incentive for Boston Gas, we did rely on the idea of shared savings when deciding on the appropriate ROE bonus. When reviewing the Boston Gas proposal the DPU considered how the proposed $2.0 million target incentive compared to the potential net benefits to be produced by the program (total avoided-cost benefits minus total costs). In Boston Gas Company's case the $2.0 million incentive represented approximately one-third of the program's net benefits. This second-level check confirmed that a 0.5 percent ROE bonus was reasonable, because it allowed the company to retain a third of the benefits it was creating, and still pass on two-thirds to ratepayers.

Because we can vary both the size of the ROE bonus and the level of the threshold, our incentive method allows us to create different incentive packages for individual companies based on the quality of their respective programs. When choosing the appropriate incentive package for a company we have considered various factors such as: (1) how well the company seems to have addressed all available program opportunities, i.e., the comprehensiveness of the program; and (2) the aggressiveness of the company's proposed penetration targets. We also consider other qualitative factors such as the amount of effort the company seems to have expended developing its programs.

As cost recovery becomes more performance-based the need for separate incentives will likely diminish. For example, the DPU

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12 We did divide the $2.0 million incentive figure by 75 percent of projected savings, however, so that if the company attains its target it will still collect the full $2.0 million incentive.

could develop cost-recovery mechanisms for program expenses that incorporate incentive payments for successful programs. This could be done by establishing a $/MMBtu figure that the company would collect as it obtained actual savings. The $/MMBtu figure could be determined by adding together an estimate of program costs and an additional incentive component, and then dividing by projected savings or projected net benefits. To the extent that a company obtains excellent savings results, and holds its program costs at or below budgeted amounts, the company would be able to earn a healthy bonus. Care would have to be taken, however, in reviewing a company's program to ensure that the company did not inflate its budget or understate potential savings.

6. Evaluation and Monitoring

Evaluation and monitoring of C&LM programs is important in order to ensure that ratepayer money is not spent on programs that are not cost-effective. For the DPU, monitoring is even more important because we have tied the recovery of lost margins and incentives to actual measured savings. Because ratepayers will be responsible for paying these costs, we want the savings estimates to be as accurate as possible.

All of the gas companies in Massachusetts (as well as a few from other states in New England) have proposed to participate in a joint monitoring study. The study would include the installation of end-use meters in a stratified random sample of residential homes. The proposed study would include both a control and test group, with each group monitored for one year before the installation of any measures in the homes of the test group. Both groups would be monitored for a total of three years, with preliminary results available after two years. A third group of customers would be monitored from the time they install measures, and by comparing their metered usage to consumption in previous years the companies hope to get some rough estimates of savings within one year. The joint project, named the gas evaluation and monitoring study ("GEMS") would also include some focus groups and customer survey to evaluate other program concerns such as the degree of free riders.

The DPU is now in the process of reviewing the GEMS proposal, and we will be evaluating whether the statistical significance of the results is adequate. The DPU will also be evaluating whether the study -- which specifies that all meters be installed in the Boston Gas Company service territory -- would provide results transferrable to other gas companies in the state.

III. LEAST-COST PLANNING ON THE SUPPLY SIDE

While the bulk of the DPU's activities for gas companies with respect to IRP have been in the area of encouraging the development and implementation of cost-effective C&LM programs, the DPU has recently begun to direct increased attention to the supply side of the planning equation. In the past, LDCs procured supply resources by nominating a specific level of bundled service (gas supply plus transportation) on the pipelines at tariffed rates approved by the Federal Energy Regulatory Commission ("FERC"). Due to changes in the gas industry, however, LDCs can now negotiate supply contracts directly with producers and arrange for transportation services from the pipelines. The DPU has jurisdiction to review any gas company contract with a supplier that is more than one year in length, and so we are taking the opportunity to investigate LDC supply acquisition procedures during the context of supply contract reviews.

Until recently, the DPU's standard of review for supply contracts was to determine whether the new contract would produce net benefits for existing ratepayers, i.e., lead to a reduction in average rates. We realized, however, that this average-cost standard was equivalent to the "no-losers" test, which we had eschewed with regards to C&LM, and we concluded that applying different standards to supply resources and C&LM resources was inconsistent with least cost planning objectives. Accordingly, we decided to develop a standard that could be applied to both supply-side and demand-side resources.

We began by looking at our least-cost planning principles for the electric industry. We have ordered electric companies to meet forecasted demand levels at the lowest total cost to

society.[13] We concluded that this standard would not be directly transferrable to our gas companies, however, because Massachusetts LDCs do not have an obligation to serve new customers and have considerable discretion over future loads.[14] Unlike the situation for electric companies, future demand levels for gas companies are not a given. Accordingly, we concluded that it is not mathematically possible to minimize total costs to serve a given level of future demand, if future demand is not a fixed number.

We concluded that the addition of a new resource (whether a supply contract or a C&LM program) to serve new loads would provide net benefits to existing ratepayers if the new resource allowed the company to provide the same level of energy service to its existing ratepayers at the same or lower cost of service.[15] (A unit of energy service is defined not as an MCF or MMBtu, but as a warm house, or hot water. Accordingly, if customers can keep their homes at 65 degrees all winter, they do not really care whether their needs are met solely with gas consumption, or with a combination of gas consumption and conservation.) We expanded this standard into a more societal perspective in a later case, by requiring LDCs to include environmental externalities as well.

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13 This language has been included in several electric cases, and it has been incorporated in to the IRM Regulations, 220 CMR 10.01 (1).

14 While our gas companies are obligated to provide reliable service to their existing firm customers, the DPU has found that gas companies are not obligated to serve new load because ready substitutes to gas are available for virtually every end-use. See Boston Gas Company, D.P.U. 88-67, Phase I, pp. 282-284.

15 Boston Gas Company, D.P.U. 89-180, pp. 14-15.

Once a company determines that net benefits can be obtained by adding a new resource (i.e., by growing), the company must select from all potential resource options the one that results in the lowest social cost per unit of energy service. Our supply contract review standard now contains two steps: (1) a company must demonstrate that with the new supply source it will still be able to provide the same level of energy service to its customers at the same or lower total cost; and (2) the company must demonstrate that it considered both supply-side and demand-side resources in its evaluation, and that it selected the resource which will result in the lowest total societal cost.

Companies have been signing new supply contracts with the hope of marketing this additional gas to new customers for uses such as cogeneration, gas air conditioning, electric utility power generation, independent power production, and residential heating. Our new standard, though broader than before, uses existing ratepayers as the unit of analysis. It does not address whether it might be beneficial from an overall societal perspective for an LDC to acquire new resources and serve new loads. This is a potential area for future DPU attention, because from an economic perspective the least social cost energy source should be used to meet a customer's needs. Whenever the marginal social cost of gas (or gas C&LM) is less than the marginal social cost of all alternative energy sources, it is economically optimal for the customer to use gas.[17] If the DPU were to adopt as a broader policy objective to goal of minimizing the total social costs of serving the state's energy needs, we would have to consider several factors. First, the DPU would need to revisit the issue of our gas companies' limited obligation to serve, and decide whether it would be appropriate to expand their service requirements. Second, we would need to recognize that the social benefits of switching

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customer costs when it applies this least-cost standard to C&LM resources

17 For example, a new gas resource might be available to serve the gas air conditioning market at a lower social cost than the only alternative, electricity, but the LDC could be deterred from acquiring the new resource if it were to lead to increased costs for existing gas customers.

more customers to gas could come at the expense of increases in the average cost per unit of energy service for existing customers.

IV. CONCLUSION

The DPU's progress with gas company integrated planning and C&LM has occurred slowly, but each incremental movement forward has been encouraging. We have found that it is important to be firm with our companies with regards to the importance of C&LM, yet at the same time remain realistic about each company's resources and limitations. After listening to utility concerns, we concluded that it is necessary to minimize the risks that gas or electric companies associate with C&LM. We think that the DPU has been able to minimize or eliminate these disincentives by allowing utilities to recover all C&LM program costs, as well as quantified lost margins. Incentives have also been useful in encouraging companies to propose more aggressive and comprehensive programs.

We have also found that it is possible to pursue integrated planning objectives for gas LDCs without instituting a formal integrated resource planning process. Although we are open to criticisms of our approach, because it is an ad hoc process, we believe that our approach offers distinct advantages. We will also benefit from our vantage point of observing how an integrated planning process works on the electric side. Hopefully we will be able to borrow portions of the IRM process (or its regulations) to help us implement gas integrated resource planning more effectively.

Before beginning to pursue any type of IRP, some groundwork is essential. Our early C&LM efforts were accomplished in both generic and company-specific cases, and so we have been able to benefit from both types of investigations. However, we seem to have established most of our natural gas C&LM and least-cost-planning precedent in gas company cases. Because we rely on case precedent in our reviews, standards established in one case are easily applied in subsequent cases. For some states, however, a generic investigation might be a good way to develop both broad and specific standards on the subject of IRP in one case. For this reason, a generic investigation might

speed up the time necessary for a state to move all of its gas companies forward with integrated planning.

One important issue to address early on, or in a generic proceeding, is the calculation of avoided costs for gas companies. Our avoided cost methodology was originally developed for electric companies, and though we have made some slight revisions to the technique, we realize that it may not be perfect. We made a decision, however, that it was better to get some estimate of avoided costs established sooner rather than later, or C&LM program implementation might be unnecessarily delayed while a more appropriate or correct methodology was being established. We plan to review the issue of avoided costs again in future cases.

The clear establishment of a concise cost-effectiveness standard is also essential. Utilities should pursue only cost-effective C&LM, or they will be wasting their ratepayers' money. Developing a clearly articulated standard early in the process is important so that utilities know the framework they must use in their analysis of potential programs. When cost-effectiveness is not clearly defined, requiring cost-effective programs is meaningless. The California Standard Practice Manual is an excellent resource in this area for helping to describe the various types of cost and benefits, and the various types of tests that can be applied.

While a cost-effectiveness standard is essential, demonstrating absolute cost-effectiveness of a particular program can be difficult due to the lack of reliable savings data for gas C&LM measures. Public utility commissions may thus have to tolerate somewhat imprecise engineering-based estimates of measure savings at the start. As companies monitor their C&LM programs, they will be able to gather actual data on savings, and can then adjust their programs as necessary to ensure continuing program cost-effectiveness. Regular commission reviews of programs and monitoring results are thus essential in early years of C&LM program implementation in order to ensure that utilities revise programs as new information becomes available.

Because cost-effectiveness is important, it is thus imperative that gas companies monitor their C&LM programs. End-use metering is probably the most sophisticated and statistically accurate method, but also the most expensive and thus less feasible for smaller companies. A useful mix of end-use metering and bill analysis could likely provide adequate results for smaller programs or smaller companies. Joint monitoring programs are also a way to reduce the costs for individual utilities.

Review of program design issues can be time consuming during C&LM cases, but electric company experience can prove helpful in this area. C&LM measures will not differ greatly between gas and electric residential programs, and so many of the same principles of program design and delivery will apply to both and electric companies. Coordinated efforts between gas and electric companies, in the form of joint program delivery, is also a good way for gas companies to learn about program implementation. Such joint efforts could also help gas companies to deliver programs more cheaply, i.e., by sharing overhead and administrative costs with an electric company.

While we have found that it is possible to encourage gas companies to pursue least cost planning through the DPU's ad hoc regulatory review process, we realize that our process is limited by its reactive nature. If a company presents a long-term supply contract for DPU approval at the moment of its need, the company's immediate demand for the resource may preclude a fair evaluation of C&LM. We realize that at a minimum the DPU may need to institute regular advance reviews of LDC planning activities in order to allow C&LM to compete against supply resources in a more fair and realistic manner.

IRP IN MASSACHUSETTS

1. Energy Facilities Siting Council

   - Review supply plans
   - Review demand forecasts
   - Ensure adequate reliable service at least cost and least environmental impact

2. Department of Public Utilities (DPU)

   - Approve C&LM programs
   - Approve supply contracts
   - Ensure existing customers are provided with required energy service at lowest social cost

C&LM Preapproval Requirements

1. Provide description of C&LM program

2. Demonstrate that program is cost-effective

3. Submit a cost-recovery proposal

4. Include results of any Request for Proposals

C&LM Program Reviews

1. Cost-effectiveness
   - of individual measures
   - of "bundles" of measures
   - of the total program
2. Calculation of avoided costs
3. Cost recovery
   - Program-related expenses
   - Lost margins
4. Incentives
5. Evaluation and monitoring

Program Cost-Effectiveness Standard

1. Costs
   - Installed cost of measures
   - Utility administration
   - Evaluation and Monitoring
   - Any quantifiable customer costs (e.g., increased maintenance)

2. Benefits
   - Avoided-cost savings
   - Environmental externalities

Avoided Costs

1. Capacity Costs

2. Commodity Costs

3. Capitalized Energy

Cost Recovery - Removing Disincentives

1. Preapproved recovery of program costs

2. Recovery of lost margins

3. Opportunity for incentive

The Three-Personality Incentive

1. An ROE bonus

2. Shared savings as a guideline

3. Performance-based recovery with a threshold

Example of C&LM Incentive

0.5% ROE Bonus	=	$2.0 million
Net Benefits	=	$6.0 million
Annual Savings	=	400,000 MMBtu
After 25% threshold	=	300,000 MMBtu
Incentive	=	$6.67 / MMBtu

Review of Supply Contracts

1. Does addition of new source produce net benefits for existing ratepayers?

2. If yes, is proposed source the least social cost option?

Net benefits: Result if a company can provide the same level of energy service to its existing customers at the same or lower cost to society.

Lessons Learned

1. Tolerate no whining

2. Formal process not mandatory

3. Spend time on groundwork
   (e.g., avoided-cost methodology
   and cost-effectiveness standard)

4. Consider lost margins

5. Consider incentives

6. Require monitoring

ANALYTICAL FOUNDATIONS OF SUCCESSFUL UTILITY DSM PROGRAMS*

Eric Hirst
Oak Ridge National Laboratory
Oak Ridge, Tennessee 37831

INTRODUCTION

Will utility demand-side management (DSM) programs fulfill their promise to provide large amounts of cost-effective and environmentally benign energy and capacity resources? Much depends on our success in measuring accurately the performance of these programs and in clearly and consistently defining the terms that characterize such programs. This paper discusses these analytical issues and then presents a scenario showing how much DSM programs could accomplish if we build a solid foundation of credible data.

EVALUATION

Evaluation is the systematic measurement of the operation and performance of DSM programs (Keating and Hicks 1990). Evaluations rely on objective measurements of DSM programs, rather than anecdotal evidence and personal impressions. Evaluations use social-science research methods to ensure that the results are valid. And evaluations are aimed at future decisions about DSM programs; they are not academic exercises.

Evaluation provides information needed by program managers and staff to improve program operations. More broadly, evaluation produces information needed by utility executives and public utility commissions (PUCs) to assess the effectiveness of these programs.

As examples, evaluation results can:

- Document the energy savings, load reductions, and cost effectiveness of DSM programs
- Show ways to improve programs by increasing participation rates, raising energy savings, or cutting costs
- Suggest ways to improve the design of future DSM programs

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*Work reported here was sponsored by the Office of Conservation and Renewable Energy, U.S. Department of Energy, under contract No. DE-AC05-84OR21400 with Martin Marietta Energy Systems, Inc.

- Support DSM budgets before the utility's budget committee and the PUC
- Provide data to strengthen the company's load forecasts and resource planning

Utilities should measure the performance of DSM programs in much the same way, and with the same competence and diligence, that they monitor the performance of power plants. Utilities have detailed information for each of their power plants on construction costs and time; operations, maintenance, and fuel costs; heat rate, availability factor, and capacity factor; the duration and causes of each outage; and fuel consumption, plant output, and emissions.

As the number, size, scope, cost, and effects of DSM programs increase, evaluations will become increasingly important. New challenges will face evaluators during the 1990s. Among the many challenges, two key ones (discussed below) are the role of evaluation in contested PUC hearings and integration of evaluation with other customer-analysis activities.

EVALUATION IN CONTESTED HEARINGS

More and more PUCs are providing financial incentives to utilities for the implementation of cost-effective DSM programs (Moskovitz 1989; Reid and Chamberlin 1990). The most popular incentives use shared-savings mechanisms, in which the utility keeps part of the net benefit provided by its DSM programs (Fig. 1). The net benefit is the difference between the total benefits and program costs. Total benefits are typically defined as the amount of energy saved by the program multiplied by the avoided energy cost plus the amount of demand reduction multiplied by the avoided capacity cost. The critical element in computing net benefits is estimation of energy and demand reductions, the province of program evaluators.

Consider a hypothetical commercial lighting program as an example of the ambiguities that arise in a carefully conducted evaluation. (I leave to the reader's imagination the controversies that might arise in a PUC hearing over a poorly designed and run evaluation.) This program is aimed at medium size office buildings and includes general information and onsite lighting audits. These activities identify suitable lighting measures and encouraging the customer to apply for the 50% rebate offered by the utility. The rebate helps to defray the costs of purchasing and installing energy-efficient lamps, ballasts, fixtures, and controls.

The utility ran a comprehensive evaluation that included three elements:

- analysis of two years of electricity-billing data, one year before participation and one year after, for samples of participants and eligible nonparticipants
- 30 days of time-of-use metering, pre- and post-retrofit, of a sample of lighting circuits for a sample of participants only (no comparison group)

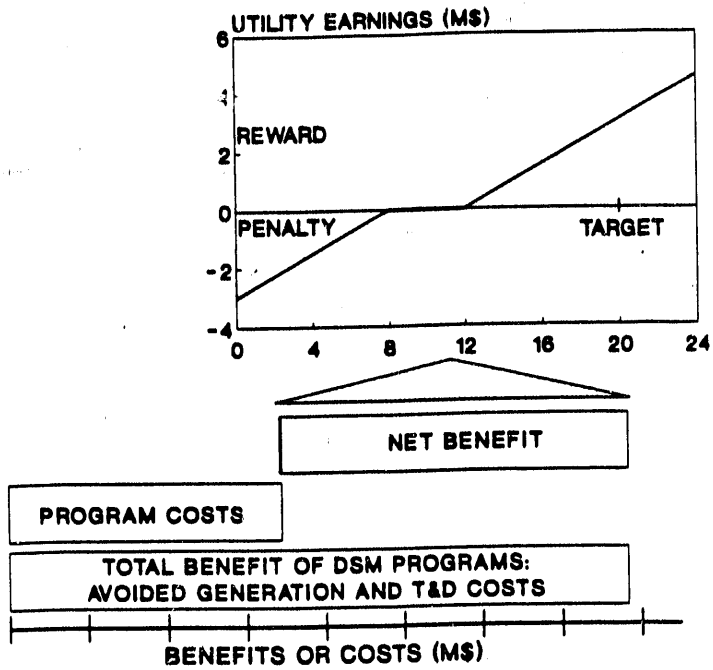


Fig. 1. **Schematic showing the mechanics of a shared-savings mechanism to reward utility shareholders for implementation of cost-effective DSM programs. In this example, the program costs $20 million, the total benefits are $40 million, and the net benefit is then $20 million. Shareholders earn $3 million because the utility achieved its net-benefit target of $20 million. Evaluations determine the actual energy and load reductions of these DSM programs, the basis for computing total and net benefits.**

- engineering analysis of the energy and load reductions caused by the measures actually installed by participants (again, no comparison group)

The utility used multiple methods to estimate program savings because each method is imperfect. Such triangulation builds confidence in the estimates ultimately used. Not surprisingly, these approaches and their associated analytical procedures gave differing estimates of net energy savings (Fig. 2). Comparison of pre- and post-retrofit electricity use, based on monthly billing data, for participants showed a reduction of 9600 kWh/year. Nonparticipants showed an increase in electricity use of 2800 kWh/year over the same two-year period. (The local economy was growing during this period, which led to higher occupancy levels and longer hours of operation for these buildings. These changes in building use help explain the increase in electricity use for nonparticipants.) And the customers who received a lighting audit but did not apply for the rebate (one-third of the total number of customers that received audits) cut their consumption by 1600 kWh/year. Figure 2 shows the roughly 50% difference in estimated annual electricity savings, based on analysis of billing data. These differences depend on whether or not participant savings are

adjusted for nonparticipant changes in electricity use and for the savings achieved by audit-only participants.

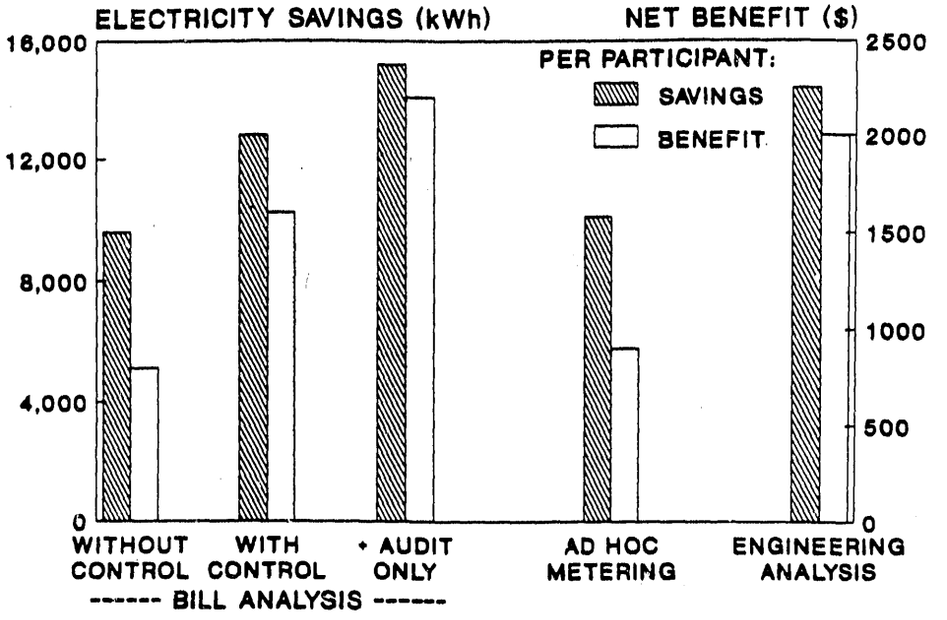


Fig. 2. **Estimated electricity savings and net benefits caused by a hypothetical utility lighting program, based on several evaluation approaches.**

The data from ad hoc metering showed savings roughly comparable to those from analysis of the billing data for the participants only. Complications arose in scaling up the metering results to a full year. The metering covered roughly 60 days over a three-month period, with the middle month devoted to installation of new lighting measures. The amount of electricity used for lighting varies with season, and is larger in the winter than in the summer. On the other hand, the indirect electricity savings associated with reduced air-conditioning loads is greater in the summer than in the winter.

Similar problems arose in estimating the savings with engineering calculations. These calculations are based on the change in connected load multiplied by the number of equivalent full-load hours of use per year. The assumed use schedules were based on data collected several years ago when vacancy rates were higher and the economy was growing slowly.

The percentage differences in electricity savings among these approaches are magnified in the estimation of net benefit (Fig. 2). This magnification occurs because net benefit is the difference between total benefit (directly proportional to energy savings) and program cost. In this case, program costs are roughly half the total benefit. Thus, a 10% error in estimating total cost leads to a 20% error in net benefit.

Which result is correct? How should the PUC decide among these estimates in determining the incentive paid to the utility? Several approaches are possible that differ in who does the evaluation and how it is planned and conducted. The utility and PUC (and perhaps other parties) could agree before the program starts on the exact evaluation methods to use, including sample frames and sizes, data-quality controls, and analysis methods. Prior specification of evaluation methods may be unworkable because programs evolve as they are implemented. Indeed, one of the major strengths of DSM resources over supply resources is their small unit size and flexibility. Predetermining all the specifics of an evaluation would rob the program of important flexibility.

The utility and PUC could select an independent group to conduct the evaluation. This group would have complete freedom to design and carry out the evaluation as it sees fit, thus preserving its independence. The evaluation contractor would then recommend to the PUC its estimate of program energy and load impacts. This approach also has problems. First, as discussed in the following section, evaluations should be closely coupled to other customer-analysis activities within the utility. Contracting out the evaluation prevents the utility itself from gaining valuable analytical experience and data on its customers. Also, using an independent contractor to conduct the evaluation does not, by itself, eliminate controversy from the PUC hearing. The utility, PUC staff, and intervenors are still free to suggest alternative interpretations of the evaluation results.

Using a collaborative process to design the evaluation and to review its progress might reduce controversy. In this approach, the utility conducts the evaluation itself, but shares the planning and oversight with PUC staff and other organizations. Finally, the commission could appoint an independent expert to review the utility's evaluation approach and results. This expert would also suggest to the commission estimates to use in computing the benefits of the utility's DSM programs.

Serious evaluation of utility DSM programs is a recent activity and the use of evaluation results in determining utility earnings is just about to begin. Therefore, the kinds of problems that might arise in PUC hearings and possible resolutions are also unknown. It is clear, however, that competent evaluations of utility DSM programs will be increasingly important (Weil 1990).

INTEGRATION OF EVALUATION WITH OTHER ANALYTICAL ACTIVITIES

Evaluations provide information useful for many purposes, beyond their direct application in assessing the performance of individual DSM programs. Evaluation results are useful for many activities within electric utilities, including DSM-program design, market research, load research, load forecasting, and resource planning. For example, evaluation results provide a detailed view of the energy-related behaviors of some customers. Such information should be useful in developing improved load forecasts. Thus, the utility departments responsible for load forecasting and for evaluations should work together, both on the design of evaluations and in applying evaluation results.

Integrated resource planning requires estimates of the likely effects and costs of future DSM programs. Typically, these estimates are based on engineering analyses of various DSM technologies and DSM-program-staff guesses at participation rates. It should be possible to use the results of evaluation in developing better estimates of future program performance and costs (Hill, Hirst, and Schweitzer 1991). Figure 3, from Seattle City Light, illustrates this opportunity to use evaluation results (Sumi and Coates 1989). SCL collected data on samples of participants and nonparticipants for an ongoing evaluation of its residential retrofit program. These historical results should be useful in estimating the future energy savings associated with both past program participants and future participants. These estimates would rely on assumptions about future electricity prices, incomes, use of wood for space heating, and other factors that might affect residential electricity use in the future.

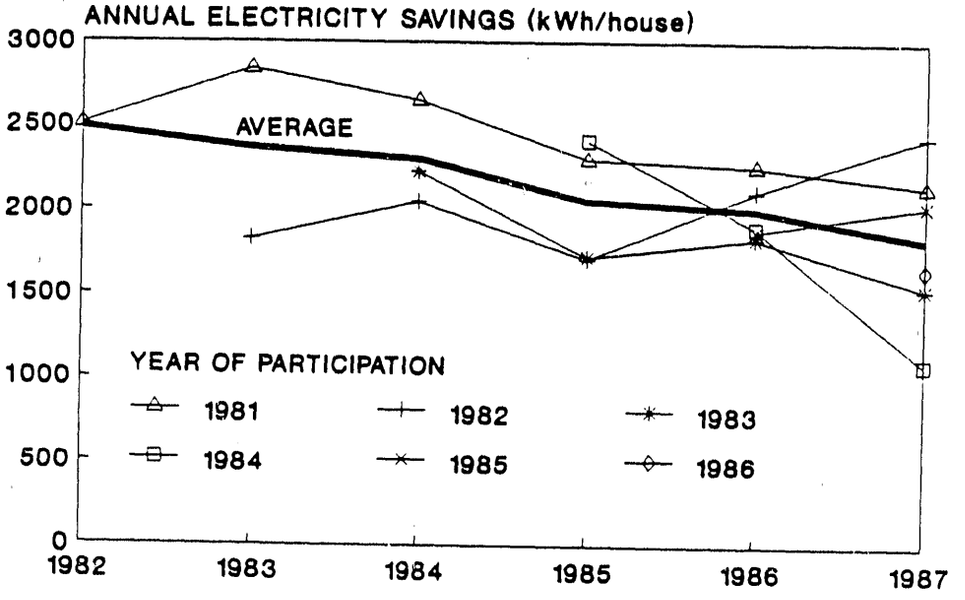


Fig. 3. **Annual electricity savings for households that participated in Seattle City Light's residential retrofit program.**

DATA DEFINITIONS

Evaluations provide important data on DSM programs. Definitions help people interpret that data. Definitions ensure comparability of terms from one program to another and from one utility to another. Because of inconsistencies in definitions, we now discuss DSM programs in a "tower of babel," leading to different estimates of DSM potential and performance (Hirst 1990).

A hypothetical example will illustrate this problem. Consider two utility programs that encourage installation of low-flow showerheads (Table 1). The two utilities show very different estimates of program costs, participation rates, energy savings, and cost

effectiveness. Casual Power & Light computed electricity savings on the basis of engineering calculations. On the other hand, Rigorous Power measured flow rates with the original showerheads and the low-flow showerheads (3.2 vs 1.6 gallons/minute), collected data on the time spent taking showers with both types of showerheads (5 vs 6 minutes/shower), and estimated the fractions of customers that would have installed the low-flow showerhead without the utility program (10%) and that would remove the new showerheads soon after installation (20%). These differences lead to the much lower, but more realistic, estimate from Rigorous Power of the electricity savings per customer achieved by the program.

Similar differences occur for the estimates of costs, participation rates, and cost effectiveness. Casual Power & Light considered only the cost of the showerhead, while Rigorous Power included the cost of utility administration and marketing as well as the cost of the showerhead. Casual Power & Light based its participation estimates on their total residential class, while Rigorous Power based participation rates on the number of residential customers with electric water heaters.

This example shows the variation in reported results that can occur with different definitions. The problem is not with the use of different definitions per se. The problem is that these definitions are rarely explicit. Thus, the user of such data does not know whether or how data can be compared across programs. (In this example, Casual Power & Light reported its estimate of total electricity savings and Rigorous Power reported its estimate of net electricity savings.)

Table 1. Hypothetical situation showing different estimates of the costs, participation, and electricity savings from DSM programs

Casual Power and Light
Savings = 450 kWh/year per participant
Participation = 1% of residential customers per year
Cost of conserved energy = 0.5 cents/kWh
Annual savings = 2.7 GWh
Rigorous Power
Savings = 270 kWh/year per participant
Participation = 6% of electric water heater customers per year
Cost of conserved energy = 1.2 cents/kWh
Annual savings = 3.9 GWh

In essence, we need to develop definitions for terms that are analogous to those used to describe power plants (Table 2). Utilities and PUCs need clear, consistent, and widely used definitions for program participation, energy and demand savings, and program costs. Consider program costs as an example (Fig. 4). Definitions of program costs can include

all costs, both those borne by participating customers as well as those borne by the utility, or include utility costs only (Berry 1989). Sometimes, costs refer to the direct costs of the devices and their installation. And sometimes costs include the utility's administrative activities (e.g., staff training, advertising, quality control, equipment, and program evaluation) plus corporate overhead. Clearly, there are different elements associated with DSM program costs. Therefore, the total cost per kWh saved (or per kW demand reduced) can reflect different contributions from utilities and customers.

Table 2. Analogous factors characterizing DSM programs and power plants

DSM programs	Power plants
Participation rate	Availability and capacity factors
Energy and demand savings	Heat rate
Program costs Fixed Variable	Plant costs Construction + fixed O&M Variable O&M + fuel

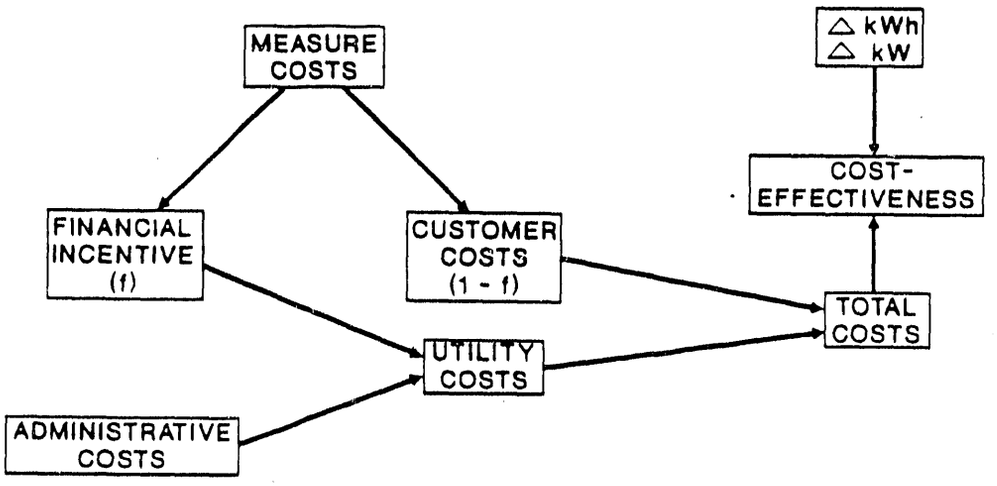


Fig. 4. Total program costs can be distributed in a variety of ways. (The fraction of the installation cost paid by the utility is f.)

AMBITIOUS SCENARIO

How might utility DSM programs affect U.S. electricity use during the next two decades? Recent trends in integrated resource planning, incorporation of environmental costs into resource planning, PUC provision of financial incentives to utilities for DSM programs, and the growing recognition of the utility role in overcoming market barriers to energy efficiency all suggest a greatly expanded role for utility DSM programs. Much depends, however, on the foundation issues discussed above. Without abundant, credible, and consistent data on the performance of utility DSM programs, such programs will not be considered alternatives to power plants and will therefore decline in importance.

The starting point for the present scenario is the reference projection developed by Energy Information Administration (1990) for the National Energy Strategy. This projection shows electricity use increasing at 3.0%/year during the 1990s and at 2.3%/year between 2000 and 2010 (left hand column of Table 3). The EIA projection assumes that utility DSM programs will have little effect on electricity use during the next two decades.

I developed a simple model of electricity use, based on the notion that the effects of utility DSM programs depend on three factors (Hirst 1991). These factors are the fraction of utilities that offer such programs, the fraction of customers that participate each year, and the fractional savings in electricity use experienced by program participants. With this simple model, electricity savings is the product of these three factors.

The ambitious scenario assumes that utility involvement increases from 20% in 1990 to 75% in 2010, participation grows from 7%/year to 12%/year, and savings per participant increase from 15% to 22% (Table 3). As more utilities implement DSM programs and as more customers participate and save energy, the total effects of these programs increase (Fig. 5). By the year 2010, electricity use is 19% lower than in the EIA case.

Table 3. Ambitious scenario of effects of utility DSM programs, 1990 to 2010

Year	EIA/NES Forecast (TWh)	Utilities with DSM (%)	Customer participation (%/year)	Savings per customer (%)	Incremental savings (TWh)	Total savings (TWh)	% reduction from EIA/NES
1990	2689	20.0	7.0	15.0	5.6	34	1.3
1995	3122	35.0	8.5	17.0	15.8	90	2.9
2000	3624	50.0	10.0	19.0	34.4	217	6.0
2005	4051	75.0	12.0	21.5	78.4	495	12.2
2010	4528	75.0	12.0	22.0	89.6	868	19.2

Whether or not the savings shown in Table 3 are reasonable can be judged by comparing them to savings expected by utilities that already run ambitious energy-efficiency programs, some of which are shown in Table 4. These utility projections all exceed the 6% reduction for the year 2000 shown in Table 3.

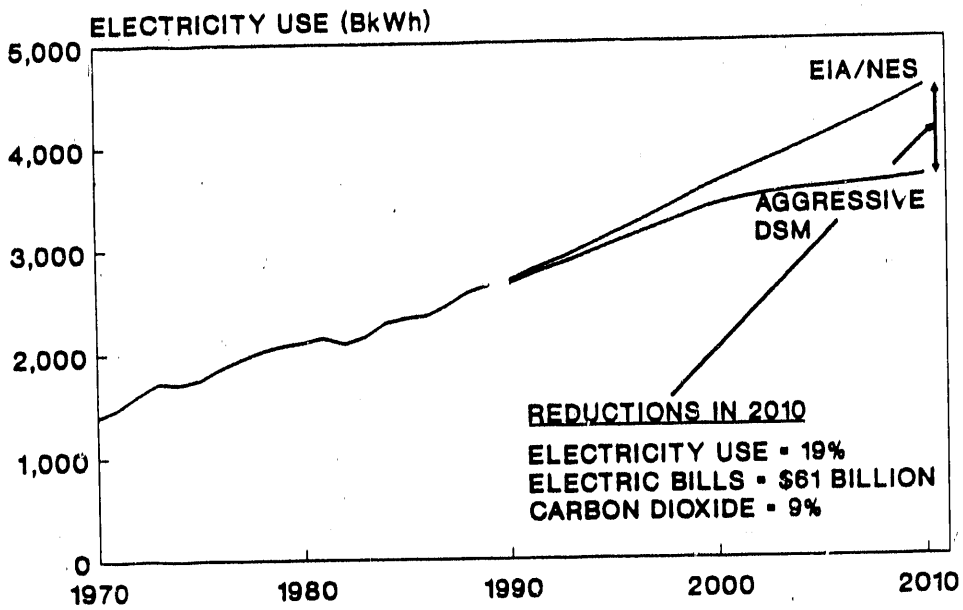


Fig. 5. **U.S. electricity use from 1970 through 2010. The top curve is from the Energy Information Administration (1990). The bottom curve is the scenario developed here.**

Table 4. **Sample of utilities with ambitious energy-efficiency programs**

Utility (state)	Projected reduction in year 2000 electricity use caused by utility DSM programs (%)
Southern California Edison (CA)	13.0
Long Island Lighting Company (NY)	9.0
Consolidated Edison (NY)	8.1
Rochester Gas & Electric (NY)	7.3
Seattle City Light (WA)	7.0
Northeast Utilities (CT, MA)	7.0
Puget Power (WA)	6.8
New England Electric (MA, NH, RI)	6.6
Wisconsin Electric Power (WI)	6.2
Pacific Gas & Electric (CA)	6.0

Sources: Hirst (1991).

The reduction in electricity use tells only part of the story. The cost of conserved energy is typically about half the cost of building and operating a new power plant (Hirst 1991). The marginal cost implicit in the EIA projection is about 7¢/kWh, suggesting an average cost of conserved energy of 3.5¢/kWh. Over the 20-year period analyzed, the present value (in 1989 dollars at a 5% real discount rate) of the cost of the utility DSM programs is $165 billion. Initially, much of this cost is likely to be borne by utilities. As utilities become more skilled in the design of programs, program participants will pay larger fractions of this cost. The value of the reduction in utility costs (both capital and fuel, $370 billion) is more than double the cost of these programs. By the year 2010, these DSM programs would cut electric bills by $61 billion a year.

In addition, total U.S. emissions of CO_2 would be cut by 9% that year relative to what they would have been without utility DSM programs, easing the threat of global warming.

Finally, the electricity savings caused by these ambitious DSM programs represent almost half of the growth in electricity use between 1990 and 2010. In concrete terms, these programs could cut the need to build 430 medium (500-MW) power plants. Also, fewer transmission lines, distribution lines, substations, and transformers would need to be built.

CONCLUSION

In response to a variety of forces, utilities are likely to increase greatly their DSM programs. Perhaps the most important impetus to improve efficiency of electricity use is the growing recognition that energy efficiency is a low-cost resource that can substitute for some power plants. Other forces encouraging more DSM programs include integrated resource planning, concerns about the environmental costs of electricity production and transmission, and provision of financial incentives to utility shareholders for running cost-effective DSM programs.

Whether DSM programs meet the expectations of their proponents depends strongly on the availability of data that document the performance of these programs. Unfortunately, the amount and quality of the data now available on DSM programs are far short of what utilities and regulatory commissions need. Lack of comprehensive, competent evaluations and lack of explicit, widely used definitions of DSM terms are key deficiencies that make it difficult to assess the contributions that utility DSM programs could make to resolving U.S. energy problems.

As utilities and commissions devote more effort to evaluations and data definitions, they will receive valuable information on the costs, timing, market segments, load-shape effects, and other characteristics of utility energy-efficiency and load-management programs. This information can transform guesses, estimates, numbers, and data into useful information that will help ensure that these DSM programs are fully considered in resource-acquisition planning and decision making. Recent data-collection efforts established by the Northeast Region Demand-Side Management Data Exchange and by EIA plus several projects on

program evaluation sponsored by the U.S. Department of Energy, Electric Power Research Institute, New York State Energy Research and Development Authority, and others suggest that such information will be forthcoming. The result of these efforts will be a balanced mix of supply and demand resources that satisfies customer energy-service-needs at reasonable cost in an environmentally benign way.

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DEMAND-SIDE MANAGEMENT AT NEW ENGLAND ELECTRIC: IMPLEMENTATION, EVALUATION, AND INCENTIVES

Alan F. Destribats, Peter G. Flynn, Elizabeth G. Hicks, and Lawrence J. Reilly[1]

INTRODUCTION

The New England Electric System has three wholly-owned retail electric subsidiaries serving 1.2 million customers in Massachusetts, Rhode Island and New Hampshire. System peak demand is approximately 4,200 MW. Since 1979, when the System published its 15-year long range plan, NEESPLAN, the System companies have been active in developing conservation and load management programs that can defer the need for traditional generating capacity.

In 1985 NEES incorporated least-cost planning into its second long-range plan, NEESPLAN II. In 1987 the System began implementing an ambitious conservation and load management program - Partners in Energy Planning - which had a goal of reducing the peak demand for electricity by 230 MW by mid-1991. In mid-1988 the Company embarked on a collaborative with the Conservation Law Foundation (CLF) which increased the conservation and load management peak reduction goal to 300 MW and the energy savings goal to 335 GWh[2]. Both the capacity and energy goals were exceeded by the end of 1990. As of that date, the System companies had achieved a peak reduction of 310 MW and energy reductions of 431 GWh. The System's long-range plans indicate that about one-third of new resources implemented over the next 20 years will be demand-side resources.

In 1990, System companies spent $71 million on DSM related activities. Projected 1991 spending is $85 million or approximately 5% of total revenue. The 1990 NEES conservation and load management program was a major undertaking for its size and complexity. This paper summarizes the results for 1990, including demand and energy savings, evaluation activities, and incentives earned.

1990 RESULTS

The NEES 1990 conservation and load management program was prepared in mid-1989 in a collaborative process with the Conservation Law Foundation based on "Power by Design: A New Approach to Investing in Energy Efficiency," the blueprint for increasing the penetration of energy efficiency improvements in the Company's service territory. NEES' comprehensive conservation plan, Partners in Energy Planning, had been in effect since January 1987 when

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[1]The authors work for New England Electric and are respectively Vice President, Demand and Least Cost Planning, Director of Conservation and Load Management, Director of Demand Planning, and Director of Rates.

[2]See "Power by Design" Volumes I and II.

NEES decided to aggressively expand the program for 1990. NEES' 1990 goals are shown in Table 1.

TABLE 1
1990 GOALS

Company	MW	MWh
Massachusetts Electric	53.3	112,300
Narragansett Electric (Rhode Island)	12.9	32,700
Granite State Electric (New Hampshire)	1.8	3,800
Standby/Interruptible	37.4	N/A
Total	105.4	148,800

As the Company moved into 1990 it became clear that New England was heading for an economic slowdown that would help relieve the region's tight capacity situation. Due to extraordinary success of the Company's commercial and industrial lighting program combined with the effects of the economic downturn, the Company's focus was changed from load management (standby generation, interruptible rates, and storage cooling) towards a more conservation oriented approach.

In each retail company jurisdiction, actual 1990 results exceeded goals. These exemplary results were achieved through a concerted effort of the System's 95 full time C&LM staff, with extensive assistance and support from the Commercial and Industrial Services staff and a wide variety of contractors. The 1990 actual results are shown in Table 2 below. In total, NEES exceeded its energy goal by 31% and its capacity goal by 11%.

TABLE 2
1990 RESULTS

Company	MW	MWh
Massachusetts Electric	60.4	123,400
Narragansett Electric	22.7	65,800
Granite State Electric	3.0	5,100
Standby/Interruptible	30.4	N/A
	116.5	194,300

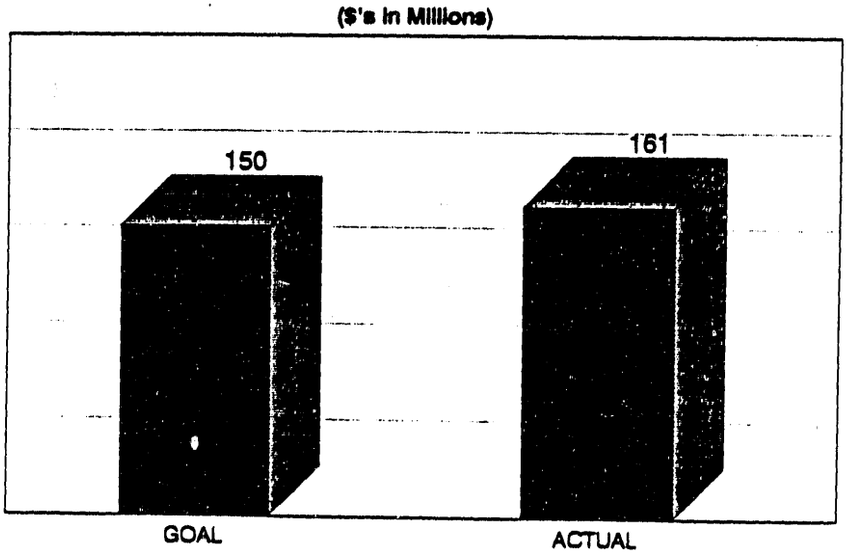
The efficiency improvements resulting from the 1990 program created substantial value. Measured in terms of avoided power expenses and reduced transmission and distribution system losses, the 1990 C&LM program created $161 million of value, $11 million more than originally

anticipated (See Figure 1). This value was achieved at a cost of $71 million. Accordingly, the net value created by the System's 1990 C&LM program was $90 million. As will be shown later, NEES earned $10.2 million of the $90 million net value as an incentive, or 11%. The remaining $80 million of net value, or 89%, was realized by NEES' customers.

Figure 1

1990 C&LM Total Value

($'s in Millions)



INCENTIVE MECHANISMS

New England Electric's conservation and load management programs were a valuable resource during the 1980's. The short lead-time associated with these resources made them an especially effective tool in meeting customer load growth. This helped satisfy both customers and shareholders, but concern was growing among utilities, regulators, and environmentalists that supply and demand side options, although equal in resource value, were not being treated equally as far as utility shareholders were concerned. Whereas shareholders have an opportunity to earn a return on capital invested in generating facilities, investments in conservation measures provided no opportunity for profit, indeed such investments would likely result in lost revenue from decreased sales. To help remedy this situation, New England Electric decided, along with the Conservation Law Foundation, to propose that the Company earn a financial incentive to encourage sound conservation and load management investments.

In the spring and summer of 1989 the Company worked with the CLF and consultants to determine what type of mechanism would provide profit opportunities for the Company while sending the correct signal, i.e. that would encourage the Company to pursue those demand side

investments that created the most value for its customers. The type of incentive the Company proposed was a "shared savings" program.[3]

A shared savings program uses the margin between the value of conservation and the cost of producing that conservation to measure the net value created for society. The net value is then split between the customers and the Company. NEES proposed a further breakdown of the Company's share of the value into "maximizing" and "efficiency" incentives. The "maximizing" incentive would be a direct percentage, five percent as proposed, of the value created by the Company's C&LM programs. The second component, the "efficiency" incentive, would vary by the efficiency with which the savings are produced. This efficiency incentive equals 10 percent of the difference between the value of the programs and the cost of implementing those programs.

The two components of the incentive are designed to accomplish different purposes. The maximizing component is designed to encourage the Company to maximize the amount of conservation and load management achieved. It establishes an incentive without regard to the underlying costs that must be incurred to achieve the conservation. The maximizing component assures that the Company has an incentive to go after all cost-effective conservation measures and not simply the least expensive measures.

The efficiency incentive is designed to encourage NEES to implement C&LM in as efficient a manner as is possible. Unlike the maximizing portion of the incentive, this portion depends on the size of the margin between value and cost. Thus, the mechanism provides a direct incentive to keep C&LM costs as low as possible. The efficiency portion of the incentive also establishes a common economic interest between NEES and customers. In other words, it assures that all parties share the goal to keep costs low.

Regulators in all three states we serve have responded positively to our incentive proposal. These actions have provided encouragement for NEES to propose the largest C&LM programs possible, which, in turn, will provide substantial benefits to customers. The Rhode Island Public Utilities Commission was the first to act on the Company's incentive proposal. They adopted the overall concept but directed that NEES include a threshold level of value, approximately 50%, that the Company would need to create before it could start earning an incentive. Once NEES reached that threshold, the incentive mechanism would work as proposed.

The Massachusetts Department of Public Utilities was next to authorize an incentive, but they modified the proposed mechanism to what is sometimes referred to as a "bounty" approach. The Department authorized the Company to earn its incentive based on the estimated lifetime savings of both kW and kWh. Each lifetime kW or kWh that NEES saved had associated with it an incentive dollar value. They also established a 50% threshold for both kW and kWh. Once the

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[3]See Reid and Chamberlin, Financial Incentives for DSM Programs: A Review and Analysis of Three Mechanisms for a discussion of incentive mechanisms.

threshold was achieved for kW or kWh, the Company could start to earn an incentive on the post-threshold savings.

The New Hampshire Public Utilities Commission held generic hearings to investigate C&LM incentives for all electric utilities in the state. The Commission approved the concept of incentives for C&LM programs that provide "extraordinary benefits" to ratepayers and found that NEES' New Hampshire subsidiary, Granite State Electric, was the only utility that satisfied the "extraordinary benefits" standard. After determining that their criteria had been met, the Commission approved the Company's proposed incentive mechanism.

INCENTIVE RESULTS

As a result of the 1990 C&LM program achievements, the following incentives were earned: Narragansett Electric, $3.8 million; Massachusetts Electric, $5.9 million; and Granite State Electric, $0.5 million. These incentives helped to stimulate the extraordinary performance of the New England Electric conservation and load management staff. New England Electric always had high level support for conservation and load management activities. However, because of the incentives, conservation is now looked upon as a profit center as well as a way to meet short term needs and manage load growth.

As the Rhode Island incentive was in place from the beginning of the year, Narragansett Electric had clear direction for its conservation and load management efforts. It surpassed its monthly goals throughout the year and created not only more value for customers, but more value per dollar spent than projected.

The Massachusetts Electric (MECO) incentive was approved in late March 1990. At that point, MECO was about 40% behind pace for achieving its 1990 C&LM goals. However, with a very determined effort in the remaining nine months of the year, Massachusetts Electric installed C&LM measures at a rate sufficient to catch up and surpass its energy savings and value goals.

The Granite State Electric incentive was approved in August, 1990. Being relatively small, Granite State Electric is unique among the NEES retail companies in that large conservation jobs can significantly affect whether or not goals are met. This was true in 1990 as several projects in the fourth quarter put us ahead of the goal for the year.

SUCCESSES AND FUTURE DIRECTIONS

One of the great successes of 1990 for New England Electric was the Energy Initiative program. The program was designed to be a major portion of NEES' conservation and load management activity but it surpassed even the Company's best hopes. The program was expected to account for approximately 50% of value but achieved almost 70%. The program is also becoming much more comprehensive in its approach. The non-lighting conservation portion of the program was projected to be 20% of the conservation activity but resulted in approximately 25%. The shift

will be even more apparent in 1991 when non-lighting conservation is projected to be 30% of the Energy Initiative program.

Another success in 1990 was the Design 2000 program. This program promotes energy efficient design and construction of new commercial, industrial, and institutional buildings. It also promotes energy efficiency in major renovations. During the year contracts representing over 2,000 kW were signed and installations totalled over 4,100 kW.

Also notable in 1990 was the Small Commercial/Industrial program. The Small C/I program was developed jointly by the Rhode Island Least Cost Planning Committee, which included the Rhode Island Public Utilities Commission, the Governors Office of Energy Assistance, and all major Rhode Island electric utilities. This program, the first phase of which was offered in 1989, is available to small commercial and industrial customers. A free lighting assessment is provided to the customer, followed by free installation of high efficiency lighting products. In 1991 the Company is adding non-lighting measures to this program.

NEES also enjoyed a number of successes in 1990 with residential programs. The Energy Fitness program, which targets low-income customers, installed efficient compact fluorescent lights and other measures in about 16,000 homes. The Home Energy Management Program uses radio signals or electronic time clocks to cycle customers' water heaters. Approximately 2,600 customers participated in this program in 1990, its first year of activity. A comprehensive conservation program for customers with electric heat was also introduced. In 1991 NEES is offering an even more aggressive array of residential programs including:

- Energy Crafted Home. Training, financial incentives and promotional marketing are provided to builders of efficient new housing.
- Energy Fitness. This program installs conservation measures in the homes of customers who reside in predominantly low-income neighborhoods.
- Home Energy Management. This program cycles one element of a customer's water heater.
- Residential Lighting. All eligible customers receive a catalogue with coupons that they can redeem to purchase efficient compact fluorescent lights through the Company or a participating retailer. Under either option, customers may purchase the lights at a substantial discount. This program will be offered to all 1.1 million residential customers in 1991.
- Residential Space Heating. This program promotes the installation of insulation, air sealing and other conservation measures in electrically heated homes.
- Water Heater Rebate. Rebates are provided for the purchase of high efficiency water heaters.

NEES is also in the process of reviewing with its regulators the following programs:

- Appliance Efficiency. Also called the "Blue Ribbon" program, Appliance Efficiency educates residential customers about appliance efficiency and promotes the purchase of high efficiency models. The program is being expanded to include appliance recycling.
- Multifamily Retrofit. Conservation measures are installed in electrically heated residential buildings with five or more units.

1991 PROGRAM AND GOALS

New England Electric's 1991 conservation and load management program includes:

- $85 million budget,
- 46 MW peak reduction goal,
- 141,000 MWh energy savings goal,
- Emphasis on residential and comprehensive commercial and industrial programs,
- Focus on evaluation, and
- Serve over 150,000 customers.

These goals are even more ambitious than the goals NEES set for 1990. The budget for 1991 of $85 million is 30% higher than the 1990 budget. If all programs goals are fully met, NEES has the potential to earn a financial incentive of $8.2 million in 1991. Even in the face of expected negative load growth due the economic situation in New England, NEES increased its C&LM budget. This decision recognizes the long-term value of investments in efficiency improvements and stands as a bold example of what can happen when conservation is made profitable for a utility.

EVALUATION OF DSM PROGRAMS

Another of the major goals in 1991 is DSM program evaluation. NEES is working in a collaborative effort with the CLF and consultants to evaluate all aspects of its demand-side management activities. NEES currently has seven DSM professionals working full-time on evaluation to prove its effectiveness and value as a resource.

By the end of 1990 NEES had process and impact evaluations underway for all programs that had been in the field for a meaningful period of time. These two types of evaluations have different goals although the same data are often used in both evaluations. Process evaluation tends to involve qualitative analyses while impact evaluation involves quantitative analyses.

Process evaluations are concerned with a program's design and operational efficiency. There is particular emphasis on critically examining customer and utility/contractor staff reaction to, and interaction with, the program. Impact evaluations measure the quantitative results of C&LM programs, distinguished from other factors that produce the same effects. The most important results measured by impact evaluations are demand, load shape, and energy usage effect, which

are necessary for a cost-effectiveness analysis. Impact evaluations also quantify changes in customer knowledge and behavior resulting from C&LM.

NEES will use the results from this effort to modify, where necessary, implementation strategy and savings estimates for all program measures. In May 1991, the Company will file in Massachusetts a "true up" of the savings estimates for measures installed during 1990. The estimates derived from this "true up" will be used to update our estimates of savings in Rhode Island. The goal is to prove that DSM can be as valuable and reliable as other types of resources and to make DSM implementation more consistent and effective.

CONCLUSION

New England Electric's 1990 C&LM program was an overwhelming success. The benefits provided to customers were substantial, exceeding our most optimistic expectations. We attribute much of this success to profit de-coupling demand side management incentives. The incentive mechanisms approved by regulators in each of the states in which we operate have allowed NEES to aggressively implement an ambitious conservation program and prove that conservation not only helps us manage load growth but provides meaningful profit opportunities.

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USE OF SIMPLE PERFORMANCE INDICES TO HELP GUIDE REVIEW OF DSM PROGRAM PERFORMANCE

Steven Nadel
American Council for an Energy-Efficient Economy
Washington, DC

INTRODUCTION

When demand-side management (DSM) programs are evaluated, the result is typically a thick report that few people have the time to read. While much useful information can usually be found in these reports, important information is often difficult to find, and sometimes is missing. In an effort to help utility managers and regulators acquire a quick "snap shot" of program results, this paper recommends that as part of periodic reports on program results, each utility should calculate and report a series of simple performance indices on each program.

The performance indices are as follows:

1. Participation rate -- annual and cumulative
2. Percentage savings
3. Free rider proportion
4. Indirect/direct cost ratio
5. $/kWh
6. $/kW
7. Ratio of measured savings to estimated savings

Definitions of each index and illustrative applications of each index are discussed below. In discussing these applications, we attempt to describe typical index values for different types of programs. These typical values can be used to help interpret indices for a particular program that is being evaluated. If an index value for a particular program is better than average, it tends to indicate that a program is going well (however, most programs will perform well on at least one index; a general assessment of a program should be based on a review of all of the indices for which data are available). If an index for a program is below average, it indicates that additional research is needed -- first to see if there is a reasonable rationale for the poor index value, and second, to see if program improvements might be justified in order to improve the index value. The indices described here tend to oversimplify complex programs. Thus, these indices cannot provide a full-measure of program effectiveness. However, these indices can help managers and regulators to focus their inquiries, so that a well-rounded perspective on program effectiveness can be obtained in a time-efficient manner.

PARTICIPATION RATE

Definition and Calculation

Participation rate is the number of participating customers divided by the number of eligible customers. Both the number of participating customers and the number of eligible customers are not always easy to quantify.

The number of participating customers is typically calculated in one of three ways: (a) the number of applications processed (this can include multiple applications submitted by a single account), (b) the number of unique account numbers participating in the program (this can include multiple account numbers used by the same home or business), and (c) the number of unique homes and businesses participating in the program. While definition "c" is probably the most useful, it is usually very difficult to calculate because computers can identify two accounts at the same home or business only if the name and address are spelled identically (i.e., do not differ by a single space or period). Definition "b" is much easier to calculate as identical account numbers are generally easy to match with a computer. For this reason, definition "b" is likely to be the preferred definition for most applications. Definition "a" should be avoided because many programs allow and encourage customers to participate more than once, which, using definition "a", makes it impossible to calculate how many eligible customers have not participated in a program.

Two other important issues in calculating the number of participating customers are (a) whether to count pending applications or only completed applications, and (b) whether to count all participants, or only participants who are not "free riders" (free riders are program participants who would have implemented DSM measures even if no program were offered). Since some pending applications never reach completion, it is usually best to count only completed applications. However, if only completed applications are counted, the number of participants in the first year of a program is likely to be very low. Most commonly, in calculating participation rates, no adjustment is made for free riders; instead, the free rider proportion is tracked as a separate performance index (discussed below).

The number of eligible customers for a program may be all of a utility's residential or C&I customers, or it may be a subset of this group (e.g., C&I customers with peak demand greater than 500 kW or new C&I accounts). At times, only a very limited subset is targeted. For example, the eligible population for Massachusetts Electric Company's Enterprise Zone Small C&I Program was C&I customers with annual electricity use of 240 MWh or less which were located in 20 targeted towns. Since approximately one-third of these customers were minimal use accounts (phone booths, billboards) which were highly unlikely to participate in the program, the number of eligible customers was further defined to be C&I customers in the 20 towns who used 5-240 MWh/year (New England Electric System, 1988).

Sometimes, the number of customers eligible for a program are large, but a much smaller number of customers are specifically targeted (the remaining customers may be targeted later, or they may be included in the eligible population for equity purposes: to provide an opportunity for participation, even if participation is unlikely). In cases where the number of eligible and targeted customers differ, it is usually useful to report two participation rates -- one based on eligible customers and one based on targeted customers.

In calculating the number of eligible customers, the same rules should be used as are used for calculating number of participating customers. For example, if definition "c" is used to calculate the number of participating customers, then the pool of eligible accounts needs to be sorted to eliminate homes or businesses with more than one account.

For some programs if may be advantageous to calculate participation rates based on factors besides participating and eligible customers. For example, for equipment rebate programs, it is often useful to portray the participation rate in terms of pieces of equipment that received rebates relative to annual sales of that equipment in a utility's service territory (the latter can be estimated with the help of manufacturers, industry trade associations, and local distributors). Similarly for commercial new construction programs, the participation rate can be calculated as the floor area of buildings participating in a program divided by floor area of all new commercial buildings in the service territory.

Interpretation

In this section on interpreting participation rates, unless otherwise noted, it is assumed that participation rates are based on customer account numbers and that participation figures are not adjusted to eliminate free riders.

Participation rates can be calculated on an annual or cumulative (since program inception) basis. Both measures provide useful information and should be reported. Participation rates vary depending on the program type, number of customers being targeted, incentive strategy, marketing approach, and other factors.

Participation rates for typical programs and for particularly effective programs (denoted "best") are summarized in Table 1. The majority of programs offered to date generally have low participation rates due to limited marketing, limited incentives, start-up difficulties, lack of commitment by the sponsoring utility, and other factors. The presence of a low participation rate (substantially less than the "best programs" column in Table 1) indicates that additional research is needed to see whether the seemingly low participation rate is due to uncontrollable factors

(e.g., participation rates are usually low in the start-up year of a program), or whether program improvements may be beneficial.

In interpreting participation rate figures it is important to bear in mind that the more limited and targeted the eligible population, the easier it is to achieve high participation rates, but these high rates may come at the expense of leaving some customers ineligible for a program.

Table 1. Participation Rates in Typical and "Best" Programs

Program Type	Participation Rate			
	Typical Program		Best Programs	
	Annual	Cum.	Annual	Cum.
C&I				
Audit	1-3%	1-4%	5-20%	60-90%
System-wide rebate				
Based on customer accts				
All customers	1-2	1-4	3-4	5-10
Large customers	1-4		10-20	10-25
Based on pieces of equipment sold	1-3		30-70	
Performance contracting		0-2		15
Comprehensive	1-2		3-15	30-70
Residential				
Audit	1-3	7		25-40
Low-cost retrofits			10-25	30-65
Moderate-cost retrofits		1-6		40
Comprehensive retrofits			4-6	25-85
New construction	2-15		40-80	

Notes:
Annual rates are only for programs that are offered system-wide and are targeted at large groups of customers.
"Cum. = cumulative.
"Comprehensive" programs combine substantial incentives with assistance identifying measures and arranging measure installation.
Blank spaces indicate missing data.

Source: Nadel, 1990a; Nadel, 1990b.

PERCENTAGE SAVINGS

Information on percentage savings is useful because it provides information on the "depth" of savings achieved -- i.e. are substantial savings being achieved by each participant. For DSM programs to have a large impact on future energy and capacity needs, substantial savings per participant will be needed. Programs with high percentage savings can provide insight into ways to maximize energy savings. Programs with low percentage savings

can also be important, if they have high participation rates and/or if they are complemented by additional efforts to achieve additional savings among the same participants.

Definition and Calculation

Energy and demand savings are usually calculated in absolute terms (e.g., kWh and kW). These absolute figures are needed for detailed analysis, but are difficult to interpret unless savings data are referenced to pre-program consumption data (savings of 1000 kWh/year are commendable for a customer using 3000 kWh/year, but are near-meaningless for a customer using 1 million kWh/year). The most common way to reference savings is to calculate savings as a percentage of the average pre-program, whole-building electricity use or demand of participating customers. In this manner, a single index can be used for all programs, regardless of customer size.

In calculating savings, it is useful to distinguish between "gross" savings and "net" savings. Gross savings measures the change in energy use among participating customers between the pre-program and post-program period. Gross savings are not necessarily due to program influences, but can instead be due to the effects of weather, prices, and other factors. Gross savings will also include savings achieved by free riders and will not include savings achieved by "free drivers" (both free riders and free drivers are discussed below). Net savings differ from gross savings in that they explicitly adjust or control for these other factors. This is most commonly done by including a control group in the analysis. The control group is similar to the group of participants, except the control group includes only nonparticipants. Since the control group is affected by the same non-program factors that affect the participant group, by subtracting control group energy savings from participant group gross savings, participant group net savings can be calculated. Since net savings identifies the savings specifically due to program influences, net savings figures should be used whenever possible.

Energy savings may be calculated based on engineering estimates, or on statistical analysis of metered energy use and demand. Engineering estimates are only as accurate as the assumptions used to calculate them. Many times, information on which to base assumptions is not available. Also, engineering estimates often do not adjust for complex interactions among systems (for example savings on lighting reduces internal heat gains, which reduces the need for air conditioning but increases the need for space heating). Furthermore, it is almost possible to calculate net savings for a program from engineering estimates. For these reasons, engineering estimates are often inaccurate.

Statistical analysis of metered data is usually more accurate, than engineering estimates, particularly if the statistical analysis employs a control group of non-participants. Depending on the statistical techniques employed and judgement calls made by

the evaluator, different estimates of net savings attributable to a program may be produced (see Nadel and Ticknor, 1989 for example). Still, when competently done, statistical analysis should produce a reasonable estimate of net energy savings.

Interpretation

Percentage savings for typical programs and particularly effective programs are summarized in Table 2. In general, comprehensive programs which seek to implement all cost-effective conservation measures at a site should reduce participating customer energy use by at least 10% and sometimes 20% or more. Programs targeted only at specific measures, which do not emphasize comprehensive retrofits, usually save less than 10%. When savings are less than 10-20%, it usually means that (a) modifications to the program are warranted in order to capture additional savings, or (b) other complementary programs are needed, to capture additional savings at the same facilities.

Table 2. Percentage Savings in Typical and "Best" Programs

Program Type	Percentage Savings	
	Typical Programs	Best Programs
C&I		
Audits	4-5%	6-8%
Lighting rebate	2-3	
Lighting direct install		10
New constructn comprehensive		20-30
Multiple end-use rebate		7
Mult. end-use comprehensive	10	15-23
Residential		
Audit	3-5	
Low-cost retrofit	3-5	
Moderate-cost retrofit	2-7	
Comprehensive retrofit		10-20
New construction	10	25-40

Blank spaces indicate missing data.
Source: Nadel, 1990a; Nadel, 1990b.

FREE RIDER PROPORTION

Free riders are program participants who would have taken DSM actions anyway, even if no program were offered. Free riders are important because they contribute to program costs but do not

provide any benefits. Nearly all programs have at least some free riders.[1]

Definition and Calculation

There are several types of free riders which are useful to distinguish. First, there are "total" free riders -- program participants whose actions were unaffected by the program. Second, there are "partial" free riders -- program participants who would have taken some action in the absence of the program, but took additional actions due to the program (e.g., they planned to install energy-saving lamps, but due to the program they also installed energy-saving ballasts). Third, there are "temporal" free riders -- program participants who would have taken DSM actions at some time in the future, but due to the program, they speeded up their implementation decision.

Free riders may be estimated by customer surveys, analysis of sales data relative to similar areas not eligible for a program, or statistical analysis.

Customer surveys are probably the least accurate way to measure free riders, as they suffer from a number of problems including poor recall of purchase decisions made many months ago, a tendency to try to please the interviewer, and a tendency to exaggerate one's plans to pursue socially desirable behavior (saving energy cost-effectively) in the absence of program incentives. The accuracy of customer surveys can be improved by asking questions a number of different ways, and using the different responses to establish a likely range for the proportion of free riders. This issue is discussed more extensively by Nadel (1990a). Survey data can be used to separately estimate the different types of free riders, if the appropriate questions are asked.

Sales data can be used to estimate free riders for equipment rebate programs. Data can be obtained from manufacturers and distributors comparing sales of efficient products within the program area to nearby areas not served by the program. Sales data can identify free riders for individual types of equipment (including total and partial free riders), but can not usually be used to quantify temporal free riders.

Statistical analysis offers probably the most accurate way to measure free riders. This analysis, which typically involves

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[1] It should be noted that in addition to free riders, many programs also have "free drivers" -- people who did not participate in a program, but were induced by the program to take DSM actions (e.g., program publicity, or the impact of the program on local availability of efficient equipment, sparked the DSM action). Free drivers enter into the determination of net savings (discussed above). Data explicitly quantifying free drivers is rarely collected.

analyzing conservation actions by program participants and non-participants with probabilistic models, is too complex to describe here -- Train et. al. (1985) provide a general description of the approach. Statistical analysis can identify free riders for each DSM measure, thereby identifying both total and partial free riders. Thus far, statistical analysis has not been used to identify temporal free riders.

Interpretation

The free rider proportion for DSM programs can vary from 0% to 80% or more. Approximately 30% free riders is typical for measures included in DSM programs (Nadel, 1990a; Nadel, 1990b). Lower free rider proportions can be obtained by promoting advanced equipment that currently has very low market share (this is illustrated in Table 3). However, by limiting incentives to a few products, participation rates are likely to be low for several years. Alternatively, a low free rider proportion can often be obtained by limiting incentives for rapid payback measures (e.g., one year payback or less), where free riders are likely, and increasing incentives for longer payback measures (Weedall and Gordon, 1990). Finally, limited research indicates that free riders may be lower for comprehensive direct installation programs, than for rebate programs (an example is shown in Table 3).

Table 3. Free Rider Estimates for NEES Lighting Programs

Measure	Free Rider %
Fluorescent lamps	65%
Fluorescent ballasts	20
Compact fluorescents	5
HID retrofits	10
Reflectors	17
Direct installation package	12

Source: Nadel, 1990a.

Conversely, high free rider proportions are not always bad. If costs per participant are low and/or benefits per participant are high, even programs with a large number of free riders may be cost-effective. For example, New England Electric found that the benefit-cost ratio of its C&I lighting rebate program was 2:1, even though free riders represented 60-80% of program participants (Nadel, 1988). Thus, the presence of a high free rider rate indicates that further research is needed. While utilities should seek to lower free rider proportions when possible, if efforts to limit free riders severely restrict participation, higher free rider rates may be acceptable. In order to decide whether a low or high free rider approach is best for a particular program, the relative energy savings and cost-effectiveness of the different approaches need to be compared.

INDIRECT/DIRECT COST RATIO

Definition and Calculation

Direct program costs are generally defined as monies paid to customers and contractors towards the installation of DSM measures. Indirect costs are all other program costs including funds paid for staff, marketing, consultants, etc. The indirect/direct cost ratio is simply the indirect costs divided by the direct costs -- calculated either on an annual basis, or a present-value cumulative basis. Typically, costs to plan and evaluate a specific program are included as part of indirect costs. Costs to prepare a general integrated resource plan are usually charged to the company-wide planning function and are not included in an accounting of program-specific costs. In calculating direct costs, most utilities include only the utility share of measure costs, because data on customer costs are usually not available. A few utilities include customer costs in addition to utility costs. In future years, it is likely that more and more utilities will collect customer cost data, and that calculations will be based on the sum of utility and customer costs. Further discussion of these issues can be found in Berry (1989).

Interpretation

For purposes of this section, we assume that the indirect/direct cost ratio is calculated only for utility costs, and that customer costs are not included. We use this definition because it is the approach that is most widely used today.

Typical indirect/direct cost ratios are shown in Table 4. These results indicate that typical programs will have an indirect/direct cost ratio of approximately .25-.40. Ratios will be higher during the start-up periods of programs. A few programs also report higher ratios after many years of program operation, as marketing becomes more difficult in the last years of a long-term program (Berry, 1989). High ratios are also likely (and desirable) for technical assistance and marketing programs that pay little or no financial incentives. Since financial incentives are not paid, direct costs are zero, and the indirect/direct cost ratio is infinitely large. Thus, high indirect/direct cost ratios (greater than .40) can be expected during the first 1-2 years of a program and for programs with little or no direct costs. If the ratio is greater than .40 after several years, further investigation is often warranted.

$/KWH AND $/KW

Definition and Calculation

Cost per kWh and kW provide a quick approximation of program cost-effectiveness. Calculation of these indices does not substitute for a detailed cost-benefit analysis.

Table 4. Indirect/Direct Cost Ratios for Selected Programs.

Utility/Program	Indirect/Direct Cost Ratio Year 1	Year 2	Year 3	Year 4
Central Maine Power				
Residential retrofit loans	.74	.28	.20	
Residential energy audits	.93	.57	.18	
Appliance rebates	1.84	.84		
Water heater wraps	.52	.38		
Motor rebates	1.34	.36		
Puget Power				
Comm'l insulation	7.57	1.72	.72	.35
Comm'l lighting	1.06	.51	.08	
Seattle City Light				
Home energy loan				.24
Low income electric				.35
Multifamily conservation				.25
Water heater rebate				.48
Water heater retrofit direct installation				.14
Wisconsin Electric				
Smart money (C&I)		.32		

Blank spaces indicate missing data.
Source: Berry, 1989.

Costs per kW are calculated by simply taking program costs on an annual or cumulative present value basis, and dividing by kW savings. Generally, savings are taken at the customer level, and do not include adjustments for transmission and distribution losses on the utility side of the meter, nor are utility reserve margin requirements taken into account. To be most useful, these calculations should include both direct and indirect costs. Savings should be estimated for the time of the system peak (i.e., not all lights will be on at the time of the peak, so coincident peak savings will be less than the nominal reduction in the connected lighting load). Generally only utility costs are included in these calculations, because most utilities do not collect data on customer costs. As customer cost data becomes available, it should be included in the calculations and reference values adjusted accordingly.

Costs per kWh are generally calculated on an average basis, over the life of the measures installed. This is generally done by assuming that annual program costs are financed with a loan, with an interest rate equal to the utility cost of capital (typically 6% real [net of inflation]), and a loan term equal to the average installed measure life. The average cost per kWh is the annual "loan payment" divided by the kWh savings in one year. As with costs per kW, costs per kWh should be based on both direct and indirect costs. Kwh savings should be at the customer level. To the extent data on customer costs are available, they should generally be included and figures labeled accordingly. Average measure life is not the rated engineering life of a product, but

rather, the length of time the measure is likely to be installed in a facility (often equipment is removed before the end of its engineering life due to remodeling and other building changes). Estimates of installed lives for many measures can be found in Gordon et. al. (1988).

Interpretation

Costs per kW and kWh can be interpreted in two ways. First, costs can be compared to reference values based on utility avoided costs ($/kWh) and to the cost of new power plants ($/kW). Whenever utility DSM program costs are substantially less than these reference values, there is a excellent chance a program will be cost-effective from the utility perspective (only when customer costs are included in the calculations can cost-effectiveness from the total resource perspective be determined[2]). Of course, a definitive estimate of cost-effectiveness requires a full cost-benefit analysis. Such an analysis is especially needed where program costs and the reference value are similar. In particular, use of the $/kWh index does not give any credit for kW savings (and visa versa). Programs which are not cost-effective based on kW or kWh savings alone, may be cost-effective when both benefits are included. In examining costs per kW, costs for peak clipping measures should be compared to the cost of new peaking plants, while costs of baseload measures should be compared to baseload plants.

Second, costs per kW and kWh can be compared to values from other programs around the country. Some of these values are summarized in Table 5. Where program costs are significantly in excess of these values, explanations should be sought. Many times a reasonable explanation will be available. For example, the typical rebate program pays incentives equal to less than half of measure costs -- where higher incentives are paid, the cost to the utility will be higher. However, where no reasonable explanation exists, program modifications should be investigated. Where program costs are less than these values, it may indicate that "cream skimming" is taking place, meaning that low cost conservation measures are being implemented, but cost-effective measures with somewhat higher costs are being ignored.

A review of the data in Table 5 indicates that C&I programs are often less expensive per kWh than residential programs and that comprehensive programs (which involve extensive services in addition to incentives) are more expensive per kWh than simple programs. However, as shown in Tables 1 and 2, comprehensive programs generally have higher participation rates and percentage savings. Thus, comprehensive programs provide greater savings, but these extra savings come at a cost.

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[2] The different cost-effectiveness perspectives, including the utility and total resource perspectives are discussed in Krause and Eto, 1989.

Table 5. Utility Costs per kW and per kWh for Typical Programs

Program Type	Typical Utility Cost* $/kW	$/kWh
C&I		
Rebate	$250-350	$.01
Loan		.008
Performance contracting	$1090	.028
Comprehensive		.03
Residential		
Low-cost retrofit		.02-.04
Moderate-cost retrofit		.06-.08
Comprehensive retrofit		.02-.05
Compact fluorescent		.025
New construction		.02-.03

* For C&I programs, costs are median costs for programs examined in Nadel, 1990a.
Blank spaces indicate missing data.
Source: Nadel, 1990a; Nadel, 1990b.

RATIO OF MEASURED TO ESTIMATED SAVINGS

The ratio of measured savings (as determined by statistical analysis of electricity consumption data) to estimated savings (typically calculated using engineering estimates) indicates how close energy savings estimates used in program planning come to actual program results. As discussed previously, measured savings should generally be determined by comparing savings for a group of participants to a control group of nonparticipants.

Interpretation

Measured savings and estimated savings should be in fairly close agreement (within 10% of each other). Where the two figures differ substantially, either the analysis procedures used to calculate the original estimates need correcting, or the program needs to be improved, so results more closely correspond to the earlier estimates. Comparisons of measured savings and estimated savings for several programs are summarized in Table 6. At times, the discrepancy between the two figures is substantial. Often this discrepancy is explained by inadequacies in the engineering estimates. Common mistakes include failure to adjust savings estimates for use of secondary fuels (e.g., some of the savings are taken in the form of wood, not gas or electricity), failure to allow for temperature setbacks, misestimating equipment operating hours, and erroneously assuming that installed equipment will operate perfectly every time. At times the discrepancy can be explained by problems in program operations -- problems such as poor quality control in measure installation, and improper commissioning of measures.

Table 6. Measured Vs. Estimated Savings for Selected Programs.

Program	Measured as % of Estimated	Reasons for Difference
Residential Retrofit:		
CMP Pkdg WZ	36%	Use of secondary fuels
GPU RECAP	22-44%	
NU Perform. Contracting	22%	Mat'l & work quality
BPA Weatherization	53%	Secondary fuels, occupant interactions
NEES Weatherization Pilot	>100%	
Residential New Construction:		
SW Public Service	131%	
BPA Super Good Cents	<100%	Baseline getting more efficient.
C&I Retrofit:		
SCE Hardware Rebate	96%	
BPA CIPP - Sm. & Med.	36%	
BPA CIPP - Lg.	109%	
BPA Institutional	~60%	Optimistic estimates.
NEES Small C&I	~101%	Small customers saved less than expected, lg. customers saved more.
C&I New Construction:		
BPA Energy Edge	72%	QC and commissioning problems

Source: Nadel, 1990b.

DISCUSSION

The definitions and data discussed above provide a good starting point for assessing the effectiveness of programs. By using these definitions and interpretive data, utility managers and regulators can see which programs are going well, and which require further investigation.

However, the definitions and data summarized in this report still need refinement. Definitions need to be refined and standardized so that all utilities can calculate values unambiguously. A taskforce has recently been formed to develop these definitions (Hirst, 1990).

Furthermore, utilities often do not calculate and report these indices, many gaps remain in our interpretive data, and even the data we do have can benefit from further refinement. As more and more utilities report these index values for their programs, the database of interpretive data can be expected to grow quickly.

In addition to the program specific indices discussed here, it might be useful to develop indices to measure a utility's overall performance in the DSM area. Illustrative indices and

examples are discussed in Geller and Nadel (1989). Additional work to refine these indices would be useful.

ACKNOWLEDGEMENTS

Much of the work summarized in the tables of this paper were originally developed as part of a project sponsored by the New York State Energy Research and Development Authority. Additional funding for this work was provided by the John D. and Catherine T. MacArthur Foundation. Eric Hirst provided helpful comments on an earlier draft of this paper.

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USE OF SIMPLE PERFORMANCE INDICES TO HELP GUIDE REVIEW OF DSM PROGRAM PERFORMANCE

Steven Nadel

American Council for an Energy-Efficient Economy

Washington, DC

NARUC Third National Conference on Integrated Resource Planning

PROBLEM

* DSM evaluation reports often thick, difficult to read

* Important information often missing

* Utility managers and regulators need a time-efficient way to review program effectiveness.

PERFORMANCE INDICES

* Can provide a quick "snapshot" of program effectiveness.

* Point out areas requiring additional investigation -- often there is a reasonable explanation for poor index values.

* Point out areas where program improvements may be beneficial.

PERFORMANCE INDICES

1. Participation rate -- annual and cumulative
2. Percentage savings
3. Free rider proportion
4. Indirect/direct cost ratio
5. $/kWh
6. $/kW
7. Ratio of measured savings to estimated savings

Participation Rate

Participation rate = $\frac{\text{Number of participating CUSTOMERS/ITEMS}}{\text{Number eligible}}$

* Use to see how many customers are being reached by a program and how many are being missed.

Issues:

* Applications vs. accounts vs. customers
* Net vs. gross participation
* Annual vs. cumulative
* Determining # eligible
  - All customers in a class?
  - Customers of a certain type or size?
  - New commercial square footage?
  - New motors, ballasts, A/C, etc. sold in territory?

Interpretation:

* If values significantly below those achieved by the most effective programs of that program type, additional research is required.

Table 1. Participation Rates in Typical and "Best" Programs

Program Type	Participation Rate			
	Typical Program		Best Programs	
	Annual	Cum.	Annual	Cum.
C&I				
Audit	1-3%	1-4%	5-20%	60-90%
System-wide rebate				
Based on accounts				
All customers	1-2	1-4	3-4	5-10
Large customers	1-4		10-20	10-25
Based on pieces of equipment sold	1-3		30-70	
Performance contracting		0-2		15
Comprehensive	1-2		3-15	30-70
Residential				
Audit	1-3	7		25-40
Low-cost retrofits			10-25	30-65
Moderate-cost retrofits		1-6		40
Comprehensive retrofits			4-6	25-85
New construction	2-15		40-80	

Percentage Savings

$$\text{Percentage savings} = \frac{\text{Savings due to program}}{\text{Pre-program elec. use of partic. customers}}$$

Use to explore "depth" of savings being achieved.

Issues:

* Net vs. gross
* Engineering estimates vs. impact evaluation

Interpretation:

If shallow (< 5-10 %) need to complement with enhanced/other program approaches.

Table 2. Percentage Savings in Typical and "Best" Programs

Program Type	Percentage Savings	
	Typical Programs	Best Programs
C&I		
Audits	4-5%	6-8%
Lighting rebate	2-3	
Lighting direct install		10
New constructn comprehensive		20-30
Multiple end-use rebate		7
Mult. end-use comprehensive	10	15-23
Residential		
Audit	3-5	
Low-cost retrofit	3-5	
Moderate-cost retrofit	2-7	
Comprehensive retrofit		10-20
New construction	10	25-40

Free Rider Proportion

Estimate through:

1. Statistical analysis
2. Equipment sales data in and outside service area
3. Participant or dealer surveys
    a. Least accurate
    b. Accuracy improved if ask indirectly and if ask question several ways:

        1. LAST YEAR, what proportion of your motor purchases were energy-efficient?
        2. THIS YEAR, what proportion of your motor purchases were energy-efficient?
        3. Why the difference?
        4. How influential was the rebate in your decision to purchase an energy-efficient motor?
        5. If the rebate were not available, would you still have purchased an energy-efficient motor?

Free riders often reported as a range.

Free Riders - Interpretation

* Typical program has approximately 30% free riders.

* Free rider proportions generally high when:

    a. Equipment being promoted has high current market share.

    b. Measures with rapid paybacks are promoted.

* Even programs with high free rider proportions can be cost-effective in some situations.

Table 3. Free Rider Estimates for NEES Lighting Programs

Measure	Free Rider %
Fluorescent lamps	65%
Fluorescent ballasts	20
Compact fluorescents	5
HID retrofits	10
Reflectors	17
Direct installation package	12

Indirect/Direct Cost Ratio

Direct - payments to customers and contractors for measures.

Indirect = all other costs (staff, marketing, evaluation, etc.)

Issues:

* Need to be clear whether customer contributions are included in direct costs.

Interpretation:

* In first year, indirect/direct ratios of over 100% are common.
* Established programs generally have ratios less than 40% (25-35% is typical)
* Ratio not useful for marketing-only programs with no direct utility costs.

Table 4. Indirect/Direct Cost Ratios for Selected Programs.

Utility/Program	Indirect/Direct Cost Ratio Year 1	Year 2	Year 3	Year 4
Central Maine Power				
Res. retrofit loans	.74	.28	.20	
Res. energy audits	.93	.57	.18	
Appliance rebates	1.84	.84		
Water heater wraps	.52	.38		
Motor rebates	1.34	.36		
Puget Power				
Comm'l insulation	7.57	1.72	.72	.35
Comm'l lighting	1.06	.51	.08	
Seattle City Light				
Home energy loan				.24
Low income electric				.35
MF conservation				.25
Water heater rebate				.48
Water heater retrofit direct installation				.14
Wisconsin Electric				
Smart money (C&I)		.32		

$/kWh AND $/kW

$/kW = Program cost/coincident peak savings

- Ignores energy benefits

Levelized $/kWh = @PMT(Cost, Discount Rate, Life)/ kWh Savings

- Calculates cost to utility if only utility costs included; to society if customer costs also included.
- Ignores capacity benefits

Issues:

* Inclusion of direct and indirect costs.
* Inclusion of customer costs.
* Maximum vs. average vs. coincident kW savings.
* Inclusion of T&D, reserve margins
* Discount rate is cost of capital.
* Measure life is average installed measure life.

$/kW AND $/kWh - Interpretation

* $/kW can be roughly compared to baseload, intermediate, or peaking plants.

* $/kWh can be roughly compared to avoided costs
  - Program likely to be cost-effective from Utility perspective if customer costs not included.
  - Program likely to be cost-effective from Total Resource perspective if customer costs are included.

* Can compare to results of similar programs:
  - Residential programs generally more costly than C&I programs.
  - Comprehensive direct installation programs generally more costly to utility than rebate programs.

* Very low costs per unit saved may indicate "cream-skimming."

Table 5. Utility Costs per kW and per kWh for Typical Programs

Program Type	Typical Utility Cost* $/kW	$/kWh
C&I		
Rebate	$250-350	$.01
Loan		.008
Performance contracting	1090	.028
Comprehensive		.03
Residential		
Low-cost retrofit		.02-.04
Moderate-cost retrofit		.06-.08
Comprehensive retrofit		.02-.05
Compact fluorescent		.025
New construction		.02-.03

Ratio of Measured Savings to Estimated Savings

Should be close to 1.

Where off, signifies changes needed in engineering estimates or in program installation/quality control procedures:

- Check assumptions in engineering calculations
- Factors not included in engineering estimates which should be:
  - Interactions with cooling and heating needs
  - Use of supplemental fuels
  - Calibration or maintenance factors
- Improve installation training and/or QC efforts.

Table 6. Measured Vs. Estimated Savings for Selected Programs.

Program	Measured as % of Estimated	Reasons for Difference
Residential Retrofit:		
CMP Pkdg WZ	36%	Use of secondary fuels
GPU RECAP	22-44%	
NU Perform. Contracting	22%	Mat'l & work quality
BPA Weatherization	53%	Secondary fuels, occupant interactions
NEES Weatherization Pilot	>100%	
Residential New Construction:		
SW Public Service	131%	
BPA Super Good Cents	<100%	Baseline getting more efficient.
C&I Retrofit:		
SCE Hardware Rebate	96%	
BPA CIPP - Sm. & Med.	36%	
BPA CIPP - Lg.	109%	
BPA Institutional	~60%	Optimistic estimates.
NEES Small C&I	~101%	Small customers saved less than expected, lg. customers saved more.
C&I New Construction:		
BPA Energy Edge	72%	QC and commissioning problems

Discussion

* Indices provide useful information to better target inquiries.

* Definitions require additional refinement.

* As additional utilities calculate and report these indices, additional interpretive data will become available.

* Might also be useful to develop indices to rate a utility's overall DSM effort.

"NARUC PROJECT ON RENEWABLE ENERGY TECHNOLOGIES"

Third Conference on Integrated Resource Planning
Santa Fe, New Mexico

April 8, 1991

by

Henry G. Williams[1]

INTRODUCTION

This paper describes a project concerning renewable energy technologies which NARUC's Committee on Energy Conservation has been undertaking. The project has been supported by a Department of Energy grant.

The project's consultants[2] have prepared a report which summarizes the project and this paper reflects that report.

ACKNOWLEDGEMENTS

Many people have contributed to our renewables project and their roles are gratefully acknowledged. Special thanks are given to the U.S. Department of Energy and particularly Lou Divone, Elaine Guthrie and Ken Schaefer. Lou and Elaine initially got the committee interested in renewables and Ken has been working with us over the past several months.

We are also grateful to the people who participated in the workshop we conducted last June. Their aggregate experience in renewable energy of more than 300 years provided insight and ideas for the consultant's report.

Thanks are also due to Mike Foley of NARUC and to all the Commissioners and staff who have helped the renewables project.

Finally, I want to thank our consultants, Carlo LaPorta and David Moskovitz who organized and conducted the workshop and prepared a report.

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[1] Commissioner, New York State Public Service Commission, Albany, NY

[2] Carlo LaPorta and David Moskovitz, R & C Enterprises, Washington, D.C.

THE RENEWABLES PROJECT

My records indicate that the Committee on Energy Conservation's interest in renewables began at our summer committee meeting in 1989 when Lou Divone of the Department of Energy talked with us about DOE's desire to form a closer relationship with NARUC on renewables. The committee responded in a positive manner and established a task force, which I was asked to chair.

At our 1989 annual meeting in Boston, the Committee approved a grant proposal to DOE. The proposal described a project having two goals: 1) To identify the factors that have led to success or failure of renewable energy technologies in various energy markets; and 2) To develop an agenda on renewable energy and utility regulation for NARUC.

To achieve the project's goals we proposed to conduct a workshop, comprised of NARUC members, regulatory staff, and representatives of utilities and vendors of renewable energy technologies. We contracted with Carlo LaPorta and David Moskovitz and they organized the workshop, conducted it and prepared a report which is based primarily on the workshop.

Note: Since the report was not officially presented to the Committee on Energy Conservation until after this paper was prepared for inclusion in the proceedings of this conference there will be a "surprise" conclusion.

I will now review the highlights of the consultant's report.[3]

RENEWABLE ENERGY CONTRIBUTIONS, COSTS AND POTENTIAL

Renewable energy technologies contribute power to electric utility grids in baseload, intermediate and peaking facilities powered by hydro, biomass, wind, geothermal and solar energy resources. Dispersed solar, wind, geothermal and biomass technologies are also offsetting demand for electricity by providing energy directly to end-users. Thus, renewables are important on both sides of the meter, as both demand and supply measures.

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[3] Subcommittee on Renewable Energy, "Renewable Energy & Utility Regulation", NARUC, Washington November, 1990

According to a 1990 DOE report, The Potential of Renewable Energy: An Interlaboratory White Paper[4], renewables in 1988 contributed 6.7 quadrillion British thermal units to the total national energy consumption of 82 quadrillion Btu (quads). This amounted to 8.2 percent of national energy supply.

Hydroelectric power (3.1 quads), geothermal electric power, and biomass energy for electricity and thermal applications together accounted for 6.6 quads of the energy contribution. These technologies are well-proven, and have operating characteristics that make them similar to fossil energy power plants that are familiar to utilities, regulators and energy users.

A 1989 study by Public Citizen reported that total renewable energy electric power capacity had grown to 97,443 megawatts by the end of 1988.[5] This figure matches total nuclear power capacity.

The cost of energy from renewable energy technologies depends on site-specific factors as well as capital and operation and maintenance costs, and costs of land and capital. Renewable energy technologies deliver energy at levelized costs ranging from 3 cents per kilowatt for some technologies to 55 cents for others that are not commercially ready. These cost figures include electricity producing technologies in power stations and in small dispersed systems.

Every state has a renewable energy resource base to exploit. Available renewable energy resources far exceed U.S energy demand and will sustain a rapid transition away from conventional energy resources as reserves dwindle and become more expensive to extract or to develop.

Predicting how much renewable energy capacity will expand over the next decade is difficult. One estimate is that the current contribution of about 8 percent could double in the next decade if incentives and favorable policies are enacted. The potential exists for states to make estimates related to their own circumstances, but only a few states are conducting such assessments.

Certain renewable technologies have gained solid market/investor confidence and they will undoubtedly expand as the economy requires more energy. These technologies include:

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[4] The Potential of Renewable Energy: An Interlaboratory White Paper. U.S. Dept. of Energy, Washington, 1990.

[5] Rader, Nancy. Power Surge. Public Citizen. Washington, 1990

Hydroelectricity
Hydrothermal geothermal
Direct combustion biomass
Waste-to-energy
Small remote photovoltaic systems

A longer list of technologies which have proven technical capacity and are gaining market acceptance. These include:

Multiple wind turbine energy plants
Individual wind turbines
Moderate temperature geothermal
Remote photovoltaic systems
Passive solar building design

The Public Citizen survey referred to above identified eight states that rely on renewable energy for more than 20 percent of their energy supplies. Washington is the leader, with over half of its energy coming from renewables.

STATES REALIZING RENEWABLE ENERGY POTENTIAL
(% of Total Energy from Renewables)

Washington	53.54%
Oregon	47.46
Idaho	46.49
South Dakota	29.42
Montana	28.97
Maine	27.00
Vermont	22.64
New Hampshire	20.21
ALA, ARK, MISS, GA, CA, NC, TENN, SC, NY	10-20%

The Public Citizen survey reported that 14 states have less than 10 megawatts of renewable energy electric capacity and 18 states receive less than 2 percent of their energy from renewables.

While many states have the resource base to contribute more renewable energy to their economies, a more comprehensive review on a state-by-state basis is required to assess actual renewable resource potential under current conditions and as contrasted with changes in regulatory and legislative policy.

FACTORS AFFECTING DEVELOPMENT OF RENEWABLES

SUCCESS FACTORS

California and Maine are examples of states where renewable energy market penetration has been substantial. With regard to utility regulation five main success factors standout:

1) Clearly articulated commission policies and regulatory pricing decisions that reflect the particular operating characteristics of renewable energy systems.

2) Standard offer contracts with pricing options that meet the needs of a wide range of renewable resource projects and compensate high value energy output.

3) An adequate renewable resource base well matched with demand profiles and need for new energy supplies.

4) Learning curve cost reductions due to high installation rates and associated technical advances.

5) A willing utility combined with an aggressive, competent manufacturer/developer of renewable energy technology possessing stamina to push past licensing and financing hurdles.

BARRIERS

If renewables are so good, why aren't they moving into the market faster? Four key barriers are:

1. Regulators do not have current and reliable information about cost, potentil, availability. and development requirements of renewable energy resources.

2. Qualifying facility screening, pricing and contracting practices undervalue renewable energy resources; this barrier includes programs that miscalculate avoided costs due to overemphasis on near-term energy costs and bidding programs with the same bias.

3. Utilities are disinterested or skeptical about faster deployment of renewable energy technologies.

4. Expiration or uncertainty about government incentives and terms that support renewable energy resource development.

KEY PUBLIC POLICY LESSONS

The workshop discussions held last June led to the identification of five energy policy lessons regarding renewables. They are:

1. Regulatory policy strongly affects renewable energy development.

2. Renewable energy development requires special attention to the cost and operating characteristics of the technologies; and designers of least cost bidding and other programs must take this into account.

3. The rate of change in the cost and performance characteristics of renewable energy technologies generally exceed the ability of regulatory bodies to track it, leaving regulators unaware of cost effective renewable energy potential.

4. Production and installation learning curve economies figure prominently in determining the delivered cost of energy from renewables.

5. Reviews of renewables and utility regulation often ignore small dispersed renewable energy technologies.

TOWARD A RENEWABLES AGENDA FOR NARUC.....

The first two sections of the report, which I have described, relate to the current status of renewable energy technologies and the key factors that govern their progress in the market. Although substantial progress in the commercial application of renewable energy technologies has occurred in the past decade, positive actions by State utility regulators are needed to realize the full potential of renewables. To assist regulators, a Renewable Energy Agenda which reflects the policy lessons, successes and barriers discussed in the report are suggested. The program items and adjunct activities included in the Agenda may be undertaken in accord with the preferences of NARUC and individual State utility regulators. It is anticipated, however, that workshops and other adjunct activities will be conducted concurrently with the various program items.

There are five program items in the agenda and several adjunct activities to complement the agenda, as follows:

1. INFORMATION NEEDS OF REGULATORS

   A significant impediment to the development of renewables is lack of current information regarding cost, potential availability and performance of renewable energy systems.

A. NARUC should develop an information system for utility regulators.

B. NARUC should prepare a model to use as a guide for the content and formatting of the information regulators need.

C. NARUC should undertake to collect and disseminate a "State of Renewable Energy Resources" Report, annually.

D. NARUC should hold conferences and workshops on issues concerning renewable energy.

E. NARUC should prepare a report detailing contractual and financing requirements of renewable energy projects.

F. NARUC should consider making information available through an on-line electronic data system.

2. INVENTORY OF IN-DEPTH CASE STUDIES

An inventory of information on specific practices is needed in order to address biases against renewables.

A. NARUC should prepare in-depth case studies to identify specific aspects of current regulatory practices.

B. NARUC should work with 6-12 states having undeveloped renewables and prepare studies of the regulatory practices that are hindering development of renewables.

C. NARUC should review the role of utility companies in development of renewables.

D. NARUC should coordinate its efforts with other interests such as environmental externalities.

3. POTENTIAL OF DISPERSED RENEWABLE ENERGY SYSTEMS

A promising, near-term application of renewables is use of dispersed systems for generating electrical and thermal energy for use on-site.

A. NARUC should collect and disseminate information about dispersed renewable energy systems.

B. NARUC should study how on-site renewables are being incorporated in Integrated Resource Planning actions.

C. NARUC should study regulatory and utility barriers to expansion of small on-site renewables.

4. NEXT RENEWABLE ENERGY STATES

Many states are not fully exploiting the potential they already have to use renewable energy resources.

A. NARUC should create a "Next Renewable Energy States" program designed to hasten development of renewables in states where conditions are most promising.

B. NARUC should invite states to participate in the "Next...States" program.

C. NARUC should identify a team to work at the state level on the "Next...States" program.

5. ENVIRONMENTAL AND TAX LEGISLATION

In addition to regulatory policies, tax and environmental policies can provide strong incentives or disincentives for use of renewables.

A. NARUC should review existing and proposed tax policies related to development of renewables.

B. NARUC should review effects of environmental policies on renewables.

C. NARUC should recommend amendments to policies that are inconsistent with development of renewables.

In addition, it is recommended that NARUC should convene workshops or seminars regarding renewables in relation to such topics as bidding, Integrated Resources Planning and externalities assessments.

Three fundamental findings form the basis of the renewables agenda:

1. Renewable energy resources have demonstrated competitiveness, and are making a substantial contribution to energy supply; but, very large untapped potential remains. Both centralized and dispersed renewable energy systems can play major roles in providing least cost energy resources with minimal environmental impact.
2. The key to the development of these resources lies in the hands of the states, and in particular, with state utility regulators. Often, however, adequate information about renewable energy resources and their deployment is lacking.
3. The federal government can undertake initiatives that will accelerate development of renewable energy resources.

NEXT STEPS

The Committee on Energy Conservation has prepared a proposal to DOE for the next phase of the renewables project. The next phase will include projects that assist and encourage regulators in the further development of renewable energy technologies.

It is expected that a detailed workplan will be drafted prior to NARUC's Summer meeting. Information needs of regulators will undoubtedly be among the items we will address, but at this time the committee has not finalized the full scope of its renewables project for the coming year.

Prepared for the Proceedings on February 15, 1991
Questions or comments regarding this
paper may be addressed to:
Commissioner Henry G. Williams
NYS Public Service Commission
3 Empire State Plaza
Albany, NY 12223

GUIDELINES FOR THE ECONOMIC ANALYSIS OF RENEWABLE ENERGY TECHNOLOGY APPLICATIONS

Frederick H. Morse
Morse Associates, Inc.
1808 Corcoran St., N.W.
Washington, DC 20009

ABSTRACT

In October, 1987, technical and economic experts from member nations of the International Energy Agency (IEA) met at the IEA Workshop on the Economics of Renewable Energy Technologies in Montebello, Quebec, Canada to develop a common approach to the economic analysis of renewable energy technologies (RETs).

More than 100 experts from IEA member countries attended the Workshop. Participants met in small groups, according to technology and sector, and through intensive discussions, reached consensus on the technology cost and performance parameters, definition of terms, and the impact of expected technology improvements on the economics of RETs. The outcome of the workshop was a recommended approach for specifying the costs of renewable energy projects and determining their economic attractiveness. After two years of additional work, this recommended approach has been converted to a set of guidelines for the economic analysis of renewable energy technologies. These Guidelines for the Economic Analysis of Renewable Energy Technologies, which will be available in Spring 1991 as an Organization for Economic Cooperation and Development (OECD) publication, represent a major step toward a consistent and structured methodology for the economic analysis of renewable energy technologies.

1. INTRODUCTION

By the mid-1980's, renewable energy research and development programs had been underway for a decade. Significant progress had been made in understanding the technical feasibility of these technologies, in improving their performance, increasing their reliability, and reducing their cost.

Progress was more limited, however, on the issue of determining the economics of renewable energy technologies (RETs), and no consistent, widely-accepted approach to economic analysis had been developed. Although many government agencies and private companies had performed assessments of the cost of different renewable energy technologies, the results were often challenged. A major reason for this was the lack of a comprehensive and consistent approach to the cost and performance parameters and the use of analysis models. Unlike the conventional energy arena where financial evaluations have been routinely performed for decades, analysts were unclear as to which cost factors must be included in determining project costs and which

economic indicators and analysis models should be applied when assessing the viability of renewable energy technologies.

This gap became even more obvious when, during 1985 and 1986, the International Energy Agency (IEA) attempted to prepare an assessment of the technical, commercial and economic status of renewable energy. It was discovered that there was little credible data on the costs of renewable energy and, even more important, no consensus on methodology.

To address these needs, the IEA sponsored a workshop on the Economics of Renewable Energy Technologies, which was held October 18-21, 1987 at Chateau Montebello in Quebec, Canada. Experts from a number of IEA-member countries were selected to lead the effort in each of the technology and application sector areas. Additional experts were identified by IEA-member countries for the RETs and application sectors of greatest interest nationally.

The results of this Workshop have been compiled in Guidelines For The Economic Analysis of Renewable Energy Technology Applications. It will be published in the Spring, 1991 by the Organization for Economic Cooperation and Development (OECD) in Paris.

2. APPROACH

This paper discusses the methodology which was developed to evaluate potential investments in renewable energy technologies, as well as for use by utilities in their integrated resource planning. It involved: 1) development of complete technology cost and performance formats which specify and define all relevant parameters needed to calculate the cost of renewable energy systems and the energy output, and 2) specification of appropriate analysis methodologies for the three application sectors (building, industry and utility), identifying their economic indicators, and defining all required terms.

In addition, to test and refine the formats and methodologies and to illustrate their application, case study examples were developed for RETs which are commercially available or in advanced stages of development. Each case study represented a typical application of a RET in one of the three sectors -- for example, a wind energy project in the electric utility sector. Twenty-one case studies were prepared prior to and at the workshop, three of which will be included in the publication as examples.

3. METHODOLOGY OVERVIEW

The methodology discussed here represents a consistent, structured, generalized approach which is well-suited for feasibility-level analyses in both the public and private sector. Fig. 1 is a diagram of the recommended methodology and shows the relationship between the inputs, the cost and performance formats, and the sector analysis models.

Information on the cost of energy from renewable energy technologies and information required to make effective energy investment decisions is provided by one or more quantities called

economic indicators. These economic indicators are calculated using appropriate economic analysis methodologies (equations) for the building, industry or utility sector. The numerical quantities required to solve these equations are compiled in the specially-developed cost and performance parameter formats for the eight renewable energy technologies covered: active solar, passive solar, photovoltaics, biomass, solar thermal, small hydro, geothermal, and wind.

3.1 Economic Analysis Model Description

The sector economic models are based on discounted cashflow analysis. In this technique, an annual schedule is estimated for both revenues (or benefits) and costs over an assumed investment time horizon or project lifetime. Revenues and costs can be calculated in either current or constant year monetary units. These currency streams are discounted and summed to a specified year using an appropriate discount rate.

The cashflow analysis model may be varied so as to calculate a number of economic indicators

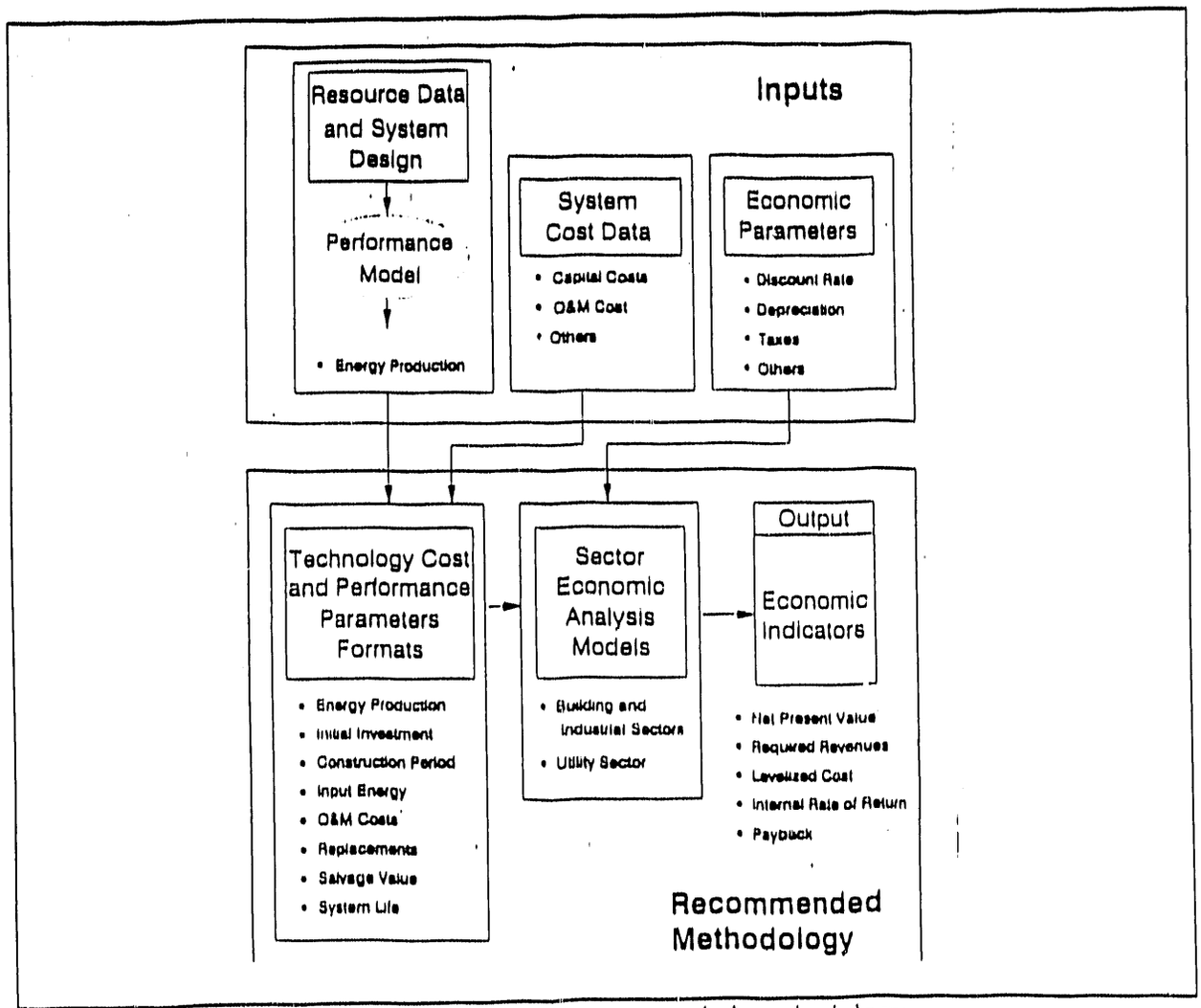


Fig. 1. Relationships of components of the recommended methodology.

or decision criteria. These indicators enable the analyst to look at the attractiveness of an investment from different perspectives. Many of these indicators are similar or inter-related and the choice will often depend upon the purpose of the analysis and the objectives of the investor.

Fig. 2 shows the data requirements and outputs for the utility sector model. The building and industry sector analysis models both utilize the Net Present Value (NPV) method. The utility sector methodology is a required revenue analysis which is the method typically used by publicly-owned and regulated utilities, especially in the U.S. (Government-owned utilities in other countries would be more likely to utilize NPV as would a private investor in an electricity generation project). More specifically:

- Net Present Value - The Net Present Value is the difference between the present value of revenues and the present value of costs or, stated another way, the sum of all discounted annual cash flows associated with the project. If a project has a positive NPV, then it is likely to be an attractive investment.

- Required Revenues Analyses - The electric utility industry, because of its monopoly franchise in many countries, is often granted a specified rate of return on equity by the public utility commission. In return, the utilities must provide their customers electric power with high reliability and at the lowest possible rates. The required revenue methodology determines the levelized annual required revenues to cover the sum of the levelized annual operating costs (fuel and operating and maintenance costs) and the annualized costs associated with the generation plant investment. Utilities use the required revenue methodology to select the generation options that will yield the lowest required revenues in return for the regulated rate of return.

Other economic indicators include: the profitability index -- defined as the ratio of the net benefit to the net cost; the Internal Rate of Return -- the discount rate that makes the NPV equal zero; payback period -- the simplest and one of the most frequently used indicators defined as the total investment cost divided by the value of first year's revenues from energy displaced; levelized cost of energy -- which is sometimes used to examine the relative costs of individual projects or technologies. "Levelization" involves calculating a stream of equal cashflows whose NPV is equal to that of a given stream of variable cashflows. Levelized cost is usually calculated in constant dollars. If a project's levelized annual cashflow is divided by the annual amount of energy produced, the result is called the levelized cost of energy.

In summary, for utility financing, cash flows are calculated from the "bottom-up" to derive required revenues (net present value of all cash flows equal to zero), whereas private corporate financing cash flows are calculated from the "top-down", starting with revenues and determining the bottom-line net cash flow and associated investment criteria.

3.2 Technology Format Description

The economic analysis models require certain key inputs on the cost and performance of contemplated projects in order to assess their economic attractiveness. A unique aspect of these Guidelines has been the development of detailed and uniform Cost and Performance Parameter

Formats for eight RETs to lead the user through the process of developing the required inputs. An example of a format, for solar thermal systems, is provided in Fig. 3. For each technology, the formats specify all appropriate categories of capital, operating and replacement costs, and energy production terms required to calculate the cost and performance values needed for the analysis models.

To complete a format, the analyst utilizes relevant engineering design, cost and performance data for the location being considered. Sources for this data are equipment manufacturers, experienced system designers and project engineers for similar operating systems. Energy output might be estimated using measured data, if available, for a similar system. More likely, a technology performance model will be used to predict performance.

While each of the technologies has different resource, design and performance characteristics and requirements, the formats were made as consistent as possible. Thus, common format section headings were developed and standardized terminology used wherever possible. A major benefit of the common format is the use of a uniform set of nomenclature and associated variable symbols, highlighting the key inputs to the economic models.

The Cost and Performance Parameter Formats were designed to be consistent while still containing the information and variables specific to each technology. They are organized into the following major headings:

- Resource Indicator - One or more key resource characteristics needed to estimate energy output.
- System Description - System descriptors and design characteristics.
- System Performance Parameters - Performance indicators including annual energy production or savings.
- System Cost Parameters - Capital, indirect, equipment replacements, and operation and maintenance costs.

In addition to the format, each technology section of the publication will include:

- A brief description of the technology, including the energy resource, elements of the system, types of systems and applications, and technical status.
- A brief discussion of the critical cost and performance parameters and how changes in these parameters may affect system cost and performance.
- A definition of each parameter or term and explanation of key assumptions.

4. PUBLIC VERSUS PRIVATE SECTOR ANALYSIS

An important topic of the Workshop was how to differentiate between public sector and private sector approaches toward investment decision-making. There are important differences between public sector economic analysis, where the perspective is often that of society as a whole, and private sector analysis, where the viewpoint is that of a private investor.

The basis for estimating costs and revenues and other parameters in private sector analysis is that of the marketplace: market prices, taxes, depreciation, the private cost of capital, and any financial incentives that the particular investment may receive. Such data are used in financial analyses to assess the costs and revenues that will actually be experienced by the private firm or individual. In contrast, the public sector investor (e.g., municipality, state, nation) uses an economic or benefit-cost analysis approach to assess the merits of a particular investment proposal or the relative merits of competing technologies.

The public sector approach attempts to recognize that, in some situations, market prices may not reflect the full value to society of using particular resources. Economists refer to the effects not fully captured by the marketplace as "externalities". The most important of the externalities are societal factors which include environmental benefits and costs; health and safety impacts; increased security of supply provided by renewable energy technology; benefits to employment; and possible costs and benefits of using social infrastructures.

These externalities are sometimes not properly considered in economic analyses, partly due to the difficulty in estimation. Where estimation is difficult or not attempted, another adjustment approach is to use a "social discount rate". This rate (generally lower than a private sector discount rate) reflects the greater value that society would place on the project because of its benefit for the common good.

5. APPLICATION OF THE METHODOLOGY

The economic analysis models for the building, industry and utility sectors presented in these Guidelines are basic models for evaluating private investor decisions. They do not incorporate social externalities, although those could be added, and they do include tax calculations appropriate to private sector analysis. However, with minor modifications these models are applicable to either public or private sector evaluations, particularly for a general feasibility level of analysis for which the methodologies are most appropriate.

It is envisioned that these Guidelines will probably find their greatest use in the public sector where they will be used by decision makers for a variety of economic assessments: 1) to compare the costs of alternative RET projects, 2) to study the effects of certain policy decisions (e.g., instituting tax credits, changing the discount rate, etc.), to assess the impact of technical advances on costs and economic viability, and 4) to con . the economics of RETs with conventional energy sources and technologies. These Guidelines will also serve the needs of both public and private utilities as input for their integrated resource planning.

FINANCIAL ANALYSIS DATA FORMAT FOR UTILITY PROJECTS

Project Information

Project Name:
Location:
Renewable Technology:
Application:
Date of Analysis: Expected Start-Up:

PART I: DATA INPUTS

Cost of the Investment

Total Installed Investment Cost (I_v)*	_____ $
Construction Period (P)*	_____ years
Installed Investment Cost, Year 0	_____ $
Installed Investment Cost, Year-1	_____ $
Installed Investment Cost, Year-2	_____ $
Replacements (R_{mi})	
Replacement 1 [Year: _____]	_____ $
Replacement 2 [Year: _____]	_____ $
Real Escalation in Price of Capital Goods (e)	_____ %
General Inflation Rate (h)	_____ %
Nominal Weighted Average Cost of Capital, After Tax (k_n)	_____ %
Nominal Common Equity Rate of Return (k_e)	_____ %
Nominal Preferred Equity Rate of Return (k_p)	_____ %
Nominal Debt Interest Rate (k_d)	_____ %
Common Equity Financing (E)	_____ $
Preferred Equity Financing (P)	_____ $
Debt Financing (D)	_____ $
Total Plant Investment (V = E+P+D)	_____ $

Levellized Fixed Charge Rate

Depreciation Period (d)	_____ years
Depreciation Base (b)	_____ %
Investment Lifetime (n)	_____ years
Insurance Cost Rate, % of Total Plant Investment (p_I)	_____ %
Rate for Other Taxes, % of Total Plant Investment (p_T)	_____ %

Operating and Maintenance Cost (in $ Thousands)

Annual O&M Costs (OM)	_____ $/year
Year 1 - 2	_____ $/year
Year 3 - 5	_____ $/year
Year 6 - 20	_____ $/year
Real O&M Escalation Rate (e_M)	_____ %

Annual Input Energy Expense (in $ Thousands)

Annual Fuel Expense (L_e)	_____ $/year
Real Fuel Cost Escalation Rate (e_L)	_____ %

PART II: DATA OUTPUTS

Levellized Costs

I (discounted capital investment)	_____ $
FCR (fixed charge rate)	_____
M_l (levelized O&M costs)	_____ $
L_{el} (levelized expenses for input energy)	_____ $

Economic Indicators

R_l (LEVELIZED REQUIRED REVENUE)	_____ $
LC (LEVELIZED COST OF ENERGY)	_____ $/kWh

Fig. 2. Data Format for Utility Sector Economic Analysis Model.

SOLAR THERMAL ENERGY SYSTEM
COST AND PERFORMANCE PARAMETER FORMAT

Project Location: _____
Country _____
Date of Analysis: _____
Date of Expected Start of Operation: _____

RESOURCE INDICATORS

Annual Total Global Insolation	_____	kWh or GJ/m^2-year
Annual Total Direct Beam Insolation	_____	kWh or GJ/m^2-year

SYSTEM DESCRIPTION

Application	_____	
Concentrator Type	_____	
Receiver Type	_____	
Energy Conversion Technology	_____	
Storage Type	_____	
Nominal Installed System Peak Power or Thermal Output	_____	kW_p (or GJ/hr_p)
System Operating Design Temperature	_____	°C
Concentrator Aperture Area	_____	m^2
Rated system power output (or Thermal Output)	_____	kW_{out}(or GJ/hr_{out})
Storage Capacity	_____	GJ or kWh
EXPECTED SYSTEM LIFETIME (n)	_____	years
Total Land Area	_____	km^2

Solar Thermal Format

SYSTEM PERFORMANCE PARAMETERS

Array Losses	_____	%
Other Losses	_____	%
System Efficiency	_____	%
INPUT ENERGY REQUIREMENT (L_i)		
Parasitic Energy (L_1)	_____	kWh or GJ/year
Hybrid or Auxiliary Energy (L_2)	_____	kWh or GJ/year
Availability	_____	%
ANNUAL ENERGY PRODUCTION (E_i)		
(Specific Energy Form) _____ (E_1)	_____	kWh or GJ/year
Capacity Factor	_____	%

SYSTEM COST PARAMETERS*

Capital Costs	Unit Cost	Total Cost
Concentrator Cost	_____ $/$m^2$	_____ $
Area-related BOS Cost		
Land Cost	_____ $/$m^2$	
Site Preparation	_____ $/$m^2$	
Receiver/Tower Subsystem	_____ $/$m^2$	
Transport Subsystem	_____ $/$m^2$	
Sub-total BOS Cost (Area-related)	_____ $/$m^2$	_____ $
Other BOS Cost		
Energy Storage Subsystem	_____ $/kWhor GJ	_____ $
Energy Conversion Subsystem	_____ $/$kW_{out}$	_____ $

Solar Thermal Format

Balance of Plant	_____ $/$kW_{out}$	_____ $
Sub-total other BOS Cost		_____ $
Total Capital Costs		_____ $
Indirect Capital Costs		_____ $
TOTAL INITIAL INVESTMENT (I_p)		_____ $
CONSTRUCTION PERIOD (P)		_____ years
Capital Cost Schedule During Construction (for P Years)		
Year 1-P		_____ %
Year 2-P		_____ %
Year 0 (Plant on line)		_____ %
EQUIPMENT REPLACEMENTS (R_{mi})		
Replacement #1 (R_{m1})	_____ $/$m^2$	_____ $
Year of Replacement #1 (m1)	_____	
Replacement #2 (R_{m2})	_____ $/m2	_____ $
Year of Replacement #2 (m2)	_____	
SALVAGE VALUE (S_n)		_____ $
OPERATION & MAINTENANCE COSTS		
Fixed O&M	_____ $/$m^2$/yr	_____ $
Variable O&M	_____ $/kWhor GJ	_____ $
ANNUAL OPERATION & MAINTENANCE COST (OM)		_____ $/yr

*Although dollars are shown, the specific monetary unit to be used will be determined by the user.

Note: A set of symbols (e.g., n, P, E_1, E_2, I_p, R_{mi}, S_n, L, and OM) is shown here for key inputs into the sector analysis models.

Fig. 3. Cost and Performance Parameter Format for Solar Thermal Systems.

GUIDELINES FOR THE ECONOMIC ANALYSIS OF RENEWABLE ENERGY TECHNOLOGY APPLICATIONS

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Based on the Findings of the International Energy Agency Workshop on the Economics of Renewable Energy Technologies

BACKGROUND

7¢/KWh So what !

Need:

- Universal
- Comprehensive
- Consistent
- Credible
- Sound economics

Response:

- IEA collaborative activity and workshop
- Renowned technical experts in each RET
- Economists and executives in each sector

SCOPE

Renewable Energy Technologies

Active Solar
Biomass
Geothermal
Passive Solar
Photovoltaics
Small Hydro
Solar Thermal
Wind

Sectors

Building
Industrial
Utility

PARTICIPANTS

• Sponsorship:	IEA, Canada, Denmark, Germany (FRG), Spain, Sweden, United Kingdom, United States, CEC.
• Organizing Committee:	7 Senior government officials
• Key technology & Senior experts:	11 scientists & economists
• Other participants:	approx. 80 from the 11 technologies and sectors

APPROACH

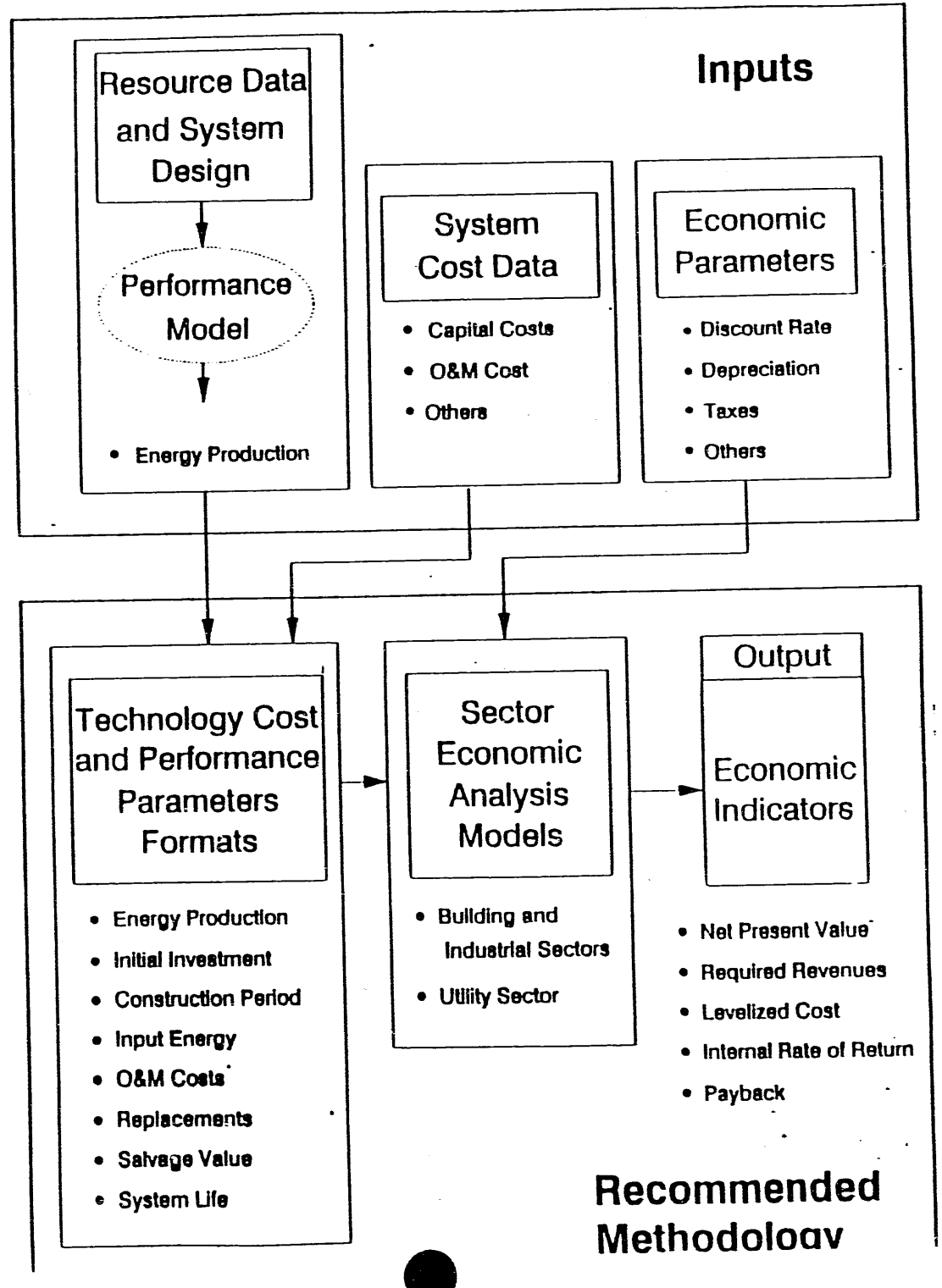
Determine all factors that affect the cost and performance of each renewable energy technology

- **Develop a common format that lists all of the factors that must be considered when determining the cost and performance of each RET.**

Determine the economic indicators commonly used in each sector to assess attractiveness of energy investments

- **Present the proper economic analysis methodologies required to calculate these economic indicators**

Test these formats and evaluations for typical RET applications and after intensive review and debate during a workshop, revise as necessary.


Inputs
Resource Data and System Design
Performance Model
• Energy Production
System Cost Data
• Capital Costs
• O&M Cost
• Others
Economic Parameters
• Discount Rate
• Depreciation
• Taxes
• Others
Technology Cost and Performance Parameters Formats
• Energy Production
• Initial Investment
• Construction Period
• Input Energy
• O&M Costs
• Replacements
• Salvage Value
• System Life
Sector Economic Analysis Models
• Building and Industrial Sectors
• Utility Sector
Output
Economic Indicators
• Net Present Value
• Required Revenues
• Levelized Cost
• Internal Rate of Return
• Payback
Recommended Methodology

COST AND PERFORMANCE FORMATS

Why? To specify and define *all* relevant parameters needed to calculate the cost of a renewable energy system and its energy output.

How? Detailed, uniform and common format contains information required by the analysis equations

Uses relevant engineering design and resource data

Uses preferred national performance model

ECONOMIC INDICATORS & MODELS

Why? To provide the numerical value of those economic indicators commonly used by the private and public sectors to determine the relative attractiveness of energy investments (general feasibility)

How? Discounted cashflow analysis methodologies appropriate to each sector

Indicators

net present value	-	building and industrial sectors
required revenue	-	utility sector
profitability index		
internal rate of return		
payback period		
levelized cost of energy		

PUBLIC VS. PRIVATE SECTOR ANALYSIS

Private Sector

- Market prices
  Taxes
  Depreciations
  Cost of capital
  Financial incentives
- To assess actual costs and revenues

Public Sector

- Value to society
  Market imperfections
  Externalities
    - Environment
    - Health & Safety
    - Security
    - Employment
- To assess likely costs & benefits
- Social discount rate often used

PHOTOVOLTAICS FOR PRESENT AND FUTURE UTILITY USE

PRESENTED AT THE

NATIONAL CONFERENCE ON INTEGRATED RESOURCE PLANNING

OF THE

NATIONAL ASSOCIATION OF REGULATED UTILITY COMMISSIONERS

BY

RICHARD H. SELLERS
DIRECTOR OF TECHNOLOGY SERVICES
SOLAR ENERGY INDUSTRIES ASSOCIATION

SANTA FE, NEW MEXICO
APRIL 8, 1991

Introduction

While the present and future potential of electrical utility use of photovoltaics (PV) is large, resistance to the integration of PV by utilities and those who regulate them is high. This suggests that barriers exist to its appropriate use in the sector that must be overcome for the technology and its benefits to be realized.

Photovoltaics is reaching its maturity at an opportune time in history. PV is no longer an emerging technology, but it is not yet mature. At the present time it is at a critical stage of development where the validation of the principals and products has been shown, but market acceptance by the market is not yet assured.

This paper will explore the current status and future prospects of PV in the utility sector, and suggest some strategies for improving the chances for the technology to be successfully integrated into utility planning and use. The intent of the paper is to make you aware of some of the characteristics and attributes of the technology in order that you may better appreciate and consider its special needs when developing rules and regulations that affect it. The main points to be covered include:

- The justification for cooperation between utility regulators and industry to share technology development costs.
- The current status and future prospects of PV systems in the utility sector.
- How PV fits into the utility sector on both sides of the meter, and in utility operations.
- Some program and policy suggestions to obtain the benefits of PV for ratepayers and the public at large.

The Basis for Cooperative Development

What is the potential for solar energy? What makes photovoltaics different from other energy technologies? Why should PV advocates suggest that technology development costs should be shared and not born by them alone? How much are these development costs expected to be? Why are there high expectations by the PV industry when considering the utility sector market?

The answers to these often-asked questions lay a basis for utility commissioners to understand PV technology and the industry that seeks to develop it.

Photovoltaic technology is fundamentally different from other energy technologies in several important ways. It is well known that PV is virtually pollution free. True, there are some hazards in manufacture, but silicon-based photovoltaic cells are environmentally benign from cradle to grave. Also, photovoltaics is solid state, and requires no moving parts. PV is more like a battery that discharges when exposed to light than a power plant. It requires no fuel, unless one considers the fusion plant saves 93 million miles overhead.

Photovoltaic technology is reliable, with life expectancies ranging from 20-40 years for modules designed for use by utilities. PV is quiet, and equally adaptable to rooftops or open land. The area needed for PV power generation is no greater than for coal or nuclear power generation, and land can be reclaimed after plant usefulness ends without difficulty or lasting environmental impacts. Most important, the sun shines everywhere, making the resource local and universal at the same time.

PV is not universally ideal, however, its major limitation is that, for all practical purposes, the sun doesn't shine all the time. Other limitations are principally caused by the relative status of technological development.

The broad benefits of PV accrue to society as a whole, and not just the companies that strive to develop it.(1) The environmental benefits, in particular, are reaped by every citizen who is not therefore affected by the pollution that would otherwise been produced by fuel-based power generation.

In these many ways, PV is different from other technologies, and its characteristics are unique. Yet in some ways, the technology is like other technologies that exhibit broad social value on the threshold of general use. As conservation technologies before it, PV will require a fundamental alteration of assumptions about what is good for ratepayers in order to be successfully integrated into the utility sector.

At a 1988 NARUC Conference David Moskovitz, formerly of the Maine PUC stated (2):

> "Our current regulatory regime focuses on the price of electricity. Sound least-cost planning requires that we focus on the customer's total bill rather than price. This seemingly small difference in focus has enormous effects on a utility's investment and planning decisions..."

While this alteration caused a fundamental shift in utilities toward integrated resource planning, it left unanswered a follow-on question. Should the focus on total bill be limited only to the current invoice, or should it be expanded to include the impact of technology cost reductions and the reduction of risk in the future? After all, prudent planning and investment for foreseeable risk is a more efficient way to manage those risks than reacting to crisis.

As we will discuss shortly, photovoltaics is a reliable technology that exhibits minimal risk in deployment and delivery of energy. Prices are steadily being reduced, and there is a high level of confidence in their value parity to other energy technologies.

Photovoltaics do not suffer from various hidden costs that are currently being paid to continue our present energy consumption patterns. These hidden costs are generally born through other forms of payment than electricity bills, be it in the form of taxes or a lowered quality of life. Some of these hidden costs are described in this chart taken from Renewable Energy for the World.(3)

Hidden Costs of Energy
($ Billion/Year)

Issue	Hidden Cost
Corrosion	2.0
Crop Losses	2.5 - 7.5
Health Impacts	11.8 - 82.0
Radioactive Waste	4.3 - 31.2
Military (Persian Gulf Forces*)	14.6 - 54.0
Subsidies (R&D, Soft Loans)	43.3 - 55.2
Employment (Lost Wages from Imported Oil)	30.6
Total	109.2 - 258.0

*Before Iraqi invasion

These facts and arguments suggest three principal justifications for public support of industry in developing the technology:

- As shown above, the marketplace does not function it textbook fashion - some technologies are already advantaged.
- Cost and benefits are not reflected in price mechanisms.
- PV development requires a critical mass of capital that industry alone cannot accumulate, as the benefits of the technology will be shared by all.

The PV industry is focused on the utility sector for a variety of reason related to these justifications. Principal among these is that utilities are monopolies that are regulated to protect the public interest. Since PV is both a socially beneficial and socially approved technology, there exists a belief that utilities may be motivated to embrace it.

Another reason is that utilities require a wide variety of energy systems in addition to power generating stations. PV systems are available to meet these needs.

Additionally, utilities populated with skilled engineers and planners who are already knowledgeable about energy systems. This means that the level and amount of education necessary to develop expertise is manageable by our relatively small industry. Finally utilities have access to capital. Affordable capital is a key component of progress for our technology, given that PV is capital intensive.

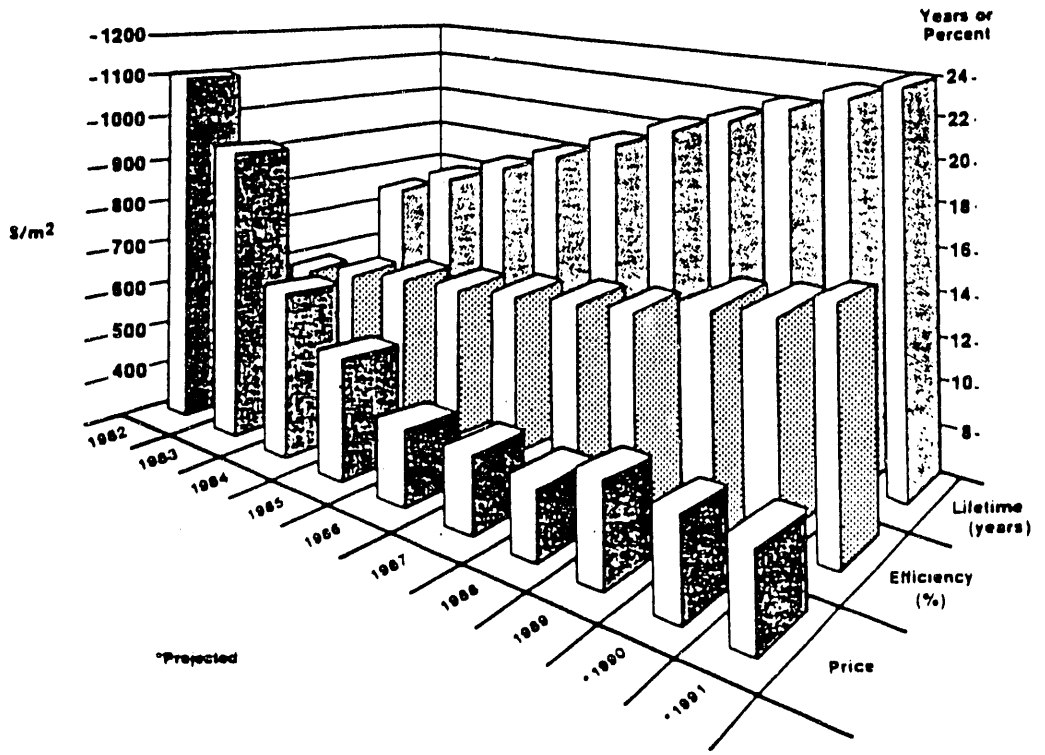
The Current Status and Future Prospects of PV

Current status of PV results from development costs of PV totalling a little over $3 billion. Two-thirds of this

has been spent by industry, and one-third by the federal government. These expenditures have been spread out over almost forty years. Photovoltaic development has been going on since 1954, when the first modern PV cell was developed at Bell Labs. It was a 4% efficient crystalline silicon cell.

As a result of this investment the price of PV modules has been reduced substantially, as production and quality have risen.

PV POWER PROGRESS-1980'S



This chart reflects the general dynamic of the industry; in every way, PV is becoming more mature. In the last decade, module efficiencies have improved about 50% while life expectancy has almost doubled. At the same time, module costs have fallen in half or better. The current cost of modules when purchased in bulk is $4-$6/Wp. This is considerably less than the $11/Wp of 1982.

This dynamic is market driven. The learning curve for photovoltaics is similar to other semiconductor technologies. This learning rate has been about 20 - 25%. Because PV is still a maturing technology, this trend is expected to continue, and each time output doubles, costs will come down approximately 20 - 25%.

PV production in recent years has similarly exhibited steady progress. DOE calculations on product output show a total global market in 1990 of ±47MW, with the U.S. industry capturing about one-third of this market.(4)

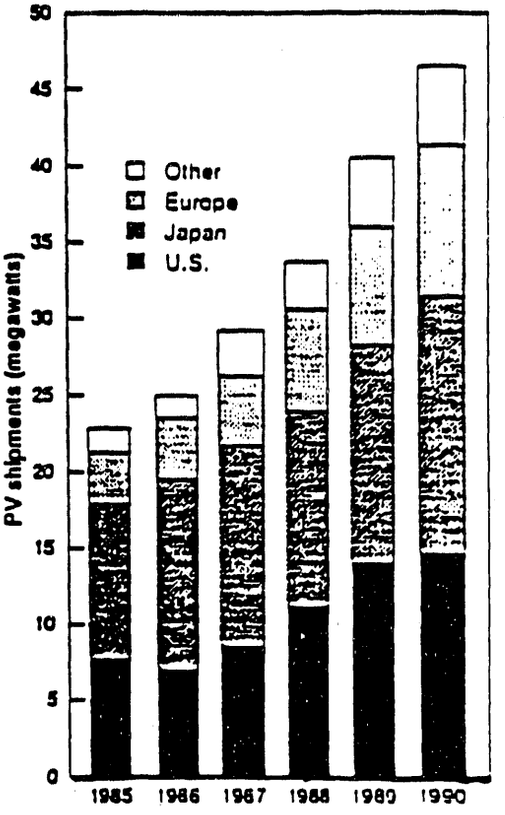


Figure 2. The U.S. share of the photovoltaics market has climbed to about 35%.

The industry that supports U.S. output consists of over 100 companies, including material suppliers, manufacturers, system fabricators, system engineering houses, distributors, and installers.

Applications products that our industry produces can be categorized in three distinct areas:

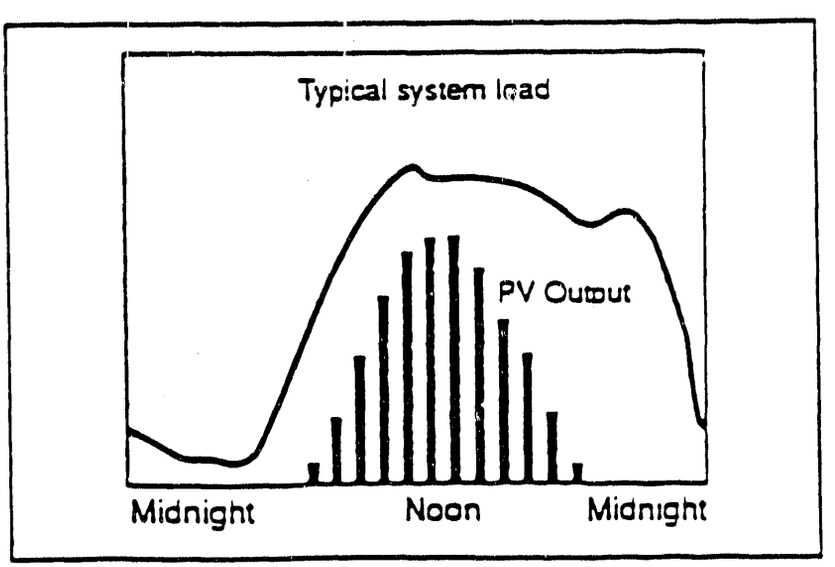
- o Consumer products
- o Stand alone systems
- o Grid connected systems

PV in the Utility Sector

There is a natural fit between PV and utility needs. This is due to the common, although not universal, circumstance of day-time, summertime peaking of utility demands. PV, without any storage, can reliably satisfy this demand.

To a great extent, this demand is driven by commercial and industrial activity. Air conditioning loads, as well as lighting and refrigeration for commerce, and day shift industrial and agricultural demands, all drive up mid-day electrical consumption.

A typical daily load profile is shown below, for New England Electric Service, with the output of a PV array superimposed. (5)



Understanding this relationship has been fundamental to determing systems that are appropriate for utility use. As a result, PV applications in the utility sector that are currently value competitive, if not least cost, fall into four prinicipal areas:

- o stand-alone systems.
- o conservation/demand management systems.
- o utility operations.
- o supply side systems for peaking and intermediate loads.

In this regard, PV is unique among energy technologies, in that it plays an important role on both sides of the meter, as well as in utility operations.

PV for Stand Alone Systems

Utilities all over the country have been dicovering what other industries, notably in the communications sector have known for some time: PV is the least-cost option for many small load applications. In a 1990 survey, PG&E's Department of Research and Development asked the operations side of the utility to identify cost-effective PV systems already in use. To their surprise, engineers identified 420 systems totalling over 38 kW, not all of them remote from the grid.(6) Engineers often reported that the techonolgy is often the "only viable option".

	April 1988		December 1989		December 1990 (Estimated)	
Application	Number	Total PV Capacity (watts)	Number	Total PV Capacity (watts)	Number	Total PV Capacity (watts)
Gas Flow Computers	19	190	147	1,470	300	3,000
Water Level Sensors	108	5,210	108	5,210	133	5,860
Automated Gas Meters	35	350	100	1,170	200	2,170
Gas SCADA RTUs	18	4,550	18	4,550	19	4,990
Cloud Seeders	13	520	13	520	13	520
Gas Samplers	4	40	10	100	15	150
Meteorological Towers	7	70	8	80	11	230
Microwave Repeaters	5	3,110	5	3,110	7	3,510
Warning Sirens	5	50	5	50	5	50
Aircraft Warning Beacons	4	1,520	4	1,520	4	1,520
Cathodic Protection	2	9,800	3	10,800	3	10,800
Automatic Gate Opener	1	40	1	40	1	40
Lights	0	0	1	40	1	40
Rupture Control Valve	1	30	1	30	1	30
Backup Generator Starter	1	20	1	20	1	20
Water Temperature Sensor	1	10	1	10	1	10
Hydro Gatehouse (water sensors, repeater, relays, lights)	0	0	0	0	1	5,800
Total	222	25,550	424	36,720	718	38,740

Two aspects of this use for PV are important. Non-grid connected systems permit utiiites to handle the technolgoy in a cost-effective manner. This stimulates learning about the technology by trained operators who are often able to apply PV to new uses. This increases the experience base for utilities with the technology; expereince that can be transferred to larger systems.

The second aspect is that this is not an inconsiderable market for the PV industry. Were PV to be used by all utilites for cost-effective stand-alone applications, the market would be many megawatts each year.

SEIA recommends that utility regulators promote the use of PV for utility stand-alone systems, on the basis of cost-effectiveness and increased experience.

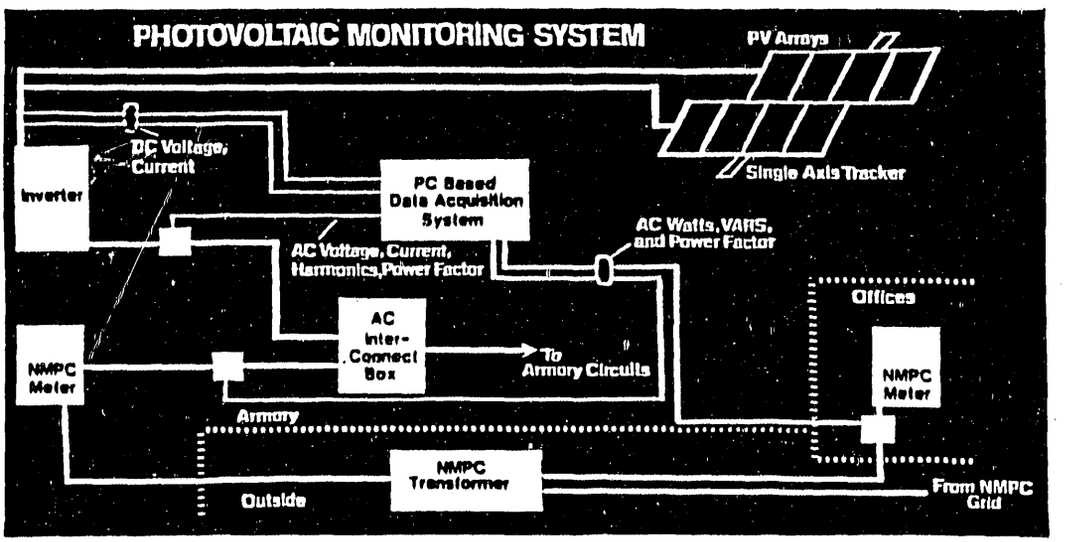
PV as a cost-effective stand-alone system for utilities has well proven. Its appropriate use with these small systems suggests that stand alone PV may contribute to an expansion of energy services that utilities might offer customers. For example, wher a customer applies for power for residential or agricultural service that is well-removed from the grid, PV, owned and operated by the utility, may prove to be the most cost-effective solution.

Non-wire grid extension allows utilities to serve additional customers, while utilizing the advantages of bulk purchasing capabilities and skilled operations personnel that they enjoy. The system capital cost could be in part diverted to the customer in the same way as excessive line extensions costs are borne by the customer.

SEIA recommends that utility regulators encourage utilities to prusue non-wire grid extension strategies through income neutral regulations.

PV for Conservation and Demand-Management

The fundamental relationship between PV system output and utility peak demand has stimulated the devlopment of systems that benfit both utilites and electricity consumers by offsetting demand. When combined with other conservation strategies to reduce daytime load, the value of PV electricity at selected sites can be below 10 cents/kWh. This value is determined by totalling the cost of a combined system and dividing it by the lifetime kWh savings.
A prototype of a PV/Conservation system has been installed on an armory in Albany, New York by Niagara Mohawk Power Company. The system, which is diagrammed here, has been operational since June of 1990.



More advanced systems, requiring fewer balance of system components and better integrated into building operations, are being prepared for installation. These systems relate to a number of building energy requirements. Systems that are suggested by a strategy of coupling PV output to conserve

energy for building systems demanding daytime delivery of power are numerous:

- o PV-assisted heat pumps
- o PV-assisted air conditioners
- o PV-assisted ventilators
- o PV-assisted lighting
- o PV-assisted industrial processes

These applications cut across residential, commercial, and industrial customers.

From the utility's point of view, PV in such systems functions exactly as do conservation options. PV reliably reduces demand, and therefore capacity requirements, on the customer side of the meter. Moreover, PV reduces demand without generating pollution, distinguishing it from co-generation and other fuel-based options.

PV's use benefits both the consumers in the form of reduced electric bills, and the utility in the form of aggregated reduction of demand. Such systems might be sized from 3-100 KW or larger, depending on the customer. These systems might be owned by the utility or the customer, depending on the rate structures and utility capabilities. Utility ownership would assure the reliability benefits sought, however, and this should be encouraged.

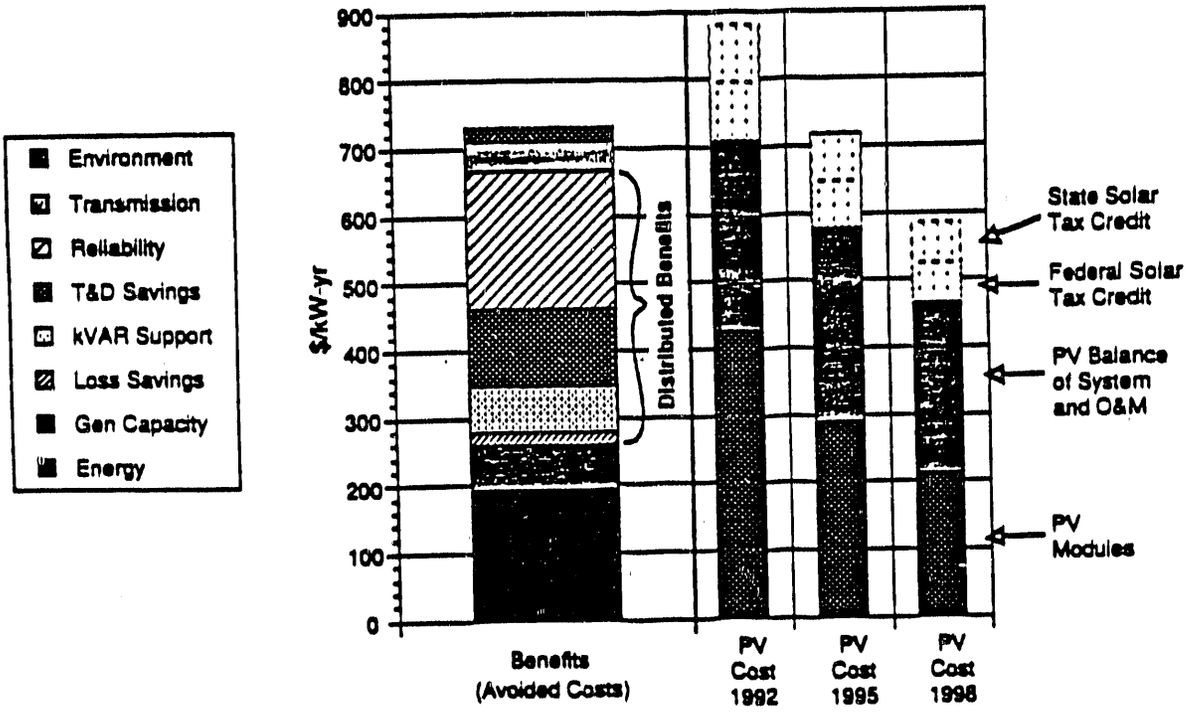
SEIA recommends that utility regulators develop income neutral regulations to promote the use of PV tied to conservation strategies. Cost-effectiveness should be determined for the combined system.

PV for Utility Operations

New research has determined a significant market opportunity for PV in the area of utility transmission and distribution support. A well-known phenomenon that has plagued utilities arises from the fact that as summer loads rise in the daytime, thermal overloading takes place, compounded by high

ambient temperature.

Daniel Shugar, an engineer at PG&E, has studied the use of PV in such a circumstance.(7) In this study, the effect of PV output at an overloaded substation was analyzed. Surprisingly, benefits were of many complementary types. In addition to the direct reduction of overloads on transformers and conductors, there were benefits in the areas of "electrical loss and savings, KVAR support, increased reliability, and transmission and distribution system capacity value. These distributed benefits add to traditional system energy and generation capacity values, and to the much-debated magnitude of the environmental value..." Shugar's characterization of the benefits is charted here, along with some assumptions of future system costs.



Benefits vs. Costs of PV in T&D Systems Results of One Test Case: Kerman Substation

Shugar's study also notes that these benefits would equally arise from a program to support an overloaded transmission and distribution line through the installation of a large

number of systems on distributed consumer roofs. Site selection is the key to successful receipt of the full benefit stream. PG&E has identified up to 80 distribution substations that suffer or will soon suffer thermal overloads where PV may alleviate the problem.

SEIA recommends that regulators encourage prioritizing the use of PV for transmission or distribution system support by allowing a broad calculation of values for such systems.

PV for Peaking and Capacity Supply

Estimates of the required new generating capacity targeted for peak demand over the next ten years range extremely high. In developing options to satisfy this new demand, regulators are uniquely positioned to encourage investment in technologies with considerable current benefits that are expected to substantially increase over time, just as costs will come down.

Photovoltaics can play an important role in supplying new peaking needs. Where local circumstances warrant, photovoltaic power plants in the tens to hundreds of megawatts will find justifications based on the principals of integrated resource planning. These justifications will come from the attributes of PV that include:

- o modularity
- o local and global environmental friendliness
- o local economic benefits
- o resource diversity
- o energy independence and security
- o freedom from fuel cost shocks
- o short planning horizon and installation widow

Already, several utilities are interested in such systems. However, such installations will not take place due to bidding and regulatory biases against PV that arise from not applying integrated resource principals to PV.

The technical basis for believing that PV systems are valid for use by utilities is well developed. The Department of Energy, working through Sandia and SERI national laboratories, has verified the performance of modules. System performance is being validated through PVUSA, a joint activity of DOE, PG&E, and other utilities. Technical performance about PV modules is available from these organizations, as well as from the PV industry.

System design has also progressed to the point where a high level of confidence exists in the tools needed for accurately sizing and engineering systems, as well as understanding their operation and maintenance cost characteristics.

The experience that has developed this level of confidence consists of reported PV systems installed by thirty-five utilities in twenty-eight states. These systems are profiled in Solar Energy Uses for the Utility Sector, a SEIA publication produced by SEIA's utility council.(8) Total utility experience reported by the study amounts to 11,912.2 kW, generating 21,441,600 kWh per year.

Other Solar Systems

In addition to the many photovoltaic systems that will find usefulness in the utility sector, other approaches to solar energy are expected to be integrated as well. Several of these system types have already been installed at a multi megawatt rate. On the conservation side, distributed solar thermal systems exhibit the same utility system benefits as distributed, grid-connected PV. To date, over 730 MW of residential and commercial hot water systems have been installed in the U.S., as well as over 3000 MW of additional hot water for swimming pools.

On the supply side, several emerging and one relatively mature technology deserve note. Solar thermal electricity can be generated by several technology approaches. Well-known from early experimentation in the 1970s is the solar thermal central tower power plant. While a new generation

plant has not recently been installed, system development has proceeded apace, and the industrial community has a well developed design to implement. New interest in the approach has been shown by D.O.E. recently.

Well-known today is the Luz Corporation parabolic trough solar thermal system. With over 355 MW of systems installed, Luz is the largest producer of solar electricity in the world. Recent contracts have pegged the price of the electricity generated at 8 cents/kWh. Luz believes that there is still room for improvement, perhaps down to 5.5 - 6 cents /kWh.

Not as well-known today is the sterling dish engine solar thermal electric system. These systems use focusing heliostats to concentrate solar heat to drive a sterling engine. Systems under development range from 3 - 25 kW, with larger sizes contemplated. These systems are expected to be commercially available within the next two years. Obtaining some of the same modularity benefits as PV, Sterling dish engines appear attractive for both distributed and central plants.

Policies and Programs to Stimulate PV Use by the Utility Sector

As a part of its activities, SEIA periodically proposes strategies to foster increased use of photovoltaics. Many of our strategy ideas are due to our intimate knowledge of the attributes of PV and a limited understanding of the characteristics and operational arrangements of the sectors where PV has great potential. Many more of the ideas, however, are developed by individuals from those sectors who learn about PV, see its benefits, and become advocates for integrating it into their plans.

As a whole, the PV community is opposed to strategies that would drastically upset the marketplace. It is one thing to encourage PV use so as to stimulate steady but rapid growth. It is altogether something else to radically alter supply and

demand balances, which might have a disastrous effect on the stability and reliability of the industry.

The eight proposals listed below are those that SEIA has proposed relevant to the utility sector:

1.) Allow solar-electric applications to be used in situations where the Clean Air Act limits new electric production. SEIA believes that a utility should be permitted and encouraged to build solar energy plants, which have no emissions, free of Clean Air Act restrictions. At the present time, however, clean air legislation has no provision for the construction of solar energy plants. Increase in federal spending: $0.

2.) Amend the Public Utility Regulatory Policies Act to allow federal set-asides for solar and renewable energy electric power plants under 150 megawatts. The effect of a set-aside, by earmarking funds for solar, would be to bypass many of the regulatory barriers to new power plant construction. Public utilities would have an incentive to make solar the energy source of choice during peak power periods. Increase in federal spending: $0.

3.) Direct the Federal Power Marketing Authorities (FPMA) to implement the selection of new generation capacity base upon modern economic methodology. The calculation for solar would include internal costs discounted at 5% per year, and would add environmental externalities. The "environmental externalities to be evaluated by the FPMA, include the costs to society of air, water, and solid water pollution. Where the new capacity would have utilized, imported fuels applicable balance of payments effects should also be factored. Increase in federal spending: $0.

4.) Direct FERC to evaluate and utilize "environmental externalities" and value fuel diversity in the approval process for competing power sales contracts. FERC should utilize environmental externality costs that are not less than the full allocated cost, including capital and operating expenses of the "best available technology," to eliminate

each type of pollution. Increase in federal spending: $0.

5.) Provide financial support for PV plants by allowing a certain portion of the plant's cost to be rate based as a "research asset." This would separately treat that portion of the cost which is related to technology development, and allow the plant equipment to be financed in the usual way.

6.) Enact an environmental "user fee" to be added to utility bills, to reflect the environmental, societal, and security costs of using conventional energy sources. According to a Barry Sussman Poll released on Earth Day in March, 1990, more than 85 percent of the American public is willing to pay additional amounts for energy in order to make greater use of solar energy. SEIA recommends a national policy guiding state utility commissions on such a user fee that would start at .5 percent of utility revenues. In addition, voluntary contributions could be made. Funds generated would be regulated by the state PUCs for use by utilities to construct renewable energy generating capacity. Also, FERC should be encouraged to enact this program on all FERC controlled electrical sales with the funds going to a "National Solar Bank". If a state adopts the program, funding of state programs will have priority and FERC assessments on those sales will cease.

7.) Establish the federal government as an early market for solar energy by mandating solar energy purchases by the Federal Power Marketing Authorities (Bonneville Power Authority, TVA, etc.). The federal government, which has supported these authorities at considerable taxpayer expense, is well positioned to place them at the forefront of a national movement toward utilizing clean and renewable energy technologies.

Conclusion

Should the responsibility for the development of PV technology be shared appropriately by stakeholders in that development, the benefits of PV will be available that much sooner. The stakeholders, including the PV industry,

technology be shared appropriately by stakeholders in that development, the benefits of PV will be available that much sooner. The stakeholders, including the PV industry, taxpayers, ratepayers and the utilities, all derive benefits from the technology that justifies this investment in its development.

Solar energy stands on the threshold of acceptance for general use by utilities and others. NARUC's interest, as expressed in the report on renewables , is timely and welcome. In particular, the second general conclusion is instructive. It states that "the key to the development of these resources lies in the states, and in particular, with state utility commissioners."(10)

PV relevance and reliability for the utility sector has been assured. The solar energy industry and its association, SEIA, is ready to work in partnership and cooperation with NARC and the Commissioners who guard the public's interest in energy. We understand your need for information about PV, just as the industry needs to learn about regulation. With the equally important sponsorship and participation of the Federal government through the Department of Energy, Conservation and Renewable Energy, the task to bring PV and its benefits to realization can be met.

1.) I am indebted to Professor Shimon Awerbuch of the University of Lowell, Lowell, Massachusetts, for many of the concepts related here to the role of government in technology innovation, as well as a broader understanding of risk based factors in utility energy planning.

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4.) Department of Energy. Draft Photovoltaics Program Plan, FY 1991 - FY 1995, February, 1991, p.3.

5.) ibid, p.5.

6.) Jennings, Christina, P,G & E's Cost-Effective Photovoltaic Applications, Pacific Gas and Electric Company, San Ramon, California.

7.) Shugar, Daniel. Photovoltaics in the Utility Distribution System: The Evaluation of System and Distributed Benefits, Pacific Gas and Electric Company, San Ramon, California.

8.) SEIA. Solar Energy Uses in the Utility Sector, September, 1990.

9.) NARC, Subcommittee on Renewable Energy. Draft Report: Renewable Energy and Utility Regulation, November, 1990.

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CONSUMERS
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ELCON
The West Towe
1333 H Street, N.W., 8th Flc
Washington, D.C. 2000ɔ
202-682-1390

NUMBER 14 DECEMBER 1990

PROFILES IN ELECTRICITY ISSUES:

DEMAND SIDE MANAGEMENT (DSM)

SUMMARY

Many states are requiring their jurisdictional electric utilities to extend their business activities to the customer (or demand) side of the meter. These demand side management or DSM programs often are implemented as part of a utility's least-cost or integrated resource plans. Such plans require utilities to consider demand side resources as well as traditional sources of supply. Some advocates of DSM programs claim that these programs can minimize customers' total cost of energy services, including selected societal costs such as environmental externalities. Utilities attempt to influence ratepayer appliance and equipment purchases and usage behavior (i.e., "manage" the demand side) by offering cash incentives to participating ratepayers. These incentives are in addition to the savings resulting from energy usage reductions or load shifts and can constitute a subsidy.

ELCON strongly supports efforts to improve the efficiency of energy utilization, including conservation. Industrial electricity consumers have made and will continue to make substantial investments in energy efficient equipment, technologies, and facilities. Such investments, where cost-effective, can help ensure the competitiveness of U.S. industry in domestic and international markets, address the nation's energy security interests, and make substantial contributions to a cleaner environment. However, for reasons set forth in this *Profile*, ELCON has serious concerns regarding the design and implementation of many DSM programs.

In this *Profile*, ELCON examines the appropriate role of DSM programs in a utility's least-cost planning effort and recommends procedures for: identifying cost-effective DSM options; measuring their actual resource value; and determining the level of financial incentives that is both efficient and equitable.

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.

Profiles in Electricity Issues:

DEMAND SIDE MANAGEMENT (DSM)

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Profiles in Electricity Issues:

DEMAND SIDE MANAGEMENT (DSM)

Summary of ELCON's Position on Demand Side Management

1. ELCON supports cost-effective demand side management 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.

Profiles in Electricity Issues:
DEMAND SIDE MANAGEMENT (DSM)

INTRODUCTION

Increasingly, states are requiring utilities to implement least-cost planning (LCP) or integrated resource planning (IRP) [1]. Common to all these efforts is the explicit encouragement of demand side management or DSM programs, especially conservation. Regulatory policies implementing LCP or IRP attempt to establish a "level playing field" in which utilities are required to evaluate DSM programs on equal terms with traditional supply side resources when planning for the future energy and capacity needs of their ratepayers.

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 barriers that allegedly prevent the adoption of energy efficiency improvements even though they may already be cost-effective for the ratepayer to implement.

The procedures by which DSM resources are integrated with traditional supply into a "least-cost" plan is the source of considerable debate. Some of the key issues in this debate are:

- *What is the appropriate relationship between rates and DSM programs?*
- *How should alleged "market barriers" to energy-efficiency improvements be overcome?*
- *How should the cost-effectiveness of DSM programs be determined relative to traditional supply side resources? Should DSM programs be allowed to bid in a utility's competitive bid solicitations for new capacity?*
- *How should DSM programs be monitored, verified and evaluated once they have been implemented? What is the real capacity and energy resource value of DSM programs?*

- *How should program costs be allocated and recovered from ratepayers if utilities do implement DSM programs?*
- *Should utilities be given incentives to implement DSM programs?*
- *Should regulated utilities provide services on the customer's side of the meter where competitive end-use markets already exist?*
- *What regulatory oversight is appropriate?*

WHAT IS THE APPROPRIATE RELATIONSHIP BETWEEN RATES AND DSM PROGRAMS?

Prior to implementing DSM programs, utilities should set rates based on cost-of-service 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.

Setting the Right Price Signal

Utilities should correct and improve the price signals sent to ratepayers, particularly by offering time-sensitive and other rates. Other ways to greatly improve price signals include the elimination of cross-class subsidies that may be 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.

Utilities typically offer their ratepayers a limited number of tariffs, which may include customer, demand, and energy charges for a fixed grade of service. Such bundled electricity rates and services are inefficient and can be anticompetitive. The provision of highly bundled services often forces ratepayers to pay for services they do not need, which can encourage uneconomic bypass. This also severely restricts opportunities for market specialization, thereby limiting or preventing the availability of goods and services that ratepayers want or need. Market specialization is a necessary feature of efficient, competitive markets.

Ratepayers should be provided a broader range of options 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.

Time-Sensitive Rates

Rates to all consumers of electricity should be based on costs actually incurred by utilities in providing the service. 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. Time-sensitive, cost-based 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; real-time pricing; 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.

ELCON believes that time-sensitive rates based on actually incurred costs provide the consumer with the proper price signals necessary to make rational decisions on energy consumption. ELCON opposes time-sensitive rates based on computations of unknown future costs or on costs associated with hypothetical capacity configurations. Time-sensitive rates based on these so-called "marginal costs" require arbitrary revenue adjustments to meet the revenue requirements allowed by law. Such adjustments result in deviations from cost-of-service and distortion of the proper price signal [2].

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 consume. 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, including cogeneration.

ELCON believes that 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.

HOW SHOULD ALLEGED "MARKET BARRIERS" TO ENERGY-EFFICIENCY IMPROVEMENTS BE OVERCOME?

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. ELCON supports utility efforts that help maximize the amount and quality of information in competitive end-use markets. Information programs involving direct customer contacts, targeted advertising and marketing, joint ventures with equipment and appliance suppliers, educational workshops, and technical assistance assure the efficient operation of the end-use markets. But utilities also must have adequate in-house market research and marketing expertise so as to more efficiently communicate the right information to their customers. To the extent that the costs of such programs are minimal, information programs make sense. However, some can be quite expensive. These should be carefully evaluated to assure that they are cost justified. In all cases, the direct beneficiaries of a program should pay the costs.

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 full reign to exercise their choices, including the option to switch fuels, if competition is to be allowed to work.

SHOULD A DETERMINATION OF NEED BE REQUIRED PRIOR TO IMPLEMENTING DSM PROGRAMS?

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. The plan should also include the utility's supply alternative. This plan should be available for public review and comment.

HOW SHOULD THE COST-EFFECTIVENESS OF DSM PROGRAMS BE DETERMINED?

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 programs' impacts on the cost-of-service of both participating and non-participating ratepayers.

The following example illustrates the added complexities of evaluating DSM resources as compared to traditional supply side resources. If a utility needs new capacity to meet forecasted load growth, it should be indifferent to whether that capacity is met with DSM resources or with traditional supply sources. However, from a ratepayer perspective, the options may not be the same. Under the DSM option, non-participants could be worse off depending upon how the costs of the DSM option are split between the utility and the participants (See Fig.1).

Figure 1

COMPARING DSM RESOURCES WITH TRADITIONAL SUPPLY

If a utility needs 100 MWs of new capacity to meet forecasted load growth, it should be indifferent to whether that capacity is met with DSM resources (e.g., by reducing 100 MWs of existing loads) or with traditional supply sources such as a new coal-fired generating unit, so long as each option costs the same and results in the delivery of an identical resource. However, from a ratepayer perspective, the options may not be the same.

Under the DSM option, non-participants could be worse off depending upon how the costs of the DSM option are split between the utility and the participants. For example, they would be worse off if they were allocated any portion of the lost revenues foregone by participants. In that case, non-participants would be directly subsidizing the bill savings of participants. To prevent subsidies, ELCON believes that 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.

The presence of lost revenues (or "avoided net revenues") distinguishes the procurement of DSM resources from that of traditional supply.

Four cost-effectiveness tests have been proposed to evaluate DSM programs:

- The *Participant Test* compares the customer's bill savings due to participation in a DSM program with the customer's out-of-pocket costs. This test measures the attractiveness of a DSM option to the customer.

- The *Non-Participant Test* compares the avoided supply costs to the DSM program costs of both participant and the utility. The costs are adjusted for the lower electricity requirements of DSM options versus comparable supply side resources to measure the impact of the program on rates. This test can identify whether one customer or customer class is subsidizing benefits received by the participating customer or customer class.

- The *Revenue Requirements Test* compares the avoided supply costs to the DSM program costs of the utility (excluding participant costs), to measure the impact of the program on the utility's total revenue requirement.

- The *Total-Resource Cost Test* compares avoided supply costs to total program costs (which includes costs paid by both the utility and the participant) to measure the relative costs of demand and supply options, exclusive of cost-of-service allocation and rate impact. A variation of this test, called the *Societal Cost Test*, attempts to internalize selected social costs (such as environmental externalities) in the test.

Exclusive use of cost-effectiveness methodologies such as the Participant Test or the Total-Resource Cost Test can result in the adoption of DSM measures that result in interclass or intraclass revenue subsidies because these tests ignore revenue shifts or income transfers.

The Non-Participant Test can be used to address this situation. If the utility's costs of the DSM program is equal to or less than the supply option, non-participating ratepayers would prefer the DSM option only if the utility's cost for that resource were less than or equal to the difference between the utility's avoided cost minus the bill savings that would occur due to the DSM program.

More effective than these tests, the market can be used to select the most cost-effective options. 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.

ELCON believes that only DSM programs that are evaluated according to the following principles are cost-effective and therefore truly least-cost:

1. Demand and supply 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. Competitive bid solicitations may be used for the acquisition of quantifiable DSM resources. DSM resources should not be selected in competitive bid solicitations based on arbitrary quotas.

5. ELCON believes programs that share the savings between participants and non participants can be offered to participating customers to the extent they are consistent with the minimization of long-run revenue requirements and do not impose cross-customer or cross-class subsidies.

6. The Total Resource Cost Test should not be used in isolation to select qualifying DSM measures from the universe of DSM candidates. This can result in cross-class or cross-customer subsidies. This effectively results in the taxation of some customers or customer classes for the sole benefit of other customers or customer classes. This form of taxation generally would be without legislative authorization.

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

HOW SHOULD DSM PROGRAMS BE MAINTAINED, VERIFIED AND EVALUATED?

DSM programs are not yet comparable to supply side resources because their aggregate operational characteristics 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 actual performance of DSM programs is highly variable and uncertain because of ratepayer discretion to modify their energy utilization and purchasing behavior in response to price, technology, or lifestyle changes. The characteristic of DSM programs to operate as designed is often called *persistence*.

Financial incentives given to DSM program participants reduce the effective price of the energy service. A lower price can increase demand in terms of overall consumption of the service. This is often called a *rebound effect*. For example, incentives for high-efficiency air conditioners may result in the purchase of a larger-sized unit, more frequent operation of the unit, or operation at a lower setpoint.

Estimates of a DSM program's value as a real capacity or energy resource must factor in the rebound effect, the lack of persistence, and technological factors. Unfortunately, chronic disappointment with the results of utility DSM efforts has tended to focus attention on utility motivations and not actual DSM effectiveness.

ELCON believes that 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. Estimates of energy and/or capacity savings must be decreased by reasonable estimates of:

   - Conserved loads which would have occurred without the incentive, including estimates of reductions by "free-riders", i.e., participants who otherwise would have conserved without the incentive;

   - Simultaneous increases in usage by participating customers resulting from the effective price decrease due to the incentive;

   - New loads which are encouraged by inefficient subsidies and/or price signals; and

   - Conserved loads which are subsequently reimposed on the system because of customer mobility or other reasons.

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.

HOW SHOULD DSM PROGRAM COSTS BE ALLOCATED AND RECOVERED FROM 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 embedded cost-of-service studies. These

studies should be used by commissions, routinely updated (e.g., at least as often as the utility files for new rate changes), and be subject to public notification and comment.

Rates should be designed to recover the costs 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 can be separated into three categories:

- *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 DSM program costs for a program designed to reduce summer peaking 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.

- *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.

- *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.

Within each of these categories, certain costs are referred to as being fixed and others are variable. *Fixed costs* are those that, in total, do not vary with output (i.e., 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.

ELCON strongly believes that 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.

SHOULD UTILITIES BE GIVEN INCENTIVES TO IMPLEMENT DSM PROGRAMS?

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 manner intended to benefit society as a whole. 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 plus a fair rate of return.

Many advocates of DSM programs 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 [3]. These include incentive rates of return, so-called "decoupling" procedures such as the electric revenue adjustment mechanism (ERAM), and cost recovery through the fuel adjustment clause (FAC) or other tariff riders.

The Appropriate Rate of Return for DSM 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 can 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. ELCON believes that 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 effectively "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. ELCON opposes the use of procedures such as ERAM. 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 absolutely not the appropriate mechanism for the recovery of avoided net revenues that result from DSM implementation. ELCON believes that, to the extent it is necessary, the FAC should be used solely for adjusting rates for rapid changes in the costs of fuels.

SHOULD REGULATED UTILITIES PROVIDE SERVICE ON THE CUSTOMER SIDE OF THE METER WHERE COMPETITIVE END USE MARKETS ALREADY EXIST?

Under the scenario described in this Profile, utilities would not just be traditional suppliers of electricity, they also are given the license to increasingly make or influence decisions regarding how, when, and where electricity will be consumed. This blurs the historic brightline between the appropriate roles of utilities and consumers. In essence, they would usurp what has traditionally been the exclusive right of consumers to plan and control their energy using behavior.

Consumers presently acquire end-use equipment and appliances (including servicing) in competitive markets. Utilities do not operate in competitive markets. They are regulated monopolists by law. ELCON questions the appropriateness of allowing regulated entities to interfere with the operation of working competitive markets. For historical and institutional reasons, utilities do not share the same motivations with the entities in competitive markets. Allowing regulated suppliers to "compete" in these markets would encourage inefficiencies and create potential anticompetitive opportunities. ELCON challenges the notion that more

efficient end-use equipment and appliance markets can be established and maintained by regulatory or other forms of government interference in the existing marketplace.

Instead, ELCON supports market-driven efforts to improve the efficiency of energy utilization, including cost-effective demand side management. In response to energy price increases and price uncertainties, industrial electricity consumers have made and will continue to make substantial investments in energy efficient equipment and facilities that are proven cost-effective. Such investments help ensure the competitiveness of U.S. industry in domestic and international markets, as well as make substantial contributions to a cleaner environment.

WHAT REGULATORY OVERSIGHT IS APPROPRIATE?

ELCON believes that regulatory safeguards are necessary to minimize the potential abuse of market power if 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 and DSM programs. Utilities must always retain the responsibility and accountability to manage the use of all their resources whether demand side or supply side.

2. Minimum filing requirements should be established that subject utilities' projected needs and planning assumptions to public review.

3. 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.

4. Prior to implementing DSM programs, 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 or supply side investments that are not both physically and economically used and useful.

6. All investments -- including DSM program 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.

ELCON also believes that certain utility business arrangements may require additional regulatory oversight to assure adequate ratepayer protections. For example, many investor-owned electric utilities are combination companies selling both electricity and natural gas at retail. Such utilities may not implement DSM programs that maximize the benefits of these fuels to their dual-use ratepayers. Their promotional programs will be influenced by the different margins on unit sales of gas and electricity [4]. Regulatory oversight is necessary to prevent potential market abuses of utility combination companies which retail both electricity and natural gas. DSM programs of combination companies must not encourage uneconomic fuel switching, nor discourage economic fuel switching.

ELCON also opposes the establishment of unregulated DSM subsidiaries of regulated utilities without adequate regulatory oversight that prevents opportunities for self-dealing. Specifically, state regulators should be given the authority to disapprove pass-through of imprudent DSM resource purchases from unregulated affiliates.

Large scale DSM programs by members of utility holding companies and "tight" power pools present special opportunities for the abuse of market power, self-dealing, and mutual self-dealing. State regulators should be given the authority to protect ratepayers from these potential abuses.

ENDNOTES

[1] Electric Power Research Institute. Status of Least-Cost Planning in the United States. EPRI EM-6133, Final report, (Palo Alto, CA: 1988), p.1. A more detailed discussion of ELCON's position on least-cost planning is contained in Profiles in Electricity Issues: Least-Cost Planning, which is available from ELCON upon request.

[2] See Profiles in Electricity Issues: Time-of-Use Rates which is available from ELCON upon request.

[3] A discussion of these proposals from the point of view of a former state regulatory commissioner is contained in: David Moskovitz, Profits & Progress Through Least-Cost Planning, National Association of Regulatory Commissioners, Washington, DC, November 1989.

[4] Some regulatory commissions may prohibit or discourage DSM programs that achieve increased energy efficiency by fuel substitution.

Valuation of Gas for Use in Gas Utility Integrated Resource Planning[1]

by
Dan Violette and Frank Stern
RCG/Hagler, Bailly, Inc.
Vince Esposito
National Fuels

1.0 INTRODUCTION

In order to compare the benefits of gas utility demand-side management (DSM) programs to the costs, it is necessary to place a dollar value on the gas impacts.[2] Utility DSM programs could include year-round base sales building, off-peak sales building, as well as conservation and load management.[3] Issues associated with avoided costs of electricity have been extensively discussed over the past decade and, while controversies remain, most would agree that at least some resolution has been reached on the conceptual issues. Now, gas utilities may need to address similar sets of questions.

Determining avoided costs for gas distribution utilities poses a substantially different problem than valuation of electricity. The primary electric supply options are utility-owned power plants with economic lives of 25 years or longer. Time horizons for forecasts in the gas industry are substantially shorter than those in the electric industry, since the primary supply options are pipeline contracts and spot market purchases. In addition, issues such as the take-or-pay provisions, pipeline open access, unbundling, gas inventory charges, and contract demand-firm transportation conversion complicate the estimation of avoided or incremental gas costs.

A recent survey of state PUCs regarding integrated resource planning (IRP) for gas utilities found that disagreement on appropriate avoided gas costs was one of the most significant

[1]Many of these concepts are based on Chapter 6 of Volume 1 of "Phase 1 Final Report: Methods Analysis for the Conservation Program Evaluation Project" (RCG/Hagler, Bailly, Inc. 1987, Boulder, CO) authored by Carol Etter and Mike Yokell.

[2]The term "impacts" is used here to refer both to gas savings from strategic conservation and to increases in energy sales from year-round base load or off-peak sales building strategies.

[3]A least-cost integrated plan can encompass a set of programs that include conservation, load management, and strategic sales growth simultaneously, with each program being cost effective.

hindrances to the development of DSM resources.[4] This paper addresses this avoided cost question. Several candidate methods for estimating gas costs for use in DSM planning are discussed, and the relative advantages and disadvantages are compared. One of these methods, the Targeted Marginal Cost approach, was recently applied as the primary approach in statewide evaluation of DSM programs in the state of New Jersey. While this approach may not be best in all circumstances, it has several desirable attributes and deserves consideration as a method for estimating avoided and incremental gas costs for DSM planning. A second approach, the Weighted Average Cost of Gas approach, was applied as sensitivity analysis. This paper focuses on the experience gained in the New Jersey project.

2.0 GENERAL GAS VALUATION ISSUES

Due to the seasonality of gas commodity costs and the manner in which various gas supplies are utilized by the distribution company, the value of a unit of gas varies continuously throughout the year. In general, gas is least expensive in the summer and most expensive on the coldest of winter days. Between such extremes, the value of gas varies in a manner which may be highly dependent on the utility's individual gas acquisition and dispatch strategy, and on weather-related demand. In addition, the avoided gas costs will depend upon both the overall volume of gas savings and the character of savings. The overall volume of gas saved produces a commodity cost savings, while the character and timing of gas savings may influence demand or capacity-related costs. An accurate accounting of cost requires a detailed examination of all supplies on a monthly basis.

Superimposed upon the seasonal character of gas costs are the cyclical and long-term price trends caused by longer-term supply and demand relationships, and (to a lesser extent) the competitive pressure caused by oil. Historically, regulation was the chief influence on prices. Gas prices were kept artificially low, and were not responsive to alternative fuel pricing. Deregulation of production, however, has promoted pricing which has since generally varied with oil prices. Issues associated with valuation are similar to problems seen in the rate design process, which links rates to costs. It has been recognized that assignment of costs "is not a matter for the slide rule. ... It has no claim to an exact science."[5]

The objective for integrated planning and for DSM program evaluation is to obtain estimates of avoided gas costs that are adequate for making business decisions regarding

[4]Goldman, C. and Hopkins, M. 1991. "Survey of State PUCs on Integrated Resource Planning for Gas Utilities." NARUC Conference, Washington, D.C.

[5]Colorado Interstate Gas Co. V. FPC, 324 U.S. 581, 589 (1945).

investments in DSM. Estimates of avoided gas in future years are uncertain, but decisions need to be made today. Decisions on conservation and sales building programs will be made. Even a decision not to undertake DSM has some estimate of avoided costs implicit in its decision.

3.0 OVERVIEW OF DIFFERENT APPROACHES

Numerous approaches to gas valuation exist. The following four representative methods of valuing gas impacts will be discussed:

(1) The Dispatch Model Approach.

(2) The Weighted Average Cost of Gas (WACOG) Approach.

(3) System Marginal Cost Approach.

(4) Targeted Marginal Cost (TMC) Approach.

3.1 The Dispatch Model Approach

A dispatch model determines the optimal utilization of utility supply options required to meet a forecasted load. The most direct and possibly the most accurate method to calculate the avoided costs associated with a reduced need for gas would involve conducting two complete gas dispatch analyses. One analysis would dispatch the entire gas throughput, including the saved gas volumes. This would be compared with another dispatch analysis, which would exclude the gas saved by conservation.[6] The differential cost between the two analyses is, therefore, the value of the gas saved. Such an approach is termed an incremental approach to valuation.

Most dispatch models in use at gas utilities are relatively short-run models (i.e., one to five years). While the useful lifetime of various conservation measures varies considerably, many of the more effective measures have lifetimes ranging from ten to thirty years. Dispatch models covering a time period of this length are uncommon at gas distribution companies.

Additionally, in the short run, the saved volumes are commonly small in comparison to typical supply contracts. Since this method does not explicitly identify cost causation, an

[6]This example focuses on conservation, but a similar analysis could be conducted for incremental sales increases due to strategic marketing.

attempt to utilize a series of short-run dispatch models may be further complicated by the difficulty of embodying a long-run least-cost strategy within the short-run models.

The use of gas dispatch models will be most practical when the saved volumes are large in comparison to typical gas supply contracts and the dispatch model is capable of handling a period of time comparable to the useful lifetime of the energy savings measures. While the dispatch model approach does have these advantages, there may be problems with the data requirements and the ability of the model to capture the operational constraints of the gas system at a level of detail equivalent to the detail on dispatch.

3.2 The Weighted Average Cost Approach

The WACOG approach is straightforward in concept and implementation. The approach weights the unit cost of each of the supplies the volume of gas delivered, thereby determining a weighted average cost of gas. This average cost is then used to value all gas savings.

One argument used to justify the WACOG approach is that some utilities do not have a great deal of supply flexibility. Gas system contractual and operational constraints may result in the utility being able to target the most expensive gas for reduced takes. In addition, some maintain that conservation savings will not cause a utility to adjust contract demands due to the growth being experienced by utilities, the magnitude of gas savings relative to annual and peak day sales, and due to the size of the blocks of gas purchased by contract.[7] As a result, the WACOG approach generally assumes that there will be no savings in demand charges resulting from conservation. This position favors a variant to the WACOG approach called the operational valuation approach. In this approach, weighted average commodity costs of gas are calculated in each month and for peaking impacts.

The primary argument against the WACOG approach is that it does not attempt to address cost causation, and thereby may underestimate the value of gas saved, depending upon the structure of contracts and dispatching operations. A typical local distribution company (LDC) employs a diverse supply portfolio which includes high load factor supplies, storage supplies, and peaking gas sources. A typical weather-sensitive load, such as a home heating furnace, has a demand profile which will follow the seasonal heating degree day profile. Consequently, the LDC employs more costly winter service supplies to meet the increased

[7]In calculating avoided gas costs, it must be remembered that an evaluation of a specific conservation program represents a snapshot in time. On this basis, the savings of any one program would never make a difference in contract "takes" of gas. However, the correct way to assess the avoided costs of conservation is as a block of savings across all programs and accumulated over several years of operation. For some utilities, savings may still be small even examined on this basis, but it is important to consider the total conservation resource and not perform marginal analyses of individual programs.

winter demand. A WACOG approach, however, will significantly soften the impact of seasonal gas costs and, thus, may undervalue the incremental savings associated with efficiency improvements related to weather-sensitive loads. Further, the argument regarding operational constraints that constrain dispatch responses are primarily short-term constraints which may not be applicable for longer term horizons.

3.3 The System Marginal Cost Approach

In contrast to the WACOG approach, which uses the average cost of all gas supplies, the system marginal cost approach identifies and utilizes the most expensive unit of gas purchased, presumably also the last unit dispatched in a least-cost strategy, as the value of the impacted gas. Gas dispatching is examined on a monthly basis, or perhaps even on a daily or hourly basis, if the analysis is run off of the dispatch model output. All of the gas saved within the specified interval of time is valued at the unit marginal cost. One disadvantage to marginal approaches is that they are more complicated to perform than a WACOG approach.

The major criticism of this method is that cost causation is not addressed. Conservation measures are many and varied. All conservation induced gas savings in a long-run marginal approach do not necessarily result in cost savings at the actual system margin. Such an approach may overvalue the conservation-induced gas savings and gas cost associated with new load in a load building program. As an example, consider a gas-fired water heater. The water mains are buried in the ground below the frost line. The soil temperature at that depth varies little with the seasons. Hot water consumption is relatively constant throughout the year and is generally a major component of base residential demand, rather than peak demand. From a cost causation viewpoint, such a base load is essentially serviced by high load factor or base supplies which are traditionally provided by long term pipeline contracts. The system marginal supply will be higher cost than the base supply, consequently, a system marginal approach may overvalue the savings ascribed to efficiency improvements that influence base load gas use.

3.4 The Targeted Marginal Cost Approach

The TMC approach to gas savings valuation is a compromise between the complexity of a fully automated dispatch model and the simplicity of other methods with all of their attendant concerns. It is similar to a system marginal approach in several respects, but overcomes its limitations by partitioning both the conservation savings and the gas supply plan into their operational components. Thus, it directly addresses cost causation, from both the viewpoints of gas savings and supply planning, and as such may be most applicable to conservation activity valuation. This costing approach has some parallels with recent discussions at the Federal Energy Regulatory Commission (FERC) related to reviewing the future direction of pipeline rate design, in that seasonal costs and cost-causation concepts

are being directly addressed.[8]

The key elements of this method are:

- The disaggregation of gas savings into their characteristic components; that is:
  - Base load savings;
  - Non-peaking temperature sensitive savings; and
  - Peaking savings.
- The segregation of gas supplies into their functional categories:
  - Base load supplies;
  - Variable load supplies; and
  - Peaking supplies.
- The identification of highest (or high) cost supplies in each functional category.
- The allocation of highest (or high) cost supplies to gas savings components.

For a period in which the utilization and cost of all supplies are known, an analysis on a monthly basis is both possible and preferred for its increased accuracy. For an extended forecasted period, however, the actual monthly utilization of supplies may not be completely known and an annual analysis may suffice.

4.0 CASE STUDY: THE NEW JERSEY CONSERVATION ASSESSMENT PROJECT

Choosing the appropriate method for valuing gas savings from conservation programs was one of the more hotly debated issues in a recent evaluation encompassing 24 programs at four gas utilities in the state of New Jersey.[9] The TMC approach was selected as the primary analysis method. A WACOG approach (operational valuation) was also applied in a sensitivity analysis. In addition, one utility maintained a gas dispatch model. The output from this model was evaluated and compared with the results from the other two methods. The following section discusses the application of the TMC approach and results

[8]See FERC Docket No. RP89-75-000, May 30, 1989.

[9]See RCG/Hagler, Bailly, Inc. 1990. "Final Report to the New Jersey Conservation Analysis Team." Boulder, CO.

from both approaches and the dispatch modeling.

4.1 Background

In 1987, a project was initiated to evaluate the DSM programs of the seven public utilities in New Jersey and to develop uniform methodologies for evaluation of these programs. The work was sponsored by all seven electric and gas utilities in New Jersey Board of Public Utilities, the New Jersey Department of Energy and the New Jersey Public Advocate, together called the New Jersey Conservation Analysis Team.

This three-year project involved a detailed assessment of all aspects of demand-side program evaluation. Over 150 demand-side projects were initially screened, approximately 70 programs were analyzed in detail, and econometric evaluation techniques were applied to roughly 35 programs. First, an analysis and review of the approach to evaluating demand-side programs was undertaken. The statistical analysis techniques for program participation and savings estimation were reviewed and utilized, including accounting for the standard problems of non-response and self-selection bias. Extensive surveys of the residential and non-residential sectors were designed and undertaken to provide both impact and participation likelihood data. Numerous building energy simulation studies were also performed to estimate the impact of certain programs and to provide load shape impacts.

Separate gas and electric valuation tasks were defined. These tasks translated the energy and demand savings estimates into net present values of avoided costs for input to the benefit/cost analysis. The benefit/cost analysis involved consideration of the costs and benefits of energy conservation programs to four groups: (1) customers participating in the programs, (2) non-participating customers, (3) the utilities, and (4) society in general. Performing the benefit/cost evaluations required the development of methods which are uniform to the maximum extent possible and the collection of data on costs and benefits necessary to perform these evaluations.

A simplified overview of the project is presented in Figure 1 (at the end of this paper) .

4.2 Outline of Valuation Approach

The gas valuation process had a term of 20 years[10] and encompassed both historical and forecasted periods. The application of the TMC process involved seven steps:

(1) Disaggregate the therm load savings (from reconciliation of econometric and

[10]The 20 year time horizon was selected as the maximum planning horizon for the gas utilities. Because some measures had lifetimes of 25 years, the savings from the five year difference were added (on a net present value basis) as end effects.

engineering estimates) into base and temperature sensitive components on a monthly and peak day basis.

(2) Determine the generic procedure for allocation of supply to each load savings component on a monthly and peak day basis.

(3) Examine historical utility gas supply usage and costs and determine the specific marginal contract to be allocated to each load savings component on a monthly and peak day basis.

(4) Examine short term utility gas supply usage and cost forecasts and determine marginal cost to be allocated to each load savings component on a monthly and peak day basis as consistent with the utility forecast format provided.

(5) Apply the historical and short term forecasted targeted marginal gas costs to each load savings component and establish annual commodity and demand nominal dollar savings.

(6) Apply the long term forecast escalation factors[11] to the last year of the short term forecast's annual nominal dollar savings to establish the long term forecast's annual commodity and demand nominal dollar savings.

(7) Combine commodity and demand savings to produce total annual nominal dollar savings throughout the analysis period.

4.3 Disaggregation of Gas Savings

The first step in the disaggregation of load savings was accomplished as follows. The non-heating season, or summer, was defined as the period of April through October. The heating season, or winter, was defined as the period of November through March. The minimum load period was determined to be July and August, and the peak day was determined to occur in January.

The average monthly load savings occurring during the minimum load period were defined as the base load savings. The load savings each month which was in excess of the base were defined as the temperature sensitive load savings. The average daily temperature sensitive load savings for the month of January were determined, as was the average daily base load savings. The peak day load savings in excess of the sum of the January average daily temperature sensitive load savings and the average daily base load savings were defined as the peak day peaking load savings. In summary:

[11] From GRI's 1989 Baseline Projections.

- The monthly savings are partitioned into two components:

  (1) The base, non-temperature sensitive load; and
  (2) The temperature sensitive load.

- The peak day savings are partitioned into three components:

  (1) The base, non-temperature sensitive load;
  (2) The average, daily peak month temperature sensitive load;
  (3) The above average, peaking temperature sensitive load.

Although peaking supplies are sized to accommodate the peak firm send out day of the year, they are used more than once per year. The peaking plant usage on that coldest day is defined as a full equivalent peak day usage. Other days may also require full usage or only partial usage. Based upon an examination of normal weather degree day distributions, it was estimated that the heating season peaking plant usage may be approximated as five equivalent full peak days. Therefore, the heating season propane consumption commodity savings were estimated as five times that determined by the engineering and econometric peak day calculations.

Figure 2 shows the disaggregation of load savings for one utility. Although peak load savings occur in December, January, and February, for the purposes of simplicity, all of the peak lead savings were assumed to occur in January.

4.4 Functional Segregation of Gas Supplies

The generic procedure for allocation of supply to each load savings component assigned both commodity and demand costs. In this procedure, all supply contracts were examined, but only those contracts which have been or are planned to be used to a significant extent were eligible for allocation. This was necessary because supply contracts are usually established for a period of many years. Many changes have occurred in the gas industry over the past five to ten years, and most utilities hold some contracts which may have been useful or prudent in the past but are no longer economically attractive. They then therefore utilize these contracts only to a minimal extent, and may eliminate them as soon as possible. Obviously, such supplies will not be affected by conservation savings and cannot be considered marginal supplies.

The base load in each month was valued as two components. The commodity component was set at the unit cost of the highest priced high load factor or pipeline contract supply. The identity of the contract for the demand component for each month was determined by the identity of the contract selected for the commodity component in January, the month in which the peak day occurs.

The temperature-sensitive load during the winter months was also valued as two components. The commodity component was set at the unit cost of the highest cost storage gas used to a significant extent during that heating season. In addition to the raw commodity unit gas cost, the unit cost of injection and withdrawal must also be included to arrive at the gate station delivered commodity cost in the winter. The demand component was selected from those storage contracts which are served by the same pipeline for which the commodity component was identified.

The temperature-sensitive load during each of the summer months is valued as the simple commodity cost of the contract identified for the base load. Examination of the utilities' dispatch records indicates that little or no storage is withdrawn in the summer. A demand charge allocation was not necessary, because the winter procedure identifies it and assigns it equally to all months of the year.

The peak day peaking portion[12] has two components: commodity and demand. For all four utilities, a propane-air peaking plant was selected as the marginal peaking supply.[13] The commodity component was estimated from EIA wholesale price data for the state of New Jersey, AGA historical utility propane costs and utility supplied data. A ten percent premium was added for fuel use, electric use and other operational costs. The demand component was based upon analysis for an incremental plant.

4.5 Results

Figure 3 presents the annual, nominal dollar savings from all programs for one utility for the period 1986 to 2005. Note that the demand component is small relative to the commodity component. Across all four utilities evaluated, the range of the percentage of demand to total cost savings was 13 to 28 percent.

Overall, the levelized cost of gas estimated with the WACOG method was 30 percent lower (weighted for all utilities) than the TMC approach. These lower gas cost estimates resulted in benefit/cost ratios for each program, using the Total Resource Cost test, of 12 to 31 percent lower.

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[12]Peak day non-peaking components were valued at the base and temperature-sensitive load values discussed above.

[13]The assumption of a propane-air plant as being the "marginal peaking supply," does not mean that it is expected that each gas utility will actually build, or even is currently planning to build, a propane-air peaking plant. Instead, the propane-air plant serves as a proxy unit analogous to the use of a combustion turbine in the electric utility avoided cost analyses. Individual utilities may well opt for alternate strategies for meeting peak, but the use of the propane-air plant provides a "place-holder" cost which serves as a proxy for the costs of a peaking strategy.

The various views of gas unit costs for the historical 1986 to 1987 period by the three methods are shown in Figure 4. It can be seen that the TMC approach estimates are close to the results of the one long-range dispatch model that were available for comparison. The WACOG approach yields estimates lower than either of the other approaches.

5.0 CONCLUSION

Four methods for estimating the value of gas impacts from DSM were discussed:

(1) The Dispatch Model Approach;

(2) The Weighted Average Cost of Gas (WACOG) Approach;

(3) System Marginal Cost Approach; and

(4) Targeted Marginal Cost (TMC) Approach.

The valuation of gas is necessary for performing benefit-cost analyses of DSM programs in integrated planning. These programs could include gas savings from peak shaving and conservation DSM programs as well as base and off-peak sales building.

Use of a dispatch model offers the greatest probable accuracy, but is the most complicated, and such a model may not be available at a given utility. In addition, it is often difficult for even detailed dispatch models to fully reflect the operational constraints of a gas distribution system. As a result the increased complexity may not yield an equivalent increase in the accuracy of the avoided cost estimates.

The WACOG method is easiest to apply, but does not identify cost causation or the supply strategy. Also, the WACOG approach assumes that the utility has no flexibility at all regarding which gas supplies are adjusted when gas is conserved. While this may be the case if there are many contractual and operational constraints influencing gas dispatch, in general, most utilities will have some flexibility. Thus, it may underestimate avoided costs. The system marginal approach partially identifies the supply strategy, but tends to overestimate savings. The TMC approach identifies both cost causation and supply strategy. It provides relatively good accuracy, but is moderately complicated. Table 1 compares the distinguishing attributes of the four approaches.

While the targeted marginal cost of gas approach has some desirable attributes, each gas company will face different contracting options and constraints, and different operating circumstances. The selection of methods to be employed must take the specifics of each company into account. Still, the targeted marginal cost approach is worth serious

consideration by gas utilities that are seeking to obtain avoided and incremental gas cost estimates that are accurate enough for making good business decisions within an integrated planning framework.

Figure 1
Overview of Evaluation Process

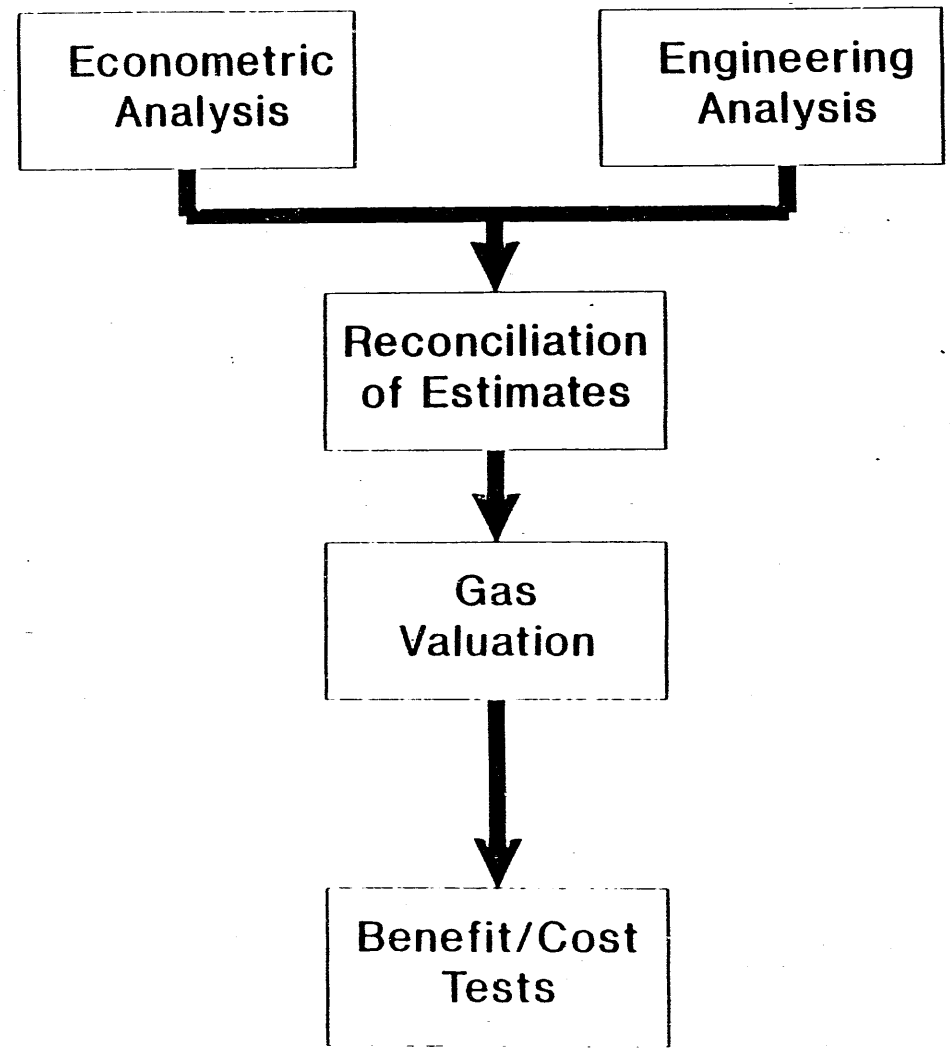
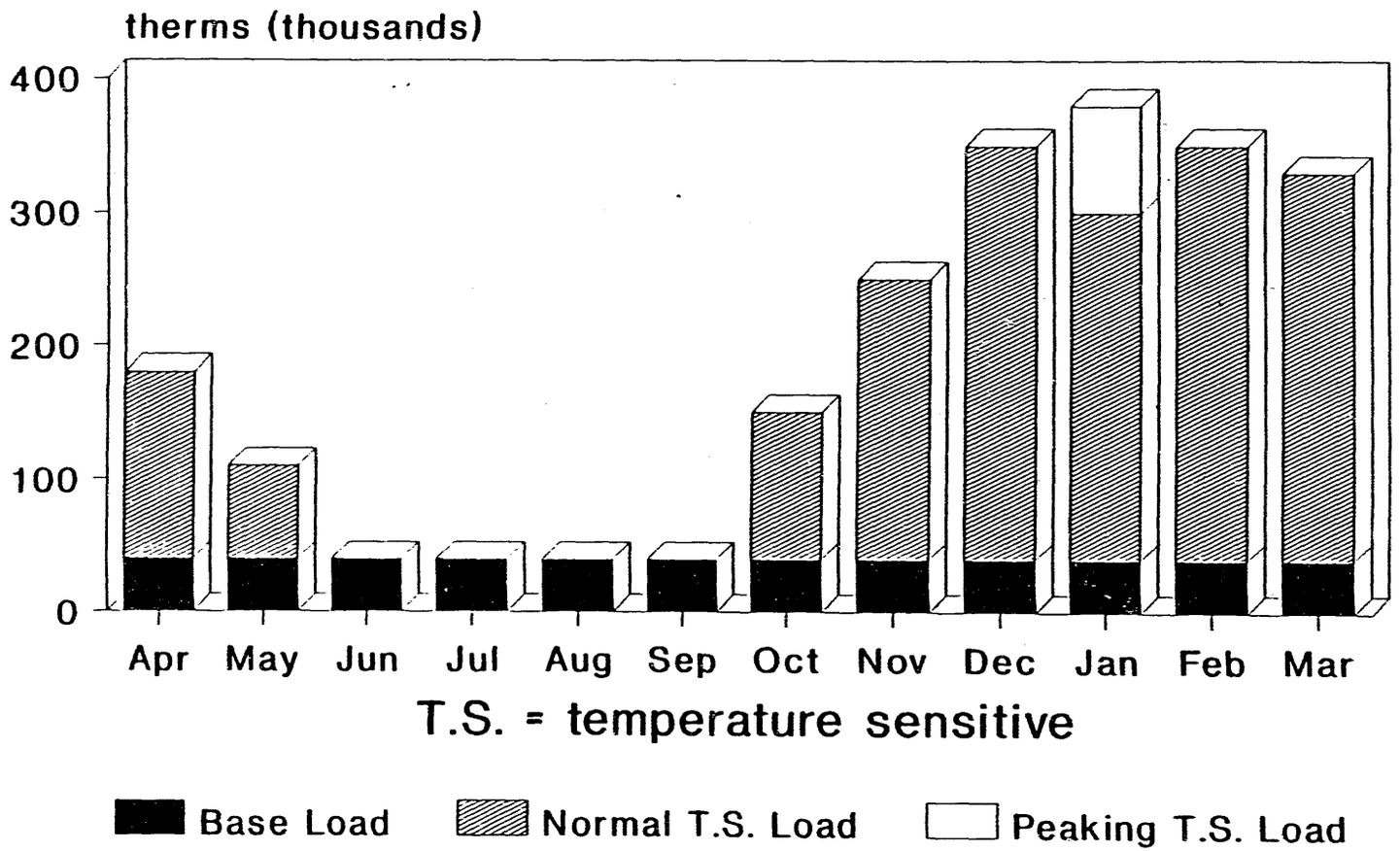
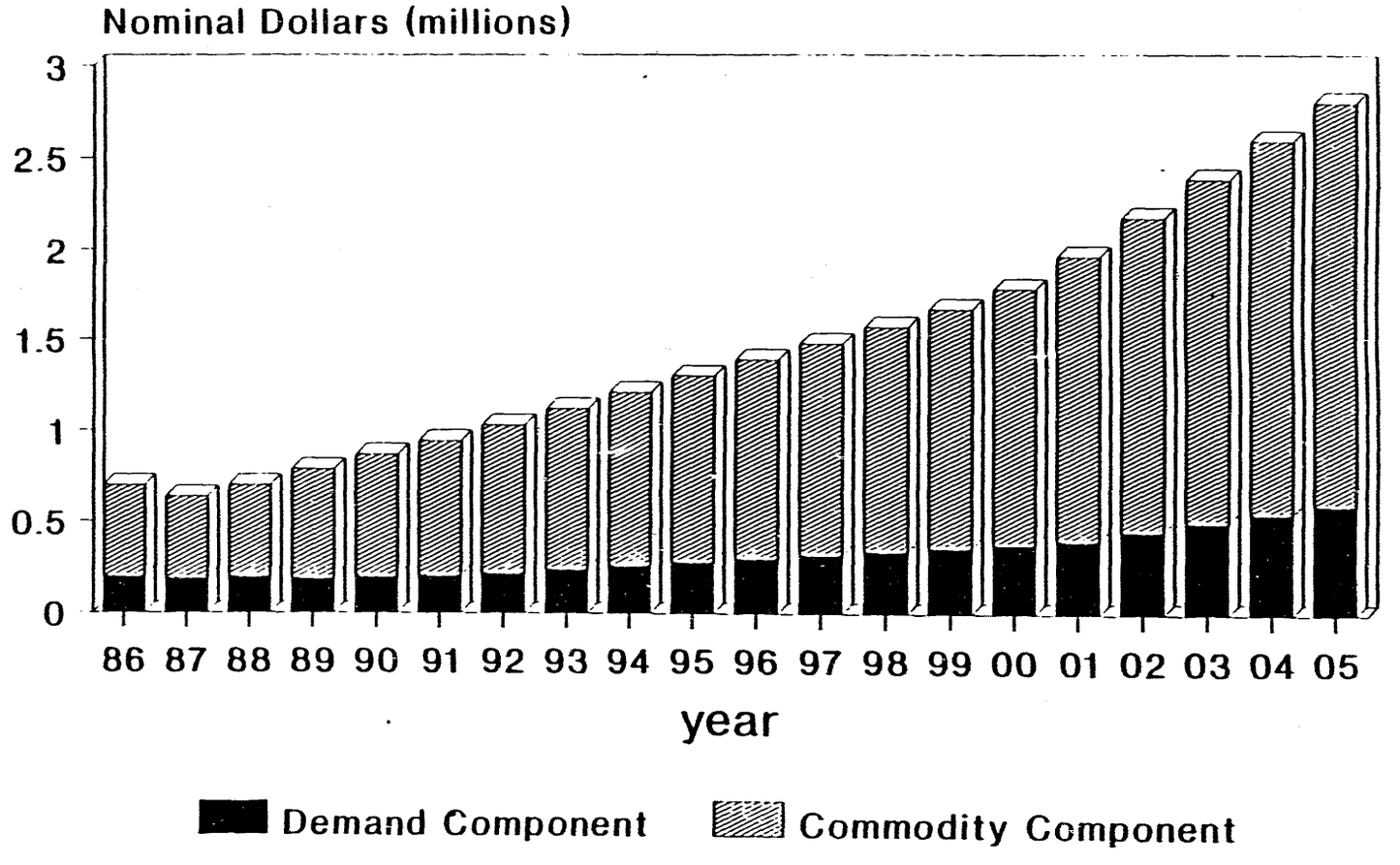


Figure 2
Gas Therm Savings Components



All peaking savings shown in January
for simplicity

Figure 3
Annual Savings Estimate



Example Utility

Figure 4
Various Views of Gas Unit Costs

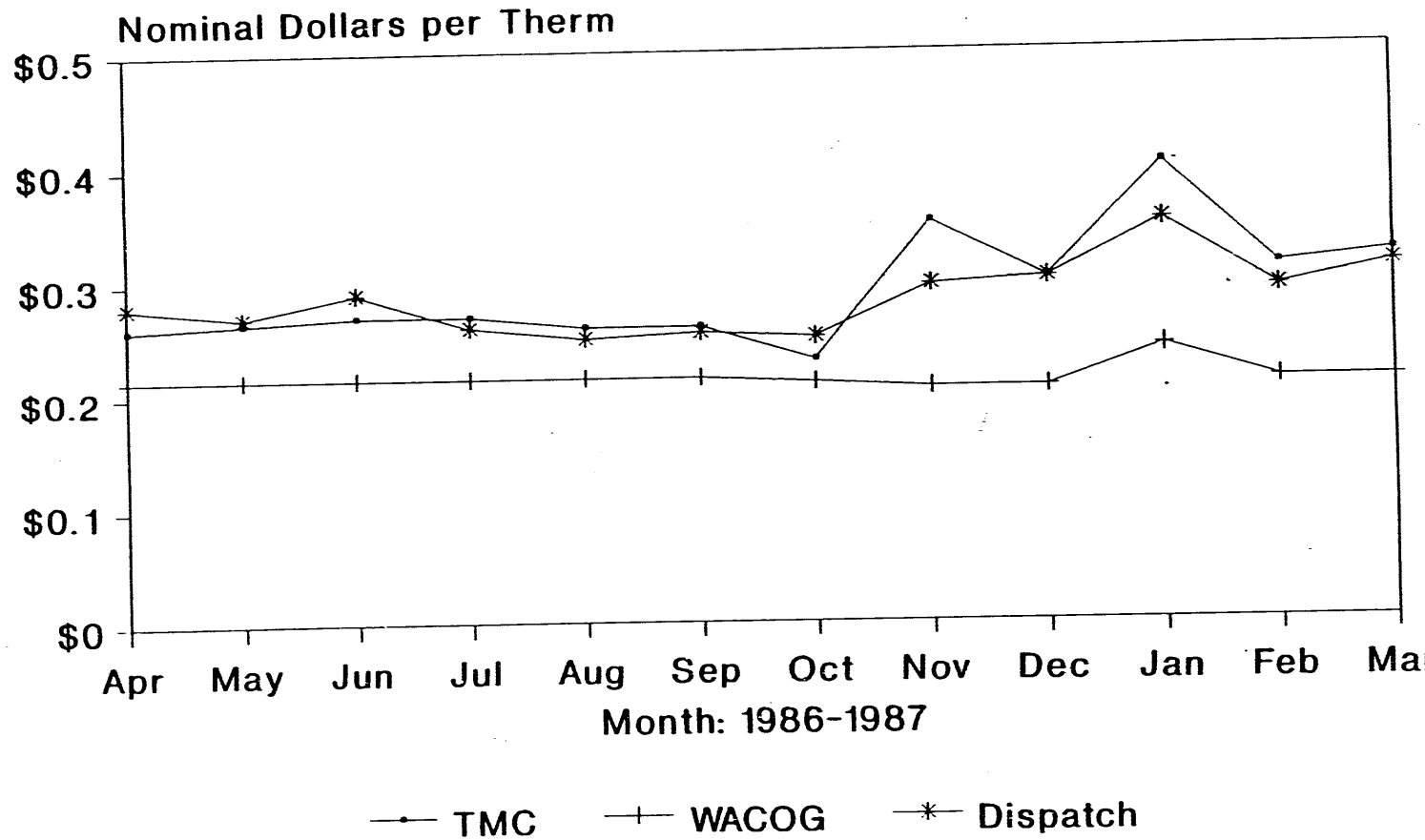


Table 1
Long-Run Gas Savings Valuation Methodologies
Distinguishing Attributes

Methodology	Accuracy	Level of Difficulty	Cost Causation Identified	Supply Strategy Identified
Dispatch Model	Probably Best	Most Complicated	No	Yes
Weighted Average	Bias—Low	Easy	No	No
System Marginal	Bias—High	Moderately Complicated	No	Partially
Targeted Marginal	Close Approximation	Moderately Complicated	Yes	Yes

CALCULATING THE VALUE OF AVOIDED GAS REQUIREMENTS: METHODS AND RESULTS

By:

Richard Hornby

Presented at:

NARUC Third National Conference on
Integrated Resource Planning
Santa Fe, New Mexico
April 8-10, 1991

Tellus Institute
89 Broad Street
Boston, Massachusetts 02110
617/426-5844

CALCULATING THE VALUE OF AVOIDED GAS REQUIREMENTS: METHODS AND RESULTS

Richard Hornby
Tellus Institute

INTRODUCTION

Establishing the value of avoided gas requirements is a critical step in Integrated Resource Planning (IRP). The estimates of avoided costs produced by these calculations are used to determine the economic potential for demand-side management (DSM) measures and electricity-to-gas fuel switching programs. As a result, the objective of providing least cost service to ratepayers depends directly upon accurate avoided cost calculations. The purpose of this paper is to describe the major methodologies and input assumptions used in making these calculations.

Perspective - Whose Avoided Costs? (Slide 1)

The value of avoided gas requirements can be calculated from a variety of perspectives - participant, non-participant, utility, society. This paper is limited to the perspective of a local gas distribution company (LDC) and of society. From an LDC's perspective, investments in conservation result in avoided economic costs (i.e., production, transmission and/or distribution costs). From society's perspective, investments in conservation result in avoided economic costs plus avoided environmental costs (e.g., carbon dioxide emissions, land use impacts).

Valuation Approaches (Slide 2)

The approaches to calculating the value of avoided gas requirements fall into two broad categories - direct calculation and proxy[1].

Direct calculation methods basically determine total system costs with, and without, the DSM measure using a simulation (e.g., dispatch) or optimization model. This

[1] Krause, F. and Eto J., *Least-Cost Utility Planning, A Handbook for Public Utility Commissioners, Volume 2, The Demand Side: Conceptual and Methodological Issues*, National Association of Regulatory Commissioners, Washington, D.C., December 1988.

approach, also referred to as the "dispatch model", "differential revenue requirements" or "decrement" approach is the generally accepted method for determining avoided costs in the electric utility industry. In this approach the Company's cost of providing service under a "business-as-usual" or base case is compared with its costs under a decrement case. The base case reflects the Company's demand/supply balance assuming no utility initiated demand side management initiatives; the decrement case (or cases) reflects the demand/supply balance after the impact of a particular category of demand side measure (e.g., reduction in base load requirements, reduction in heating season requirements). The difference in costs and requirements between the base case and the decrement case is used to calculate unit avoided costs (i.e., $/Mcf), which reflect the value to the utility of the demand side measures.

Proxy methods determine the value of the decrement (or increment) in terms of a specific avoided resource, or resources, identified by the analyst. The avoided resources used for this purpose may be a specific proxy, such as the LDC's next avoidable supply block or a composite proxy, made up of several resources.

If applied properly, both approaches can play a role in IRP. Proxy methods are relatively easy to use and therefore are attractive for "first cut" estimates of avoided costs for preliminary screening of DSM options. Direct calculation methods are more exact and therefore most appropriate for the detailed economic analyses needed to develop an IRP.

Of the two, the direct calculation approach is preferable for two major reasons. First and foremost, **LDCs should be using this approach in their traditional supply planning**. Most of the firm supply resources available to LDCs entail fixed cost commitments over a 5 to 20 year timeframe. Therefore, to develop a traditional "least-cost" supply plan LDCs should be using a long-term planning horizon. Regulators should be pressuring LDCs to use long-term supply-planning models **regardless** of the status of integrated resource planning in their state.

The second reason for favoring a direct calculation approach is that it does **not** involve a significantly greater level of effort. The major difference between the two approaches lies in the identification of avoided resources. Direct calculation approaches use a long-term supply planning model, proxy approaches rely on the judgement of an analyst viewing a short-term supply mix. While supply planning models covering a 5- to 20-year timeframe are currently not common among LDCs, there is no major impediment to their development and use. Several LDCs are already employing this type of model for planning purposes[2].

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[2] Consumers Gas (Ontario, Canada), Washington Gas Light, Southwest Gas Company, Peoples Gas Light and Coke Company, Boston Gas Company.

CALCULATION OF AVOIDED COSTS

Establishing the value of avoided gas requirements with a direct calculation method consist of seven major steps. The "proxy" method consists of the same steps plus one additional step. These steps are as follows (Slide 3):

- Forecast Requirements
- Inventory Potential Resources
- Project Costs of Resources
- Identify Avoided Resource(s)
- Allocate Capacity Costs of Avoided Resource between Avoided Peaking Capacity and Avoided Energy (**proxy method only**)
- Calculate Avoided City-Gate (i.e., Production and Transmission) Costs
- Estimate Avoidable Distribution Costs
- Calculate Avoided Externalities

This section of my paper discusses the key assumptions and methodological issues which arise during each of these steps.

Forecast Requirements

The first step in determining an LDC's avoided gas costs is to generate a long-term (i.e., 10 to 20 year) forecast of its peak day (i.e., peak demand or capacity) and annual (i.e., average demand or energy) sendout requirements under a "reference" or business-as-usual case. This long-term forecast is essential in the proxy approach, as well as the direct calculation approach, in order to identify the marginal or "avoided resources" which would be displaced by the DSM measures. If the LDC is forecasting essentially no growth in requirements the marginal resource will likely be an existing resource; if the LDC is forecasting significant growth the marginal resource will likely be a new resource.

A discussion of the issues which arise in developing a long-term gas requirements forecast is beyond the scope of this paper. Suffice to say that in addition to the

numerous issues which arise in developing any long-term fuel demand forecast, there are several major questions specific to LDCs. These include:

- the "share" natural gas will have in certain competitive energy end-use markets;
- the level of non-core or interruptible customer load (i.e., dual-fuel capable customers); and
- the extent to which customers currently using transportation service will want to subscribe to stand-by sales service or to return to sales service.

The latter two points are particularly important given the fact that from one-third to one-half of an LDC's annual sendout is gas which it is simply "re-delivering" to industrial and commercial "transportation" customers. These customers, many of whom are capable of switching to other fuels, are purchasing their gas from third-party suppliers and having it delivered to the LDC's city-gate for re-delivery to their facilities. In developing a forecast of requirements an LDC must resolve its "obligation to serve" these customers in the long term.

The next step is to determine the size and shape of anticipated change in load over time associated with the DSM or fuel-switching initiative. In a direct calculation approach this determination would be implicit in the long-term forecast of peak and annual demand developed for the "Conservation" case(s). In a proxy calculation approach this determination would take the form of an explicit "decrement".

In either approach it is important to select a realistic decrement. For example, a 5% wedge-shaped annual decrement which reflects the gradual implementation of conservation programs and their cumulative impact over time may be more realistic than a 5% rectangular decrement which assumes a steady level of annual savings. (Slide 4)

The decrement may be further disaggregated into a temperature-sensitive decrement (e.g., an attic insulation program in the residential sector) and a base load decrement (e.g., energy-efficient cooking equipment in the commercial sector), as indicated in Slide 5.

Inventory Potential Resources

The next step is to identify the major gas supply resources potentially available to the LDC over the planning horizon. In order to appreciate the issues which arise in this regard it is important to understand the structure of the gas industry.

Electric utilities typically own most of their production and transmission resources. LDCs typically **contract** for most of their production, transmission and storage resources.

In light of the structural differences between the electric and gas utilities, and the "unbundling" of pipeline services which has taken place over the last several years, LDC resource planners think in terms of the individual components which need to be combined to constitute a supply resource at their city-gate. These components include production (e.g., gas wells, propane-air plant), transportation (e.g., pipeline) and storage (e.g., storage field, LNG facility).

As indicated in Slide 6, these resources can be grouped into three broad categories - firm supplies, non-firm supplies and storage.

- Firm supplies provide the LDC access to fixed levels of capacity and energy at specified times. These resources include service agreements with pipelines, firm direct purchase contracts with third-party suppliers with corresponding firm pipeline transportation agreements, and propane-air plants.

- Non-firm supplies provide the LDC access to energy, but not at fixed levels nor at specified times. One such resource is "best efforts" direct purchase contracts with third-party suppliers plus corresponding transportation arrangements (which may be either firm or interruptible). A second non-firm resource is interruptible sales customers who the LDC may curtail during peak periods. Although the levels of energy available from these resources are not fixed, the LDC can project their availability on a probabilistic basis. For example, the probability of acquiring spot gas is considerably higher in July than it is in January.

- Storage resources are really a special form of firm supplies, in that they provide the LDC access to fixed levels of capacity and energy at specified times. By allowing the LDC to purchase and inject gas in the summer for withdrawal and dispatch in the winter, they allow the utility to transform "non-firm" off-season supplies to "firm" peak season supplies. Storage resources include storage service agreements with pipelines and Liquefied Natural Gas (LNG) facilities, both of which must have the corresponding production and transportation arrangements needed to inject gas into, and withdraw gas from, the storage facility itself.

Again, this inventory is essential in the proxy approach, as well as the direct calculation approach, in order to identify the marginal or "avoided resources" which will be displaced by DSM measures.

Project Costs of Resources

Having identified the major gas supply resources available to the LDC, we now project the cost of each resource over the planning horizon. This can be done relatively easily by establishing the initial cost of the resource and then forecasting the annual rate at which that cost will escalate. The initial cost of the resource can be determined from actual costs for existing resources and from engineering estimates for potential resources (e.g., new pipeline capacity, new propane-air plant).

In interpreting these resource costs one must consider the structure (i.e., fixed versus variable) of each cost component from the perspective of the LDC (Slide 7). Since these cost structures are determined more by contractual and regulatory factors than engineering economics they can change over time. For example:

- Gas Acquisition Costs - LDCs currently see these as "energy" costs since they are paid on a volumetric basis. However, the introduction of Gas Inventory Charges[3] (GICs) means that LDCs will see these costs as a combination of "capacity" and "energy" charges.

- Transportation and Storage Costs - LDCs see these costs in the form of capacity charges - i.e., fixed monthly demand charges, and energy charges - i.e., volumetric transportation charges. However, the level of demand charges relative to volumetric charges can change, and has changed, over time as a result of changes in rate design philosophy (e.g., Seaboard, United, Fixed-Variable, Modified Fixed Variable).

Annual escalation rates for each cost component can be determined from long-term forecasts published by such agencies as the Gas Research Institute, the American Gas Association and the Energy Information Administration. In interpreting these published escalation rates it is important to recognize the essential difference between gas production costs and the other major cost components. Most analyses expect gas acquisition costs to increase in real terms (i.e., faster than inflation) in the long-term since producers must replace depleting reserves on an ongoing basis. In contrast, transportation, storage and distribution costs are typically projected to escalate at lower rates because once these facilities are built the bulk of their costs are fixed in nature.

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[3] A GIC is a fixed rate established by a pipeline to recover, from customers wanting firm sales service, the gas supply costs it incurs in standing ready to provide sales service. The GIC is distinct from D-1 and D-2 demand charges which are designed to recover the pipeline's transmission and/or storage facility costs.

Finally in assessing the unit cost of gas from any of these resources one must be very conscious of the **load factor** at which the resource will be used. For example, gas from a propane-air plant is less expensive than pipeline supply for meeting peaks 10 days per year (i.e., .3 % load factor), it is more expensive than pipeline supply for meeting requirements 250 days per year (i.e., 75% load factor). (Slide 8)

Identify Avoided Resource(s) and Their Costs

In this step the analyst identifies the resource(s) that will be displaced by DSM. This identification is based on the relative economics of the various supply resources available to the LDC and the ability of the LDC to "avoid" the costs associated with those resources, particularly the fixed costs of existing resources.

With direct calculation methods the identification of avoided resources is fairly straightforward. The analyst determines the optimal supply mix for both the Reference and Decrement cases (Slide 9); the two sets of results are then compared to identify the specific resources that have been "avoided" (Slide 10). The advantage of this method is that the "avoided resource" is identified by the Gas Supply Planning section of the LDC with the same analytical techniques they use for their traditional supply planning. As a result, the avoided resource identified by this method will be consistent with the LDC's long-term gas supply strategy.

With proxy methods the identification of avoided resources rests much more heavily upon the judgement of the analyst. This can lead to problems when dealing with a 10 to 20 year planning horizon and an LDC that has access to several supply resources, each with different fixed and variable charge rates.

Consider, for example, an LDC with Contract Demand service agreements with Pipeline A and Pipeline B. The commodity charges of the pipelines are $3.00/Mcf and $2.50/Mcf respectively. The LDC uses a proxy method to identify the supply resource avoided by base load DSM. This method assumes that baseload DSM will be valued at, i.e. will displace, the baseload supply resource with the highest average monthly commodity charge in a particular year. Such a decision rule could very well identify the wrong "avoided resource" from a long-term planning perspective.

The rule would identify Pipeline A as the avoided resource. But, as indicated below, Pipeline B would be the correct avoided resource if the LDC is purchasing gas from these pipelines at an 80% load factor.

	Commodity Charge ($/Mcf)	Demand Charge ($ per year per Mcf/day)	Total Unit Cost @ 80% LF ($/Mcf)
Pipeline A	**$ 3.00**	$ 182.50	$ 3.625
Pipeline B	$ 2.50	$ 365.00	**$ 3.75**

Other factors which could reduce the accuracy of the decision rule would be anticipated changes in the relative economics of the supply resources over time.

A problem common to both direct calculation and proxy methods is an LDC's ability to avoid fixed charges associated with existing capacity which becomes excess as a result of DSM. An LDC in the middle of a long-term sales service agreement may assume that it cannot avoid paying the fixed demand charges associated with that agreement even if it no longer needs the capacity because of a DSM decrement. Such assumptions need to be scrutinized carefully, since the annual fixed costs associated with this capacity may in fact be either partially or fully "avoidable". For example:

- freeing up existing capacity in winter months may allow the LDC to make more interruptible sales;
- the LDC may be able to "broker"[4] its excess pipeline capacity rights to a transportation customer or another LDC;
- the LDC may be able to negotiate a reduction in the capacity commitments in its service agreement.

This last option is realistic because of the national nature of the natural gas industry. A surplus of production capacity relative to demand in one region can often be diverted to serve the needs of other regions of the country. A surplus of interstate pipeline

[4] Capacity brokering involves the selling, trading, or reassigning of firm transportation rights on an interstate pipeline to customers (e.g., LDCs) who, in turn, may be permitted to sell, assign, or reassign those rights to others at unregulated market prices.

capacity relative to the needs of a particular customer can often be reassigned to other customers served by that pipeline.

Allocate Capacity Costs of Avoided Resource Between Avoided Peaking Capacity and Avoided Energy (Proxy Method Only)

The value of a decrement often varies according to its load shape. As a result, many analysts distinguish between the avoided cost of a temperature sensitive decrement and the avoided cost of a base load decrement. Direct calculation methods allow the analyst to calculate the avoided capacity and energy costs associated with these types of decrements from model results. Proxy methods require this additional step.

An avoided resource identified by the proxy method typically has capacity and energy costs associated with it. For example, a pipeline sales service has fixed demand charges and volumetric commodity charges. The question then arises as to whether, and how, the annual fixed capacity costs of the avoided resource should be allocated between avoided temperature sensitive requirements and avoided base load requirements. The importance of this allocation lies not in the calculation of the LDC's total avoided costs, but in determining the relative value of measures with different load shapes, i.e., the value of a temperature sensitive decrement relative to a base load decrement.

The modified peaker method, an allocation approach developed in the electric utility sector, can be used for this purpose. The "modified peaker" method reflects the fact that the capacity available from most types of firm gas supply resources is used to provide peak day capacity **as well as** annual energy. In other words, a pipeline sales service agreement is a source of capacity on a peak day but, as indicated earlier, an LDC would **not** contract for this type of capacity solely for peaking purposes (i.e., 1 day per year or .3% load factor). If a LDC needs capacity solely for meeting peak day requirements, it will typically choose a resource with a low capital cost and a high operating cost, such as a propane air plant.

In order to accurately reflect the dual-services provided by the avoided resource analysts must allocate its capacity costs between "avoided **peaking** capacity" and "avoided energy" categories. The portion allocated to the "avoided peaking capacity" category should be based upon a determination of the LDC's cost of incremental peaking capacity. The remaining portion allocated to the "avoided energy" category should be treated as a commodity cost through the "capitalized energy" concept.

Once the capacity cost of the avoided resource has been allocated between these two categories, the analyst can determine the value of avoided temperature sensitive and base load decrements.

A simple example of this allocation is presented in Slide 9. As indicated in the Slide, failure to recognize this fact may have serious repercussions for the IRP. Specifically the LDC may over-value temperature sensitive decrements and under-value base load decrements. It may also under-estimate the cost of providing gas to customers in off-peak periods, leading to inappropriate rates for summer season sales services.

Estimate Avoidable Distribution Costs

This aspect of avoided cost calculations has received very little attention. LDCs typically do not have significant physical capacity constraints on their distribution systems and the variable cost of moving an incremental therm are usually minimal. Further study needs to be done to determine the extent to which distribution, administrative and general costs can be avoided as a result of DSM measures.

Calculate Avoided Externalities

One method for incorporating environmental impact considerations in energy resource planning is monetization of environmental costs. This can be done by placing a dollar value on the environmental benefits which result from a reduction in gas usage. In other words an environmental avoided cost, expressed in $/therm, is established which can be added to direct economic avoided costs.

A discussion of the merits of different monetization approaches is beyond the scope of this paper. However, it is clear that avoided gas requirements do have a value in terms of avoiding environmental externalities such as carbon dioxide emissions and land impacts from pipeline construction. The existence of these environmental externalities **increases** the value of DSM relative to traditional gas supply resources. The value of these externalities will vary according to the monetization method. As indicated in Slide 10, estimates range from a low of $.15/Mcf in New York to a high of $11.50/Mcf in Southern California.

RESULTS

Examples of direct calculations and proxy approaches can be found in recent gas IRP projects. Direct calculation approaches have been used/are being used by Boston Gas, District of Columbia Natural Gas, Southwest Gas and Consumers Gas. Proxy approaches have been used in New Jersey, New York, California and Wisconsin.

Results from several of these studies are presented in Slide 11. For comparison purposes these results are expressed in terms of a 10-year levelized avoided cost ($1990).

Estimates of the value to a utility of a base load decrement range from $ 3.00/Mcf to $5.00/Mcf, values for temperature sensitive decrements range from $4 to $7. If environmental externality values are added, the social avoided costs are even higher, as indicated in Slide 12. By comparison, the national average city-gate cost of gas in 1990 was approximately $3.00/Mcf.

One of the most interesting features of these avoided cost estimates is the significant variation in individual cost components, as shown in Slide 13. While some of this variation can be explained by differences between LDCs, much of the difference is attributable to differences in terminology and calculation methodologies. This variation indicates that considerable work remains to be done to establish a standard approach to avoided gas cost calculations. Widespread adoption of the direct calculation approach will be an important step in advancing the usefulness and acceptability of IRP as a planning concept in the natural gas industry.

CALCULATING THE VALUE OF AVOIDED GAS REQUIREMENTS: METHODS AND RESULTS

LIST OF SLIDES

1. Perspective
2. Valuation Approaches
3. Steps in Calculating Avoided Costs
4. Requirements Forecast
5. Decrement Load Shapes
6. Potential Supply Resources
7. Cost Structure of Supply Resources
8. Unit Costs of Resources
9. Gas Supply Mix, Reference and Decrement Cases
10. Avoided Resources (Decrement Case)
11. Capacity Cost Allocation
12. Avoided Externalities
13. Utility Avoided Costs
14. Social Avoided Costs
15. Variation in Avoided Cost Components

AVOIDED COST CALCULATION PERSPECTIVES

- DSM Participants
- Non-Participants
- **Natural Gas Utility**
- Electric Utility
- Total Resources
- **Society**

SLIDE 1

VALUATION OF AVOIDED GAS REQUIREMENTS

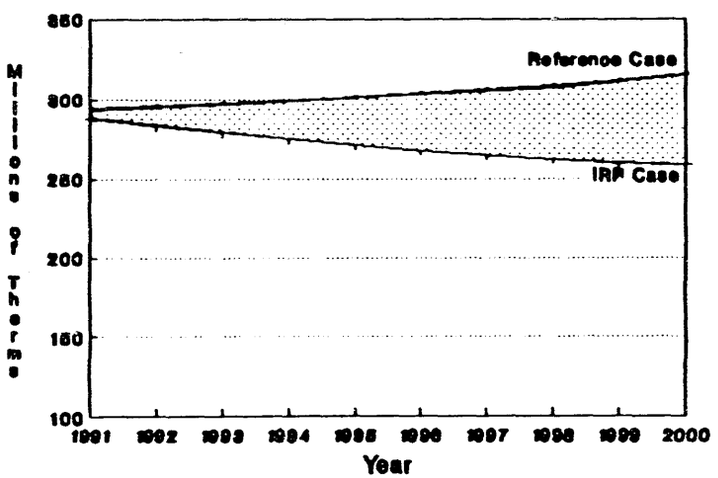
- **Direct Calculation Approaches**
- Proxy Approaches

STEPS IN VALUATION OF AVOIDED GAS REQUIREMENTS

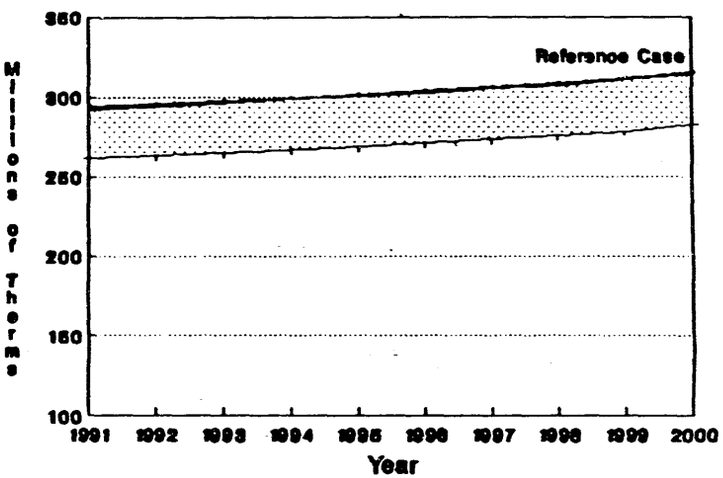
- Forecast Requirements
- Inventory Potential Resources
- Project Costs of Resources
- Allocate Capacity Costs **(Proxy method only)**
- Calculate Avoided City-Gate (i.e. Production and Transmission) Costs
- Estimate Avoided Distribution Costs
- Calculate Avoided Externalities

FORECAST ANNUAL REQUIREMENTS

IRP DECREMENT

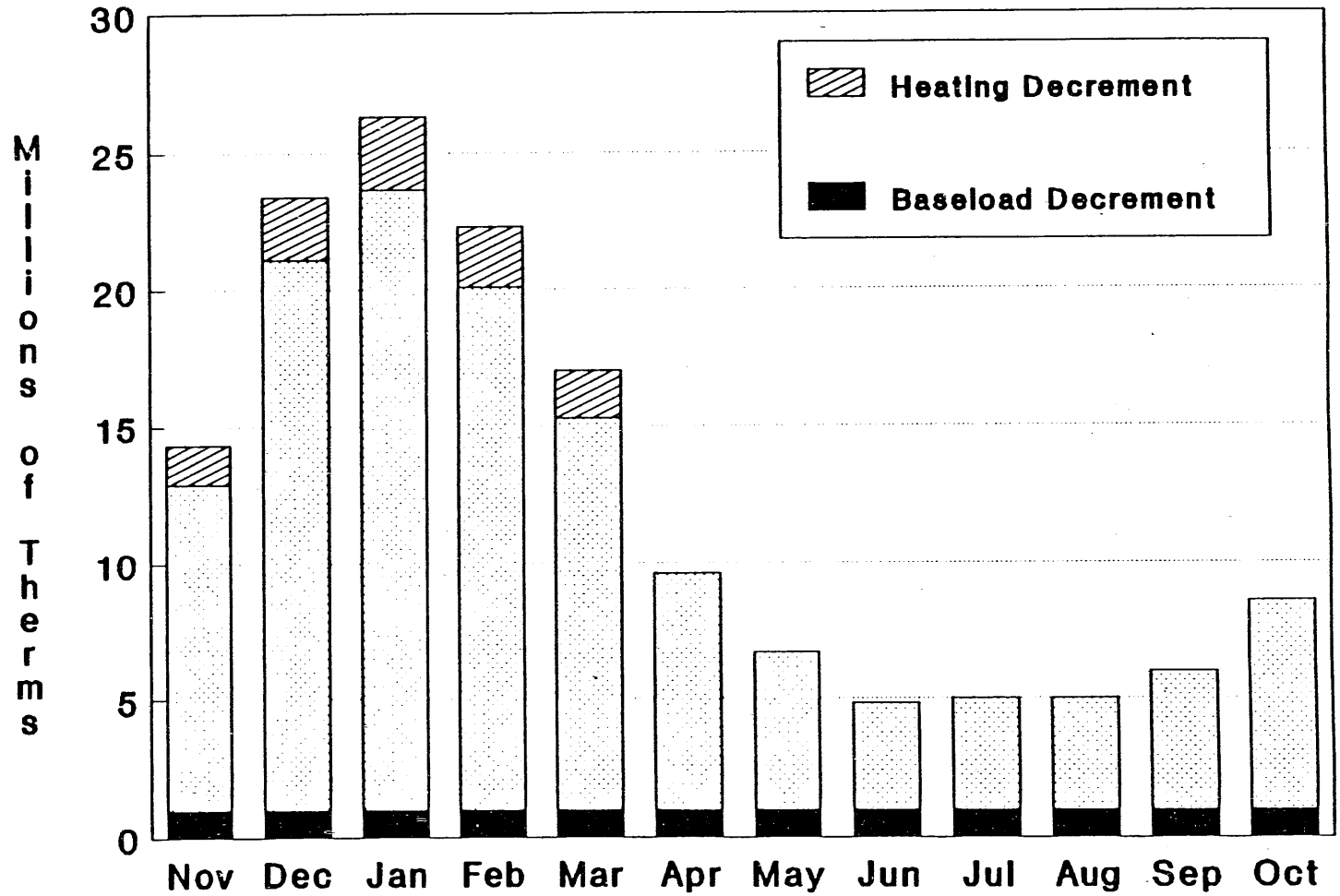


BLOCK DECREMENT



SLIDE

DECREMENT LOAD SHAPES



SLIDE 5

REPRESENTATIVE SUPPLY RESOURCES

Firm

- Contract Demand service agreement with pipeline
- Firm Direct Purchase contract with supplier plus firm transportation service agreement with pipeline.
- Propane-Air Plant.

Non-Firm

- Spot Purchases from supplier delivered under an interruptible service agreement with pipeline.
- Interruptible sales load.

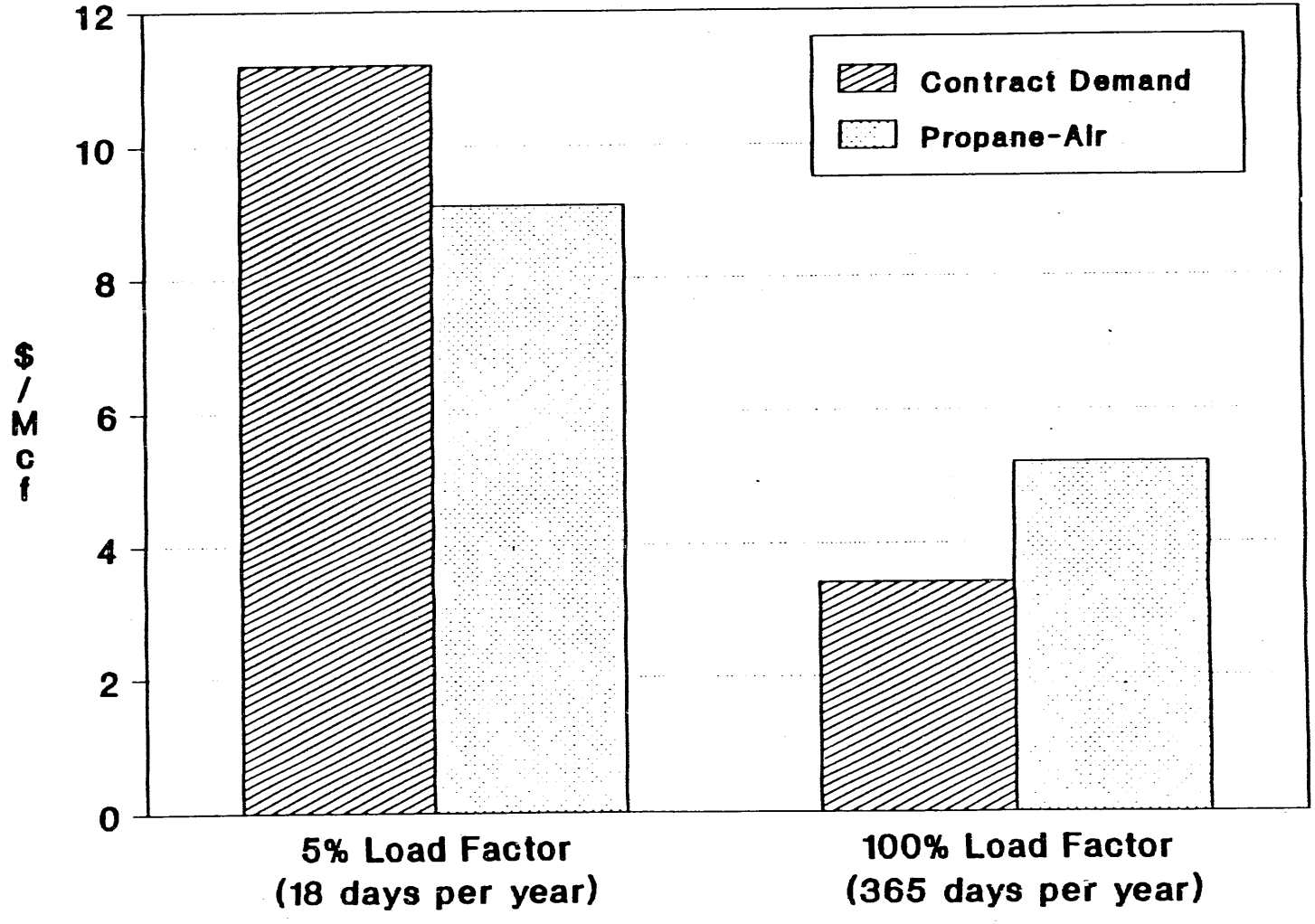
Storage

- Storage Service agreement with pipeline.
- Liquified natural gas (LNG) facility.

Cost Structure of Supply Resources

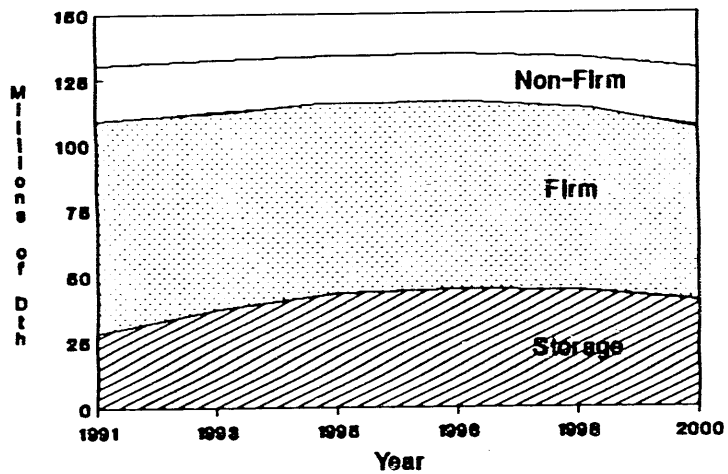
Resource	Costs	Annual Escalation
Contract Demand		
• commodity charge (city gate)	$3.00/Mcf	3.0%
• demand charge (D-1, D-2)	$150/yr/Mcf/day	0.0%
Firm Direct Purchase (new pipeline)		
• acquisition price	$2.00/Mcf	5.5%
• delivery charge	$0.20/Mcf	0.0%
(city gate)	$2.20/Mcf	
• demand charges (D-1, D-2)	$400/yr/Mcf/day	0.0%
Propane-Air (new)		
• fuel price (propane)	$5.00/Mcf	2.5%
• capacity charge	$75/yr/Mcf/day	0.0%
Storage (acquisition, delivery & demand charges depend upon supply source)		
• injection & withdrawal	$0.02/Mcf	0.0%
• capacity charge	$80/yr/Mcf/day	0.0%

UNIT COSTS OF RESOURCES

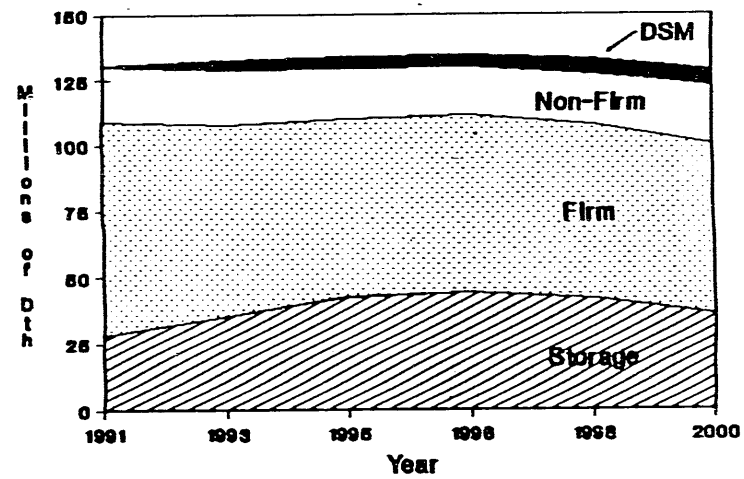


GAS SUPPLY MIX

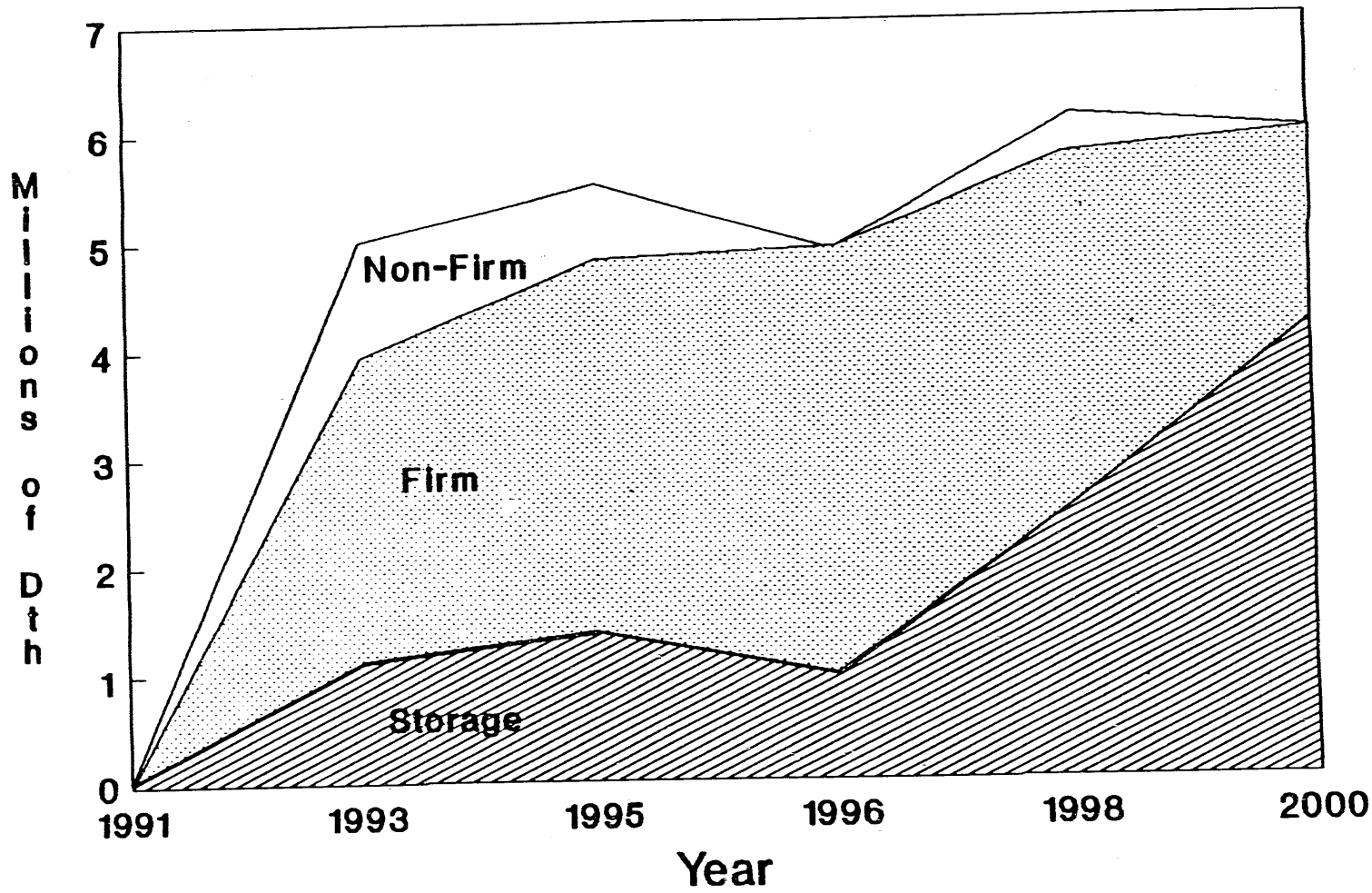
Base Case



Decrement Case



Avoided Resources



SLIDE 1

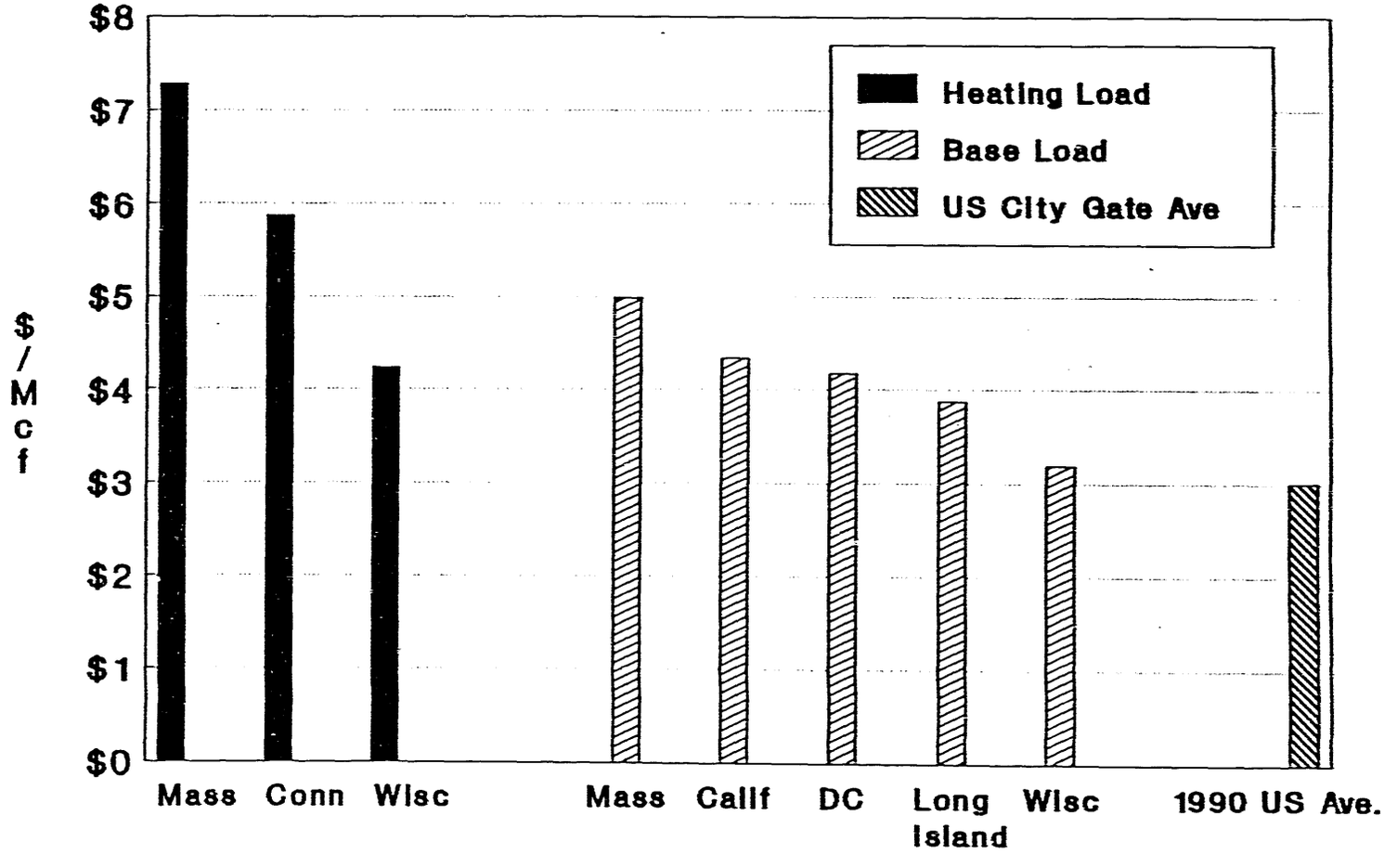
CAPACITY COST ALLOCATION
(Peaking Capacity and Capitalized Energy)

	No Allocation	Allocation
Heating Decrement		
Avoided Capacity Charge	$400	
- Pure Peaking Component	$0	$75
- Capitalized Energy Component	$0	$325
Unit Capacity Cost	$4.57/Mcf	
- Pure Peaking Component (24% LF)	$0.00/Mcf	$0.86/Mcf
- Capitalized Energy Component (100% LF)	$0.00/Mcf	$0.89/Mcf
Avoided Commodity Charge	$3.00/Mcf	$3.00/Mcf
AVOIDED COST	**$7.58/Mcf**	**$4.75/Mcf**

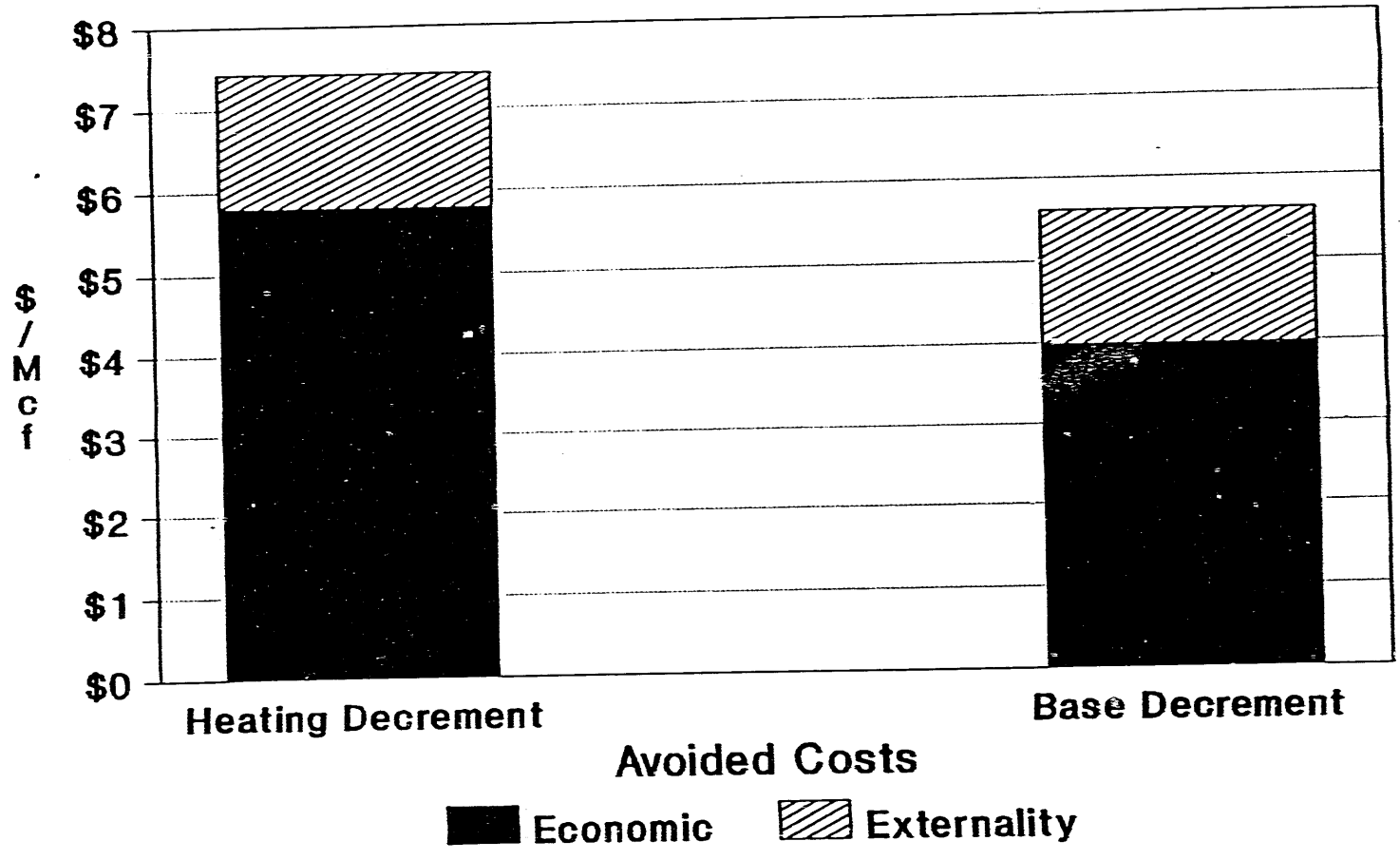
EXTERNALITY VALUES

	levelized (1990$)
Tellus	
• California (SCAQMD)	$11.49/Mcf
• California (CEC)	$0.92/Mcf
• Long Island	$1.62/Mcf
LILCO	
• Long Island	$0.15/Mcf

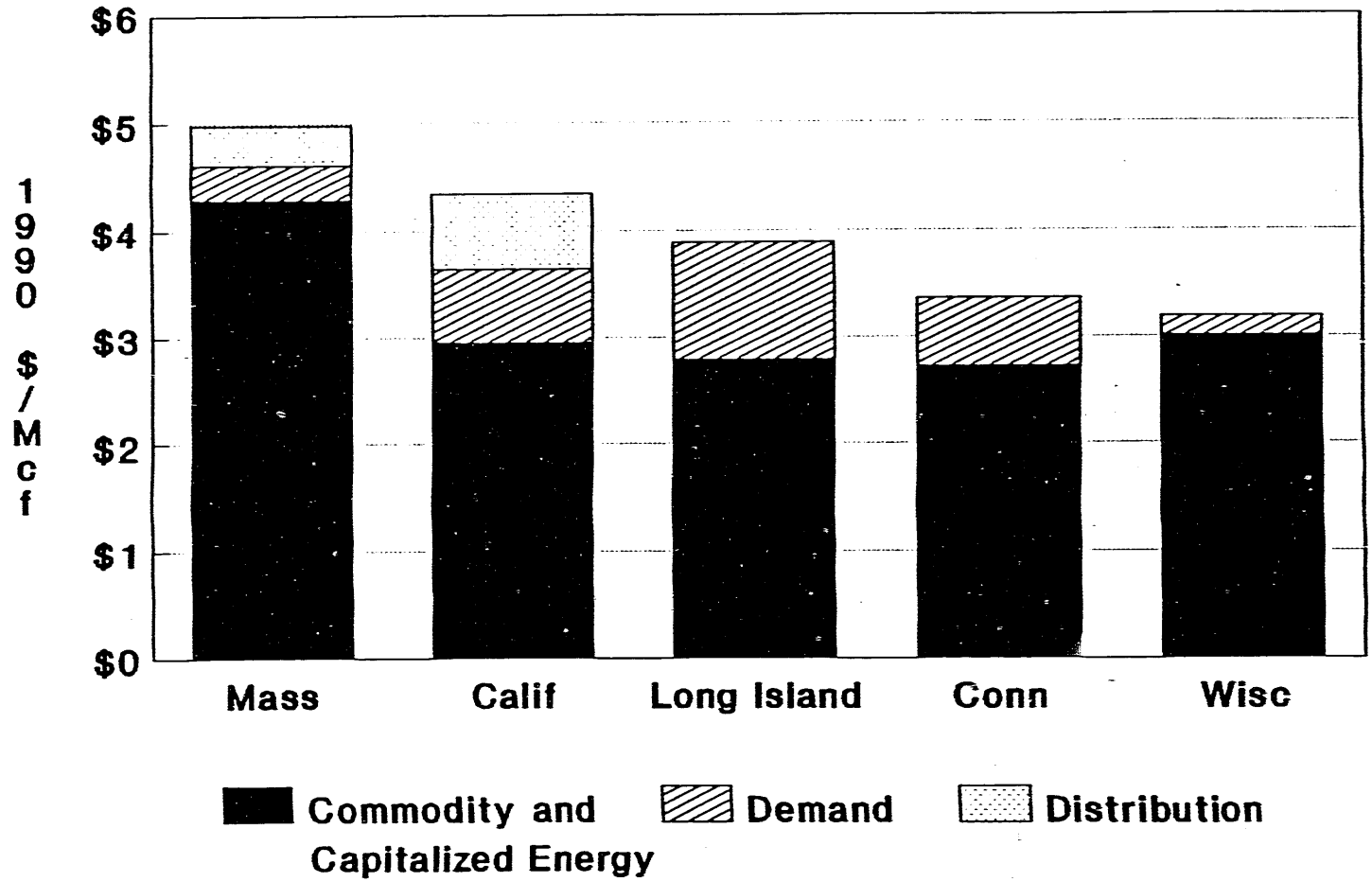
UTILITY AVOIDED COSTS
10 year levelization (1990 $)



SOCIAL AVOIDED COSTS
10 year levelization (1990 $)



AVOIDED COST COMPONENTS
Base Decrement, 10 year levelization



A SYSTEMATIC APPROACH TO GAS INTEGRATED RESOURCE PLANNING

DAVID M. BOONIN, COMMISSIONER
PHILADELPHIA GAS COMMISSION

NARUC THIRD NATIONAL CONFERENCE ON INTEGRATED RESOURCE PLANNING
SANTA FE, MEW MEXICO, APRIL 9, 1991

Over the years, I have witnessed what can only be described as occurrences of peculiar behavior in the utility industry. For example, I have seen:

* gas utilities vigorously pursue new heating load while interrupting base load customers because of inadequate winter supplies,
* gas utilities at "war" with their local electric utilities over air-conditioning load while the electric utility is spending big bucks to control its summer peak,
* the heating season end year after year with large inventories of gas remaining in storage while interrupted customers paid a premium to burn oil,
* gas utilities frustrated by increasing uncollectible expenses while average consumption increased,
* utility management complacently sit by during the debate over the nation's ozone and acid rain problems while transportation fleets in their service territory burn gasoline, and
* gas utilities spend more per Btu to supply a customer than that customer would need to spend if the Btu's were provided by another fuel.

This is not just a list of peculiar behavior but is also a list of symptoms of gas utilities operating without integrated resource plans. This peculiar behavior demonstrates what can happen when a utility is unfamiliar with the full range of resources available to meet its customers' energy needs. It also demonstrates a lack of understanding of how these resources can be joined together into innovative packages which serve both ratepayer and investor.

These symptoms also demonstrate that the regulatory environment faced by these utilities is probably a stifling strict return on rate base approach. Before going any further, let me show my hand. I am a regulator and an economist. As such, I am prone to ask myself when something is not going as it should - for example, a group of utilities aren't minimizing costs - "What am I doing wrong as a regulator to engender this behavior?". Therefore, after laying out the scope of what an integrated resource plan must consider in the gas industry, I want to get back to the regulatory environment necessary to allow for not just integrated resource planning but for the implementation of integrated resource programs. Additionally, as an economist, I believe that a role of regulation is to try to have goods and services provided efficiently - as though competition were providing the guidance through its invisible hand.

Integrated resource planning for gas utilities and for those who regulate them has a scope which goes beyond the gas industry itself. Integrated resource planning extends to the entire energy marketplace and to related environmental concerns. Failure to have a broad perspective will lead to the consideration of far too few resources and will may produce suboptimal results, penalizing not just ratepayers but the entire economy.

It is important to stress the great breadth of resources that need to be considered when developing an integrated resource plan for a gas utility. Although there is much to learn from the experience gained by electric

utilities in the area of integrated resource planning, more competition exists in the gas marketplace than does in the marketplace for electricity. In the electric industry the resource questions are more often ones of competing electric technologies (e.g. compact florescents lights versus incandescent lights). In the gas industry it is often a choice between gas and a competing energy resource. This competitive environment is the source of the breadth of resources which must be considered.

Issues reflective of the competitive environment such as fuel switching gain relative importance in a gas resource plan. An example of a potential fuel switching strategy which might meet the standards of a least cost integrated resource plan is encouraging customers to install gas-cooling in conjunction with electric heat.

In short, the scope of integrated resource planning is basically anything that leads to a least cost result from the consumers' perspective, keeping in mind that utilities should profit and not suffer from good decisions. Areas of an integrated resource plan may include: fuel procurement, peak supply strategy, valley filling, conservation, fuel switching, etc. If a resource has the potential for reducing the total cost paid for energy by gas customers, it should be included in the integrated menu of potential resources.

Before laying out four basic building blocks to systematic integrated resource planning in the gas utility industry, allow me to stress the importance of one other factor - the importance of analytical tests. As we all know the wrong test can lead us to make wrong choices. At this juncture, lets consider two tests which won't get the job done: minimizing the average cost per mcf (often equivalent to the rate) and the total cost of gas to the ratepayer.

I can recall trying to convince a summer peaking electric utility that using minimum average cost per kwh as their resource test could lead them to embrace the wrong resources. Initially, this advice fell on deaf ears. It wasn't until I proposed shooting out thew windows of all the electric heating customers as a strategy for reducing the average cost per kwh that they decided to abandon this ill conceived test.

Given the breadth of resource options that a gas integrated resource plan must include, it can also be misleading to only consider the total cost of gas. In fact, gas costs could go up and total energy costs could go down in cases where cost effective fuel switching is the resource approach.

With the guidelines of breadth, the need for proper tests and the importance of a conducive regulatory environment under our belts, lets move forward.

Here are four tasks which must be included in the systematic development of any integrated resource plan.

1) KNOW THE LOAD: If you want to influence your own future, it is imperative that you understand your current situation and where you think you may be heading without your intervention. This is true whether the issue is personal finances, health planning or integrated resource planning in the gas utility industry. What is the gas utility's current and forecasted load? How do customers in the service territory use gas and meet their energy needs? Again, it is not enough to know just how gas is used but how other energy is used and could be used.

Gaining this information requires performing end-use surveys of gas customers and competitors' customers. The end use analysis must include potential uses of gas. For example, if customers' cooling needs are not understood - needs which are probably met by electricity - how are gas cooling options to be considered? If the steam and electric usage patterns of certain customers are not known how can cogeneration be considered as a resource? What about compressed natural gas for transportation applications, especially for fleets?

End-use data needs to be linked to demographic information. For instance, a conservation program targeted to low income heating customers may be beneficial, although the same program when applied to all customers may not be beneficial.

A complete end-use data base also requires keeping abreast of changing technologies and economics to identify potential market opportunities. For example, have the economics of gas co-fired electric generation changed with the passage of the Clean Air Act?

A final consideration in the needs assessment is what level of reliability is desirable and or required in serving each of these end-uses or potential uses. This becomes a question of not just cost but of public policy.

Competition, end uses, demographics, changing technologies and reliability are all important parts of knowing both the current and the potential load.

2) SUPPLY RESOURCES - PLANNING & PROCUREMENT: Although all resources require planning and procurement, for clarity, I am limiting this section to gas supply planning and procurement. For years, commissions have been monitoring the gas procurement practices of utilities. The question asked has been, is the lowest cost mix of gas being purchased. Issues such as take-or-pay, spot versus contract supplies, transportation gas have dotted this landscape.

In the area of supply planning, peak resource issues have received attention. How much LNG, storage, LPG, etc. is needed to meet firm demand requirements? Probably not enough attention has been given to the question of what options to reliably supplying peak demand are available and plausible and what is meant by the term "reliable". That of course brings us right back to the core of this conference, integrated resource planning. When developing systematic integrated resource plans (whether with supply or demand resources), utilities and commissions must be prepared to face the difficult questions of reliability versus cost trade-offs.

Additionally, and more in the area of the other speakers on this panel, having a solid understanding of the gas marketplace and the avoidable resources and costs is imperative to making rational integrated planning decision. Without belaboring this issue, proper assessment, quantification and inclusion of demand charges, long term avoided costs and supply risks are critical if integrated resource planning is to be performed fairly, completely and systematically.

3) RESOURCE MENU: Again, forgive the arbitrary split between supply and demand, but this section will focus on the demand side. As with any menu, there is a left side and a right side. The left side is driven by the results of the load

analysis. What potential opportunities exist for conservation and load management? Many utilities face the problem of poor load load factors, caused by space heating requirements. In addition to seeking ways of shaving the peak through programs such as insulation and interruptible service, utilities in this situation may also wish to consider encouraging valley filling programs such as gas air-conditioning. End uses with flat load factors such as cogeneration and compressed natural gas vehicles may also be beneficial to utilities with poor load factors. Building the left side of the resource menu takes creativity, an ability to listen to existing and potential customers and a willingness to explore new ideas.

The right side of the menu is where these concepts start to come together into an integrated resource plan. This is achieved by not just looking at the costs associated with a program but the benefits. Benefits in addition to gas related savings must be included where applicable.

The estimation of costs is not always straight forward and often requires more than just picking up a supply catalogue or engineering manual. Think about a relatively simple program - a water heater wrap program, for example. What are the program's fixed and variable costs? What participation rate is expected? Is there a free rider issue? What income is added or lost? As you can see there is room for "reasonable minds" to differ.

Program costing gets more complex and accurate, when the analyst is willing to consider what are often considered secondary costs or externalities. For example, a least cost component of an integrated resource plan could include a low income conservation plan. If the only costs that were acknowledged in this analysis were the direct program costs and the avoided cost of gas a full appreciation of this program would not be gathered. It would also be necessary to consider secondary issues such as reduction in uncollectible expenses. It may also be necessary to include as a benefit the sales to a base load customer (e.g. a cogenerator) which is now possible because peak resources have been made available through this program.

In the area of externalities, it may be desirable to include the value of clean domestic fuels when considering fuel switching. Electric utilities and especially combination gas and electric utilities may wish to get involved in programs where environmental benefits exist. I should note that when considering externalities and secondary impacts it is important to treat all resources with a common degree of scrutiny. Biased results will be the by-product of including the environmental costs of one resource (possibly because they have been internalized through legislation) while ignoring the environmental costs (because they remain externalities) of other resources.

4) OPTION COMPARISON: We now have a list of options - both supply and demand resources. We have estimates of the costs which pursuing these strategies would place upon customers. What test should be used to determine which resources should be incorporated into an integrated resource portfolio? We know not to use average cost per mcf nor to use the total cost of gas. What test should then be used to determine what load to pursue and where to target conservation? Which supply resources should be enhanced and which ones purged? In making these decisions, utilities and consumers have different perspectives.

Utilities want to increase their sales base. More than that, they want to keep rates for services facing competition low. More than that, they want to maximize profits.

Consumers want low rates. More than that, they want a low gas bill. More than that, they want low total energy bills.

Indeed, it is the last desire of utilities and consumers which should direct resource choices. Maximization of profits (subject to regulatory constraints) and minimization of total energy costs to the ratepayers (subject to quality of service constraints) are the tests which represent the utilities' and ratepayers' perspective on these resource decisions.

At times these two goals - energy cost minimization and profit maximization - do conflict. For example some conservation programs minimize costs but also require that the utility forego potential profit. These conflicts can be avoided, however, by using the cost minimization test exclusively and regulators create an environment where utilities profit from cost minimization.

One way of accomplishing this is to allow utilities to recover lost income which accumulates between rate cases associated with a conservation programs. This can be accomplished by allowing a utility to recover the costs of such activities through separate tariff clauses on a current basis or by allowing the capitalization of such costs for recovery in the future. Shared savings approaches sometimes have interim benefits in creating a favorable regulatory atmosphere. Another regulatory device would be to allow for contract cancellation costs to be recovered when it can be shown that cancelling a supply contract plus the associated cancellation costs is cheaper than continuing the contract. Of course prudence must be demonstrated by the utility. Although the "carrots" just mentioned are generally preferable approaches, excess supply or inefficiency adjustments in rate proceedings are other ways of creating a least cost regulatory environment.

These tools do work. The management of one electric utility with whom I have had extensive dealings decided that gas air-conditioning may actually be a way to control peak demand growth. This occurred after years of not giving serious consideration to this technology. What caused this change? In my view, it was their commission's apparent willingness to allow for full cost recovery, including lost income, on a current basis. These cost recovery mechanisms can also provide the regulator with better oversight of the implementation of resource plans. Dollars are not simply budgeted in a rate case and then forgotten.

For integrated resource planning to be successful for gas utilities it must be systematic. This requires four general building blocks: know the load, efficient supply planning and procurement, a comprehensive resource menu including a complete "right side" and a rigorous and appropriate option comparison test. For this process to be meaningful, systematic resource planning must include a broad based exploration of options which provide energy services to consumers at the least cost while rewarding utilities who successfully pursue least cost strategies. When integrated resource planning is performed systematically, the solutions which are found will bring the efficiency of this regulated sector of the economy closer to the competitive solution. Although not quite the "invisible hand" of competition where profit maximizing behavior by each individual leads to the efficient solution - systematic resource planning by gas utilities and their regulators can lead to solutions which benefit consumers, investors and the general economy.

RATEMAKING FOR ELECTRIC UTILITIES IN LIGHT OF DSM AND ENVIRONMENTAL EXTERNALITIES

By:

John Stutz

Presented at:

NARUC Third National Conference on
Integrated Resource Planning
Santa Fe, New Mexico
April 8-10, 1991

Tellus Institute
89 Broad Street
Boston, Massachusetts 02110
617/426-5844

RATEMAKING FOR ELECTRIC UTILITIES IN LIGHT OF DSM AND ENVIRONMENTAL EXTERNALITIES

John Stutz
Vice President - Tellus Institute

Introduction

As is the case in most areas of the U.S. economy, the electric utility industry undergoes a process of constant change. Currently, the inclusion of demand-side management (DSM) and environmental externalities ("externalities") within the framework of utility planning is a major source of change in the industry.[1] In this paper I will focus on the impact of DSM and externalities on electric utility ratemaking. This is a natural extension of the discussion of DSM and externalities as part of the utility planning process.

Currently DSM and environmental externalities are recognized as legitimate parts of the electric utility planning process. This is reflected, for example, in the description of the planning process provided in the *NARUC Handbook*:

> Least-cost planning is a way of analyzing the growth and operation of utilities that considers a wide variety of both supply and demand factors so the optimal way of providing electric service to the public can be determined. A path is chosen that will ensure reliable service for the customers, economic stability and a reasonable return on investment for the utility, environmental protection, equity among ratepayers, and the lowest costs to the utility and the consumer.
>
> (*Least-Cost Utility Planning Handbook for Public Utility Commissioners*, Vol. 1, NARUC, Oct. 1988)

At the state level there have been numerous considerations of the role of DSM in utility planning. Recently a number of states have discussed externalities as part of their consideration of the utility planning process, and some cases have required that environmental externalities be considered explicitly in the planning process.[2]

In a recent paper, presented at the NARUC meeting in Los Angeles, I discussed recent developments in utility planning, particularly the expansion of traditional approaches to the broader notion of integrated resource planning (IRP), and the relationship of planning to ratemaking.[3] I pointed out that, while there is currently some linkage between planning and ratemaking, there are still important gaps in the relationship between the two.

I suggested that it might be appropriate to design rates, in part, so as to meet the objectives of least cost planning. Others have made similar suggestions. Commissioner Myron Katz of Oregon has suggested a procedure he calls "Reverse Ramsey Pricing" in order to bring ratemaking into better agreement with the goals of IRP.[4]

My L.A. paper and the discussion by Commissioner Katz both deal with the connection between ratemaking and DSM and externalities without looking at the details of the connection. In particular, what is lacking is a thorough discussion of the connection between DSM and environmental externalities and the development of the charges per kW or kWh, included in rates. That connection will be the major theme of my discussion here.

Rate design should be consistent with the utility planning process. Here I will argue that such consistency leads to rates in which the charges, per kW or kWh, are based in part on marginal costs which take into account the cost of environmental externalities. As I will explain, DSM is a natural and important part of this argument.

I will discuss three rate forms, beginning with a simple, two-part retail rate, and going on to a wholesale rate and a three-part rate. In each instance the focus will be on the changes caused by the use of marginal costs which take into account the cost of externalities. While I will focus on marginal costs and rates, but I will not ignore either embedded costs or the setting of class rates or return. Both will be discussed.

The approaches discussed in this paper rely on the use of both marginal costs for ratemaking and the inclusion of the costs associated with externalities in utility planning. Some may be sympathetic to the general concerns raised here but unwilling to embrace the approach proposed. With that in mind I would point out that the concerns discussed here could, and probably should, lead to the reconsideration of traditional ratemaking practices on their own terms. I will provide one example of such a fresh look.

The discussion in the body of this paper relates only to the electric utility industry. One could consider similar issues for the gas industry. There is currently a greater linkage between the gas and electricity industries than has existed in the past, due in part to concerns about DSM and externalities. I hope to address both industries in a subsequent paper.

The Main Argument

Electric utility ratemaking begins with the utility's allowed revenues. It involves a two-step process. First one develops class revenue requirements and then one designs rates to produce the revenue required from each rate class. This process is based on two sets of cost studies, embedded cost-of-service studies and marginal cost studies. It is in these studies, particularly those of marginal costs, that one finds the root of the connection between DSM and externalities, and the charges included in electric rates. The

consideration of marginal cost studies also provides the basis for linking DSM and environmental externalities in this paper.

The main argument I want to present in this paper goes as follows:

- An important benefit of DSM is the avoidance of externalities associated with incremental electric production. Concern with the correct valuation of DSM leads to the inclusion of the cost of externalities in the computation of avoided costs.

- The development of avoided costs and marginal costs are two sides of the same coin. If environmental costs are included in avoided costs, then they must also be included in the development of marginal costs.

- Marginal costs are a major factor in setting the "tailblock" charges in utility rates. The cost of externalities enters the charges in rates via the use of marginal costs to design rates.

- Changes in the cost of incremental consumption, based on marginal costs, in turn impact the savings potential of DSM.

Marginal costs are both the natural choice for use in pricing "tailblock" usage and the natural vehicle by which to introduce considerations involving DSM and externalities into the ratemaking process. It is the multifaceted role of marginal costs which makes my main argument work. In light of this fact it is useful to look carefully at the development and use of marginal costs in the ratemaking process. In the course of doing so in the next section I will both amplify my main argument and raise some questions about the role which embedded costs have traditionally played in setting revenue requirements for rate classes.

Cost Studies

Ratemaking is an essentially quantitative undertaking. One of its key objectives is the development of the charges, per kW or kWh, in a utility's rates, on the basis of which the utility collects the bulk of its revenues. (Rates also contain customer charges, but I will not discuss them since they are not related to my concerns here.) These charges are based on a variety of considerations, enumerated for example in Bonbright's well-known *Criteria for a Sound Rate Structure*.[5] The entire ratemaking process rests on an analysis of the utility's marginal and average cost of providing service. These are provided respectively, in the marginal cost studies and embedded cost-of-service studies prepared routinely by many electric utilities. Here we will assume some familiarity with the mechanics of such studies. They are described in a number of places.[6]

Marginal and embedded cost studies both provide costs which can be used to develop the kW and kWh charges reflected in electric rates. Here I will focus initially on the marginal costs. Marginal energy and demand costs are simply the cost of supplying the last kWh or meeting the last kW of demand. (I have used the term "the last" to avoid wandering into a discussion of incremental vs. decremental calculations, which is beyond the scope of my discussion here.) Since any customer can be responsible for "the last" kWh or kW, it is plausible to base "tailblock" charges on marginal costs.

There are, in fact, two separate lines of thought which support basing charges in electric rates on marginal costs. One follows from general considerations of economic efficiency which prescribe setting prices at the marginal cost of production. Despite problems of a revenue constraint of second-best pricing [7], economic efficiency arguments of a general sort are generally cited as a basis for the use of marginal costs to price at least incremental demand and usage. A second line of thought looks more narrowly at the efficiency of the utility industry. The cost of producing an additional kWh is simply the marginal cost of energy. Similarly the incremental cost of meeting current or future demands is the utility's marginal demand cost. With this in mind one does not have to invoke general economic theory to justify charges based on marginal costs. One simply has to agree that charges to the customer should reflect the costs which their additional consumption or demand causes the utility to incur.

The connection between utility planning and marginal costs leads directly to the need for incorporation of costs associated with environmental externalities in the estimation of marginal costs. Economic theory and common sense both suggest that those whose activities create environmental externalities should face a cost structure which forces them to incorporate those externalities into their decision-making process. Normally this involves a tax which internalizes the cost of the externality.[8] In the case of an electric utility this means including the cost of such externalities in their planning process. Regulation can't include an "environmental tax" directly in the utility's total costs without radically changing the way revenue requirements are set. However, it can have the same effect by requiring utility planners to account fully for the costs of externalities in the development of their least cost plans. With the emergence of DSM as an important factor in electric utility planning, the consideration of externalities in the development of least cost plans becomes essential.

Investment in DSM provides an alternative to the production of additional electricity, as well as a means of deferring or avoiding the addition of generating capacity. A key issue is the value of such avoidance. If one does not include the environmental benefits of avoidance, DSM will be undervalued. Thus correct valuation of DSM forces the consideration of externalities into the utility planning process. Of course externalities should have part of the planning process all along. But when the only real response to growth was to build, the outcome of the planning process didn't turn sharply on their presence or absence. With the advent of large-scale utility DSM programs it may.

Once one has decided to include the costs associated with externalities within the utility planning process, these costs become part of both the utility's avoided cost computations and the development of marginal costs. Both reflect the change in a utility's required revenues due to perturbing the utility's least cost plan. Indeed, in describing the methods for the development of avoided costs, the National Regulatory Research Institute relied on the existing methods for computing marginal costs.[9]

The role of DSM and the environment is quite different in the development of embedded costs than it is for marginal costs. Utility investments associated with these areas will be reflected in the utility's costs. And the impact of DSM will be reflected in the development of the allocators used in embedded cost studies. DSM investment alone can influence rates and bills.[10] However, there is little possibility for the reflection of externalities in embedded costs. Every kWh produced has associated externalities. However, since the logic of an embedded cost study requires that the costs considered be part of the utility's allowed revenues, there is no reasonable way to take these costs into account in an embedded cost study. One could simply put "adders" into the calculations, but then one would no longer be discussing embedded costs. A similar problem arises with the allowances created by the Clean Air Act. They clearly have a value, and in fact they have already become an aspect of sales of generating plant between utilities. However, they are certainly not embedded costs.

The inability to reflect externalities undercuts, in a fundamental way, the support for the use of embedded costs in setting class revenue requirements. The argument for the use of embedded costs, and particularly class rates of return, is based in large part on fairness. Each class should pay the costs imposed on the utility to meet its demand and consumption requirements. Class rates of return indicate the extent to which the revenues from a rate class cover its share of expenses, including debt, plus a return on its share of the rate base. Relative equality of class rates of return is thus one measure of fairness.

There is an obvious problem with the use of embedded cost study results to test if rate classes pay a fair amount. Such a test ignores entirely the costs due to externalities associated with the production of electricity. This does not mean that the results of embedded costs studies should not be considered at all in setting class revenue requirements. However, in light of a concern with environmental externalities and their associated costs embedded cost studies should be given less weight, and methods which reflect marginal energy and demand costs that include the cost of those externalities be given greater weight in setting class revenue requirements. One such method is to set class revenue requirements in proportion to the fraction of a utility's total marginal energy and demand costs which are contributed by each class. (Total marginal costs are simply the result of pricing all consumption and demand at marginal cost.)

Having discussed the costs used in the ratemaking process in light of a concern with DSM externalities, I now want to turn to the discussion of the impacts which might occur in rates if such marginal energy and demand costs were used to set the charges in rates.

Rate Design

Rate design for an electric utility is a complex process. One way to simplify its discussion is to divide the process into a qualitative step, in which the form and structure of the rate are selected, and a quantitative step in which the charges appropriate to the form and structure selected are specified. For example as a form one might select a two-part rate, consisting of a monthly customer charge and charges per kWh. This is given structure by deciding if the kWh charges will be seasonally differentiated and if there will be blocks or flat charge(s). Once form and structure have been specified, charges must be developed. For a seasonal two-part rate, one might set the customer charge to cover the cost of a meter, service drop and billing, and set the tailblocks based on summer and winter marginal cost. The initial block is then priced residually to meet the class revenue requirement.

Once externalities are reflected in the utility planning process, the computation of marginal costs will be affected dramatically. For example, marginal energy costs will increase due to the addition of "adders" for emission impacts to the production costs. Tellus studies suggest adders of about $.05 to $.10 per kWh for existing plants and $.01 to $.05 per kWh for new plants with the cleanest technology![11] Changes in dispatch order based on the recognition of environmental costs could further increase marginal energy costs. Discussion of marginal demand costs is more complex, due in part to the wide diversity of approaches to the calculation of these costs. However, examination of marginal energy costs alone is enough to make my key point: once externalities are taken into account, marginal costs will likely increase substantially.

In the case of the seasonal two-part rate discussed above, my analysis leads to precisely the situation envisioned by Commissioner Katz in his discussion of Reverse Ramsey Pricing. Commissioner Katz argued that the tailblock in such a rate "...should be placed at a level which reflects marginal costs and externalities." Commissioner Katz assumed that this would lead to an inclining block rate, or at least that it should. I have shown that it is appropriate to include the externalities in the computation of marginal costs. Normal rate design procedure suggests that the tailblock be priced at marginal cost. Given the size of the impact of externalities on the computation of marginal costs, this should lead directly to inclining block rates. Thus, consistent application of utility planning and costing principles, including the internalization of externalities and normal rate design procedures, will produce rates which meet the objectives set forth in Commissioner Katz's approach.

In Commissioner Katz's approach there is no discussion of seasonal differentiation. In my example I have postulated a seasonally-differentiated, two-part rate. Often electric utilities which use two-part rates for their residential customers incorporate inclining blocks during the on-peak season and declining blocks during the off-peak season. Here I want to draw attention to potential impacts in the off-peak season, due to the inclusion of externalities.

Marginal energy costs for the off-peak season usually reflect the use of baseload units. In many instances these baseload units will be coal-fired. The environmental externalities associated with coal combustion impose significant costs which will appear in the relevant marginal energy costs. In this situation the inclusion of externalities is likely to at least flatten and possibly invert the rate in the off-peak season. This result is consistent with Commissioner Katz's approach. It leads to a rate which provides a stronger, clearer signal concerning the value of incremental consumption, due in part to its externalities.

Two-part rates of the type I have been discussing are often thought of primarily as retail rates applicable to residential and small general service customers. However, a similar rate structure has important potential at the wholesale level as well. In a recent New England Power (NEP) wholesale rate case, FERC approved a wholesale rate with separate demand and energy charges, each of which had the classic two-block structure. In the NEP rate the tailblock for both demand and energy was set at marginal cost. The initial block was set residually, to meet the total demand and energy charges approved by FERC.[12]

Clearly, if one were interested in promoting ratemaking which reflects externalities, it would be helpful to have FERC wholesale rates which are at least consistent with this approach. The example of the NEP wholesale rate suggests a way in which this could occur. The marginal costs included in the tailblocks of the NEP rate do not currently reflect environmental externalities. However, they could. If FERC rates were restructured along the lines suggested by the NEP rate, and if environmental externalities were included in the development of the marginal costs employed, we would have taken a long step in the direction of a ratemaking approach which incorporates externalities.

One of the most interesting facts about the NEP rate is its origin. The NEP rate came about due to provisions in the stipulation settling in a NEP rate case, provisions suggested and indeed pressed by the Massachusetts DPU. Those interested in promoting the wholesale type of rate design discussed above might consider "pushing" the adoption of similar marginal cost based rates in any FERC cases they might enter. After all, it is easier to do the correct thing in retail rate design if one begins with wholesale charges developed on a consistent basis.

The two-part rate we have discussed up to now is one of the simplest rate forms used in the electric utility industry. With more sophisticated metering, one can have a variety of more complex rate forms. For example, there is the three-part rate in which there are separate charges for energy and demand, each of which may have one or more blocks. Further, one can have time-of-day (TOD) rates or seasonal rates, or a combination of the two. Such rates will, of course, be affected by the incorporation of externalities, as was the simple two-part rate. Here, rather than running through all of the different rate forms possible, I will focus on the three-part rate

The use of separate energy and demand charges allows one to address the issue of customer load factor directly via rate design. Most rate designers assume that, all else being equal, it is desirable to increase customers' load factor. Having separate charges for each kWh consumed and each kW of demand provides a simple way of encouraging customers to increase their energy consumption, but not their demand, and thus improve their load factor. One simply prices energy as low as can reasonably be justified, and then sets demand charges residually. One way to do this would be to set the charges for incremental consumption equal to the marginal cost of energy.

In order to justify an increasing load factor, one must price incremental usage so as to recover not only the variable cost of production, but also the cost of the environmental externalities associated with that production. This means using marginal energy costs which include externalities in setting the charges for incremental consumption. This could turn the situation around. When environmental costs are included, one may end up with a rate which discourages load factor improvements.

In general the consideration of externalities undercuts arguments favoring the improvement. However, some may argue that some valid arguments for load factor improvement remain. Thus, as is often the case in practical considerations, some compromise may be required.

A Fresh Look at a Three-Part Rate

A three-part rate is a very common rate design for commercial and industrial customers. In the preceding section I discussed such rates, based on a ratemaking approach which involved the use of marginal costs and externalities. However, such a rate can easily be developed using only data available from an embedded cost-of-service study. Here I want to re-examine one such traditional approach to the design of three-part rates, in light of the concerns raised, but without the direct use of the methods developed in the preceding portion of this paper.

One approach to the design of a three-part rate begins with unit costs. Unit costs are an output of an embedded cost-of-service study. They are developed by aggregating costs based on their **classification** as demand, customer, or energy, and then dividing by the appropriate units. The results are costs, by rate class, for demand ($/kW-mo.), customer ($/bill) and energy (mills/kWh). One way to design a three-part rate is to set charges at unit cost, or as close to that as is practical. In evaluating such a rate the key question is obviously the reasonableness of the development of the unit costs.

In order to explain how difficulties can arise with this rate design procedure, it is necessary to specify the method used to allocate generation plant related costs in the cost-of-service study. Here, for purposes of illustration, I will assume that the average and excess demand (AED) method is used. This is one traditional choice.

Allocators developed using the AED Method consist of two components, average demand and excess demand. Average demands are derived by dividing annual class usage by the number of hours in the year. Excess demand, on the other hand, reflects only coincident and non-coincident peak as measured in a particular application of the AED Method.

The AED method allocates the majority of generation plant costs on an energy basis. The fraction allocated on an energy basis is equal to the system load factor. The remainder is allocated on an excess demand basis. However, utilities that use the AED method often treat production plant related costs as solely demand-related in the development of unit costs. Instead, part of these costs should be treated as energy-related. This change is required to ensure that the development of unit costs is consistent with the allocation of costs using the AED method.

The difficulty here arises in part through an inconsistency between classification and allocation in an embedded cost-of-service study. While the use of the AED allocator allocates the bulk of production plant related costs on an energy basis, AED is usually referred to as a **demand** allocator. When utilities classify all production plant costs as demand-related, they include all such costs in the unit **demand** costs. This creates a serious inconsistency. In my view the conflict should be resolved by charging the portion of production plant costs allocated on an energy basis to an energy classification. I believe that traditional cost-of-service procedures, such as those described in the *NARUC Electric Utility Cost Allocation Manual* are consistent with this approach.

The chapter on classification the NARUC manual states that "Fixed costs are thus demand-related **only** to the extent that demand is determinative of necessary plant investment, and of necessary expenses to insure service availability." (emphasis added) A large part of the expenditure on utility plant is made in order to provide low-cost energy to ratepayers. Choice of the AED method reflects this fact. So should classification.

The changes in the computation of unit costs suggested here can have important implications for rate design. The increase in unit energy costs and the corresponding decrease in demand costs can change rates dramatically. However, those who are interested in seeing how my approach would work in a specific situation in their jurisdiction may be in for a bit of a shock. In order to perform my calculation one would need to rerun the utility cost-of-service model with a change in the classification of certain costs. This simply may not be possible. The classification may be "hard wired" into the utility model. This was the situation in one recent case in which I testified.

The review of a traditional, three-part rate design grows naturally out of the concerns raised in the previous section. There I was concerned that a three-part rate might stimulate usage, and so increase the cost burden due to environmental externalities. Here I have shown that there may be instances where three-part rates contain inappropriately low energy charges, due to a flaw in the application of a traditional ratemaking approach. Even if one

doesn't want to depart from traditional ratemaking, this example makes it clear that it is worth taking a fresh look at the details of utility rate designs, particularly rate designs which have environmental consequences.

Rate Design Impacts on DSM

At this point I come full circle in my discussion. I began by pointing out that concerns about the valuation of DSM in the utility planning process should lead planners to make good on the commitment to include externalities and their costs in that planning process. Inclusion of these costs led to the computation of significantly higher marginal costs, and therefore to significantly higher "tailblock" charges in rate design. Having come this far, I want to point out that increases in tailblock charges will in turn impact DSM. The direction of the impact is clear. Because tailblock charges are increased, there is an increased potential for customer savings from DSM. Thus, all else being equal, DSM should become more attractive to ratepayers. Here, however, I would add a note of caution. Numerous studies have shown that, even when DSM investment is extremely cost-effective, ratepayers have shown themselves to be loathe to undertake it.[13] This under-investment in DSM has been shown to exist among both residential and commercial ratepayers. Thus, while the appropriate incorporation of externalities will give DSM a boost, it would be unrealistic to believe, based on rate design changes alone, that one could induce the socially-optimal level of DSM.

NOTES AND REFERENCES

1. This subject is discussed at length in the Proceedings of the National Conference on Environmental Externalities, held in Jackson Hole, Wyoming on October 1 to 3, 1990. The conference proceedings have been published by NARUC.

2. Massachusetts adopted this approach in the Order of the MDPU in D.P.U. 89-239, dated August 31, 1990. A similar approach was adopted by the Nevada PSC in its Order in Docket No. 89-752, dated January 22, 1991.

3. John Stutz, "Breaking Down the Wall Between Integrated Resource Planning and Rate Design," presented at the NARUC 1990 Summer Meeting in Los Angeles.

4. Myron Katz, "Proper Price Signal, The Case for Reflecting Externalities in Utility Rates." This appears in the Proceeding identified in 1. above.

5. James Bonbright, "Principles of Public Utility Rates," Columbia University Press, 1961, page 291.

6. Both marginal and embedded costs are discussed in Edward Kahn, "Electric Utility Planning and Regulation, ACEEE, 1980.

7. See for example M. Bruce Johnson, "The Problem of Second Best and the Efficient Pricing of Electricity," EPRI Report No. EA-1852-SR, May 1981. This report makes it clear that one should consider both the theoretical and practical rationale for marginal cost pricing.

8. The economic basis for such a tax is discussed in W. Baumol and W. Oates, "The Theory of Environmental Policy" 2nd ed., Cambridge University Press, 1988.

9. Roger McElroy et al., "Marginal Cost Ratemaking for Cogeneration, Interruptible and Back-Up Services," NRRI, February 1981. See in particular pages 27 to 40.

10. Results of this type were presented by Dr. Richard Rosen of Tellus Institute to the NARUC Energy Conservation Committee at its Fall 1990 meeting.

11. See for example the data presented in S. Bernow et al., "Full Cost Economic Dispatch: Recognizing Environmental Externalities in Electric Utility System Operation," which appears in the Proceeding identified in 1.

12. A description of the NEP rate is provided in an article in the *Electric Utility Week* of October 10, 1988. The rate was approved by FERC in July of 1990.

13. Numerous studies of the type mentioned here are summarized in F. Krause and J. Eto, *Least Cost Planning Handbook for Public Utility Commissioners*, Vol. 2, NARUC, December 1988.

DEMAND-SIDE COST RECOVERY: TOWARD SOLUTIONS THAT TREAT THE CAUSES OF UTILITY UNDER-INVESTMENT IN DEMAND-SIDE RESOURCES

John Plunkett
Paul Chernick
Resource Insight, Inc.

NARUC Third National Conference on Integrated Utility Planning
April 9, 1991

I. Introduction

A variety of factors makes comprehensive demand-side investment less attractive to investor-owned utilities than conventional supply acquisition. Lower short-run profits from sales losses and uncertainty surrounding recovery of program costs are the obstacles utilities usually raise first with regulators. Aside from removal of these roadblocks, DSM advocates have also sought special incentives for utilities pursuing DSM programs. Both of these types of regulatory solutions should be linked directly to the achievement of explicit least-cost planning objectives of demand-side investment. In this paper, we outline those objectives and suggest cost-recovery approaches that encourage utilities to meet them.

II. Least-cost objectives and planning imperatives for utility demand-side investment

A. Least-cost objective of utility DSM investment

Regulators must define exactly what utility behavior they want before considering reforms to encourage that behavior. Least-cost planning requires that utilities pursue all demand-side resources costing less than supply, while doing so as cost-effectively as feasible.

This objective is not as obvious as it may seem. It does not mean, for example, that utilities should pursue only the most cost-effective resources. Such a cream-skimming approach would ignore resources that cost less than supply. Nor will least-cost planning result if utilities confine their efforts to maximizing peak demand savings, which would ignore energy savings that can avoid the most expensive supply resources. The pursuit of all cost-effectively achievable DSM should therefore be the

objective that is promoted by the changes made in utility cost-recovery rules and utility incentives.[1]

In considering the problems that demand-side resources pose for utilities, regulators should keep in mind the barriers preventing utility customers from investing in energy-efficiency. These market barriers are so powerful and pervasive that almost every home, building, or factory probably holds some potential for energy-efficiency savings at less than avoided supply costs.[2] The utility's challenge is to design and implement programs that capture as much of this potential in as many buildings as cost-effectively as possible. Cost-recovery and incentive mechanisms should encourage this job.

B. Essential requirements for accomplishing least-cost planning objectives of DSM

Three related imperatives grow out of the least-cost objectives of utility demand-side investment: capability-building, prevention of lost opportunities, and comprehensive investment.

1. Building the capability to deploy demand-side resources

First, demand-side programs will not be viable resource options until and unless utilities can effectively deploy them. To deploy them, utilities must build the capability to deliver demand-side resources on a strategic scale. Utilities must be able to count accurately, and count on, the costs and savings of a wide variety of measures installed within a large number of diverse customers. Studies and experiments that focus on the performance of specific efficiency measures will not provide this capability. Only staged implementation leading to full-scale deployment will establish the most effective investment strategies and delivery mechanisms for achieving large savings

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[1]See Chernick, P. and Caverhill, E., Integrated Resource Planning in Indiana: Building Reliable Economic Energy Efficiency for the Next Generation, November 1990, and Plunkett, J., et al., Comments on the 1991-1992 Annual and Long Range Demand Side Management Plans of the Major Electric Utilities, September 1990.

[2]NARUC, Least-Cost Utility Planning: A Handbook for Public Utility Commissioners, Vol. 2. December 1988.

from a large number of customers. Early and thoughtful attention to monitoring and evaluation is also critical for successful capability-building.

2. Capturing efficiency opportunities before they disappear

Second, utilities must pursue, and avoid creating, lost opportunities. Lost-opportunity resources are one-time opportunities for savings that disappear once they are missed. Opportunities are most commonly lost in new construction and equipment replacement, when customer do not incorporate energy-efficiency choices that are much more expensive or impossible to retrofit later. Utilities and regulators must recognize the least-cost imperative to pursue all lost-opportunity resources immediately.[3]

3. Buying resources comprehensively vs. selling programs piecemeal

Third, designing and implementing energy-efficiency programs require a comprehensive approach. Market barriers to efficiency investment are numerous, strong, and pervasive. A 2-year payback requirement on 20-year investments is the market's way of saying something's wrong -- customers turn down all but the cheapest and easiest efficiency measures. The result of such weakened price signals is customer under-investment in energy efficiency, and

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[3]Regulators in several jurisdictions have recognized the importance of capability building and lost opportunities. The Northwest Power Planning Council first urged Bonneville Power Administration and the region's utilities and regulators to pursue capability-building strategies and lost-opportunity in its 1983 Plan. Its 1986 Plan reaffirmed this recommendation, in spite of a large capacity surplus. (1986 Northwest Plan, 9-28 through 9-30) In Vermont, the Public Service Board and the utilities it regulates are making capability-building and lost-opportunity resources their top priorities. The Idaho Public Utilities Commission recently ordered utilities under its jurisdiction to submit a "Lost Opportunities Plan" and a "Capability-building Plan." (See Order No. 22299, Case No. U-1500-165, January 27, 1989) More recently, the New York Public Service Commission has made lost-opportunity resources a high priority. (12/29/89 Decision in Case 28223, Appendix A at A6) The Wisconsin PSC also declared that utilities should not let such valuable yet transitory efficiency opportunities escape. (Fifth Advance Plan Order, pp. 33-4)

utility over-investment in more costly supply.

Comprehensive demand-side investment is needed to bridge the payback gap between what customers will spend on efficiency and what utilities will spend on supply. The Vermont PSB requires utility DSM investment to be comprehensive "in terms of the customer audiences they target, the end-uses and technologies they treat, and the technical and financial assistance they provide."[4]

Unless utilities invest comprehensively, they will create lost opportunities when they run weak, piecemeal programs by declining to pay enough to overcome serious market barriers. The most common mistake utilities make is implementing single-measure programs that fail to capitalize on opportunities to achieve higher savings from more and stronger efficiency measures. The result is higher program costs and lower savings. To avoid this inefficiency, comprehensive programs invest customer by customer, not end-use by end-use.

A typical example of poor program design is a water-heater insulation program that excludes water-conservation and lighting measures. This fragmentary approach reduces savings realized per household and drives up costs of the savings that are achieved. Separate programs that return to each house for lighting, then for water conservation, may cost too much on their own to be cost-effective. Equally unproductive would be a program for new commercial construction that focussed only on lighting, sacrificing savings from interactions among lighting, HVAC, and building shell (e.g., a downsized AC system due to reduced lighting and solar gain).

III. Overcoming Utilities' Distaste for Pursuing All Cost-Effective Demand-Side Resources

Next we address the factors that discourage utilities from investing in all cost-effective DSM resources, and discuss the advantages and disadvantages of competing strategies for overcoming these problems.

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[4]Vermont Public Service Board Decision in Docket No. 5270, Investigation into Least-Cost Investments, Energy Efficiency, Conservation and Management of Demand for Energy. April 16, 1990. Vol. III, p.44.

A. Raising efficiency lowers short-run profit

For every kWh of sales lost to improved efficiency, a utility loses its sales margin. This margin is the difference between tail-block tariff and short-run variable costs, mostly fuel. Lost margin is particularly high for utilities with excess or expensive baseload capacity. Short-run production costs are often a few cents per kWh, while the revenue lost from reduced sales is typically upwards of 8 cents for commercial customers. The more effective a utility's demand-side investment, the more it loses. In terms of the objectives stated above, this is precisely the wrong signal for ratemakers to send a utility.

The pressure to avoid lost sales margins is persistent and powerful. Test-year adjustments to sales levels in a rate case will not remove this disincentive to sales-reducing DSM investment: the temptation to restrain sales erosion crops up the day the rate order is signed. The problem is particularly severe for utilities which are reluctant to seek regular base-rate relief from the problem and fear regulatory scrutiny in other areas may simply lead to countervailing cost disallowances in rate cases.

Correcting the problem that energy efficiency poses for short-run utility profits may do two positive things for utility demand-side investment:

- help utilities abandon the biased and restrictive no-losers test for screening demand-side investments; and
- eliminate worry about saving "too much" electricity, facilitating transition from selling kWh commodities to selling least-cost energy services.

Below we discuss several current and proposed regulatory mechanisms for removing the profit-reducing effects of sales losses from DSM investment.

1. ERAM

Unfortunately, fixing the profit-erosion problem of efficiency investment is highly controversial. California operates on the Electric Rate Adjustment Mechanism (ERAM), a straightforward uncoupling of sales from profits. ERAM not only removes the disincentive for conservation, but also eliminates incentives for

sales promotion and avoids weather-related fluctuations in earnings.

Automatic adjustments, however, are anathema to many regulators. ERAM appears to some as a blunt instrument for fixing a narrow problem, no matter how important. A slow economy will automatically raise rates, as fixed costs are automatically spread over a declining sales base, magnifying the short-term economic stress. Some worry that ERAM-like changes could backfire politically, with customers equating rate increases with conservation. Finally, ERAM is not a viable option for utilities whose rates are set based on a historical test year.[5]

2. Inter-utility bill comparisons

Initially suggested as an alternative to ERAM, the proposal by David Moscowitz recommends compensating utilities according to how the resulting utility bills compare with those of others. The advantage of this approach is that it may be able to align a utility's incentives directly with the least-cost objective of minimizing customer bills. On the other hand, this approach seems difficult to measure and administer: rate cases would be entirely redesigned! Such tasks as selecting a comparison group and isolating unrelated factors could make this a bonanza for consultants.

3. Correcting for sales losses directly from utility DSM savings

Vermont has adopted an approach that adjusts sales for estimated and/or measured DSM savings, net of savings that would have happened anyway.[6] Under the Vermont approach, known as the Account Correcting for Efficiency ("ACE") mechanism, these adjustments accrue like AFUDC between rates cases; accruals are allowed in rates after review in the next rate proceeding. A similar approach has been negotiated in principle for the Potomac Electric Power Company as part of a collaborative process

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[5]ERAM reconciles revenues to the forecast level, which was expected to provide an adequate return. Jurisdictions with historical test years generally do not produce revenue forecasts that are meaningful targets.

[6]Vermont Public Service Board, supra note 4, pp. 18-21.

involving parties before the Maryland PSC.[7] The New York PSC has adopted a variant on this approach.[8]

The biggest advantage of this approach is that it links revenue adjustments with utility achievement. In addition, it reinforces the need for utility focus on monitoring and evaluation. It should not involve substantially greater effort than that already necessary for sound integrated planning (i.e., utilities need to count savings anyway if they are going to integrate them into resource plans).

One possible disadvantage of this approach is that it may tempt utilities to "game the system," potentially leading them to over-claim results. In particular, utilities may be more inclined to pay customers to install measures that have become, or are becoming, standard practice. However, this temptation could be healthy if it counteracts a lingering tendency to understate DSM savings in favor of supply. Also, measurement is tricky: should calculations of lost sales adjust only for kWh changes, or should adjustments include credit for "take-back" effects of DSM, such as a decrease in kWh saved because customers choose to make their more energy-efficient buildings more comfortable? Another example would be situations where energy cost reductions make businesses more competitive and thus enable them to expand output.

B. Conventional prudence and "used and useful" standards for cost recovery create headaches for demand-side investments

1. Problems

The need for comprehensiveness and capability-building implies large, rapid outlays for demand-side investment. Capability-building efforts practically invite mistakes through trial-and-error and the need to press efficiency beyond cost-effective limits to establish supply curves for efficiency resources. Likewise, genuine efforts to be comprehensive may lead utilities to overspend or overreach in pursuit of all cost-effective savings. Traditional application of cost-recovery rules could

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[7]PEPCO Collaborative, Proposed Collaborative Demand Side Cost Recovery. October 1, 1990.

[8]Plunkett, J., et al., Comments on the 1991-1992 Annual and Long Range Demand Side Management Plans of the Major Electric Utilities. September 1990.

therefore undermine capability-building and comprehensive investment.

Intentional demand reductions through DSM programs will also magnify problems for utilities with excess capacity. This creates another strong temptation (i.e., beyond sales losses or potential disallowance of program costs) to avoid or postpone demand-side investment. Depending on the utility involved, this disincentive could easily overwhelm the others mentioned here: failing to recover $1500/kw of excess supply may pose a bigger threat to a utility's earnings than would the disallowance of a half-hearted $300/kW DSM program.

2. Solutions

a. Clarify the rules

The best way to overcome utilities' fear of program cost disallowances is for regulators to provide clear information in advance on how traditional standards will apply to demand-side investment. We favor Vermont's approach, which ties DSM prudence to clear principles of program design and implementation.[9] The Vermont Board will also accept programs as "used and useful" if they are expected to be cost-effective in the aggregate for each customer class. The Vermont PSB ruled that:

> without the aggregate used and useful test, there is a clear temptation for cream skimming: utilities would tend to exclude certain measures or customers from programs unless they appear extremely cost-effective, reasoning that it would be better to be safe than sorry.[10]

This approach works best with linkage of the prudence and "used and useful" standards. As laid out by the Vermont PSB, standards of prudence include comprehensiveness in program design; effective, efficient implementation; early attention to evaluation in program design; and frequent reviews for rapid feedback to enable mid-course correction. Prudent programs are essentially defined to be used-and-useful.

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[9]Vermont Public Service Board, supra note 4, p. II-172.

[10]Vermont Public Service Board, supra note 4, p.32.

One implication of the prudence standard is that cost-recovery is not guaranteed for a program just because it looked cost-effective at the start. As with supply investments, prudence requires utilities to revisit their demand-side commitments periodically to determine whether changing circumstances have rendered them uneconomical.

On the other hand, consistent application of prudence and used-and-useful standards should not require the capability-building stage of utility DSM investment to be "cost-effective" on its own. The purpose of capability building is to develop and set controls for the subsequent resource acquisition stage. As long as DSM programs are cost-effective over both the capability-building and resource-acquisition stages, costs should be considered used and useful, and therefore recoverable.

b. The pre-approval option

Pre-approval of DSM plans should be an option for utilities, if not a requirement. If so, pre-approval should generally apply to a utility's entire resource portfolio, not just to individual programs. The Vermont PSB concluded that:

> [r]ules for recovering demand-side costs are inseparable from the demand-side programs that generate such costs. ... Therefore, the Board will seek to address the reasonableness of a company's entire set of demand-side programs and will not review individual program elements in isolation. This perspective is a natural and necessary implication of the requirement that utility DSM investments be comprehensive.[11]

Massachusetts also offers DSM pre-approval.[12]

c. Exclude offsets of DSM from excess-capacity calculations

Regulators should permit utilities to exclude savings from new

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[11]Vermont Public Service Board, supra note 4, pp. 33-4.

[12]Massachusetts DPU Docket 86-36-F. November 30, 1988, p. 29.

DSM programs from calculations of excess capacity involving existing or already-approved resources. This creates another incentive for utilities to overstate savings, but helps counter the tendency to "low-ball" savings to protect supply. This approach was built into the collaborative design process involving PEPCO and parties before the Maryland PSC.[13]

C. Allow utilities to earn a return on DSM expenditures

Utilities may have several reasons for preferring to capitalize DSM investments. For example, recovery of capitalized expenditures is less sensitive to rate case timing. Utilities may also be concerned that expensing recovery will damage short-term competitiveness. It has become fashionable to discount the Averch-Johnson effect, which posited that utilities would tend to over-capitalize given the prospect of a regulated return on investment (as opposed to no return on expenses). To the extent that a utility prefers to increase its rate-base, insisting that all DSM expenditures be expensed would relate unnecessary peril to least-cost planning objectives discussed earlier.[14] For all these reasons, rate-basing (or equivalent treatment) should be allowed.

Amortization of rate-based DSM expenditures should generally match measure lives. That is, the cost of compact fluorescents should not be stretched over 20 years, and a utility's direct investment in new commercial construction efficiency should not be written off in two years.[15]

D. Final thoughts on removing disincentives

Regulators should not feel obligated to resolve all issues for all utilities. Depending on circumstances, utilities will differ in how they react to these apparent disincentives. Some utilities are driven by revenue losses, some are concerned about

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[13]Maryland Public Service Commission, Memorandum of Understanding. pg. 5.

[14]Many utilities would rather expense more of their cost recovery than currently allowed, even though this reduces rate base.

[15]Cashflow and rate trajectory considerations will also affect the choice of amortization periods.

excess capacity, and some worry about cost recovery of capability-building investment. Resolving the one or two issues utilities care about most should go a long way toward improving the DSM content of their resource diet.

III. Beyond disincentives to rewards

A. Opposing perspectives

If regulators remove disincentives for utilities to invest in all cost-effective DSM, need they do more? The debate on whether to offer affirmative incentives for DSM investment seems divided along three positions:

- offer positive incentives in addition to removing disincentives discussed earlier, so that cost-effective DSM has a decided advantage over supply;
- do not add incentives, because removing disincentives should be enough to level the playing field; and
- offer rewards that are symmetrical with respect to the risks assumed by utilities in pursuit of all cost-effective DSM.

Below we summarize the three perspectives, and then provide guidance on proceeding with incentives.

1. Positive incentives are essential

Citing the longstanding utility hostility to aggressive DSM, this position argues that utilities must be given an offer they can't refuse. It is consistent with NARUC's resolution that a utility's least-cost plan should be its most profitable plan. Some consumer advocates resist this approach, maintaining that it over-compensates utilities at the expense of ratepayers (see below).

2. Removing disincentives is enough

As long as you take away penalties for doing the right thing, bribes shouldn't be necessary. A reasonable opportunity to recover demand-side costs and to earn a return on demand-side investments should suffice, as long as shareholders' interest in profits are not directly at odds with ratepayers' interest in

least-cost resource planning. It is entirely likely that, after the removal of disincentives, DSM may lower the risks associated with utility resource acquisition. In such a case, one could plausibly argue for lowering utility rewards, not raising them.[16]

3. Offer additional incentives, but tie them to utility performance and/or utility risks

Adherents to this perspective (among whose ranks we count ourselves) suggest that utilities should receive rewards for demonstrably superior performance, or be offered rewards commensurate with the risks they assume. The performance-based approach rewards excellence, which is usually defined explicitly in terms exceeding some reasonable expectation. The commensurate-risk approach seeks to balance up-side rewards against the possibility of down-side penalties, possibly with some dead-band or neutral zone of achievement. The least-cost plan is still the most profitable plan; poor plans are distinctly unprofitable.

B. Structuring an incentive mechanism

If a utility is to be eligible for special rewards, regulators should ensure that performance objectives are measurable and consistent with least-cost planning. The incentive structure should reward achievement of objectives, not level of effort. For example, paying an extra 2 percent return on demand-side investment encourages utilities to spend money, and to call whatever they spend it on conservation. Moreover, regulators should avoid rewarding utilities for maximizing the benefit-cost ratios of their demand-side programs. Such an approach deliberately encourages cream-skimming.

One approach is to reward utilities for exceeding target levels of customer participation, savings per participant, or total savings. Such targets can be set in absolute terms (e.g., the 125-MW blocks of savings the Wisconsin PSC offered to reward WEPCO for), or in relative (e.g., as a percent of class sales or total savings sought). For any achievement beyond established targets, Narragansett Electric gets 5 percent of gross benefits

[16]The Vermont Public Service Board explicitly recognized this possibility. See Order Opening Investigation in Docket 5270, April 22, 1988.

from DSM as a "maximizing" incentive (i.e., to be comprehensive), plus 10% of net benefits (after subtracting DSM costs and maximizing incentive) as an "efficiency" incentive.[17] The general danger with thresholds, however, is that they may create perverse incentives. For example, utilities may engage in behavior that is far from least-cost in order to meet a threshold target, or likewise, cease DSM efforts once such a threshold has been met. Careful design of the incentive structure can avoid these problems.

Alternatively, utilities could be paid a "bounty" per kWh/kW saved beyond some target, perhaps on a progressively sliding scale, as long as the savings are cost-effective. Bounties create no incentive for cost minimization, and therefore require supplemental review mechanisms.

IV. Conclusions: Linking cost-recovery reform to least-cost objectives

A big step toward getting utilities to do the right thing is understanding what constitutes the wrong kind of behavior -- such as spending money wastefully; pursuing only the cheapest, easiest savings, pursuing any savings at any cost; or paying customers to do what they would have done anyway. This understanding helps regulators remove disincentives to appropriate utility behavior, and avoid the trap of creating perverse incentives. Another important step is to understand why and how existing ratemaking practices discourage aggressive pursuit of least-cost objectives.

But it will take more than mere recognition of the objectives and the impediments to them to obtain least-cost performance from utility demand-side investment. We are convinced that regulators need to link mechanisms for demand-side cost-recovery directly to standards for demand-side performance. Cost-recovery issues should not be treated in a vacuum: there is too much at stake, and too much can go wrong, for regulators to set rules and incentives and expect comprehensive program design and effective implementation to follow naturally.

Consequently, regulators should consider the quality of utility demand-side plans -- in terms of the objectives and imperatives presented above -- when establishing cost-recovery

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[17]The maximizing incentive can have serious adverse effects on utility cost-minimization incentives.

rules; likewise, they should consider the quality of the execution of those plans when applying the mechanisms. Such linkage is particularly critical with affirmative incentives intended to reward utility performance. Regulators should not agree to a generous set of cost-recovery and revenue-loss provisions without a real opportunity to influence program design and implementation of a utility's entire demand-side portfolio. Establishing cost-recovery rules is relatively clear-cut; enforcing good program design and implementation is not so simple.

Finally, the process for resolving these program design and regulatory policy issues is best handled in a collaborative one - that is, through well-structured negotiations between opposing parties that aim for definitive decisions on the issues. "Workshops" where ideas get tossed back and forth without resolution have proven, in our experience, ineffective. A structured negotiation process, with utility funding of intervenor experts, can resolve most issues and provide for informed Commission resolution of issues that cannot be resolved in the collaborative. Programs that issue from such a process should carry a presumption of prudence, at least as far as program design. Effective implementation remains the responsibility of the utility.

PROMOTING INTEGRATED RESOURCE PLANNING THROUGH EFFECTIVE RATE DESIGN

NARUC THIRD NATIONAL INTEGRATED RESOURCE PLANNING CONFERENCE

April 8 - 10, 1991 Santa Fe, New Mexico

Concurrent Session B *9:00 - 10:30 a.m. April 9, 1991*

Rate Design And Cost Recovery Issues In IRP

Panelist: Andy Niven, Manager of Revenue Requirements
Pacific Gas & Electric Company

Major contributors to this paper were
Dennis Keane, Supervisor of Electric Rates at
PG&E, and Ren Orans, Principal with Energy &
Environmental Economics

INTRODUCTION

What is effective rate design and how can it promote integrated resource planning?

How have Pacific Gas & Electric Company's rate design innovations promoted integrated resource planning?

What is Pacific Gas & Electric Company doing now in the area of rate design that may promote integrated resource planning in the future?

In the course of addressing these questions this paper will:

- stress the importance of designing rates that reflect the marginal cost of providing service in order to make the most efficient use of a utility's and society's resources;
- describe how PG&E's time-of-use and load management rate options, based on aggregated system marginal costs, have promoted integrated resource planning for PG&E's generation resources; and
- look ahead to how rate design reflecting disaggregated localized marginal costs may promote integrated resource planning for PG&E's electric transmission and distribution resources.

MARGINAL COSTS, RATE DESIGN, AND INTEGRATED RESOURCE PLANNING

The primary goal in designing rates that recover a utility's authorized revenue requirement should be to make efficient use of utility resources. This means that a price should give the customer a signal conveying the cost to the utility of providing the service. Tempered though they may be by the revenue requirement constraint and other important considerations such as rate stability, cost-based rates serve the best interests of all ratepayers in the same way that market pricing in the broader economy serves the best interests of society at large: by working better than any other mechanism to allocate limited resources efficiently.

Marginal Costs

Economic theory holds that prices maximize social welfare when they are set at the marginal cost of production. In general terms, marginal cost is defined as the change in a firm's total costs due to a small change in output. Marginal costs are those costs that change because of the incremental unit of production; as such, they ignore the value of past expenditures (i.e., embedded costs). Setting prices based on marginal costs can inform consumers of the economic costs of their consumption choices. At this price level, consumers' decisions to purchase particular goods or services are based on the value to society of the resources used to produce those goods or services. Consumers weigh the value they derive from the products against their true cost. In this way, the maximum value is provided from the resources available to society. It follows that marginal-cost-based electric utility rates should result in a more efficient allocation of the utility's resources than rates based on other factors would.

Traditional electric utility service can be thought of as including: (1) the provision of electricity over time (kilowatthours); (2) the provision of electricity demanded at an instant in time (kilowatts); and (3) the provision of customer access to the utility system and associated meter reading and billing services. Thus a change in output is measured as a change in the demand for one or all of these three services: marginal energy costs measure how costs change as a result of producing one additional kWh; marginal demand or capacity costs measure the cost associated with serving one additional kW of customer load; and marginal customer costs measure the costs of providing access to the system for one additional customer.

Marginal energy costs reflect the expected incremental costs (comprised of incremental fuel costs and variable operating and maintenance expenses) of providing the last kWh of generation at any given time. While total energy costs are a function mainly of the fuel resource mix over time (e.g., high-cost fossil fuels vs. low-cost hydropower), marginal energy costs are a function mainly of the fuel resource mix at a particular point in time. It is generally immaterial who uses that last kWh and how or where it is consumed; what is crucial is when it is used, because that is the major determinant of its cost. Since more expensive energy usually is dispatched only after less expensive

energy is being used to its fullest, marginal energy costs usually are high whenever energy demand is higher and vice versa. In other words, the paramount driver of differences in a utility's marginal energy costs is the time of use (TOU).

Marginal demand or capacity costs are separated into generation, transmission, and distribution components. Marginal generation capacity costs are the costs of one additional kW of electric generation, while marginal transmission and distribution capacity costs are the costs of one additional kW on the utility's transmission and distribution systems, respectively. As with marginal energy costs, marginal generation capacity costs vary mostly as a function of when the additional kW is demanded, with the highest marginal generation capacity cost occurring at the time of the system peak. While the same generally holds true for marginal transmission and distribution capacity costs also, these portions of the utility system may have marginal costs associated with local geographic areas. Therefore the most important driver of marginal generation cost differentiation is the timing of when the capacity is demanded, while the major drivers of marginal transmission and distribution cost differences are both the time of the demand and its location on the utility's system.

Marginal customer costs consist of two components, the costs to connect a new customer and customer maintenance and operation costs. Marginal customer costs are driven in largest part by the type of customer. For example, the size of the transformer needed to be installed to meet the customer's needs is a major ingredient, as is the configuration of the necessary distribution hook-up.

Marginal Cost Revenues

Once the marginal energy, capacity, and customer costs are calculated, then marginal cost revenues can be calculated for customer classes and rate schedules. This gives the revenue the class would pay if the utility priced its services at marginal cost.

Establishing the marginal cost revenues associated with marginal energy and customer costs is straightforward. Marginal

energy cost revenues are calculated by multiplying the marginal energy cost per kWh in each TOU period times the kWh consumption in that TOU period and then summing the products for all TOU periods. Marginal customer cost revenues are simply the product of the marginal customer cost for the type of customer defined by the customer class (e.g., residential, commercial, industrial) and the number of customers in each class.

The calculation of marginal capacity cost revenues is more complicated. First the marginal generation, transmission, and distribution (both primary distribution and demand-related secondary distribution) capacity costs are allocated to two components: (1) costs associated with customer demands at the time of system peak, termed coincident peak demand costs; and (2) costs associated with the demands which customers impose on the portions of the transmission and distribution systems serving them, termed noncoincident peak demand costs. After determining an appropriate weighting between coincident and noncoincident peak demand costs for generation, transmission, and distribution, the marginal capacity cost revenues are calculated by multiplying the marginal capacity cost in each TOU period times the kW demand in that TOU period and them summing the products for all TOU periods.

Marginal-Cost-Based Revenue Allocation

Having calculated the marginal energy, customer, and capacity cost revenues for each customer class or rate schedule, then an adjustment must be made to apportion the total revenue requirement among the customer classes and rate schedules. This is because only by rare chance would the marginal cost revenues equal the revenue requirement, which is based on embedded costs. Average embedded costs may be below marginal costs when capacity is constrained and generating units with high operating costs must be used, or they may be above marginal costs when new baseload resources with low operating costs are added to rates.

Theoretical work on deviations from marginal cost pricing holds that the least deviation in consumption levels from those that would occur under marginal cost pricing is obtained when

the excess cost above marginal cost is reflected in prices that vary inversely with consumers' demand elasticities. However, it is hard to develop demand elasticity estimates rigorous enough to allow use of the inverse elasticity rule for regulated pricing. Moreover, inverse elasticity pricing can result in price variations among customer groups which may not appear equitable.

In lieu of inverse elasticity pricing, the California Public Utilities Commission (CPUC) has adopted an alternative way of basing prices on marginal costs: the Equal Percent of Marginal Cost (EPMC) method. Under the EPMC method, first the revenue responsibility of a rate class or schedule is determined by calculating the revenue the class would pay if the utility priced its services at marginal cost--that is, the marginal cost revenue. Then the class marginal cost revenue is adjusted by a ratio equal to the total utility revenue requirement divided by the total marginal cost revenues for all classes. The EPMC method is effectively a special case of inverse elasticity pricing, in which all demand elasticities are assumed to be the same.

Marginal-Cost-Based Rate Design

Electric rate design is concerned with setting the charges for various electric services. These services can be distinguished for rate design purposes into the same categories used for revenue allocation: customer access, coincident and noncoincident demand, and energy services. Revenue allocation assigns the system revenue requirement to customer classes and schedules based on their use of these services. Rate design achieves a further allocation of revenue responsibility to individual customers by setting the prices customers actually pay.

The same considerations of economic efficiency that apply to revenue allocation also apply to rate design. The most efficient rate design would be one in which a utility's services are priced at their marginal costs. However, the need to recover a revenue requirement above or below marginal cost means that deviations from marginal cost prices are necessary. The inverse elasticity principle suggests that the revenue in excess of marginal cost be spread to rate components in inverse proportion to the elasticity of demand for the various electric service. In rough terms, customer access is the least elastic component of

service, followed by noncoincident demand, coincident demand, and finally energy. PG&E's rate design process begins with full EPMC charges, then applies adjustments based on bill impacts and the inverse elasticity principle.

Under a perfectly EPMC-based rate design, each customer would pay the EPMC prices for the services he or she consumed. This pricing scheme would result in a monthly customer charge; a coincident demand charge assessed against a customer's demand at the time of system peak; a noncoincident demand charge assessed against a customer's maximum demand; and energy charges differentiated by TOU periods, if not on an hourly basis.

Unfortunately, metering capabilities render such perfectly cost-based prices impractical. It is true that customer charges could be set at full EPMC, if bill impacts were not severe. Yet most customers lack demand meters. Even with demand meters in place, it is not possible to determine the annual system coincident peak until the end of the year. Pricing on this basis would result in significant delays in signalling the cost of the services consumed. Finally, most customers also do not have TOU energy meters. As a result, energy prices must be averaged over at least a one-month billing period. The cost of purchasing and installing the demand and TOU energy meters required for pure cost-based pricing for all customers outweighs the possible gains in efficiency for many customers.

Marginal-Cost-Based Rates And Integrated Resource Planning

If in fact marginal-cost-based rate design does result in the most efficient use of a utility's and society's resources, then least-cost or integrated resource planning is promoted to the extent that rate design is based on the marginal costs of providing service. This holds true to some extent even if the application of marginal-cost-based rate design extends only to the most basic of traditional ratemaking distinctions: class of customers served (residential, commercial, and industrial) and nature of services provided (customer, demand, and energy). The more that rate design reflects the major marginal cost drivers--TOU for marginal energy and capacity costs, type of customer for marginal customer costs, location for marginal

transmission and distribution capacity costs--the more that integrated resource planning will be promoted.

PG&E'S CURRENT RATE PROGRAMS PROMOTING IRP

Consistent with the general marginal-cost-based ratemaking principles and approaches sketched above, PG&E has developed several rate programs that enhance integrated resource planning. They may be classified into time-of-use (TOU) rates and load management (LM) rates.

Time-of-Use Rates

Conceptual Basis for Time-of-Use Pricing

The basic idea behind TOU rates is a simple application of the principle of cost-based rate design: to charge customers prices for electricity that vary by time period to more accurately reflect the utility's costs as they vary by time period. Since the cost of generating and delivering electricity is highly dependent upon the level of customer demand, these costs vary substantially as demand fluctuates over the hours of the year. Varying the price charged to customers to reflect these cost differences provides a more accurate signal to customers about the true cost of their electricity consumption, resulting in a more economically efficient outcome. A utility implements TOU rates by disaggregating the hours of the year into distinct time periods and charging prices which reflect the costs pertaining to particular TOU periods.

TOU rates can take many forms, depending upon the level of disaggregation employed by the utility in defining its time periods. The simplest type of TOU rate is the seasonal rate, where the utility divides the year up into two seasons, usually summer and winter, and charges a different price in each. For example, a summer-peaking utility would charge a higher rate during hot summer

months when customer demands--and therefore utility costs--are high.

More typically, the term "TOU rates" is used to refer to a pricing structure that charges customers prices that vary over the course of a day. For example, a utility might charge a high price for usage on summer weekdays between noon and 6 p.m. (the on-peak period), a low price for usage from 10 p.m. to 6 a.m. (the off-peak period), and a medium price for all other weekday hours (the partial-peak or shoulder-peak period). Usage on weekends, when system demand is much lower, might be charged entirely at the low off-peak rate. The specific TOU period definitions would be chosen by each utility to match its cost conditions, by grouping together hours with similar costs.

The typical TOU rate schedule, with perhaps six distinct TOU periods (three each in summer and winter), is still quite aggregated. Although it permits a substantial improvement in the accuracy of its price signals over a schedule which charges a single rate all year long, it may still frequently communicate a misleading price signal to customers. For example, on many weekday summer afternoons the weather may be mild, customer demands low, and power inexpensive. Nevertheless, the TOU schedule will charge a high on-peak rate, discouraging sales on a day when capacity is ample. A more disaggregated TOU rate that also can be altered as cost conditions change, will give better price signals.

Real-time pricing (RTP) is such a rate. In its pure form, prices are charged for very short time intervals (an hour or less) and can be updated quickly (in "real time") over the course of the day as the utility's costs change. Pricing electricity in real time has the potential to greatly improve economic efficiency and customer welfare. A whole literature exists extolling its theoretical virtues. In practice, however, the key issue is whether these efficiency benefits are sufficient to offset the additional utility costs required to implement the program (e.g., the costs to transmit the prices, to meter usage at short time intervals, and to bill customers) and the additional transaction costs imposed on customers by having to respond to prices that constantly vary.

PG&E's Time-of-Use Rate Programs

TOU rates are widespread at PG&E. Except for the standard residential rate, all electric rate schedules have prices which vary at least by season. Using the narrower definition of TOU, which requires that prices vary by time-of-day, PG&E still has a substantial program, with more than 100,000 electric customers (out of roughly four million) taking service on such rates.

Table 1 summarizes PG&E's TOU rate offerings.

TABLE 1

Pacific Gas and Electric Company
Time-of-Use Rates

Customer Class	Rate Status	Dates Offered	Number of Customers	Saturation
Industrial (>500 kW)	Mandatory	1977-Present	3,000	100%
Commercial (<500 kW)	Voluntary	1984-Present	6,000	1%-2%
Residential	Voluntary	1982-Present	60,000	1%-2%
Agricultural	Voluntary	1980-Present	40,000	60%

TOU rates are available to all types of customers. For nearly 15 years PG&E has been charging mandatory TOU rates to all its large industrial customers with peak demand over 500 kW. For smaller customers, PG&E offers TOU rates as a voluntary option to standard rates. For the past four years, PG&E has installed approximately 20,000 meters per year, in compliance with a TOU meter installation schedule mandated by the CPUC. It is anticipated that this growth rate in customer subscriptions to TOU programs will continue in the near future. PG&E is currently conducting a study to predict the long-run saturation level of these rate options.

PG&E also offers RTP, on an optional basis, to large industrial customers. Begun as a small demonstration project in 1986, the RTP program currently has 14 customers. Customers are billed based upon daily schedules of 24 hourly prices, which are typically communicated to the customer on the afternoon of the previous day. Since these prices are not continuously updated and transmitted, the program can be characterized as "quasi-real-time." However, if PG&E's spinning reserve margin is forecasted to fall below a specified threshold on any particular day, customers are immediately sent a very high price (from $0.50 to $0.75 per kWh), termed the "load management pricing signal." Thus the program can be operated in real time, if PG&E's capacity situation begins to deteriorate to near-critical levels. Because of its load management pricing signal feature, the RTP program can also be viewed as a dispatchable load management program (as noted later on page 14).

Program Evaluation And Self-Supporting Rates

When TOU rates were first introduced by PG&E, much attention was paid to determining the degree to which these rates induced customers to shift load from peak to off-peak periods. PG&E performed numerous studies estimating load shifts and price responsiveness, and reported results annually (or more frequently) to the CPUC.

For the residential class, PG&E even designed a sophisticated statistical experiment to estimate the impacts of a variety of TOU rate structures. This experiment was notable for its research design, which enabled estimation of load shifting from a voluntary TOU rate; it differed from the Department of Energy-sponsored experiments of the 1970s which all examined the effects of mandatory TOU rates. Because of economic and political considerations, mandatory TOU rates for residential customers are frequently not feasible, and PG&E's experimental design allowed researchers to solve a number of complicated analytical issues that arise when customers can self-select for a particular rate.

Beginning in 1987, though, the emphasis at both PG&E and the CPUC shifted away from estimating load impacts and toward the concept of a self-supporting TOU rate. PG&E asserted, and the CPUC agreed, that TOU rates can be justified on the grounds that they provide a beneficial, more accurate price signal to customers--aside from whether or not they induce any load shifting. So long as the participating customers pay for the additional cost of the TOU metering equipment (typically via a monthly metering charge), the degree to which load shifts is immaterial.

It is important to note that this does not mean that load shifting is unimportant or does not occur. It is certainly important for utility cost avoidance, and empirical studies have shown that shifting does occur. Rather, the concept of self-supporting rates means only that the rates provide a more efficient price signal that has economic value even in the absence of any load shifting.

This can be illustrated by the example of the so-called "free rider." This is the customer who, despite being on a standard rate, already has little usage during the on-peak period. When a utility offers an optional TOU rate, this customer can save on her or his bill by joining even if it does not alter her or his usage pattern. In this extreme case, the utility does not avoid any cost (because its system load has not changed), yet it collects less revenue. Depending upon the regulatory rate recovery mechanism in place, this causes one of two outcomes: either the utility's earnings are reduced or it has to raise rates to collect the revenue shortfall.

In California, a revenue adjustment mechanism provides that rates will rise to collect the revenue shortfall and that the utility's earnings will not be affected. For PG&E this is the Electric Revenue Adjustment Mechanism (ERAM). With ERAM, the effect of a pure free rider subscribing to a TOU rate will be to increase rates for other customers. But is this something to be avoided? Consider the situation prior to the introduction of the TOU option. The pure free rider was, in effect, subsidizing other customers, since it had to pay higher, standard rates despite its low cost-to-serve usage pattern. By making

TOU rates available, the utility merely allows the pure free rider to pay a lower bill that more accurately reflects the lower costs incurred to serve it. The effect of self-supporting TOU rates is thus to undo an unfair subsidy that existed prior to their introduction.

The Value of Choice

Before turning to a discussion of PG&E's LM programs, it is worth mentioning an additional important benefit to offering TOU rate options: they provide customers with an opportunity to manage their electric bills. There is value to customers (even to those who choose not to exercise the option) of having choices. An electric utility offering TOU rates is similar to the airline industry offering reduced prices to customers who fly during off-peak, weekend hours. In both cases, differentiating the product by TOU and offering a menu of choices adds value in the minds of customers.

Load Management Programs

Conceptual Basis for Load Management Programs

The basic idea of LM programs is also simple: customers are offered monetary incentives to take actions that will reduce peak loads and provide a cost savings for the utility. There are two types of LM programs: dispatchable and load shaping. Dispatchable programs offer lower reliability service at a discounted price. Customers receive lower rates (or incentive payments) in exchange for volunteering to take the risk that the utility may curtail their loads (i.e., interrupt part or all of their service) during critical periods when it has difficulty supplying power to all of its customers. Load shaping programs, on the other hand, offer customers financial incentives to install equipment and/or change operating procedures that result in a permanent shifting of load from the peak to the off-peak period.

PG&E's Load Management Programs

PG&E's LM programs are listed in Table 2.

TABLE 2

Pacific Gas and Electric Company
Load Management Programs

Customer Class	Program	Dates Offered	Number of Customers	Load Shifting Capability (MW)
Dispatchable Programs				
Industrial (>500 kW)	Interruptible/Curtailable	1981-Present	230	500
Industrial (>500 kW)	Real-Time Pricing	1986-Present	14	2
Commercial (<500 kW)	Group Load Curtailment	1981-Present	40	15
Commercial (<500 kW)	Interruptible	1986-Present	13	3
Commercial (<500 kW)	Air Conditioner Control	1982-1984	630	2
Residential	Air Conditioner Control	1977-1988	60,000	53
Residential	Water Heater Control	1981-1984	2,200	0
Agricultural	Pump Control	1983-Present	212	2
Load Shaping Programs				
Commercial (<500 kW)	Thermal Storage	1985-Present	50	11
Non-Residential	Process Management	1986-Present	105	8

The upper part of Table 2 shows the dispatchable programs that have been offered historically at PG&E, while the load shaping programs are listed at the bottom. As with TOU rates, PG&E's LM offerings have covered all customer sectors. All programs are offered on a voluntary basis. During the 1980s, PG&E experimented extensively with these programs and evaluated their cost-effectiveness. Some programs are still ongoing, others are not.

In the industrial sector, PG&E offers two LM options to its largest customers: Interruptible/Curtailable rates and Real-Time Pricing. The Interruptible/Curtailable rate program is by far PG&E's largest in terms of load shifting capability, with more than 500 MW of subscribed load. Customers choosing this option receive rate discounts on the portion of their load that they designate as curtailable (all or part of their load, but at least 500 kW, can be so designated). In return, PG&E can curtail these loads (up to a maximum number of days and hours per year) if capacity conditions dictate. Customers are provided with one-hour advance notice of any curtailment and the duration of the curtailment cannot exceed six hours. Failure to comply with requests to curtail result in customers being assessed stiff financial penalties. Customers may earn an additional incentive by agreeing to the installation of an under-frequency relay that interrupts their load for brief periods when system frequency drops below a threshold level.

The RTP program has already been described earlier (pages 8 and 10). The load management pricing signal feature, as noted, imparts to RTP the character of a dispatchable program. In concept there is very little difference between dispatching very high prices for brief periods and requesting that customers curtail their loads. In both cases, the customers ultimately decide how much load to curtail, if any. And in both cases those who choose not to curtail must pay for that decision, either in the form of a very high price or a noncompliance penalty. PG&E's RTP program at present typically provides about 2 MW of load relief.

The Group Load Curtailment (GLC) and Small Commercial Interruptible (SCIP) programs are similar to Interruptible/Curtailable rates, with commercial customers being asked to curtail loads to designated firm service levels on hot summer afternoons. GLC relies on cooperative groups of

participants, rather than individual customers, to provide load relief. Each group must curtail its aggregate load upon request, and customers have communication links with others in the group to help meet the group's curtailment obligation. This program is capable of providing PG&E with approximately 15 MW. SCIP, on the other hand, is designed for individual customers and is marketed primarily to those with some form of back-up power supply. SCIP is still a small program in the experimental stage, with 13 customers providing about 3 MW.

The next three programs in Table 2, the Commercial and Residential Air Conditioner Control programs and the Residential Water Heater Control program, were tested by PG&E during the late 1970s and 1980s and are currently not offered to customers. All involved direct control by PG&E of specific customer end-use loads. This control, which was implemented by sending a radio signal that switched off the customer equipment, caused customers to incur partial outages for a limited period of time on hot days. Depending upon the control strategy employed, customers could lose control of the equipment entirely for the duration of the LM operation (typically four hours). Alternatively, PG&E might cycle their equipment, turning it off and on intermittently for short periods of time (e.g., every half-hour) for the duration of the operation. At their peaks, these programs were subscribed to by 60,000 residential customers and over 600 commercial ones, and delivered a combined 55 MW of load relief.

The final dispatchable program listed in Table 2 is the Agricultural Interruptible program, which employs a similar method of direct control to farmers' irrigation pumps. It, too, uses radio control to switch off the pumps, but farmers are provided with the ability to override the radio control when required to continue pumping. The program has about 200 participants and provides 2 MW of load relief. PG&E has requested permission from the CPUC to cancel it, since it is not cost-effective.

The final two entries shown are load shaping programs: Thermal Energy Storage (TES) and Process Management (PM). Both programs pay customers up-front incentives to induce them to install equipment or change operating procedures to shift load out of the peak period. The TES program provides payments to commercial customers to

induce the purchase of thermal storage air conditioning equipment, which costs more than conventional equipment. This equipment shifts load off-peak by producing ice during off-peak periods and then cooling the building during the peak period by blowing air across the ice. The main load, the compressor, is thus run only during off-peak hours. During the peak period, the compressor is not used (or used infrequently), replaced by fans which draw much lower loads. The PM program offers similar payments to industrial, commercial, and agricultural customers who install specific load shifting equipment. For both programs, customers are generally also placed on TOU rates so they can receive the benefit from their load shifting activity in the form of lower bills.

Program Evaluation and PG&E's Capacity Situation

Evaluating the success of LM programs is simple in concept, although not always in practice. The benefits of the program are essentially the generation capacity costs that the program permits the utility to avoid. These benefits are compared with the costs of the program to determine whether it is cost-effective. Cost-effectiveness is frequently examined from a number of perspectives (e.g., the utility perspective, the ratepayer perspective, the societal perspective), and utilities' and regulators' evaluations generally take into account multiple perspectives. These perspectives differ from each other in the list of items that are considered to be program benefits and costs. For example, the cost of the incentive paid to participants is often paid for by non-participants (in the form of higher rates). This cost will appear in a cost-effectiveness evaluation from the ratepayer perspective but will not appear in one from a societal perspective, since it represents a transfer from one segment of society to another.

For PG&E, the overriding factor influencing cost-effectiveness evaluations during the 1980s was its avoided generation capacity cost. In the early part of the decade, capacity costs were quite high. PG&E was nearing the completion of three major generating units and capacity was in short supply. During this period, the avoided cost benefits were high and many LM programs were cost-effective. By

1986, though, when PG&E had completed and brought on-line its Helms Pumped Storage Plant and the two nuclear units at Diablo Canyon Power Plant, the capacity situation had changed dramatically. Capacity has been in ample supply since then, and program cost-effectiveness results have shown a corresponding decrease. This is underscored by the fact that in the three-year period from 1983 through 1985 PG&E called 18 curtailments, while in the five years since then it has called just one. And, since PG&E will not need additional generation capacity for a decade or so, the value of LM programs as a means for avoiding generation capacity costs probably will remain low for several years.

Looking Ahead: TOU and LM for T&D

PG&E's experience over the last ten years has shown that there is a definite market for LM programs. Large numbers of customers have demonstrated a willingness to participate in programs that curtail or shift their electric load during periods of capacity shortage. Like TOU rates, LM programs provide options that can be offered to customers. Returning to the airline analogy of the previous section, LM programs are like airline standby rates: in both cases, there is a segment of customers that is willing to take a less reliable form of service--and risk being curtailed or "bumped"--in exchange for a lower price. Offering a lower reliability service option, like offering time-differentiated rates, increases the menu of customer choice and adds value to the product.

But in the near term for PG&E, the value of LM is not in the traditional area of generation capacity cost avoidance. Rather, PG&E sees a much brighter immediate future for LM in avoiding transmission and distribution (T&D) capacity costs. Unlike generation, PG&E expects to be making substantial investments in T&D capacity over the next several years. LM programs have the potential to defer those investments. In many instances, deferral of T&D facilities, even if just for a few years, can result in large avoided costs--which is good for utility shareholders and ratepayers alike. The remainder of this paper focuses on this application.

PG&E'S NEW RATE PROGRAMS PROMOTING IRP

Since the early 1980s the CPUC has had a policy to develop rates and various rate programs using estimates of the utility's marginal costs. Until recently, these costs have been developed on a system average basis, instead of by geographic area. That is, those utilities that develop estimates of marginal costs usually have single system average estimates of generation, transmission, and distribution costs of capacity. While it is true that the generation and backbone transmission facilities are built to provide reliable service for an entire utility service territory, local transmission and distribution systems provide service to specific areas.

Over the last two years, PG&E has been conducting a study of the area-specific costs of its transmission and distribution system. This section will describe some of the preliminary results of this study and suggest how they may be used to develop innovative rate designs and programs to promote least-cost or integrated resource planning for local transmission and distribution systems.

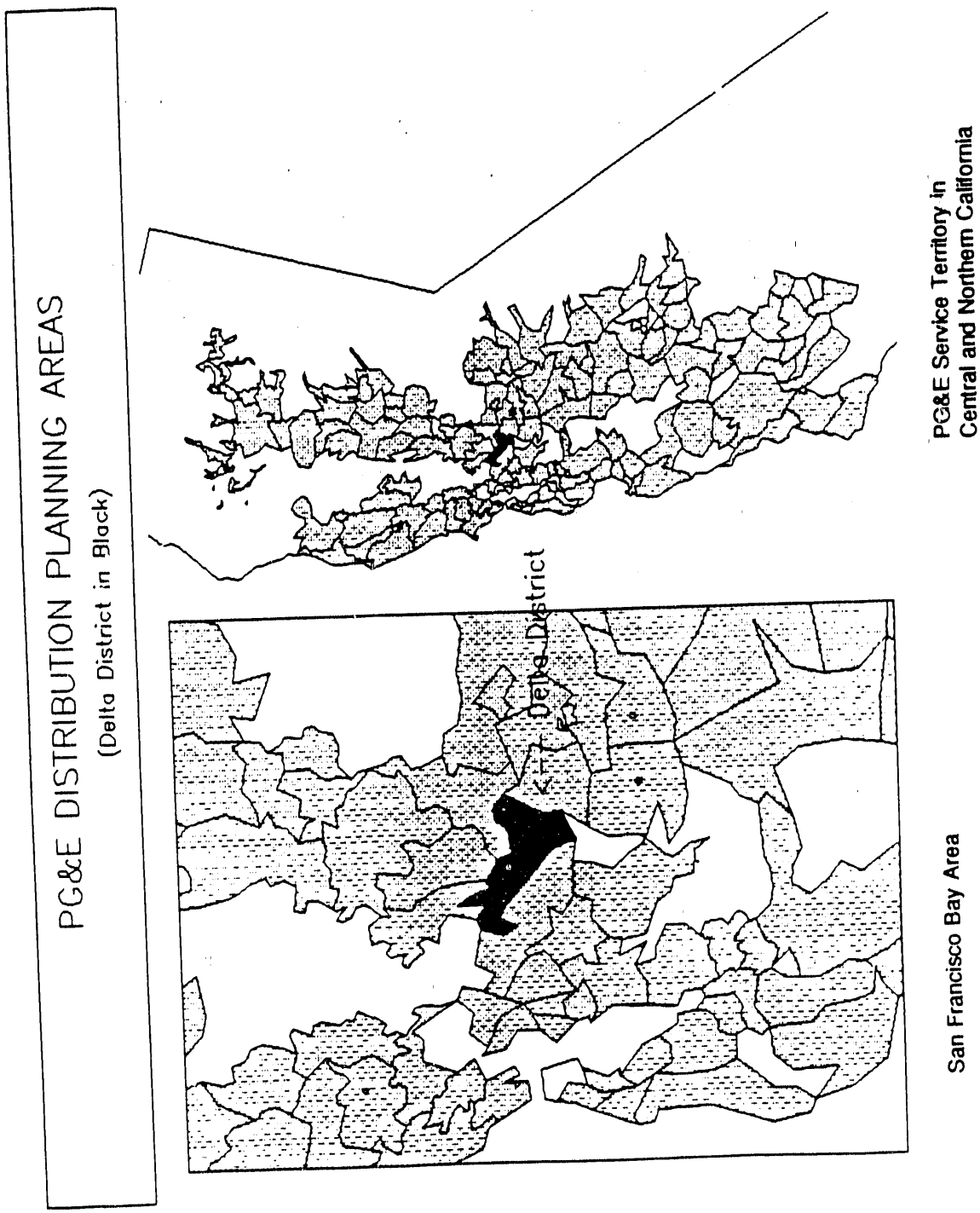
Conceptual Basis for Developing Area-Specific Transmission and Distribution Costs

PG&E is an extremely diverse utility. It has about 100,000 miles of distribution line serving approximately four million customers. Its transmission and distribution systems reach from densely populated coastal regions to rural inland farming areas. Although PG&E's demand is collectively growing at only about two percent per year, it invests a significant portion of its capital budget to provide hook-up and capacity to a relatively small number of rapidly growing suburban areas.

Investment in transmission and distribution (T&D) capacity is built on the concept of a planning area. All loads within a planning area can be summed to create estimates of area-peak loads to be compared with area capabilities. PG&E has almost 200 distribution planning areas and approximately 25 local transmission areas. A map showing the boundaries of each of PG&E's distribution planning areas is shown in Figure 1 on the following page. (The black area encompasses the Delta District, the site of PG&E's DSM pilot project described on pages 21-24. The white areas within PG&E's service territory are so thinly populated that they have no distribution systems.)

Figure 1

Map of PG&E's Distribution Planning Areas



The marginal cost of providing T&D capacity can be differentiated by planning area. For example, an area with a significant amount of excess capacity may have a relatively low marginal cost, compared to an area that is short of capacity. Type of facility (underground or overhead), density of loads, age of equipment, and growth also are related to an area's cost. These differences are captured in an area's expansion plan. The expansion plan describes the least-cost method of increasing the area's capability to meet future expected growth. PG&E has used its expansion planning data from each of its plannings areas to develop area-specific investment data for the estimation of area-specific marginal costs.

Estimating the Value of Capacity By Area and Over Time

PG&E has developed a costing methodology that produces estimates of marginal T&D capacity costs that vary from year to year, depending on the pattern of investment shown in each expansion plan. To the extent that the expansion plans are area-specific, the method produces estimates that are area-specific also.

The general idea behind the method is intuitive and relatively easy to implement. Under the traditional obligation to provide reliable service, the cost to a utility due to a change in load in a planning area is the shifting of the entire future expansion plan in time. In other words, an increase in demand accelerates the need for the next T&D investment and for other future investments as well. The value of moving the expansion in time is equal to the opportunity costs of the change in investments. This value is defined by the difference between the present values of the investments under the original timetable and under the new timetable, adjusting for inflation and technological progress.

This method has been called the Present Worth of System Incremental Cost method, or simply Present Worth (PW). It allows the unbundling of capacity costs from year to year, rather than the flat (constant dollar) annual estimate that is the result of most annualization techniques.

Some Preliminary Results

Figure 2 on the following page shows the results of applying the PW costing methodology to the 200 area-specific distribution expansion plans at PG&E. Although these results are only preliminary, they have some very interesting implications for rate design, revenue allocation, and the design and evaluation of DSM programs. For example, the figure shows that while the majority of the distribution planning areas have regional distribution capacity costs that are less than 100 $/kW-year, there are a few areas that have much higher distribution capacity costs. PG&E currently is working on developing TOU rate designs that reflect the timing of these high-cost area loads. We have found that many of these areas have distribution peaks that are coincident with the residential dinner hour rather than the system afternoon peak. In addition, there are a variety of LM programs that may be effective at reducing some of the high-cost area loads.

Although PG&E is not planning to develop area-specific rates at this time, it does plan to tailor some of its LM programs and its TOU designs to reflect these costs. The following section describes some preliminary results of a PG&E pilot project.

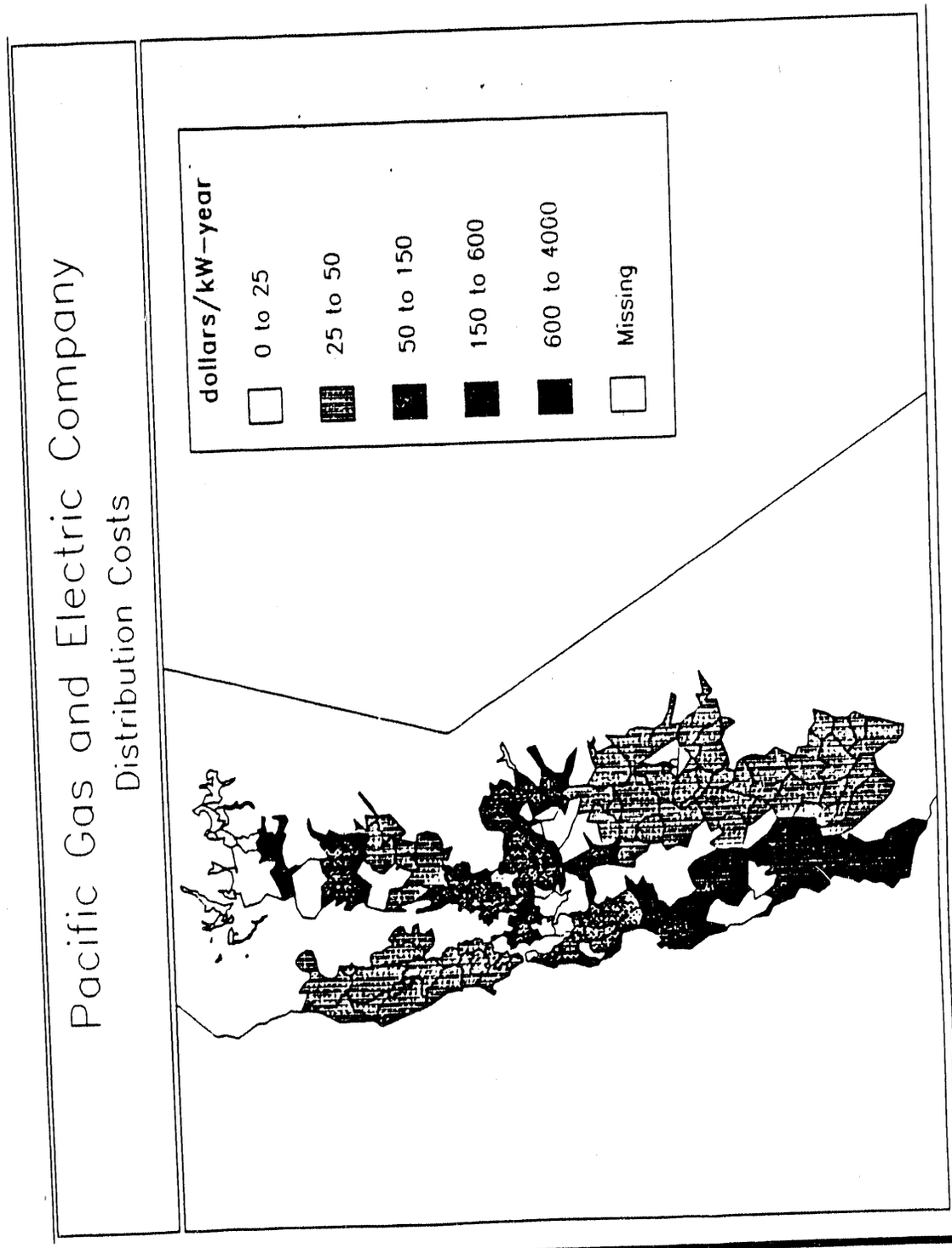
The Delta District DSM Pilot Project

In June of 1990 PG&E and the Electric Power Research Institute began a collaborative case study of PG&E's Delta District distribution planning area. The study objective was to develop an integrated plan for the Delta District using area-specific estimates of loads and marginal costs. This section describes some of the preliminary results of this study.

The Delta District is located in a distribution planning area in PG&E's service territory. It is a typical fast growing suburban area in Northern California. Delta District is part of a larger planning area that has two distribution substations and 5 primary distribution (21KV) feeders. The planning area has a native load of approximately 90MW that is growing at about 7.7 MW per year. Most of the growth is due to residential new construction. Over the next 10 years PG&E had planned to invest approximately

Figure 2

Map of Area-Specific Distribution Capacity Costs



$14.5 million in T&D capacity and several million dollars per year in new business expenditures to provide reliable service to the Delta District area.

The Delta District Demand-Side Management Pilot Project is PG&E's effort to find out if DSM programs can meet the district's T&D capacity needs at lower cost than traditional T&D construction. The objective of the Delta project is to develop the tools and methods that will enable PG&E to select the least-cost mix of DSM programs over the life of the expansion plan. At first glance, we are just performing a simple benefit/cost analysis where the benefits include the energy and capacity costs saved by implementing a program and the costs consist of the investment in DSM. More specifically, if DSM program costs, less avoided energy and generation capacity costs, are lower than the cost of T&D investment, then DSM is preferable; if not, then investment in T&D is preferable.

Both DSM program costs and associated energy savings are readily available from PG&E's regulatory filings and other integrated planning studies. Unfortunately, the system average estimates of T&D capacity costs are not useful in developing least-cost integrated resource plans at the T&D level. We have identified two key problems with their use in evaluating DSM programs:

1. PG&E's existing T&D capacity cost estimates do not reflect the substantial geographic variation in found in T&D costs across different planning areas. We have found that the costs of adding distribution capacity in Delta are relatively high compared to other areas.

2. PG&E's existing estimates of marginal T&D costs do not reflect the changing value of localized capacity from year to year. That is, we would expect the value of a change in load to be much higher immediately prior to a large investment in capacity than after it.

To solve these problems, PG&E developed area- and time-specific estimates of T&D capacity costs using the PW costing method and expansion planning data available for the planning area that encompasses Delta District. Then, using the DSM vs. T&D investment benefit/cost analysis, the process sorts through a variety of potentially cost-effective alternatives and chooses the most cost-effective programs to bring into the plan until no more are

cost-effective. As might be expected, the application of this technique is more complicated than the concept. The problem is that the value of each program depends on the load in the area, and the load in turn depends on the level of DSM investment.

Despite these complications and the use of very conservative estimates, the economic analysis of a limited list of programs resulted in slightly more than 6 MW of local peak load reduction due to DSM in the first year of the plan. The level decreases at approximately 15 percent per year over the life of the plan, due almost entirely to the limitations imposed by the decreasing stock of the remaining retrofit market as we move from one year to the next.

If PG&E were to implement a DSM blitz of cost-effective programs in the Delta District, it would cost approximately $28.3 million (1990 $'s) in combined investment in supply and DSM over a 20-year period. This is nearly double the cost of the unintegrated T&D investment plan that was estimated to cost PG&E about $14.6 million. But the investment in DSM will save approximately $14.3 million in energy costs, $4.3 million in generation capacity costs, and $3.4 million in local T&D capacity costs. Overall, PG&E estimates that the integrated DSM plan will save PG&E approximately $8 million over the course of the entire 20-year period.

(Note that this analysis uses the simple utility cost perspective, where neither the participant's own costs nor the revenue transfers due to lost sales are included. The consideration of either of these costs would have the result of reducing the cost savings estimates.)

CONCLUSION

Electric utility rates based on marginal costs should result in a more efficient allocation of the utility's resources than rates based on other factors would. More precisely, least-cost or integrated resource planning will be promoted to the extent that rate design reflects the major drivers of different marginal costs: time-of-use for marginal energy and generation capacity costs, time-of-use and location for marginal transmission and distribution capacity costs, and type of customer for marginal customer costs.

PG&E and other California electric utilities base their rates mainly on the marginal costs of providing service. Consistent with this general ratemaking approach, PG&E has developed several rate programs that enhance integrated resource planning for generation capacity. These rate programs provide either different rate levels for different times of energy use, rate discounts or incentive payments in exchange for the risk of occasional curtailment, or financial incentives to shift load permanently from one time period to another.

All these rate programs have in common their emphasis on the time of the customers' use of electricity. In this way they better reflect the major marginal cost drivers for energy and generation capacity and, to some extent, transmission and distribution capacity. But neither these rate programs nor the standard marginal-cost-based rates reflect the location of the customer within the service area, which is a major driver of local transmission and distribution capacity costs.

To try to promote integrated resource planning of the transmission and distribution systems as well as of generation capacity, PG&E is conducting an area-specific study of marginal transmission and distribution capacity costs. By calculating the marginal cost of transmission and distribution capacity on a local planning area basis rather than on an aggregated system-wide basis, PG&E is able to assess the cost-effectiveness of localized demand-side management programs as compared with more traditional transmission and distribution investment. PG&E's Delta District Demand-Side Management Pilot Project is providing a valuable test case for this application of integrated resource planning to local transmission and distribution systems.

CURRENT DESIGNS OF REGULATORY TECHNIQUES TO ENCOURAGE DSM

John H. Chamberlin
Barakat & Chamberlin, Inc.
and
Philip E. Hanser
Electric Power Research Institute

It is generally acknowledged that utilities can meet growth in the energy requirements of their service area through a carefully crafted combination of demand-side (i.e., load management, strategic load reduction, valley-filling, etc.) and supply-side (new generation, purchased power, etc.) options. A number of utilities and regulators have adopted some form of planning process to attempt to evaluate both types of options and to arrive at a blend of demand- and supply-side measures that meet the goal of minimizing, in some fashion, the provision of energy services to customers.

This planning process implies that in evaluating demand and supply alternatives there is a "level playing field" and that DSM options have equal standing with supply-side investments in the evaluation process. An important element of planning for future requirements for utilities is the establishment of this level playing field. While the concept of balancing demand and supply possibilities is appealing, utility involvement in demand-side management (DSM) strategies is not universally accepted. A central theme to the creation of equivalence between demand and supply is, "What are the appropriate incentive mechanisms for stimulating DSM activity?"

Until recently, the size and significance of DSM efforts have been relatively modest compared with overall utility investments in supply resources. Thus concerns related to achieving equity and comparability between supply and demand investments have not been high priorities either within utilities or with regulators.

In the "old days," many DSM programs were audits and information-providing programs, were typically expenses in the year in which they occurred, and were relatively unimportant to utility investment decision making. Today, DSM programs with higher investments and multi-year impacts mean greater visibility and potentially greater financial exposure and risk for the utility.

In attempting to achieve parity between DSM and supply options and to encourage DSM options where appropriate, it is important to remember the underlying fact that demand-side options are inherently different from supply-building possibilities. Most DSM options reduce energy sales by the utility; supply

additions, in contrast, provide the basis for energy sales increases. Simply put, rate-of-return regulation for the most part does not provide an incentive for cost-effective energy sales reductions. Thus the increased visibility of DSM as integral to the meeting of customer energy services requires a more thoughtful evaluation approach for DSM.

WHY ARE DSM INCENTIVES SOUGHT?

An oft-repeated reaction to the concept of DSM incentives is, "Why give utilities an incentive to do something they should be doing anyway?" Implicit in this question is the assumption that DSM incentives represent a reward, or bonus, above and beyond the costs of doing DSM. While there is a reward component to most incentive proposals, we believe the major need for incentives is to overcome the *disincentives* inherent in traditional regulation that affect utilities' interest in, and motivation for, DSM programs. To a large degree, the disincentives are financial; that is, pursuit of DSM operates at cross purposes with utilities' financial interest, and thus imposes costs that must be compensated for. Disincentives also arise due to perceptions that DSM will increase utilities' exposure to risk. The principal disincentives are discussed below.

Failure to Recover All Program Costs

In many instances utilities' expenditures on DSM have not been recaptured in rates. This is most prevalent in states that base their ratemaking on historic test years. While growth in DSM outlays is sought by both regulators and intervenors, cost recovery in historic test year states is limited to the amount expended in a prior year. Even in states that use future test years, the problem can occur if program expenditures are greater than anticipated (for example, if participation exceeds forecasted levels).

The timing of cost recovery can create a more subtle disincentive for DSM. In many instances recovery of DSM expenditures is deferred significantly until after their incurrence, but no adjustment is made for the loss of interest (carrying charges) in the intervening period. While often not seen as a "real cost," the loss of carrying charges must be considered a cost from the standpoint of financial motivation.

Loss of Revenues

In the absence of special adjustment procedures, such as California's ERAM (Electric Revenue Adjustment Mechanism), DSM programs that reduce kilowatt-hour sales work as cross purposes with utilities' financial interests. This

phenomenon is often referred to as the "lost revenues" problem. The practical effect, in many instances, is that the utility under-recovers its allowed fixed costs—costs that were authorized for collection by the regulatory commission in the prior rate case.

This problem may be mitigated somewhat by use of a forward-looking test year (which adjusts test year sales for anticipated DSM impacts) and by more frequent rate cases (which bring actual and test year sales into closer alignment). Even with such policies, however, utilities' motivation may be in the direction of less DSM (and greater sales), because every kWh not sold due to DSM reduces the contribution to fixed costs and earnings. Even if unanticipated sales growth puts the utility above its test year sales amount, every conserved kWh cuts into earnings.

Loss of Financial Opportunity

The third financial disincentive to DSM is the potential loss of opportunity for the utility to grow. Financial theory dictates that growth in a utility's size *per se* is not of intrinsic value: what matters is the rate of return on capital. But this theoretical view is not necessarily shared by utility executives and shareholders: growth in sales, rate base, earnings, and other statistics are often viewed as indicators of financial strength.

DSM works counter to a utility's growth interest in two ways. First, unless DSM expenditures are included in rate base (as is allowed in some states), choosing DSM resources over supply-side options substitutes an expense item for a capital item. In a worst-case scenario, the possible result is what might be called "the incredible shrinking utility": the utility's rate base declines due to amortization of old supply-side investments, which are not replaced (in rate base) by demand-side investments. Second, sales that are lost as the result of DSM are *permanently* lost (assuming persistence of DSM benefits). The result is that future fixed costs will be spread over a smaller sales volume, possibly leading to higher rates and possibly adverse impacts on the utility's competitive position.

Proponents of ERAM-type adjustment mechanisms claim they eliminate the incentive for utilities to increase sales. We believe this to be true only in the short run—i.e., between rate cases. ERAM recaptures for ratepayers any over-recovery of fixed costs resulting from sales above the test-year amount. Nonetheless, a utility that increases sales will enter its next rate case with a greater sales base over which to spread fixed costs (assuming the increases are not transient). This may be desirable for competitive reasons, since it may allow lower average rates; it is doubly desirable if shareholders and managers value growth in areas other than profits (sales, rate base, number of employees, etc.) for its own sake.

Therefore, even under ERAM utilities may view long-run sales growth as in their financial interest, and DSM as at odds with that interest.

Risks of DSM

In addition to the direct financial impacts described above, there are a variety of considerations that affect utilities' perceptions of the risk of DSM and therefore set up additional disincentives that must be overcome. Conservation advocates have often asserted that conservation programs are *less risky* than supply-side options for a variety of reasons: modularity (the ability to obtain DSM in small units), short lead time, lack of environmental risks, and so forth. The fact remains, however, that utilities seldom *perceive* DSM as a low-risk proposition. Several risks enter into utilities' views toward DSM.

Regulatory Risk

A retrospective review of today's DSM programs may conclude they were done imprudently or were not "used and useful" and should therefore not be accorded full cost recovery. (Alternatively, regulators could extract a penalty in some other way, such as a reduction in the allowed return on equity.) This risk is heightened by the knowledge that turnover among regulators is high, and that decisions by today's regulators concerning DSM programs will not be binding on their successors.

Impact Risk

Underlying the incorporation of DSM into a utility's integrated resource plan are assumptions concerning the expected energy and demand impacts, generally developed on a per-participant basis. The quality of the data used to generate impact assumptions varies greatly depending on the technologies employed and the quality of end-use data available. Further complicating impact estimation is the need to account for coincidence with system peak demand and the extent of free-ridership (the prevalence of customers whose DSM-related actions cannot be attributed to the program). The quality of information available for estimating impacts is steadily increasing, thanks to growth in DSM evaluation activities. Nonetheless, there is still some risk that actual impacts will be less than expected, which implies two further risks: (1) possible need to spend additional dollars on supply- or demand-side measures to make up the shortfall; (2) greater likelihood of adverse actions by regulators, as described above ("regulatory risk").

Market Acceptance Risk

Even where the technologies used in DSM programs and the expected impacts per customer are well-understood, there often remains substantial uncertainty about DSM program acceptance. Customer response to even the most prevalent types of programs (such as high-efficiency appliance rebates) cannot be predicted by today's models with adequate confidence. As with impact risk, possible outcomes of low market acceptance include the need for additional outlays to make up the difference, and greater exposure to regulatory risk.

Competitive Risk

Increasingly, states are adopting the Total Resource Cost (TRC) test as the principal benefit-cost criterion for DSM program selection. A consequence of this decision rule is that utilities are being directed to implement programs that pass TRC but fail the Rate Impact Measure (RIM) test (also known as the nonparticipants or no-losers test). Such programs increase average rates. Therefore, even if all the direct financial risks identified above are "cured" through incentive adjustments, utilities may still be concerned that DSM-related rate increases will be harmful in competitive markets, possibly driving away incremental customers or sales, with consequent loss of contributions to margin. This problem may be exacerbated by "pure incentives" or bonuses, which exert additional upward pressure on rates.

Balance Sheet Risk

Unless DSM expenditures are given immediate recovery, they result in the creation of "regulatory assets" or "IOUs" that are probably less secure (from shareholders' and bondholders' perspectives) than traditional supply-side assets. Further, such assets are not bondable property, i.e., they cannot be pledged as collateral to support a debt issue. If DSM programs become sufficiently large, there is risk of an increase in the cost of capital.

ELEMENTS OF A DESIRABLE INCENTIVES APPROACH

It follows from the preceding discussion that incentive mechanisms should address each of the major areas of disincentive. Specifically, they should:

- Provide for full and timely recovery of all program costs.
- Adjust for DSM-induced revenue losses.

- Counterbalance risk and loss of financial opportunity by providing a bonus, or "pure incentive," *above* cost.

It is unlikely that any single regulatory change can serve all of these objectives. Thus, the challenge becomes one of crafting packages of mechanisms that are comprehensive in scope.

Given the complexities of test year definitions, fuel and purchased power adjustment clauses, statutory restrictions on the components of rate base, and so forth, it is unlikely that any one mechanism or package of mechanisms will be applicable without modifications across different states. Superior incentive proposals will be developed with state-specific regulatory practices in mind. It is also important, I believe, to tailor the approach at the utility-specific level. Different utilities may respond in different ways to the same incentive due to differences in structure, rate level, extent of competition, balance sheet characteristics, and management's perceptions.

PROPOSALS FOR DSM INCENTIVE MECHANISMS

A number of proposals have been advanced in attempting to provide a greater level of financial incentive for DSM development. These range from modest variations on the ratebasing "theme" to reasonably bold structures. The latter, if adopted and implemented, would alter, in some cases dramatically, the current rate-of-return regulation, investments in supply, and energy sales. Some of these proposals would significantly advance the discussion regarding the possibilities for building a financial reward framework that would accommodate the restructuring of the industry. Table 1 provides an overview and summary of incentive mechanisms proposed throughout the U.S.

SUMMARY

As is evident from the summary of incentive proposals, there has been substantial activity nationwide over the past year in the development of incentive mechanisms. While there is still a great deal of variety in the proposals themselves (reflecting the substantial differences in regulatory accounting and state policies), it seems clear that shared savings mechanisms are becoming the most popular form of incentive. This is probably true for two reasons:

- it provides an opportunity for a substantial return to be earned by utilities, perhaps even as great as the equity return on the capital that would otherwise be invested in generation; and

- it establishes clear and consistent incentives between ratepayers (and society as a whole) and the utility. That is, the things which utilities are encouraged to do by the incentive mechanism are precisely those things which are in society's interest.

Finally, the nature and breadth of DSM incentive mechanisms are clearly accomplishing their purpose; they are making a substantial difference in the way in which utilities view the financial consequences of conservation activities.

Table 1
ELECTRIC UTILITIES WITH DSM BONUS MECHANISMS

Utility (State)	Bonus Type	Bonus Description	Citation
Central Hudson Gas & Electric (NY)	Shared savings	20% of net resource savings (avoided costs plus environmental benefits less program costs).	Order issued 1/4/90; modified by rate settlement, Opinion 90-16. Structure follows Opinion 89-29 in Cases 89-E-041 and 89-E-176, 9/27/89.
Consolidated Edison (NY)	Shared savings	5% of net resource savings (avoided costs plus environmental benefits less program costs). Note: Con Ed has told the PSC that the 5% incentive is inadequate and has asked for revisions.	Order issued 1/4/90. Structure follows Opinion 89-29 in Cases 89-E-041 and 89-E-176, 9/27/89.
Consumers Power (MI)	Per unit saved	Bonuses of $.01-.05/kWh for savings above 50–80% of target levels for individual programs. Precise bonus levels calculated from programs' cost-effectiveness results.	Order issued in 3/90 in Case U-9496.
Granite State Electric (NH)	Shared savings	Two-part bonus. The "maximizing incentive" is 5% of the present value of DSM programs, as measured by avoided cost. The "efficiency incentive" is 10% of avoided costs less the sum of program costs and the maximizing incentive.	Docket 89-187, Order No. 19,905 issued August 7, 1990.
Green Mountain Power (VT)	Shared savings	A recent order said GMP and other Vermont utilities will be allowed to retain 10% of the "customer savings exceeding pre-established targets for superior performance." Performance targets for GMP are being established in a separate docket on DSM programs (5270-GMP-2).	Docket 5428, order issued 1/4/91.
Long Island Lighting (NY)	Shared savings	15% of net resource savings (avoided costs plus environmental benefits less program costs).	Order issued 8/29/90. Structure follows Opinion 89-29 in Cases 89-E-041 and 89-E-176, 9/27/89.

Utility (State)	Bonus Type	Bonus Description	Citation
Massachusetts Electric (MA)	Per unit saved	Bonuses of $8.32/kW-year and $.00308/kWh, based on estimated lifetime savings of DSM measures. Bonuses are received on all savings above thresholds that are approximately 50% of program goals.	Docket 89-194/195, order issued 3/3/90.
Narragansett Electric (RI)	Shared savings	Two-part bonus. The "maximizing incentive" is 5% of the present value of DSM programs, as measured by avoided cost. The "efficiency incentive" is 10% of avoided costs less the sum of program costs and the maximizing incentive. Bonuses are received on all savings above thresholds that are approximately 50% of program goals.	Docket 1939, Stipulation signed 12/12/89. Approved by PUC order issued 5/16/90. Extended through 1991 by PUC order in Docket 1939, issued 2/14/91.
New York State Electric & Gas (NY)	Shared savings	15% of net resource savings (avoided costs plus environmental benefits less program costs).	Order issued 1/4/90. Structure follows Opinion 89-29 in Cases 89-E-041 and 89-E-176, 9/27/89.
Niagara Mohawk (NY)	Shared savings	10% of net benefits. Gross benefits equal avoided costs plus participants' benefits other than bill reductions. Costs equal program costs plus participants' costs not reimbursed by the utility.	Opinion 89-29 in Cases 89-E-041 and 89-E-176, 9/27/89.
Orange and Rockland Utilities (NY)	Adjustment to overall ROE	ROE adjusted +90/-20 basis points depending on performance against DSM goals. Performance measured in two areas: net resource savings (avoided costs plus environmental benefits less program costs) and cumulative kWh saved.	Agreement and settlement in Cases 89-E-175 and 89-E-176, 6/8/90.
Pacific Gas & Electric (CA)	(1) Shared savings (2) Markup on expenditures	(1) 15% of net savings (Utility Cost Test basis) for resource-oriented DSM programs. (2) Certain other programs, such as informational and low-income programs, receive a bonus of 5% of expenditures.	(1) and (2) Decision 90-08-068, 8/29/90.

Utility (State)	Bonus Type	Bonus Description	Citation
Portland General Electric (OR)	Shared savings	5% of the avoided long-run incremental cost (LRIC) per kWh saved; plus 10% of the difference between LRIC and levelized utility program costs; plus 10% of the difference between LRIC and levelized total resource costs.	Order No. 91-98, 1/18/91
Public Service of Colorado (CO)	Shared savings	5% of avoided costs, fixed by stipulation at $14/kW-month. Bonus can be increased or decreased based on weighted average life of DSM measures and cost/kW.	Stipulation and Settlement Agreement in Docket 90A-147E, 10/26/90, accepted by PUC in 11/90.
Rochester Gas & Electric (NY)	Shared savings	20% of net resource savings (avoided costs plus environmental benefits less program costs).	Opinion 90-17, 7/6/90. Structure follows Opinion 89-29 in Cases 89-E-041 and 89-E-176, 9/27/89.
San Diego Gas & Electric (CA)	(1) Per unit saved (2) Shared savings (3) Markup on expenditures	(1) A 1988 settlement established bonuses per kW or per kWh for performance above target levels in certain programs. (2) 13.5% of net savings (TRC Test basis) for most new resource-oriented DSM programs, and 9% of gross benefits for new construction programs. The bonus can be adjusted +/- 20% depending on the difference between projected and actual costs. (3) Direct-installation programs receive a bonus of 5% of expenditures.	(1) Settlement in "1989 GRC" (general rate case). (2) and (3) Decision 90-08-068, 8/29/90.
Southern California Edison (CA)	Markup on expenditures	Certain informational and low-income programs receive a bonus of 5% of expenditures.	Decision 90-08-068, 8/29/90.
United Illuminating (CT)	Ratebasing with a bonus ROR on DSM	Variable bonus of 1-3% additional return on ratebased DSM. The base bonus percentage is 2%; it can be increased to 3% or reduced to 1% if the ratio of program costs to benefits differs from base-case projections by more than 15%.	Dockets 89-08-11 and 89-08-12, order issued 1/24/90.

Utility (State)	Bonus Type	Bonus Description	Citation
Western Massachusetts Electric (MA)	Per unit saved	Variable bonuses of up to $2.20/kW-year and $.0028/kWh, based on estimated lifetime savings of DSM measures. Bonuses received only on savings above thresholds that are approximately 75% of program goals. The bonus amount as a percentage of the maximum bonus varies. If actual savings meet or exceed 125% of program goals, the full bonus per unit is paid. For achievement of 100% of program goals, 50% of the maximum bonus is paid.	Docket 89-260, order issued 6/29/90.
Wisconsin Electric Power (WI)	(1) Ratebasing with a bonus ROR on DSM (2) Fixed bonus pool for employee performance incentives	(1) WEPCO is collecting the last (or possibly next-to-last) installment on its old bonus mechanism, established in 1986. This mechanism provides a 1% additional return on ratebased DSM for every 125 MW of peak demand reduction achieved. Measures installed up through the end of 1990 were eligible for the bonus. WEPCO's cumulative bonus under this mechanism has totaled $2.98 million, and could reach $3.7 million if the company's estimates of savings are borne out in the evaluation. (2) Most recent rate order authorized $500,000 to be used for DSM-related incentive compensation to employees. WEPCO's proposal for a 10% shared-savings bonus was denied.	(1) Docket 6630-UR-100, order issued 12/30/86. (2) Docket 6630-UR-104, order issued 1/2/91.

Do Electric Utilities Need Financial Incentives to Promote Demand-Side Measures? Investor and Managerial Perspectives

by

Steven G. Kihm
MSB Energy Associates, Inc.

Presented at the

Third National Conference on
Integrated Resource Planning

Santa Fe, New Mexico

April 1991

Introduction

It is popularly believed that since demand-side management (DSM) programs limit utility sales growth, DSM must be bad for utility investors. The logic of this argument is that reducing sales growth reduces earnings growth. Since investors benefit from earnings growth, the logic continues, if we purposely limit sales growth investors will be harmed financially. The response of some commissions to this perceived problem is to provide financial incentives to utilities if they successfully promote DSM. Or, alternatively, some have suggested that we redesign the rate-making process to eliminate the negative impacts of DSM programs on utility investors.[1]

What is lacking, however, is theoretical or empirical evidence that utility investors are harmed by slowing sales growth. In fact, financial analysis texts criticize managers for such thinking, as is shown below:

> Growth and the management of growth present special problems in financial planning, in part because many executives see growth as something to be maximized. Their reasoning is simply that as growth increases, the firm's market share and profits should rise as well. From a financial perspective, however, growth is not always a blessing. Rapid growth can put considerable strain on a company's resources, and unless management takes steps to control it, rapid growth can lead to bankruptcy. It is a sad truth that almost as many companies go bankrupt because they grow too fast as do those who grow too slowly.[2]

The empirical evidence also suggests that growth is not necessarily a prescription for financial success. For example, a recent Goldman Sachs' study found that, over the long run, the best-performing utility stocks tend to experience significantly slower growth than do the worst-performing utility stocks.[3] This paper will present additional evidence that utility investors can fare quite well in a slow-growth environment.

After showing that the utility investor is not necessarily harmed by, and may in fact benefit from, the growth-slowing effects of DSM, this paper will explore impacts of slower utility growth on utility managers. The evidence indicates that managers may have economic and psychological reasons for not wanting to promote DSM. This leads to the conclusion that the focus on incentives for DSM should perhaps be on changing managerial pay systems and corporate cultures, rather than on providing financial incentives to utility stockholders.

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1 See for example, David Moskovitz, ***Profits and Progress Through Least-Cost Planning***, National Association of Regulatory Utility Commissioners, November, 1989.

2 Robert C. Higgins, ***Analysis for Financial Management***, Second Edition, Richard D. Irwin, 1989, p. 105.

3 Robert C. Jones, "Designing Factor Models for Different Types of Stocks: What's Good for the Goose Ain't Always Good for the Gander," ***Financial Analysts Journal***, March/April 1990, p. 28. The study covered the period from 1969 through 1987.

Investor Returns and Sales Growth

It is relatively easy to show that utility sales growth and investor returns are not positively related. We can use the Moody's Electric Utilities to demonstrate this point.[4] Table 1 lists the upper and lower quartile of the Moody's Electric Utilities in terms of kWh sales growth from 1972 through 1989.

Table 1
Moody's Electric Utilities

kWh Sales Growth (1972-1989)

Upper Quartile - (Fastest Growing)	Annual kWh Sales Growth Rate (%)
Public Service of Colorado	5.1
Florida Progress Corporation	5.0
Pennsylvania Power and Light	4.3
Central Maine Power	4.2
Baltimore Gas and Electric	3.9
Houston Industries	3.4
Median growth rate of the quartile	**4.2**

Lower Quartile - (Slowest Growing)	Annual kWh Sales Growth Rate (%)
Northeast Utilities	2.0
Commonwealth Edison	1.9
Philadelphia Electric	1.7
SCE Corp.	1.7
Detroit Edison	1.3
Consolidated Edison	0.7
Median growth rate of the quartile	**1.7**

Source: ***Moody's Public Utility Manual.***

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[4] The Moody's Electric Utilities consist of 24 major U.S. electric utilities. For a complete list of the utilities see ***Moody's Public Utility Manual.***

Table 1 shows us that the utilities in the upper quartile grew, on average, more than twice as fast as those in the lower quartile. If sales growth is a significant determinant of investor returns, we should expect to find that investors in utility stocks in the upper quartile made more money than those who invested in companies in the lower quartile. Table 2 shows annual investor returns for each of the companies in the upper and lower quartile.

Table 2 clearly shows that, contrary to what the "growth is good for the investor" hypothesis would suggest, investors in the typical high-growth company earned about the same return as investors in the typical low-growth company.

Table 2
Moody's Electric Utilities

Investor Returns
1972-1989

Upper Quartile - (Fastest Growing)	Annual Investor Return (%)
Public Service of Colorado	10.4
Florida Progress Corporation	11.9
Pennsylvania Power and Light	12.8
Central Maine Power	10.8
Baltimore Gas and Electric	13.7
Houston Industries	9.2
Median return of the quartile	**11.4**

Lower Quartile - (Slowest Growing)	Annual Investor Return (%)
Northeast Utilities	12.4
Commonwealth Edison	10.1
Philadelphia Electric	11.4
SCE Corp.	15.4
Detroit Edison	11.1
Consolidated Edison	17.6
Median return of the quartile	**11.9**

Source: Calculations based on data from ***The Value Line Investment Survey***.

Note: Assumes that dividends are reinvested.

These data tell us that sales growth is neither necessary nor sufficient for high investor returns. Simply because high sales growth or low sales growth occurs does not tell us anything about the attractiveness of a utility stock from an investor's perspective. As we shall see in the next section, variables other than sales growth are much more important determinants of investor returns.

Financial Opportunities for Utility Investors in Slow-Growth and Fast-Growth Environments: The Cases of Consolidated Edison and Pennsylvania Power and Light

This section of the paper focuses on the operational and investment performance of two of the Moody's Electric Utilities: Consolidated Edison of New York and Pennsylvania Power and Light. Using the actual data from these companies helps to demonstrate that a slow-growth environment can be just as attractive, if not more attractive, than a rapid-growth environment to utility investors. As Figure 1 shows, Consolidated Edison had almost no sales growth from 1972 through 1989, while Pennsylvania Power and Light saw substantial growth.

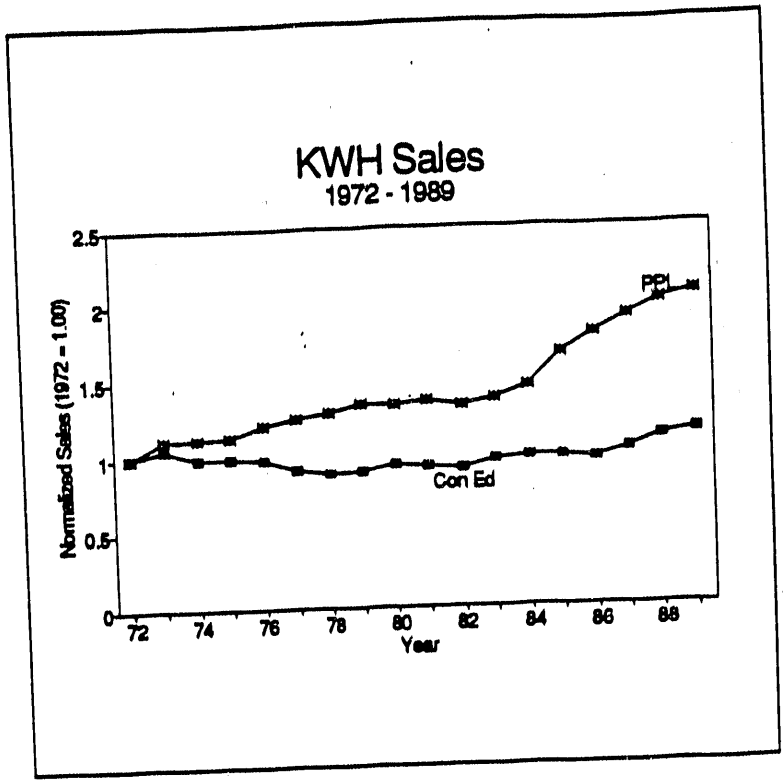


Figure 1 ***Pennsylvania Power and Light's sales more than doubled over this period while Consolidated Edison's barely grew at all.***

Source: ***Moody's Public Utility Manual.***

Increases in sales do not, however, occur in isolation. Fast-growing utilities need to add capacity to serve new loads. Utilities that have limited sales growth are less likely to need to add plant and it can be added in smaller increments. As is shown in Figure 2, over the 1972 through 1989 period, Pennsylvania Power and Light's investment in net plant grew dramatically while Consolidated Edison had little growth in net plant.

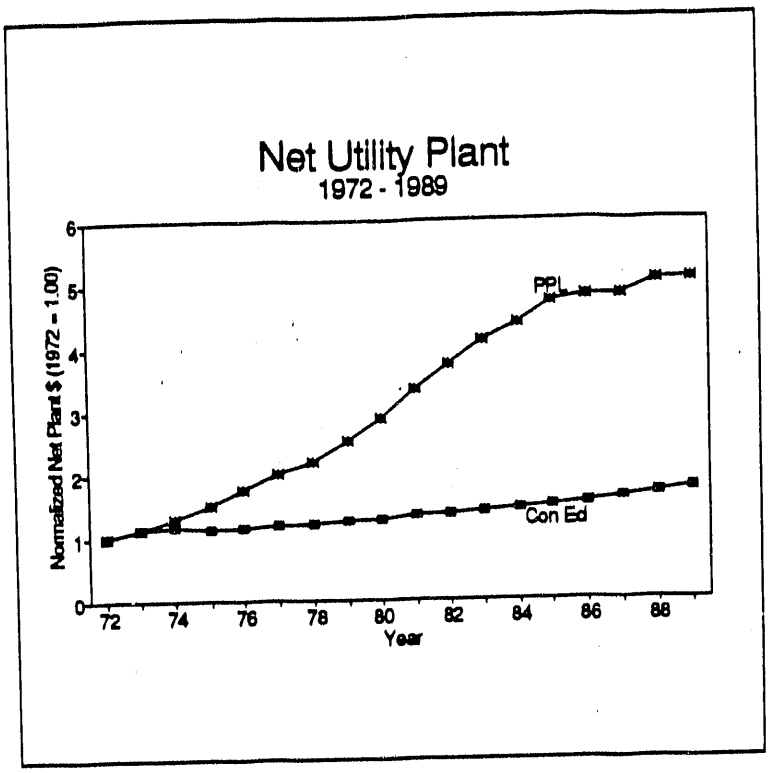


Figure 2 ***Pennsylvania Power and Light's net plant in 1989 was over five times its 1972 level. Consolidated Edison's 1989 net plant grew to only one and one-half times its 1972 level.***

Source: ***The Value Line Investment Survey.***

The preceding graphs show that Pennsylvania Power and Light and Consolidated Edison were clearly facing different operating environments over this period. We will next examine some of the differences in their financial situations. Figure 3 shows the net cash flow of the two utilities. Net cash flow is defined here to be internally generated funds minus construction requirements. As the figure shows, Consolidated Edison was, in general, generating excess cash, while Pennsylvania Power and Light was, in general, running cash deficits.

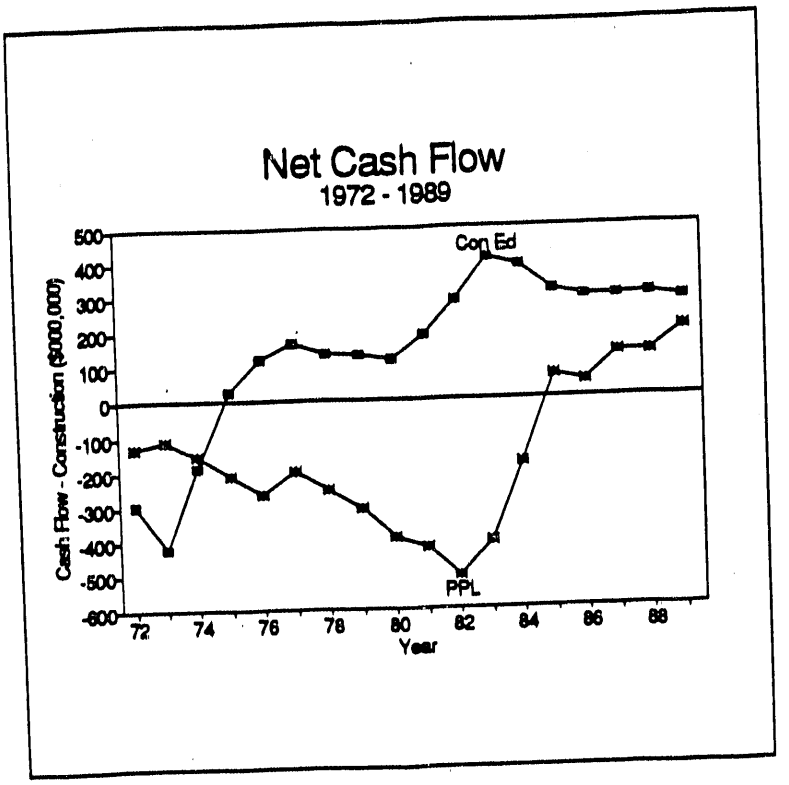


Figure 3 ***Consolidated Edison was a net cash generator while Pennsylvania Power and Light was a net cash user.***

Source: ***The Value Line Investment Survey.***

The cash-flow impacts of growth are often ignored by those who claim that utilities need incentives if we are to expect them to limit sales growth. A slow-growth environment can be very financially attractive to a utility if it can trim its construction budget to match its sales growth. Consolidated Edison is an example of such a slow-sales-growth, slow-plant-growth utility. On the other hand, Pennsylvania Power and Light's high-sales-growth, high-plant-growth environment put it in a cash-poor situation.

Pennsylvania Power and Light's large cash needs required it to rely heavily on external financing. Figure 4 shows that Pennsylvania Power and Light sold tremendous amounts of common stock over this period to finance its construction. Consolidated Edison, on the other hand, with its lack of major construction, had little need to issue new common stock.

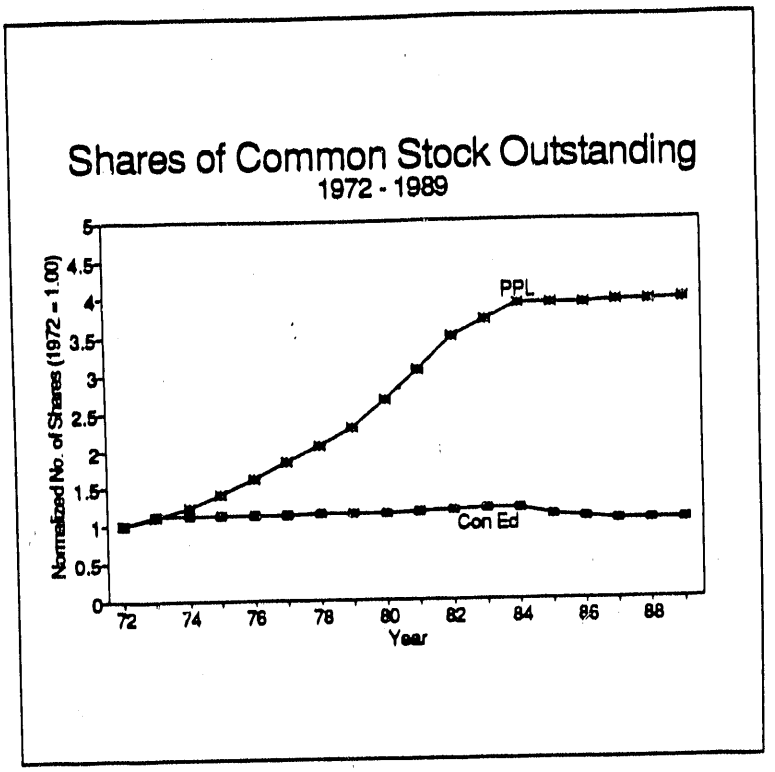


Figure 4 ***Pennsylvania Power and Light's external financing needs required it to increase its number of shares of common stock to four times its 1972 level. Consolidated Edison's number of shares outstanding was roughly the same in 1989 as it was in 1972.***

Source: ***The Value Line Investment Survey.***

The dramatic difference in the number of shares of common stock issued over this period caused Pennsylvania Power and Light and Consolidated Edison to experience different degrees of earnings dilution. In Pennsylvania Power and Light's case any earnings gains from increased net plant had to be shared with the large number of new shareholders. Consolidated Edison's shareholders, on the other hand, had essentially no dilution because the number of shares changed very little from 1972 through 1989.

The number of shares issued is an important determinant of earnings-per-share growth. That is, the fewer the number of shares issued, the greater the potential for earnings-per-share growth. Since earnings per share is a ratio of aggregate earnings to the number of shares outstanding, the low growth in the number of shares of common stock for a slow-growing utility countervails its lower aggregate earnings growth. Conversely, while a rapid-growth utility is likely to see rapid aggregate

earnings growth, if it has to increase the number of shares of stock outstanding, it may not experience rapid earnings-per-share growth and, in fact, may see its earnings per share decline. As Figure 5 shows, the slow-growing, cash-generating Consolidated Edison had significantly greater earnings-per-share growth than did the rapidly-growing, cash-poor Pennsylvania Power and Light Company.

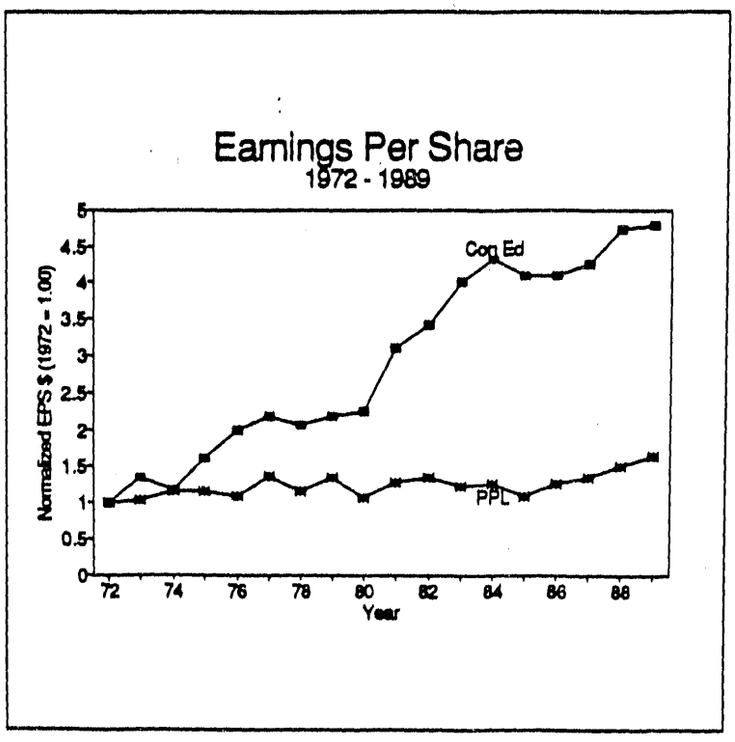


Figure 5 ***Consolidated Edison's 1989 EPS share were almost five times as great as its 1972 EPS. Pennsylvania Power and Light's 1989 EPS were only one and one-half times its 1972 figure.***

Source: ***Moody's Public Utility Manual.***

It should be noted that Consolidated Edison's success in increasing its earnings per share was not due to differences in earned return on equity. In fact, Consolidated Edison's average earned return on equity from 1972 through 1989 was lower than Pennsylvania Power and Light's over this period.[5]

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[5] Source: ***The Value Line Investment Survey.*** It should also be noted that Con Ed was able to generate additional earnings by increasing its common equity ratio. This was made possible by the company's strong internal cash flow resulting from its lack of construction.

With its dramatic increase in earnings per share, Consolidated Edison was able to increase its dividends per share at a rapid rate, and investors bid up the price of its stock. Because Pennsylvania Power and Light's earnings per share suffered from the diluting effects of the large number of new shares issued, its dividend-per-share growth was limited and its price did not climb nearly as much as did Consolidated Edison's. Figure 6 shows that, if you invested in Consolidated Edison in 1972 and reinvested your dividends as you received them, by 1989 you would have twice as much money as you would have had if you had invested in Pennsylvania Power and Light.

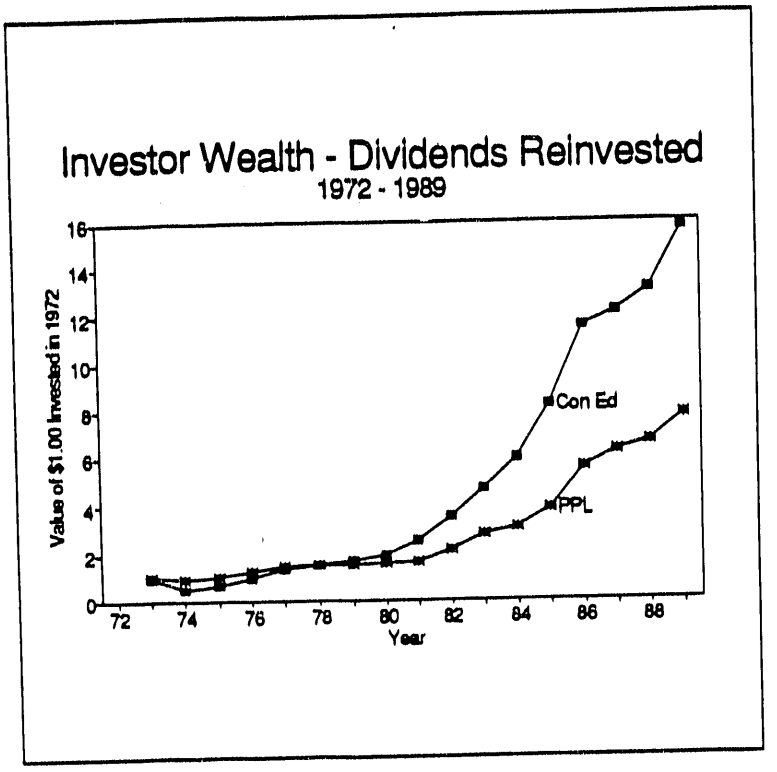


Figure 6 ***Investors in slow-growing Consolidated Edison earned substantially more than investors in rapidly-growing Pennsylvania Power and Light.***

Source: ***Calculations based on data from The Value Line Investment Survey.***

This analysis demonstrates why greater sales growth does not necessarily lead to greater investor returns. Statements indicating that sales growth is not necessarily good for utility investors can readily be found in the financial press. Take, for example, this quote from ***The Value Line Investment Survey*** regarding the likely effects of sales growth on Delmarva Power's financial attractiveness. The text begins with a rather glowing appraisal of the stock:

> Delmarva Power's good yield will attract many investors. Based on our expectations of another modest dividend hike next March, the estimated year-ahead return is about a full point above the utility industry average. Moreover, the payout appears to be adequately covered by the companies earnings and financing.

But when the impact of rapid growth in load is factored in, the outlook becomes more gloomy:

> But the stock has less interest as a total return vehicle. As shown in the operating statistics to the left, last year's peak load was about 89% of Delmarva's generating capacity. That ratio is on the high side; most utilities strive for a ratio of 80% or less to ensure adequate supplies at peak periods. At the same time, load growth has been expanding at a good clip, reflecting the economic health of the service area. That means that capital outlays will have to remain high to finance the needed capacity increases. A fair amount of this capital will have to be obtained from public debt and equity offerings. The cost of this new capital may put a damper on share earnings and dividend growth at least through the 1993-95 period.[6]

Investors clearly recognize that sales growth leads to plant additions which in turn lead to earnings dilution. That makes sales growth unattractive to utility investors in many instances.

Demand-Side Management and Managerial Interests

The preceding analysis should lead one to question the need for utility investors to be compensated through special incentives when the utility tries to control its load growth with DSM programs. The fact is that if demand-side programs are successful in controlling load growth and construction can be deferred or limited to some extent, investors are likely to benefit.

It has been well documented, however, that managers in general have a bias toward sales-growth maximization rather than maximizing investor value. The following quote from a standard industrial organization economics text is an example:

> In a seminal statement of the proposition, Professor William Baumol argued that instead of maximizing profits, either short-run or long-run, firms with monopoly power tend to maximize sales revenue, subject only to the condition that profits not fall below some specified minimum value. He was led to this break from orthodoxy by repeated observation of managers' preoccupation with the level and growth of their companies' sales rather than current profits.[7]

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6 ***The Value Line Investment Survey***, September 21, 1990, p. 174.

7 F.M. Scherer, ***Industrial Market Structure and Economic Performance***, Houghton-Mifflin Company, 1980, p. 261.

Why do we find utility executives wanting to increase sales growth when the evidence suggests that sales growth is not related to investment performance?

One reason is that many people, including some utility executives, do not understand the complex relationship between sales growth and investor returns. Recall the quote in the introduction of this paper in which executives were criticized by financial experts for failing to realize the potentially harmful effects of growth on a company's financial situation. But there is more to this phenomenon that a lack of financial training.

While it is clear that investors are not harmed when growth is limited, utility managers might be. The impacts can be economic or psychological. From an economic perspective, managers are likely to earn more when the utility grows. From a psychological perspective, managers are likely to feel better in a growing environment.

With respect to company size and salary level, analysis of ***Business Week*** data shows that the chief executive officers of large U.S. electric utilities earned about 25 percent more than the CEOs of the small electric utilities.[8] That means that an executive is likely to see greater pay increases if he or she increases the size of the utility. Because the responsibilities and complexity of work tend to increase with the size of an organization, the salary level is higher for the employees of the bigger firms. But again we must remember that the increase in size and complexity do not necessarily benefit investors.

At least as important as the potential salary increases, however, is that growth and size provide psychic value to many managers, as is evidenced by the following quote:

> Being human, most hired managers derive considerable satisfaction from achieving personal prestige and power. Both seem to be correlated more closely with the volume of a firm's sales than with the size or rate of profit it earns.[9]

This evidence indicates that utility executives have incentive to increase sales even if there is no benefit to utility investors.

The fact that managers and stockholders face different incentives is known as a "principal-agent conflict." The utility managers are agents of the utility stockholders (the principals). Finance theory has recently recognized that principal-agent problems may be the cause of what appears to be irrational behavior on the part of managers

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[8] See "Executive Compensation Scoreboard," ***Business Week***, May 7, 1990, pp. 104-108. The largest companies were the upper quartile of companies in terms of 1989 sales revenue. The smaller companies were the lower quartile of companies. The CEOs of the largest utilities earned on average $735,000 per year; the CEOs of the smaller utilities earned on average $594,000 per year.

[9] Scherer, p. 35.

(such as promoting sales growth when it may not be good for investors). The behavior becomes more rational when the managers' incentives are revealed.[10]

If utility managers are likely to be harmed either economically or psychologically by slowing sales growth, then it is understandable that many of them do not wholeheartedly support DSM programs. What this means is that, rather than utility investors, it is utility managers that may have to be given incentives that make promoting DSM attractive to them. For example, bonuses for achieving certain kW or kWh reduction targets may be part of the compensation package of some utility managers. In an attempt to examine this issue more closely, the Wisconsin Public Service Commission will investigate the consistency of utilities' managerial compensation schemes with least-cost planning objectives in its next long-term planning review.[11] The Wisconsin Commission has also recently allowed Wisconsin Electric Power Company to set aside $500,000 for employee bonuses to be paid to WEPCO's conservation sales force if they aggressively market demand-side measures. The purpose of the program is to "... change its [WEPCO's] corporate culture to an integrated least-cost planning entity ..."[12] It is such corporate culture changes that need to be encouraged if DSM promotion is to be successful.

Changing A Utility's Corporate Culture

We have seen that utility managers' failure to support DSM promotion without special incentives is based to some extent on fuzzy thinking and to some extent on real economic and psychological needs of utility managers. Based on the evidence we have reviewed, we could take the hard-line position that shareholder incentives should not be allowed. But will this help to persuade those managers who still believe that growth is good for investors to abandon their basic ideas about DSM? Probably not.

Shareholder incentive mechanisms do appear to motivate utilities to pursue DSM as a resource option. If this is what it takes to motivate some managers who would not otherwise promote DSM to do so, and if the commission finds that aggressive DSM promotion is in the public interest, shareholder incentives may be appropriate. The key purpose of this type of incentive is to change the basic corporate philosophy away

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10 See Amir Barnea, Robert A. Haugen and Lemma W. Senbet, ***Agency Problems and Financial Contracting***, Prentice-Hall, 1985.

11 See Public Service Commission of Wisconsin, ***Order in Docket 05-EP-5***, April 6, 1989, p. 85.

12 "WEPCO Incentive Earnings Show Gains as Conservation Savings Near 250 MW," ***Electric Utility Week***, January 28, 1991, p. 15.

from "growth is good" to "DSM is good." Over time as DSM promotion becomes more ingrained in the utilities' corporate cultures, the need for shareholder incentives is likely to disappear.

With respect to the economic disincentives for managers to promote DSM, changing utility pay systems appears to be in order. The recently-approved Wisconsin Electric Power Company employee bonus plan for successful DSM promotion is likely to reinforce the idea that DSM is good. Once economic rewards for DSM promotion are earned, the psychological concerns about working for a slow-growing company may disappear. This would be the ultimate achievement in switching utility managers thinking away from growth as the measure of success to increasing energy efficiency as the principal corporate goal.

Conclusion

There is a widespread misconception that limiting utility sales growth is bad for utility investors. The evidence overwhelmingly contradicts this view. Limiting sales growth via DSM programs should not, therefore, be assumed to be financially unattractive to utility investors. Growth-limiting DSM programs may be unattractive to utility managers, however, because less growth could mean lower salaries and less power and prestige. The analysis suggests that the focus of DSM incentive programs should be on utility employees, not the stockholders. The ultimate challenge for utilities and commissions is to find ways to change utility corporate cultures to be more supportive of DSM.

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Do Electric Utilities Need Financial Incentives to Promote Demand-Side Measures? Investor and Managerial Perspectives

by

Steven G. Kihm
MSB Energy Associates, Inc.

Presented at the

Third National Conference on
Integrated Resource Planning

Santa Fe, New Mexico

April 1991

Growth and the management of growth present special problems in financial planning, in part because many executives see growth as something to be maximized. Their reasoning is simply that as growth increases, the firm's market share and profits should rise as well. From a financial perspective, however, growth is not always a blessing. Rapid growth can put considerable strain on a company's resources, and unless management takes steps to control it, rapid growth can lead to bankruptcy. It is a sad truth that almost as many companies go bankrupt because they grow too fast as do those who grow too slowly.[2]

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2 Robert C. Higgins, ***Analysis for Financial Management***, Second Edition, Richard D. Irwin, 1989, p. 105.

Moody's Electric Utilities

kWh Sales Growth (1972-1989)

Upper Quartile - (Fastest Growing)	Annual Growth
Public Service of Colorado	5.1
Florida Progress Corporation	5.0
Pennsylvania Power and Light	4.3
Central Maine Power	4.2
Baltimore Gas and Electric	3.9
Houston Industries	3.4
Median growth rate of the quartile	**4.2**

Lower Quartile - (Slowest Growing)	Annual Growth
Northeast Utilities	2.0
Commonwealth Edison	1.9
Philadelphia Electric	1.7
SCE Corp.	1.7
Detroit Edison	1.3
Consolidated Edison	0.7
Median growth rate of the quartile	**1.7**

Source: ***Moody's Public Utility Manual.***

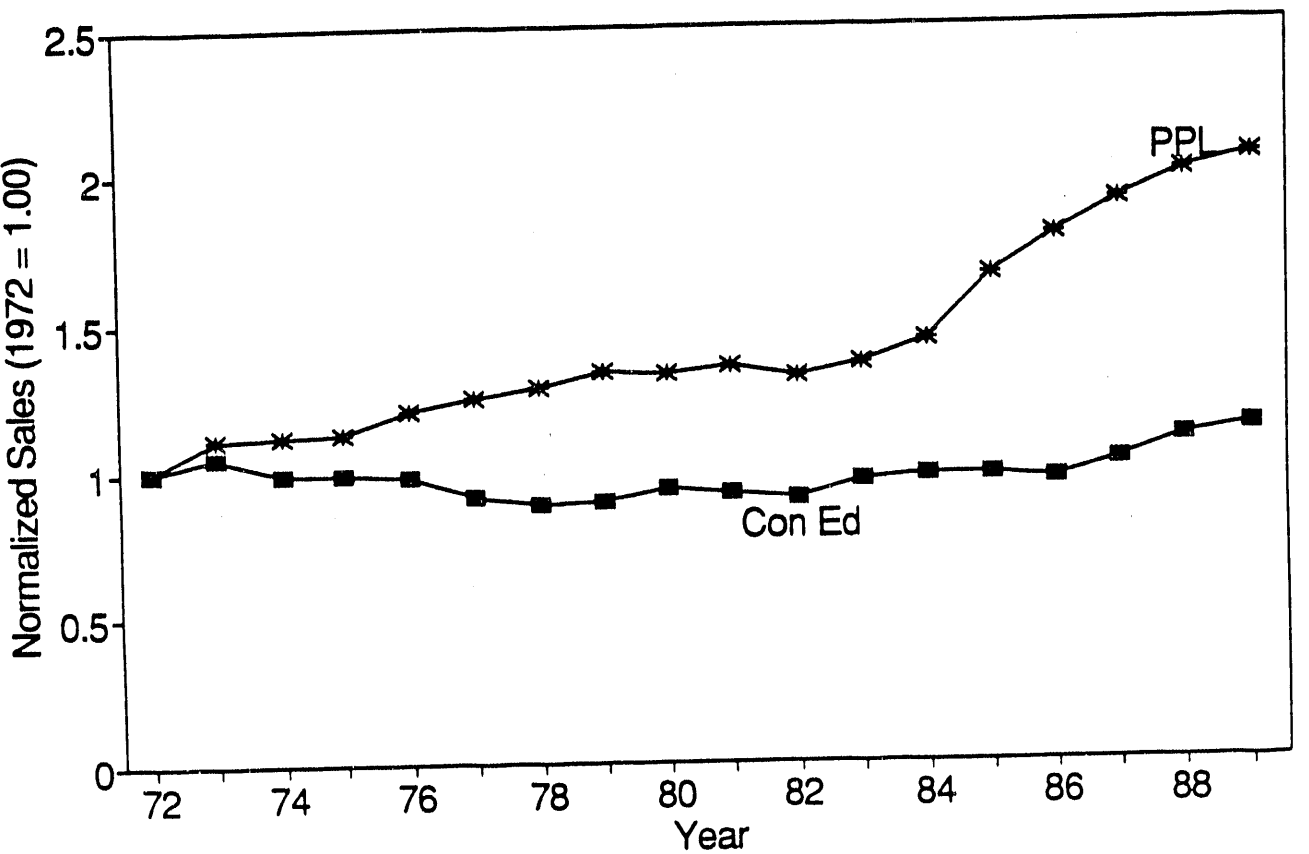
Moody's Electric Utilities

Investor Returns

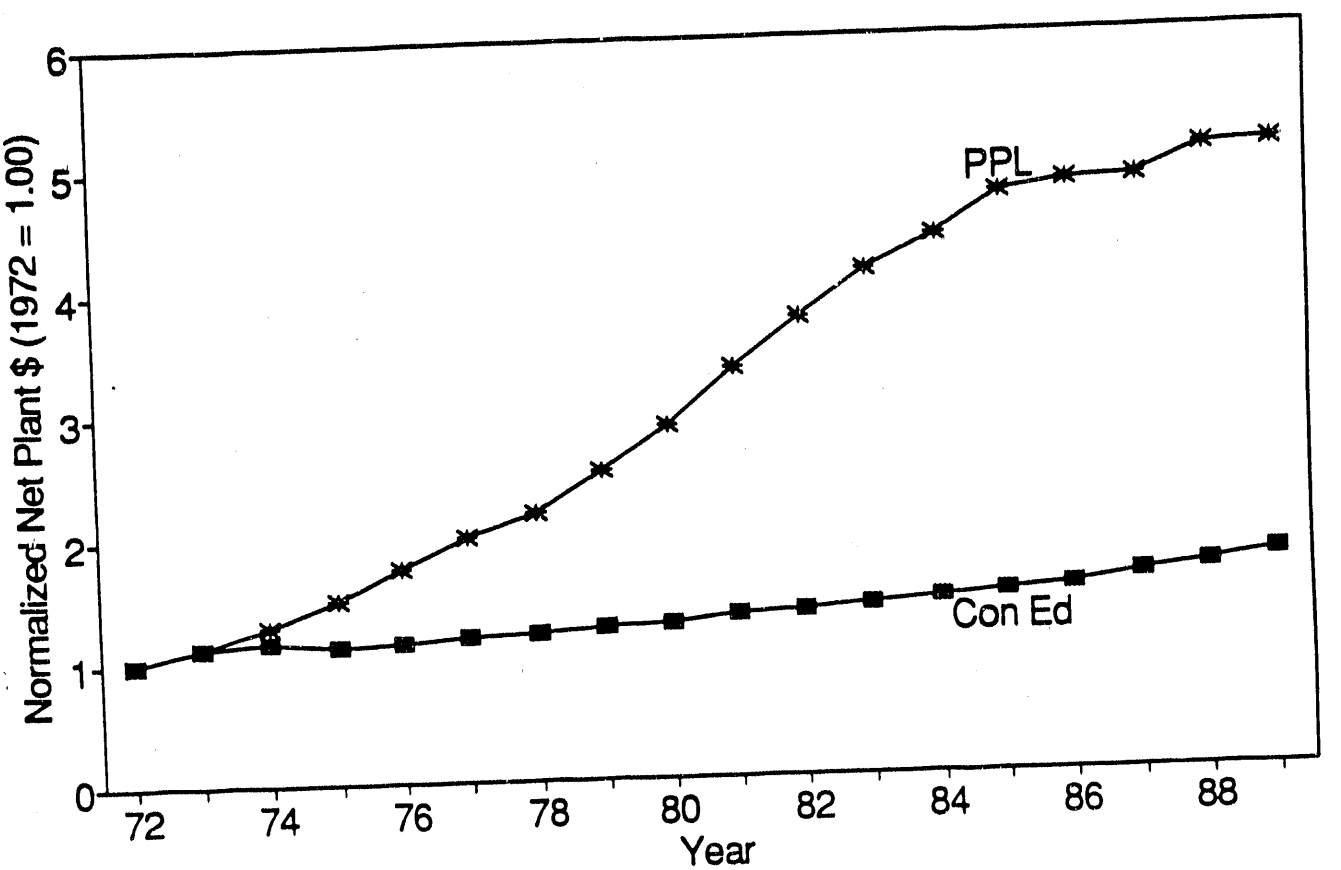
Upper Quartile - (Fastest Growing)	Annual Return
Public Service of Colorado	10.4
Florida Progress Corporation	11.9
Pennsylvania Power and Light	12.8
Central Maine Power	10.8
Baltimore Gas and Electric	13.7
Houston Industries	9.2
Median return of the quartile	**11.4**

Lower Quartile - (Slowest Growing)	Annual Return
Northeast Utilities	12.4
Commonwealth Edison	10.1
Philadelphia Electric	11.4
SCE Corp.	15.4
Detroit Edison	11.1
Consolidated Edison	17.6
Median return of the quartile	**11.9**

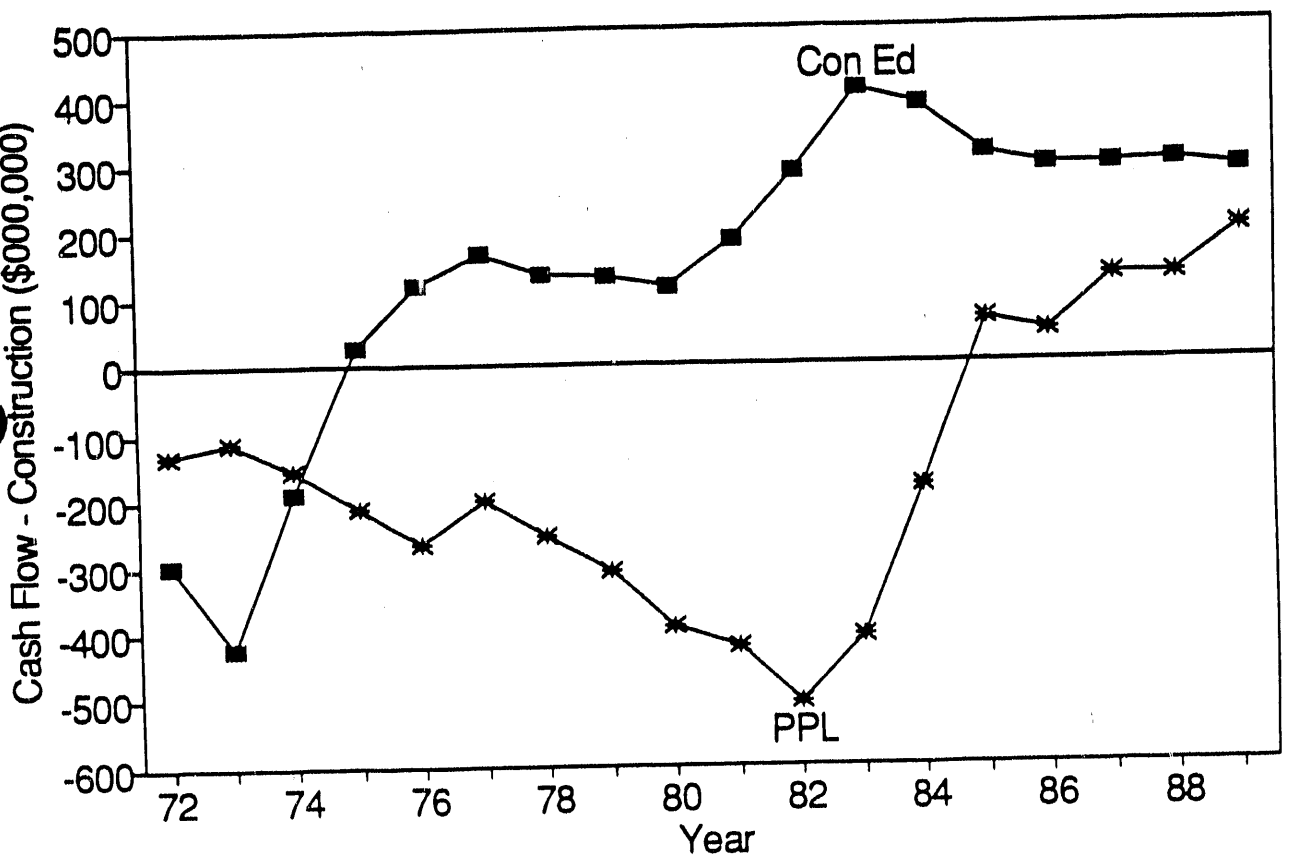
KWH Sales
1972 - 1989



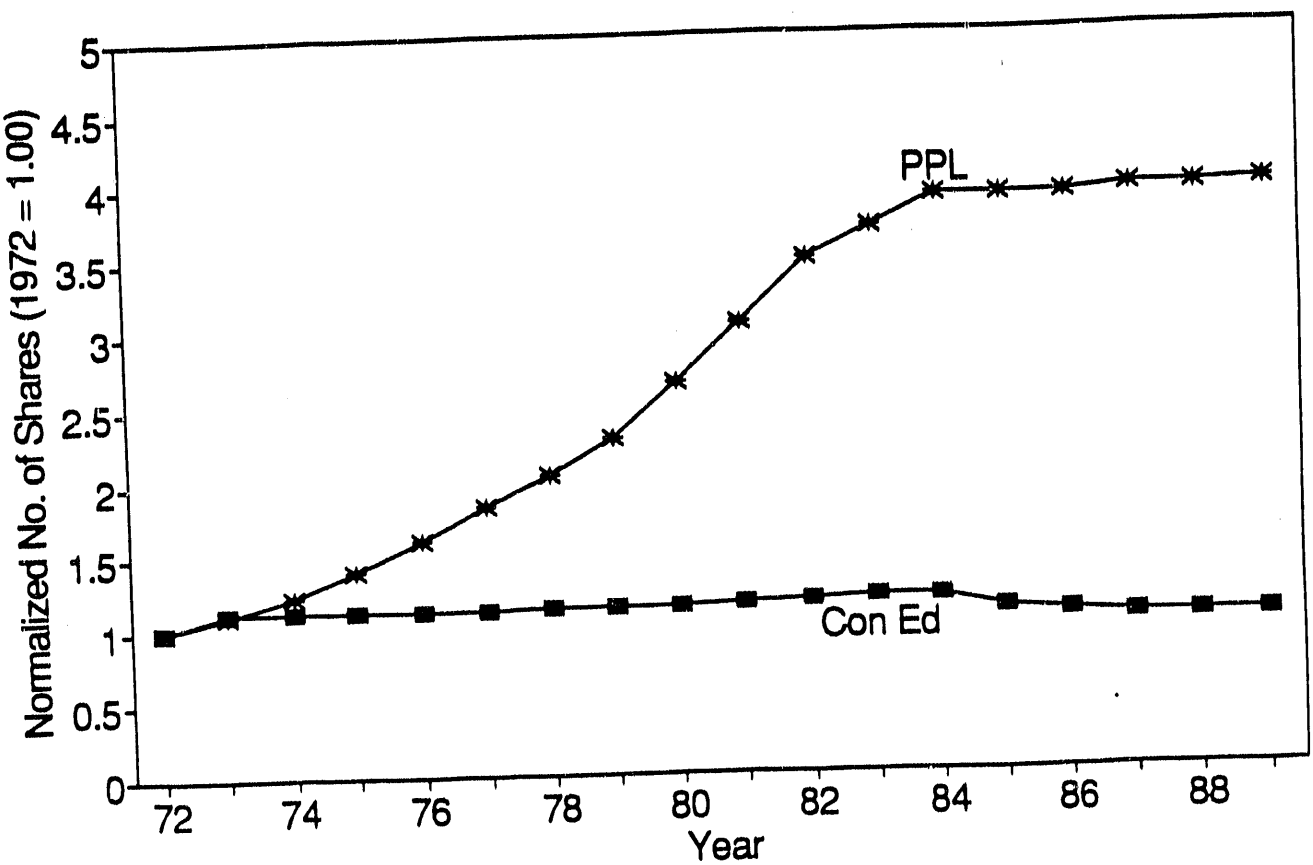
Net Utility Plant
1972 - 1989



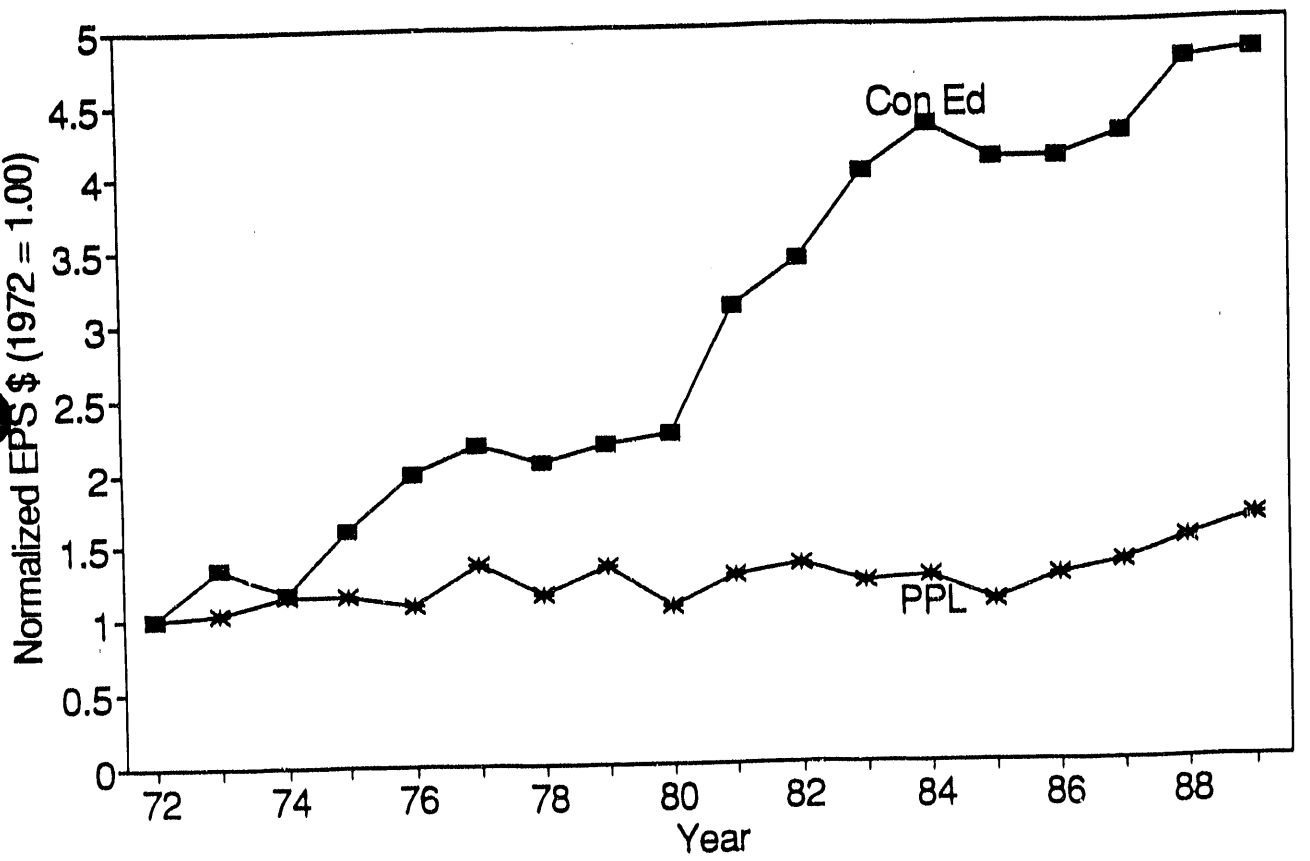
Net Cash Flow
1972 - 1989



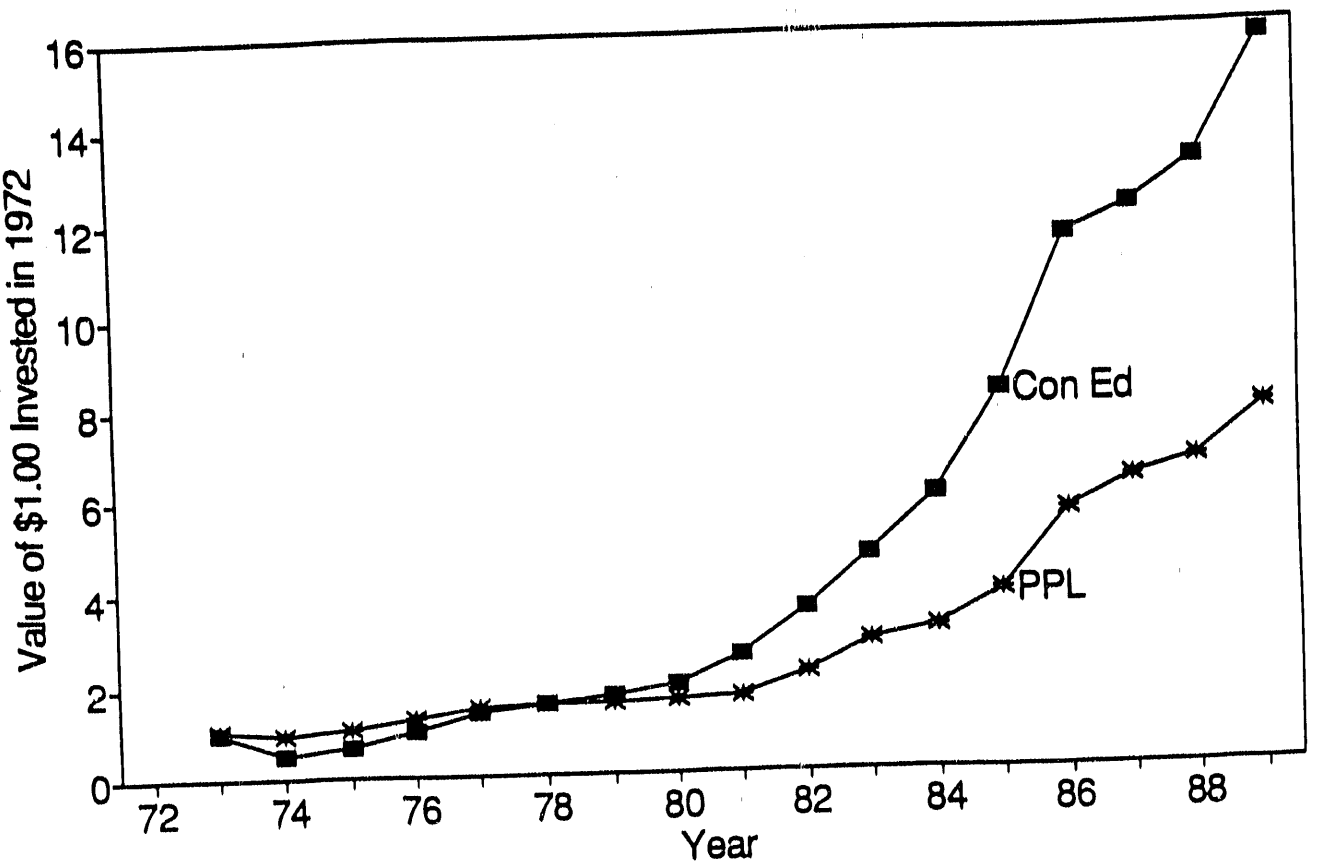
Shares of Common Stock Outstanding
1972 - 1989



Earnings Per Share
1972 - 1989



Investor Wealth - Dividends Reinvested
1972 - 1989



In a seminal statement of the proposition, Professor William Baumol argued that instead of maximizing profits, either short-run or long-run, firms with monopoly power tend to maximize sales revenue, subject only to the condition that profits not fall below some specified minimum value. He was led to this break from orthodoxy by repeated observation of managers' preoccupation with the level and growth of their companies' sales rather than current profits.[7]

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7 F.M. Scherer, ***Industrial Market Structure and Economic Performance***, Houghton-Mifflin Company, 1980, p. 261.

Why do utility managers want financial incentives?

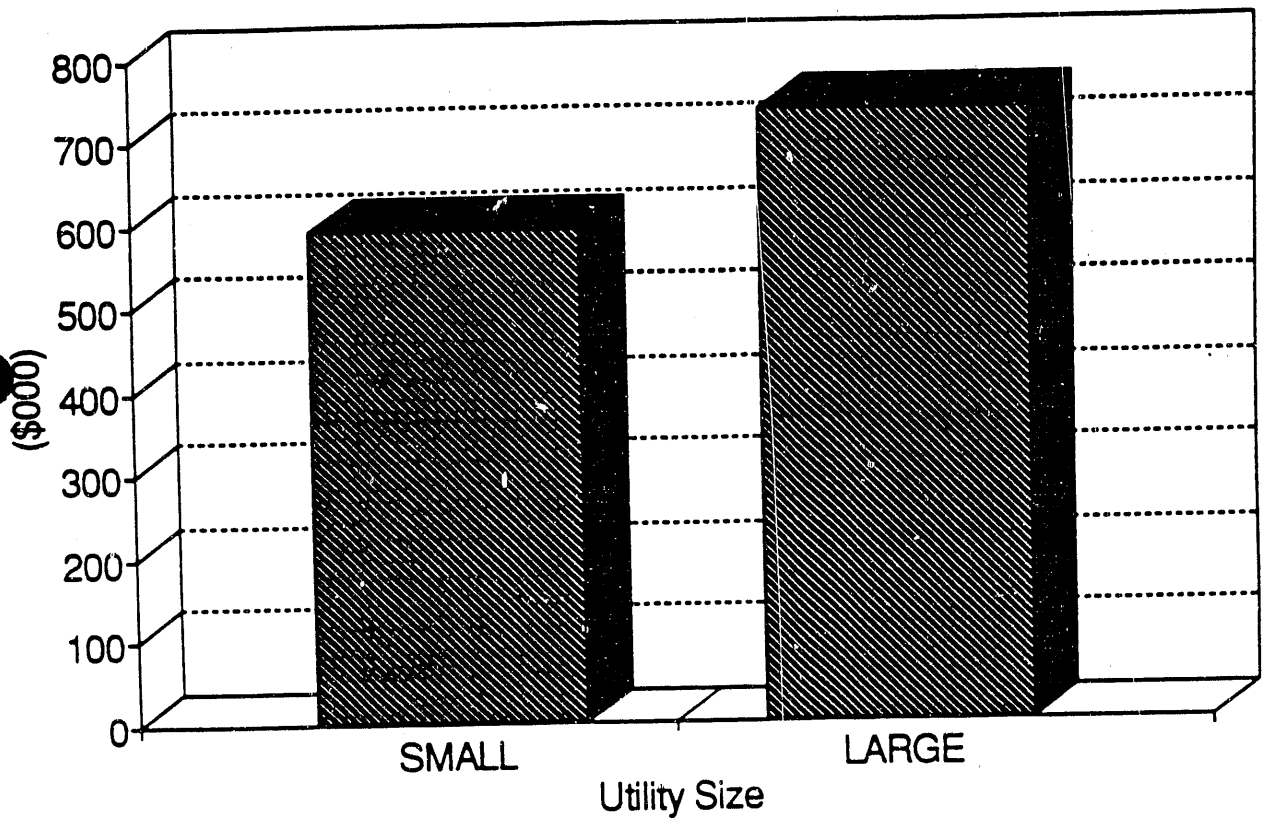
- Fuzzy thinking

- Economic (pay)

- Psychological (size)

Average Annual Compensation of CEO

Business Week Electric Utilities - 1989



Being human, most hired managers derive considerable satisfaction from achieving personal prestige and power. Both seem to be correlated more closely with the volume of a firm's sales than with the size or rate of profit it earns.[9]

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9 Scherer, p. 35.

New Approaches

- Managerial incentives

Changing Corporate Cultures

- Do Shareholder Incentives Do This?

DESIGN OF A UTILITY INCENTIVE TO ENCOURAGE ELECTRIC ENERGY CONSERVATION

NARUC Third National Conference on

Integrated Resource Planning

Santa Fe, New Mexico

APRIL 8 - 10, 1991

By: Mary Kilmarx
Director
Energy Policy & Planning
R.I. Public Utilities Commission
100 Orange Street
Providence, RI 02903

401-277-3500

Peter Wallis
President
Wallis Energy Company
33 Boston Post Road West
Suite 270
Marlborough, MA 01749

508-485-9370

DESIGN OF A UTILITY INCENTIVE TO CONSERVE ELECTRIC ENERGY IN RHODE ISLAND

OVERVIEW

In December, 1989, the Rhode Island Public Utilities Commission (RIPUC) approved an incentive for the state's largest electric utility, Narragansett Electric Company, to encourage the Company to implement energy conservation where it was cheaper for ratepayers than the capacity and energy it would displace. Narragansett thus became, we believe, the first utility in the country to make a profit above and beyond cost on the installation of electricity conservation equipment and the Rhode Island Commission the first regulatory agency to put into action the NARUC resolution calling for conservation to be a profitable utility endeavor.

Narragansett, working in collaboration with the Conservation Law Foundation, had presented to the Commission a two-pronged incentive design in conjunction with the filing of its proposed 1990 Conservation and Load Management Programs. After a series of technical sessions with the Division staff, the Attorney General, and an intervening party (a group of large commercial and industrial customers), a negotiated settlement regarding the incentive was achieved which the Commission later endorsed.

This paper will describe the incentive and its underlying principles, how the value of conservation for the purpose of calculating the incentive is derived, and how the incentive is then reflected in the rates. It will conclude with some comments on how the incentive appears to have had a positive influence on Narragansett's 1990 conservation program results.

THE INCENTIVE

The four basic principles guiding RIPUC's approved incentive to promote electricity conservation are:

1) Require that the utility cost for conservation plus incentive not exceed avoided cost (Value Requirement).

2) Establish a minimum level of performance before any incentives are given (Threshold Requirement).

3) Encourage the utility to maximize the amount of kW and kWh saved (Maximizing Incentive).

4) Reward the utility for reducing the cost of saving kW

and kWh (Efficiency Incentive).

Value Requirement RIPUC became interested in providing Narragansett an incentive after RIPUC determined that many electricity conservation measures were more cost effective than building new power plants. It recognized that regulatory restructuring was necessary to engage the utility's interest in vigorous pursuit of this course of action. The corollary principle is that an energy conservation measure will only be given an incentive if the measure costs less than the value of the energy and power saved.

The value of the savings is determined based on the utility's avoided cost. The avoided cost is simply the marginal cost which Narragansett would pay its wholesale supplier, New England Power, for capacity and energy over the life of the conservation measures. In practice, prior to approving Narragansett's 1990 Conservation and Load Management Program, RIPUC reviewed the proposed conservation measures to ensure that Narragansett was planning to implement only those measures which cost less than the value of the kW and kWh saved.

Threshold Requirement RIPUC's purpose in providing an incentive to Narragansett was to encourage aggressive pursuit of cost effective conservation opportunities beyond a base level. In other words, the incentive is not viewed as a reward for all conservation, but as an inducement to reach farther and dig deeper. Therefore, RIPUC stipulated that Narragansett had to install a Threshold Requirement of conservation valued at $13.7 million in 1990 (about half of the amount projected) to begin receiving a profit on its conservation programs. If Narragansett had been unable to install $13.7 million worth of conservation, it would have received no profit for its conservation efforts and would have been reimbursed only for its costs.

No penalty for poor achievement was established. Although this symmetry is conceptually appealing, it was considered unthinkable that at least this amount of conservation could not be achieved, given the comprehensiveness of the programs and their attractiveness to consumers. A schedule of frequent (bimonthly) reporting to the Commission was required and more aggressive marketing could be encouraged if program response lagged. As it happened, Narragansett, which had anticipated $31.5 worth of conservation from its 1990 programs, installed a whopping $49.5 million and thus was entitled to receive the incentive payments described below. (As described below under Value Calculation, this total program value is adjusted to subtract evaluation costs and customer direct costs. Thus the total adjusted program value on which the incentives are based was, for 1990, $47.3 million.)

Maximizing Incentive Since RIPUC adopted the Value Requirement principle, all the conservation measures installed by Narragansett have a net benefit to the ratepayers. Therefore, the more conservation Narragansett installs, the better. After Narragansett achieves the Threshold Requirement, RIPUC rewards Narragansett for each additional dollar of conservation value (qualifying value) it can install in the program year.

To that end, RIPUC approved a Maximizing Incentive of 5% of the qualifying value. In 1990, Narragansett installed conservation valued at $47.3 million, $33.6 million more than the Threshold Requirement of $13.7 million. Thus, Narragansett earned a Maximizing Incentive of 5% of its qualifying value of $33.6 million - $1.6 million.

Efficiency Incentive RIPUC also wants to ensure that Narragansett has the incentive to install conservation measures as inexpensively as possible. Therefore, RIPUC approved the additional Efficiency Incentive of 10% of the difference between the qualifying value and its associated cost (including the Maximizing Incentive).

The calculation of the Efficiency Incentive requires several steps. The first task is to allocate Narragansett's program costs between the conservation effort to achieve the Threshold Requirement (base value) and the conservation effort above the Threshold (qualifying value). In other words, the ratio of the base costs to qualifying costs is equal to the ratio of base value to qualifying value.

In 1990, Narragansett's adjusted total value was $47.3 million and its program costs were $14.3 million. Narragansett's base value was the Threshold Requirement of $13.7 million and its qualifying value was therefore $33.6 million. Since the base value represented 29% of the total value, the base costs were 29% of total costs or $4.1 million. Likewise, since the qualifying value represented 71% of the total value, the qualifying costs were 71% of total costs or $10.2 million.

The Efficiency Incentive equals 10% of the qualifying value of $33.6 million less the qualifying cost of $10.2 million and less the Maximizing Incentive of $1.6 million. Thus, the Efficiency Incentive for Narragansett in 1990 was 10% of $21.7 million or $2.2 million.

(All of the above figures are rounded. The actual calculations are shown on the attached table.)

VALUE CALCULATION

Calculating the dollar value of the electricity conservation

resulting from Narragansett's programs is a three step process. First, the kW and kWh savings are determined for each measure. Second, the value of a kW or a kWh saved must be determined. Third, the value of all the measures installed must be modified to account for associated administration and customer costs. Each of these steps is described below.

KW and kWh Savings. Every conservation measure installed has different annual hours of operation and hours of life. Moreover, there are issues of quality of installation, quality of operation and maintenance (O&M), life of the facility, breakage, and manufacturing variability of both the conservation measure and the equipment it is replacing. In fact it is impossible to exactly predict the energy and power savings of an energy conservation measure over its useful life. It is possible, however, to make average savings estimates per measure based on a large number of installations using reasonable assumptions. This is the approach taken in Rhode Island.

The replacement of a four 40 watt lamp fixture with a four 32 watt lamp fixture with electronic ballast in an office building will be used as an example of the calculations Narragansett makes to determine kW and kWh savings. [1] The savings of this measure is 68 watts per hour. It is assumed that the fixture will be used 3000 hours per year and 85% of those hours will be during the on-peak period. The fixture is expected to last an average of 20 years taking into consideration breakage, O&M, and renovation or demolition of the facility.

Furthermore, the savings are increased because transmission and distribution losses were avoided. 47% of the measures are expected to be installed in facilities which take power at the primary level and 53% are expected to be installed in secondary level facilities. The on-peak energy, off-peak energy, and capacity savings are multiplied by 1.118, 1.068, and 1.175 factors respectively. Also, a capital factor is added in to the avoided cost capital factor to take into account the avoided capital investment in transmission and distribution. The weighted average factor is $28.42 per kilowatt.

As noted above, the total value of savings is reduced by subtracting the associated administration and customer costs. (See attached table.)

REFLECTION OF INCENTIVE IN RATES

In an annual filing with the Commission, anticipated total

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[1] The illustrative example uses 1991 program engineering calculations.

conservation program expenditures are calculated based on the utility's and the customer's cost per measure and the expected customer participation. Customer paid costs are subtracted. Added to the total utility expenditures is the estimated 10% maximizing incentive for value achieved over the threshold. The total estimated kwh sales is derived from a forecast agreed on by the Commission in a separate proceeding. (This projection takes into account the expected reduction in kwh sales from the conservation programs and hence resolves this aspect of the "lost revenues" issue.) At this point simple arithmetic sets a per kwh amount to be collected. This is adjusted to account for the 4% gross earnings tax which the utility must pay.

The conservation factor is thus set and collection begins. All program costs and the maximizing incentive are recouped more or less as expended. Narragansett reports regularly to the Commission on the amount collected and spent, details on program penetration and a narrative description of progress and difficulties along the way. A clause in the stipulation allows for mid-course readjustment of the factor in the event that costs vary more than 10% from those predicted.

The 5% Efficiency Incentive is not collected during the program year, but in the following year after calculation of the actual program costs and value achieved. Thus in the beginning of the second year, there is a true-up of the first year's costs and collection and the addition of the efficiency incentive for the preceding year. (The issue of retroactive ratemaking has not arisen in Rhode Island, and fuel and purchased power are also trued up. It is particularly important to be able to true up for conservation, since the expenditures are so much a consequence of unpredictable consumer behavior.)

Two further points to note: first, the program expenditures for all customer classes are totalled and all customer classes pay equally on a straight per kwh basis. While at least in the initial years the bulk of the program costs - and benefits - have primarily been in commercial and industrial lighting, because of the extraordinary cost effectiveness of these programs and the strong customer response in Rhode Island, the value in relation to avoided cost accrues to all ratepayers. Thus RIPUC does not attribute costs on a customer class basis.

The second point is that this conservation factor does not appear as a separate item on ratepayer bills. The decision was made that there was no need to do so for conservation any more than for specific supply side costs. The Commission generally favors full disclosure of information to ratepayers and utility bills do have the fuel adjustment factor displayed separately. However, the difficulties of explaining value achieved in relation to avoided costs to every ratepayer overcame the Commission's predilection in this instance.

INCENTIVES TO MANAGEMENT AND STAFF AS WELL AS SHAREHOLDERS

All of the above describes the incentive plan adopted by the Rhode Island Commission to turn conservation into a profit center and hence presumably also to turn the heads of the Company's top management toward it. Early on, however, the importance of a company-wide commitment to conservation was recognized, reaching out to the all-important customer service representatives. They deal directly with the customers, on whose actions the success of the programs ultimately stand or fall. A great deal of attention to this point was paid during the negotiating sessions with the Company. Narragansett and its parent company also recognized the need to motivate personnel whose job over many years has been to sell electricity, not what we now call "electric service", that is demand-related services as well as more traditional supply-related services. To the Company's credit, they have adopted a specific C & LM goal for employees tied to the Company's success in earning its financial incentive. We hear that employees await with great anticipation the reports of each month's installed conservation. Districts compete with each other to show higher results. Company awards and bonuses recognize extraordinary successes in conservation.

CONCLUSION

There are many reasons for Narragansett's outstanding success in 1990. Because the commercial and industrial lighting programs are so cost effective, there is free installation of energy efficient lamps and substantial rebates for electronic ballasts and many other measures. Rhode Island is a small state and the press gave these programs a strong play. News travels fast here, and the short paybacks were soon noted within the close knit business community. The strong results largely reflect the strong response to these programs.

Nonetheless, the Rhode Island Commission believes that the impetus given to Narragansett because of the incentive was instrumental at least in part in this success. The design of the incentive also seems to have been efficacious. Conservation was certainly maximized - the total value achieved was 57% above that which had been projected. And program costs did not rise commensurately but were held to a 34% increase.

The Commission decided to continue the incentive in 1991, increasing the threshold and modifying the evaluation that leads to establishing the conservation value, but basically retaining the two-pronged shared savings concept that seems to work so well.

CALCULATION OF NARRAGANSETT ELECTRIC COMPANY
MAXIMIZING AND EFFICIENCY INCENTIVES FOR 1990

Total Program Value Before Adjustment	$49,555,200
New England Power Evaluation Costs	$383,020
Customer Direct Costs	$1,810,000
Total Adjusted Program Value	$47,362,186
Base Value Created	$13,700,000
Qualifying Value Created	$33,662,186
Total Program Costs	$14,317,698
Base Costs	$4,141,542
Qualifying Cost	$10,176,156
Maximizing Incentive	$1,683,109
Efficiency Incentive	$2,180,292
Total Incentive to Narragansett	$3,863,400
Net Savings to Customers	$29,181,088
Savings in kilowatts	18,288
Savings in kilowatthours	63,704,802

Presented at the "Enhancing Electricity's Value to Society" conference
sponsored by Canadian Electrical Assbciation, Toronto, Canada, Oct. 22-24, 1990

HEAT ISLANDS, WHITE SURFACES, URBAN TREES: IMPACT ON HEATING AND COOLING ENERGY USE AND THE URBAN ENVIRONMENT

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Hashem Akbari, Ph.D.
Lawrence Berkeley Laboratory
Mail Stop 90-4000
Berkeley, CA 94720

Bien avant l'existence des systèmes de conditionnement d'air, les êtres humains assuraient le refroidissement de leurs demeures en été en s'assurant qu'elles soient entourées d'arbres et en peignant leur surface extérieure de couleur pâle. L'abandon de ces pratiques dans plusieurs zones urbaines contribue à la formation d'«îlots de chaleur» présentant un écart de température moyen type de 3 à 5 °C. Par ailleurs, on utilisait également des arbres comme écran contre le vent pour réduire la charge de chauffage, l'hiver.

Ce document porte sur l'utilisation d'arbres et de surfaces pâles dans les villes comme stratégie d'économie d'énergie à faible coût. Les arbres améliorent le climat urbain; en fournissant de l'ombre, en assurant une évapotranspiration et en servant d'écran contre le vent, ils permettent de réduire la consommation d'énergie résultant de l'utilisation accrue de la climatisation dans les bâtiments. Le recours à des peintures pâles et l'utilisation de sable à la surface de l'asphalte des rues et des terrains de stationnement permettent également de réduire la charge de refroidissement. En outre, l'emploi d'arbres comme écran contre le vent permet de réduire la charge de chauffage en hiver.

Le document présente des évaluations d'économies d'énergie directes et indirectes résultant de l'utilisation d'arbres en zones urbaines ainsi que des albedos pour un certain nombre de villes ayant des conditions climatiques variées. La plantation d'arbres autour d'un bâtiment et le fait d'utiliser des couleurs pâles pour peindre ses surfaces ont pour effet de modifier l'équilibre énergétique et d'abaisser les besoins en refroidissement de ce bâtiment. Et lorsque ces mesures s'étendent à toute une ville, l'équilibre énergétique global de celle-ci est modifié, ce qui produit un changement climatique général. Les phénomènes associés à ce changement climatique sont appelés «effets indirects».

INTRODUCTION

Long before mechanical air conditioning, people cooled their homes in the summer by surrounding them with trees and painting the walls and roofs white. The lack of such practices in many urban areas contributes to summer "heat islands" with a typical daily average intensity of 3 °C to 5 °C. Several studies have suggested developing guidelines to mitigate this negative effect, on both micro- and meso-scales (Landsberg, 1978; Thurow, 1983).

In this paper, we discuss the use of urban trees and light-colored surfaces as inexpensive, city-wide energy conservation strategies. Trees improve the urban climate and, by shading, evapotranspiration, and wind shielding, reduce summer cooling energy use in buildings at only about 1% of the cost of the avoided power plants and air-conditioning equipment. In cold climates, wind shielding can also reduce winter heating loads. Using light-colored paints and surfacing the asphalt of streets and parking lots with light-color sand are equally effective means to reduce summer air conditioning electricity use.

DIRECT AND INDIRECT EFFECTS OF MODIFYING THE URBAN ENVIRONMENT

The effects of modifying the urban environment, planting trees and increasing albedos, are best quantified in terms of direct and indirect contributions. The direct effect of planting trees around a building or painting its surfaces a light color is to alter the energy balance and cooling requirements of that particular building. However, when trees are planted and albedos modified through an entire city, the energy balance of the whole city is modified, producing city-wide changes in climate. Phenomena associated with the city-wide changes are referred to as indirect effects. The energy use of an individual building is indirectly affected by the changes made throughout the city.

An important reason for making the distinction between direct and indirect effects is that while direct effects are well recognized and can be well accounted for in present models of building energy use, indirect effects have received much less recognition. Methods of accounting for indirect effects have not been as well developed and remain comparatively much less certain. It is worth noting that the phenomenon of summer urban heat islands is itself the consequence of inadvertent indirect effects of the built environment. We are proposing use of the same principles to create cooler cities.

SIMULATING THE MICRO-CLIMATIC EFFECTS OF TREES

Trees affect the heating and cooling loads of buildings through several processes: (1) reducing solar gain on windows, walls, and roofs by shading, (2) changing the long-wave heat balance of a building by lowering the temperatures of the surrounding surfaces through shading and changing the building-sky radiation exchange, (3) reducing conductive and convective heat

gain by lowering dry-bulb temperatures through evapotranspiration during the summer, (4) increasing latent cooling loads by adding moisture to the air through evapotranspiration, and (5) reducing the natural ventilation potential, changing the convective heat balance of a house, and reducing the infiltration rate by lowering ambient wind speeds. This study concentrates only on the wind-shielding and shading effects of trees.

Wind Shielding

The wind-shielding effect of trees can be both beneficial and detrimental to a building's heating and cooling load. Wind affects a building's energy balance in three ways.

1. A lower wind speed on a building shell will result in lower convective heat transfer from the building surfaces. This, in turn, produces higher surface temperatures and more conductive heat gain through the building shell. This phenomenon is beneficial in the heating season but detrimental in the cooling season.

2. A lower wind speed will result in a lower infiltration. This phenomenon is beneficial in both heating and cooling seasons. The reduction in infiltration has a major impact on reducing heating energy requirements for old and leaky houses. During peak cooling hours, when ambient temperatures are very high, reduction in the amount of wind-driven infiltration may slightly reduce cooling loads.

3. Reductions in wind speed are detrimental during those hours in the cooling season when natural ventilation can be used to extend the comfort zone. This will result in increased reliance on mechanical cooling.

All of the above-mentioned phenomena can be modeled using the DOE-2.1D program.

For houses in open terrain, reductions in wind speed due to shelterbelts can be estimated from the density and height of the trees, their orientation relative to the wind, and their distance from the house (DeWalle, 1983). For houses in typical suburban areas, however, wind speed reductions at the building height (0-15 feet above ground) depend on a large number of parameters, including the roughness, density, and height of the urban canopy, as well as the location of nearby buildings and trees. Therefore, data from shelterbelt studies cannot be used to study wind speed effects in suburban conditions.

The 1989 Heisler study was a detailed effort to gather concurrent wind speed measurements in four suburban neighborhoods and to correlate the observed variations in wind speeds to differences in urban characteristics, such as the amount, location, and height of nearby trees and buildings, as well to ambient

air conditions (Heisler, 1989). The tree canopies of the four neighborhoods varied from very dense in what had been a forest to very low in a new development with practically no trees. In addition to the four neighborhood sites, simultaneous measurements were also made at a control site in an open field and at a nearby airport. Measurements were made in both summer and winter to discern changes in wind-shielding effects due to the loss of tree foliage.

The project report produced complex regression equations with up to 22 terms for various urban and building parameters. For this prototypical study, however, it was most appropriate to use a simplified formulation that related wind speed reductions to the total canopy density, defined as the percentage of surface area covered by either buildings or tree crowns (Heisler, 1989, private communication). The estimated average wind speed reduction during the summer is given in Equation 1.

$$u = u_o (0.292 + 0.728e^{-0.0424C}) \quad (1)$$

where

u = wind speed at site
u_o = wind speed on open urban field
C = total canopy density (trees plus buildings)

The estimated average wind speed reduction during the winter when the trees are bare is given in Equation 2.

$$u = u_o (0.356 + 0.644e^{-0.0397C}) \quad (2)$$

Figure 1 is a plot of the wind speed reductions from these two equations as a function of the total canopy density. For comparison, the figure also shows the observed wind speed reductions from a similar monitoring effort done in Davis, CA, in 1973 (McGinn, 1982). The McGinn study was less comprehensive and included only summer days. Moreover, data from residential areas were mixed with those from an orchard with high tree density but no buildings, an atypical condition for residential areas.

Shading

The shading effects of trees can be simulated in DOE-2.1D as exterior building shades, once the geometry and transmissivity of the trees have been determined. Tree transmissivities vary by species, ranging from 6% to 30% during summer months and 10% to 80% during winter months (Thayer, 1983; McPherson, 1984). This study considers trees placed for shading on the west or south side of the house.

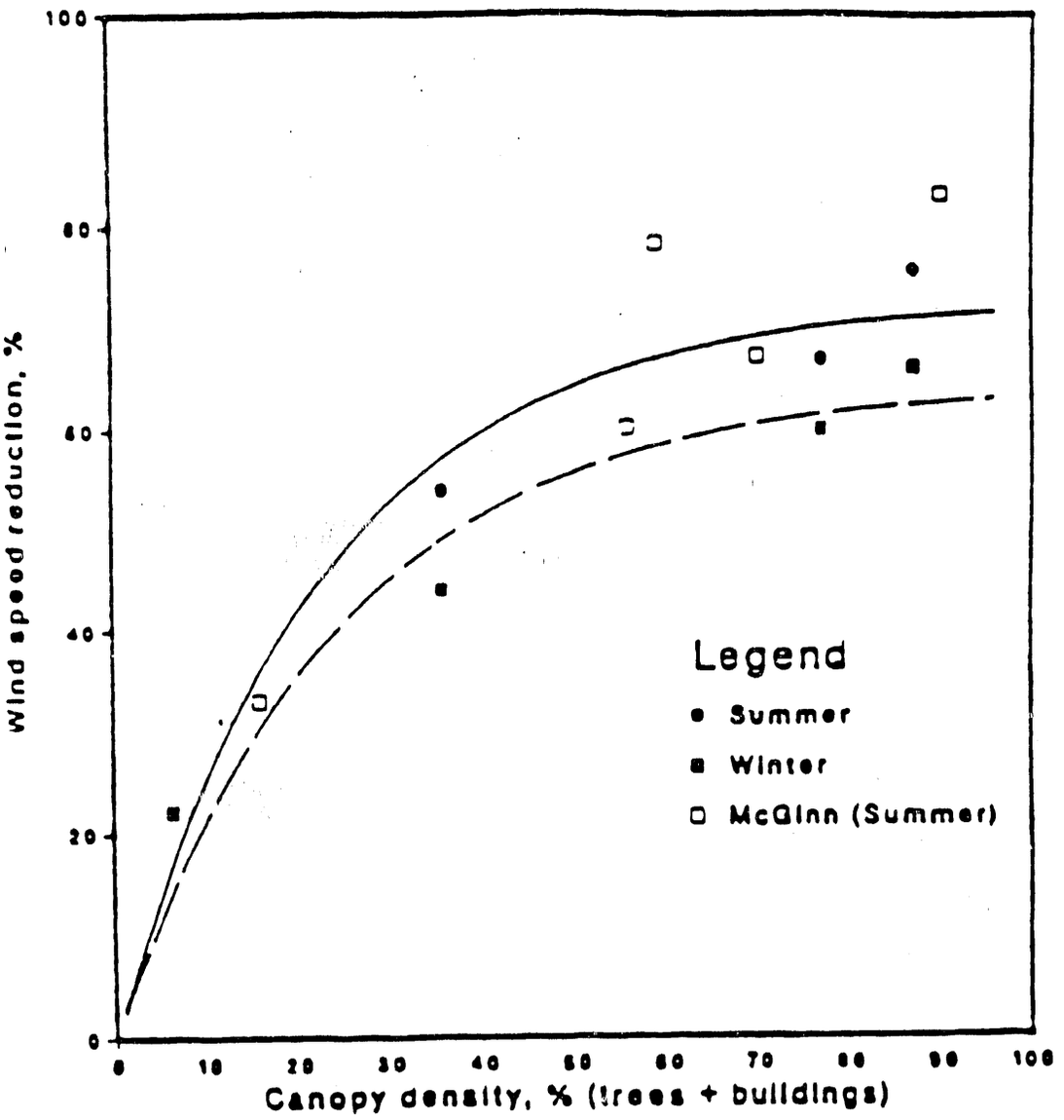


Figure 1 *Wind speed reductions for different canopy densities as compared to a control site with no trees or buildings*

To explore the energy impacts of trees on heating and cooling loads, we modeled the effects of one tree planted on the west and one or two more on the south side of the house (Figure 2). For the three-tree case in cooling-dominant climates, we assumed that two of the trees are on the west and one is on the south side of the house. We assumed that each mature tree had to a top view projection area of 600 ft^2 and a suburban housing density of one house per 6,000 ft^2 of land. Therefore, the equivalent increases in the urban tree canopy for these three configurations are 10%, 20%, and 30%, which corresponds to one, two, or three trees per typical housing lot.

Tree shading reduces not only the direct solar gain striking the building envelope but also the diffuse light reflected from sky and surrounding surfaces. This change is approximated in DOE-2.1D by modifying the inputs for sky- and ground-form-factors, which define the amount of each visible from a building surface.

Tree shading also alters the exchange of long-wave radiation between the building and its surroundings. During the day, tree shading reduces long-wave heat gain to the house by keeping the surface temperatures of the sidewalks and street lower. At night, trees reduce radiative cooling by blocking the amount of night sky visible from the walls and roof. The impact of these changes on building heating and cooling loads cannot be modeled by the DOE-2.1D program, but a simple calculation shows that the effects are small compared to those due to reductions in direct solar gain (Myrup and Morgan, 1972).

Evapotranspiration

A major micro-climatic impact of trees that is frequently overlooked is their capability to affect daily temperature swings through the evaporation and transpiration of moisture through leaves, a phenomenon agriculturalists call "evapotranspiration."

From the point of view of energy conservation, during the summer a tree can be regarded as a natural "evaporative cooler," using up to 100 gallons of water a day (Kramer, 1960). This rate of evapotranspiration translates into a cooling potential of 230,000 kcal/day. This cooling effect is the primary cause for the 9 °F differences in peak noontime temperatures observed between forests and open terrain and the 6 °F difference found in noontime air temperatures over irrigated millet fields as compared to bare ground (Geiger, 1957, p. 294). Temperature measurements in suburban areas recorded similar but smaller variations in daytime peaks of 4 °F to 6 °F between neighborhoods under mature tree canopies and newer areas with no trees (McGinn, 1982, p. 59).

The effect of evapotranspiration is minimal during the heating season. This reduction can be attributed to the absence of leaves on deciduous trees, lower ambient temperatures, and lower solar gain.

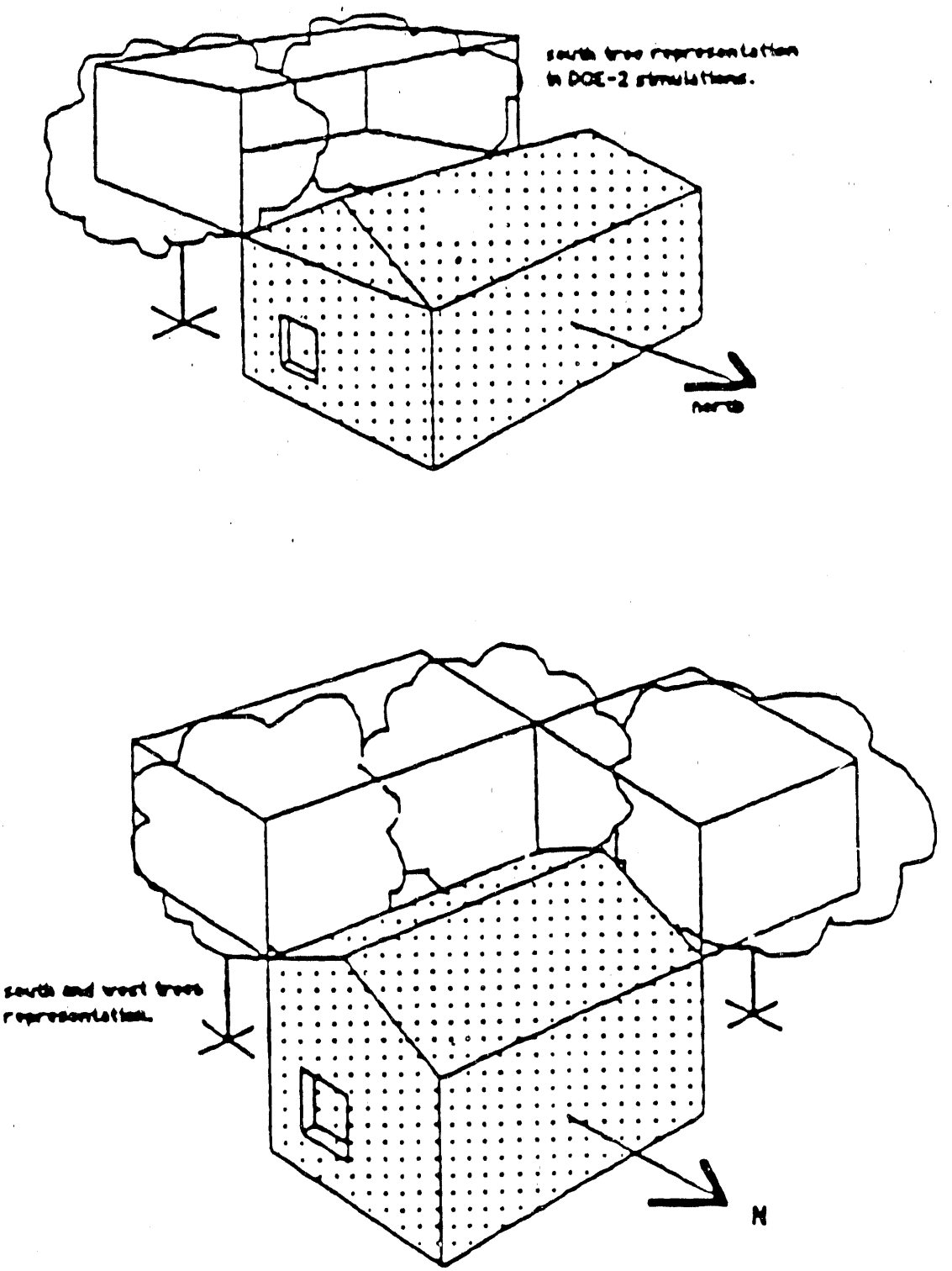


Figure 2 *Tree canopy shade modeling used for DOE-2.1D simulations*

We have developed a quantitative model for microclimate modifications due to evapotranspiration as a function of time, ambient conditions, and the amount of added moisture (Huang et al., 1987). The model has been applied to several U.S. cities to estimate the cooling potentials of evapotranspiration. The conservation potentials of evapotranspiration are much larger than the effects of wind-shielding and shading during the summer. This study, however, focuses on the wind-shielding and shading effects of trees and does not model the effects of evapotranspiration.

ALBEDO AS AN ENERGY CONSERVATION STRATEGY

The energy balance of a building, or an entire city, depends on the net thermal radiation reflected from its surface. To describe this dependence, one uses the property albedo. Whereas the reflectance of a surface depends on the frequency of the radiation incident upon it, albedo refers to the reflectivity of a surface averaged over the entire solar spectrum. An albedo of 1.0 corresponds to a surface that completely reflects, while an albedo of 0.0 refers to one that completely absorbs all incident radiation. The albedo of an individual building can be modified to achieve direct savings: a lighter building reflects more solar radiation and stays cooler. The albedo of an entire city can be modified to achieve indirect savings by changing city-wide temperatures.

In nature, albedos of different surfaces range from extremes of 0.90 (reflective white) to 0.05 (dark black). Most buildings and cities have albedos in the range of 0.20-0.35, although these values can differ depending on characteristics of the surfaces. Traditional cities of white-washed buildings found in hot climates have albedos in the range of 0.30-0.45 (Taha et al., 1988). Reflective roof membranes and the popular "solar control" glazings of commercial buildings both have albedos of up to 0.8. There is a practical constraint in the maximum achievable urban albedo if this strategy is used in conjunction with increased urban vegetation, since a dense urban tree canopy will cover a large amount of the surface area (the albedo of trees is 0.25). We have estimated an upper limit of 0.40 for the albedo of a highly-vegetated city with light-colored surfaces.

In practice, using albedo as an energy conservation strategy requires a good understanding of the local climate. In a given location, one needs to be concerned with the impact of albedo on both cooling and heating energy use. Although in general, an effective strategy is to increase the albedo in hot climates to decrease cooling loads, and to decrease the albedo in cold climates to reduce heating loads.

ESTIMATION OF ENERGY SAVINGS

In previous papers (Akbari et al., 1987; Huang et al., 1987; Taha et al., 1988; and Akbari et al., 1990), we analyzed the potential energy and power savings resulting from the use of urban trees and albedo. An analysis of savings was

made for both direct and indirect contributions for a number of cities with a variety of climate regimes.

Direct effects were modeled using DOE-2.1D, a computer model for building energy analysis. The direct effect of trees was modeled by increasing building shade and reducing local wind speeds. To simulate a 30% increase in cover, three trees (one south, two west) were added around each house. The effect of varying foliage density of deciduous trees was accounted for. The reduction in wind speed within the canopy was simulated based on tree cover, where we used an empirical formula derived for vegetated suburban houses by McGinn, 1982 and Heisler, 1989. Although in these studies wind was modeled as an indirect effect, the distinction between direct and indirect effects of wind is inexact, and, for convenience, in this paper we have assumed it to be a direct effect only. The direct effect of albedo was modeled by changing the absorptivity of the building shell, thus affecting the external surface temperature and the conductive heat gain.

The ability of DOE-2.1D to accurately model the direct effects of shading, absorptivity, and infiltration is well recognized. We believe the simulations we have done to be accurate representations of effects nation-wide. However, modeling city-wide climate variations due to trees and albedo is less certain. Our quantifications of indirect effect are preliminary and our methods deserve further discussion.

Indirect effects were simulated using models of urban climate which quantified the impact of trees on wind speed, temperature, and humidity (Huang et al., 1987) and the impact of albedo on ambient dry bulb temperature (Taha et al., 1988). The modifications in ambient conditions were input to DOE-2.1D to simulate the modified building energy and power consumption.

To simulate the effects of evapotranspiration, the amount of water released to the atmosphere was first computed based on meteorological conditions and canopy characteristics. The water vapor was then mixed in an atmospheric volume determined by the dimensions of the city and the time-varying mixing height above it. The depression in dry-bulb temperature and increase in specific humidity were obtained assuming uniform mixing of the water vapor within the volume.

The indirect effects of albedo were simulated with a one-dimensional model of the urban boundary layer, where the energy balance state at the urban surface accounted for representative values of surface albedo. The albedo values used were obtained from spatially averaging the albedos of the major surface components in the urban area. The indirect effect of trees was to reduce the ambient temperature and increase the local humidity. Temperature reduction was beneficial, while the increase in humidity slightly added to the cooling loads of buildings. The combination of these effects was fully accounted for in the building energy analysis. In the warm cities we have selected, the indirect effect

of increasing albedo was to reduce the urban ambient temperature, so that the building was actually simulated in a cooler microclimate.

Since the indirect effects of albedo modifications were simulated one-dimensionally, our calculations implicitly assumed that the increased albedo would affect the urban temperature but not the radiative budget at the building site (Taha et al., 1988). In other words, the geometry of reflection is not accounted for, nor does the reflected radiation have any effect on surrounding windows or surfaces. Although higher albedos could increase the net heat gain through fenestration because of the increase in reflected radiation, this is not accounted for in our model. In the real world, some design considerations would be necessary to avoid this problem. The re-orientation of windows as well as the careful design of shades would be important. Urban trees could be so located as to block the reflected energy from neighboring buildings. If only the roof surfaces of the houses were whitewashed, the problems of glare and increased heat gain through windows would not exist at all. Finally, we should note that the indirect effects of trees (evapotranspiration) and albedo (temperature depression) have so far been simulated independently. There is now no account for feedback effects which could be significant, since trees may decrease the local albedo and the lower temperature (resulting from higher albedos) may in turn decrease evapotranspiration.

ENERGY SAVINGS

Table 1 gives the incremental savings in heating and cooling energy and peak power resulting from the direct effects of increased urban tree cover and albedo. The results are shown for both the 1973 housing stocks and newer 1980 houses. The 1973 stock is representative of leaky and poorly insulated housing, while the 1980 homes are tight and well insulated. The "Base" column in each case represents the base case for a building with normal albedo (30%) and no surrounding trees. The "Trees" column gives the effects of a 30% increase in tree cover (3 trees) and is broken down into effects of increased shading alone, wind reduction alone, and combined wind and shading effects. It can be seen that by reducing heat gain, shading always reduces cooling loads. The effects of wind reduction, on the other hand, can be beneficial or detrimental depending on outdoor conditions. In the 1973 houses, with relatively high infiltration and conductive heat gains, ventilation is useful in removing the built-up indoor heat. Therefore, reducing wind speed would result in increased cooling energy and power. In the better insulated 1980 houses, infiltration is proportionally significant than condition, therefore reducing wind speed reduces the cooling peak power. But similar to the 1973 stock, reducing wind speed increases the cooling hours. The "Albedo" column shows the direct effect of increasing the house albedo to 70%. This is the effect of albedo alone, and it is positive in all the cases. Finally, the "Combined" column gives the effect of combining the higher albedo with a 30% increase in tree cover. All entries other than those in the "Base" column represent percent savings.

Table I. Direct savings in cooling energy and peak power resulting from planting trees and whitewashing buildings. All columns, except the bases, are in percent (Δ%) relative to basecases. Symbols "s", "w", and "a" stand for shading, wind, and albedo, respectively. The tree cover was increased by 30% with respect to the base case, whereas albedo was increased from 30% to 70%. Note the large negative impact of wind reduction (column "w") that is mainly the result of our modeling of ventilative cooling. We have kept these conservative estimates for calculating the national savings. For further discussion, see the text.

Location	1973 Houses (leaky and low-insulation)						1980 Houses (tight and high-insulation)					
		Trees			Albedo	Combined		Trees			Albedo	Combined
	Base	s (Δ%)	w (Δ%)	s+w (Δ%)	a (Δ%)	a+s+w (Δ%)	Base	s (Δ%)	w (Δ%)	s+w (Δ%)	a (Δ%)	a+s+w (Δ%)
Chicago IL	1400 ft^2						2000 ft^2					
Peak kW	3.60	19.4	-2.5	16.9	5.8	23.6	3.20	21.0	2.8	23.8	5.3	29.1
Annual kWh	2584.0	29.7	-26.6	3.11	14.8	19.9	1888.0	30.9	-22.8	8.1	12.8	21.6
Miami FL	1400 ft^2						1600 ft^2					
Peak kW	5.42	7.0	-9.2	-2.2	20.5	25.3	3.29	14.0	3.0	17.0	6.3	23.4
Annual kWh	13623.0	15.8	-19.3	-3.5	18.6	22.5	8730.0	14.8	-5.6	9.2	7.4	16.5
Minneapolis MN	1400 ft^2						2000 ft^2					
Peak kW	3.14	23.9	-1.9	22.0	3.5	27.1	2.65	29.1	0.0	29.11	4.1	31.7
Annual kWh	1916.0	27.3	-18.9	8.4	11.3	20.2	1325.0	36.6	-22.1	14.5	11.1	22.6
Phoenix AZ	1400 ft^2						1600 ft^2					
Peak kW	7.56	12.6	2.7	15.3	7.6	26.2	5.18	11.4	11.2	22.6	5.8	31.1
Annual kWh	13117.0	15.9	-12.0	3.9	12.9	19.8	7769.0	15.0	-8.9	6.1	8.9	17.3
Pittsburgh PA	1600 ft^2						1600 ft^2					
Peak kW	3.50	26.8	-12.2	14.6	13.7	24.9	2.38	27.5	-9.7	17.8	9.3	23.3
Annual kWh	1821.0	34.0	-35.5	-1.5	19.1	23.3	1177.0	33.1	-28.8	4.3	12.0	20.1
Sacramento CA	1400 ft^2						1600 ft^2					
Peak kW	5.40	19.7	-10.1	9.6	13.3	25.4	3.85	16.7	0.2	16.9	7.5	26.0
Annual kWh	3767.0	34.6	-36.8	-2.2	22.3	28.3	2372.0	29.3	-21.5	7.8	11.5	23.8
Washington DC	2000 ft^2						2200 ft^2					
Peak kW	5.80	17.4	1.7	19.1	10.5	30.3	3.98	19.1	6.0	25.1	6.7	29.4
Annual kWh	4358.0	25.7	-21.8	3.9	16.4	22.7	2790.0	26.6	-15.5	11.1	10.6	20.0
Average												
Peak kW						26.3						28.0
Annual kWh						21.9						18.6

Table 2 shows the simulated indirect savings in cooling energy and peak power. For the cities modeled, the effect of an additional three trees per building results in approximately 30% savings in annual cooling energy and approximately 15-20% annual savings in peak cooling power. The indirect effects of albedo were quantified for Sacramento, CA, for only four days in July. Simulations showed that increasing the albedo of the surroundings from 0.25 to 0.40 reduced the cooling energy by 45% and peak power by 21%. This suggests that for residential buildings the potential savings from albedo and vegetation are roughly equivalent.

We have comparatively few simulations of indirect effects. Since our urban climate models are still under development, we conservatively interpret these results as maximum effects. When extrapolating to determine national savings (Table 3), we typically assume smaller effects.

Table 3 shows savings of primary energy use for air conditioning in the U.S. The total residential electricity use for air conditioning (room and central) is about 100 billion kWh or 1.2 quads of primary energy per year (Akbari et al., 1990). In the U.S. in 1987, commercial buildings used 670 billion kWh of electricity (EIA, 1987) of which approximately 20% was used for cooling, corresponding to about 130 billion kWh or 1.5 quads of source energy per year. Together, residential and commercial cooling uses 2.7 quads of source energy per year, worth $20-25 billion.[1]

In our calculations, we have assumed that tree planting and albedo modification can be applied to only 50% of the 51 million air-conditioned houses in the U.S. Tree density may already be high (especially in older cities) and increasing tree cover and/or albedo may not be acceptable to all municipalities, and some areas may not have a significant cooling load. We have also assumed that half of the commercial building stock of 4 million buildings is small enough to be directly affected by shading and albedo increase.

The analysis shows that the direct effect of planting three trees per house and changing the building albedo from 30% to 70% is equivalent to an average of 20% cooling energy savings. Apply this to the 25 million available houses, using 75 million trees, would result in energy savings of 0.12 quad. The corresponding direct savings due to the planting of a 30% tree cover around small commercial buildings is about 8% (Akbari et al., 1987). When this is applied to 50% of the 2 million small commercial buildings, using another 25 million trees, this would save an additional 0.03 quad. Conservatively, a direct savings of 0.15 quad would be achieved if 100 million trees were planted.

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[1] Most residential electricity is still sold at an average price of ~7.5¢/kWh, but air-conditioning power is mainly on-peak and the cost of new peak power is closer to 10¢/kWh.

Table 2

Simulated indirect savings in cooling energy use and peak cooling power for single-story 1980-prototype houses. Canopy savings are annual figures. Albedo savings are for the period from July 9 to July 12 only. (All entries are indirect effects.)

Location	Urban canopy density increased by 3 trees/house*	Albedo of house and surrounding increased**
	Percent energy savings	Percent energy savings
Sacramento CA		
Peak kW	23	21
Annual kWh	37	45†
Phoenix AZ		
Peak kW	12	--
Annual kWh	27	--
Lake Charles LA		
Peak kW	15	--
Annual kWh	31	--

* Data from Huang et al., 1987. Assumes an increase of 3 trees per house.

** Data estimated from Taha et al., 1988. Assumes an increase from 0.25 to 0.40 in the albedo of the surroundings.

† Canopy savings are annual savings. Albedo savings for the period from July 9 to July 12.

Table 3

Annual Cooling energy savings and reductions in released carbon from heat island mitigation using trees and white surfaces.[a] We assumed 100 million trees, white colored homes, streets, and parking lots.

	Residential			Small Commercial			Large Commercial			Total	
		Energy	Carbon		Energy	Carbon		Energy	Carbon	Energy	Carbon
	(%)	(10^{15} Btu)	(M Tons)	(%)	(10^{15} Btu)	(M Tons)	(%)	(10^{15} Btu)	(M Tons)	(10^{15} Btu)	(M Tons)
Cooling Energy Use		1.2	36		0.75	24		0.75	24	2.7	84
Heat Island Portion[b]	15	0.18	5	10	0.08	2	3	0.02	1	0.27	8
Direct Savings	10[c]	0.12	4	4[d]	0.03	1	0	0.0	0	0.15	5
Indirect Savings	20	0.23	8	12	0.09	3	5[e]	0.04	1	0.36	12
Total Savings	30	0.35	12	16	0.12	4	5	0.03	1	0.51	17

a. Production of carbon (as CO_2) from a peak power plant assumes 11,600 Btu/kWh sold, and ~14,500 Btu/lb. of carbon.

b. We assumed that the overall heat island effect on the cooling energy use is 10%. We estimate that the effect of heat islands to be largest (15%) on residential, moderate (10%) on small commercial, and small (3%) on large commercial buildings.

c. **Residential.** We assumed 3 trees (plus light surfaces) for 50% of our 50 million air conditioned homes, so 75 million trees (plus light surfaces).

d. **Small Commercial.** We assumed 30% coverage by trees (25 million more trees).

e. **Large Commercial.** We assumed no additional trees.

Data presented in Table 2 suggest that the indirect effects of tree planting and albedo modification alone can save at least 20% of the 1.2 quad of residential cooling energy use (thus 0.23 quad). Because small commercial buildings are less sensitive to outdoor temperature than houses, we expect indirect savings of only about 12% of the 0.75 quad of small commercial cooling energy use (thus 0.09 quad). By reducing urban temperatures, these measures also decrease cooling energy use in large commercial buildings by increasing system efficiency and economizer operating hours. We estimate this would save an additional 5% or 0.04 quad.

CO_2 SAVINGS

Carbon, produced in the form of CO_2 from electricity generation, varies from about 0.5 lb carbon/kWh for natural gas-fired power plants to about 1 lb carbon/kWh for coal-fired power plants. Because cooling energy is almost always used during periods of peak demand (except in the case of thermal storage), the electric utility must meet this demand using a combination of coal-, oil-, and gas-fired power plants. The fraction of each fuel type used varies greatly, depending on the region of the country, and can vary from all coal in some parts of the East to all oil and gas in Texas. However, the national average is approximately half coal and half oil and gas (DOE, 1988). This results in an average emission of 0.8 lb carbon/kWh generated for peak power.

About half the savings from the combination of direct and indirect effects shown in Table 3 would result from planting 100 million urban trees. This savings of 0.25 quads (22 billion kWh) corresponds to a savings of 9 million tons of carbon. A fast-growing forest tree sequesters carbon at the rate of ~13 lb carbon per year. Therefore, 100 million trees could directly sequester 0.65 million tons of carbon, or only one-fifteenth of the energy saved through their reduction in cooling energy use. To directly sequester the amount of carbon saved by the planting of 100 million urban trees would require planting 1.5 billion forest trees corresponding to 1.5 million hectares of forest (by comparison, the total area of Connecticut is about 1.3 million hectares).

THE COST OF HEAT ISLAND MITIGATION MEASURES

Table 4 gives the cost-effectiveness, energy savings, and carbon reduction of urban trees/light surfaces compared to other conservation and generation strategies. All energy conservation measures that reduce fossil fuel use also reduce carbon emissions. For example, the trend to more efficient electric appliances yields a cost of conserved energy (CCE) of about 2¢/kWh, equivalent to a cost of conserved carbon (CCC) of 2.5¢/lb carbon. Another conservation strategy is to improve efficiency in automobiles. The cost of conserved carbon in going from a 26 mpg to a 36 mpg automobile is 10¢/lb carbon. Both these measures are effective, but they are much more expensive than urban trees and light-colored cities.

Table 4

Cost-effectiveness, energy savings, and carbon reduction of urban trees/light surfaces compared to other conservation and generation strategies. (Source: Akbari *et al* 1988)

Strategy	CCE[1] (¢/kWh)	CCC[1] (¢/lb C)	ΔE (Quad/yr)	ΔC (M Tons/yr)
Conservation (Direct + Indirect Effect)				
Urban Trees/ Light Surfaces (direct CO_2 sequestered)	0.2-1.0	0.25-1.25	0.5	17 (0.65)
Efficient Electric Appliances[2]	2	2.5	0.6	21
Efficient Cars[3]	4.2 (50¢/gal)	8.3	2.8	60
New Generation				
Coal Power	8	Base Case	—	Base Case
Nuclear Power	11	4	—	60

1. CCE is Cost of Conserved Energy and CCC is Cost of Conserved Carbon.
2. Improved standards as defined by National Appliance Energy Conservation Act (NAECA).
3. Improved car efficiency from 26 mpg to 36 mpg.

Urban trees and light surfaces have a CCE of about 0.2 - 1.0¢/kWh and a CCC of about 0.3 - 1.3¢/lb of carbon. This is as much as 10 times less expensive than either of the alternative strategies just cited. The point of the comparison is not to discredit the other conservation strategies but to suggest that planting urban trees and modifying urban albedos seems attractive and definitely worth investigating.

ACKNOWLEDGEMENT

This work was supported by the Assistant Secretary for Conservation and Renewable Energy, Office of Building and Community Systems, Building System Division of the U.S. Department of Energy, under contract No. DE-AC0376SF00098. This work was in part funded by a grant from the University-Wide Energy Research Group, University of California-Berkeley.

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Table 1. Direct savings in cooling energy and peak power resulting from planting trees and whitewashing buildings.

All columns, except the base cases, are in percent change (Δ%) relative to the base. The tree cover was increased by 30% (approximately 3 trees per house) with respect to the base case, whereas albedo was increased from 30% to 70%. For further discussion, see the text.

	1973 Houses (leaky & poorly insulated).				1980 Houses (tight & highly insulated)			
Location	Base Case	Trees (Δ%)	Albedo (Δ%)	Combined (Δ%)	Base Case	Trees (Δ%)	Albedo (Δ%)	Combined (Δ%)
Chicago	(1400 ft²)				(2000 ft²)			
Peak kW	3.60	19.4	-2.5	16.9	5.8	23.6	3.20	23.8
Annual kWh	2584	3.11	14.8	19.9	1888	8.1	12.8	21.6
Miami	(1400 ft²)				(1600 ft²)			
Peak kW	5.42	-2.2	20.5	25.3	3.29	17.0	6.3	23.4
Annual kWh	13623	-3.5	18.6	22.5	8730	9.2	7.4	16.5
Minneapolis	(1400 ft²)				(2000 ft²)			
Peak kW	3.14	22.0	3.5	27.1	2.65	29.11	4.1	31.7
Annual kWh	1916	8.4	11.3	20.2	1325	14.5	11.1	22.6
Phoenix	(1400 ft²)				(1600 ft²)			
Peak kW	7.56	15.3	7.8	26.2	5.18	22.6	5.8	31.1
Annual kWh	13117	3.9	12.9	19.8	7789	6.1	8.9	17.3
Pittsburgh	(1600 ft²)				(1600 ft²)			
Peak kW	3.50	14.6	13.7	24.9	2.36	27.5	-9.7	17.8
Annual kWh	1821	-1.5	19.1	23.3	1177	4.3	12.0	20.1
Sacramento	(1400 ft²)				(1600 ft²)			
Peak kW	5.40	9.6	13.3	25.4	3.85	16.9	7.5	26.0
Annual kWh	3767	-2.2	22.3	28.3	2372	7.8	11.5	23.8
Washington	(2000 ft²)				(2200 ft²)			
Peak kW	5.80	19.1	10.5	30.3	3.98	25.1	6.7	29.4
Annual kWh	4358	3.9	16.4	22.7	2790	11.1	10.6	20.0
Average								
Peak kW				**26.3**				**28.0**
Annual kWh				**21.9**				**18.6**

Table 2. Simulated indirect savings in cooling energy use and peak cooling power for single-story 1980-prototype houses.

Canopy savings are annual figures; albedo savings are for the period from July 9 to July 12 only (all entries are for indirect effects.)

Location	Urban canopy density increased by 3 trees/house*	Albedo of house and surrounding increased**
	Percent energy savings	Percent energy savings
Sacramento		
Peak kW	23	21
Annual kWh	37	45†
Phoenix		
Peak kW	12	--
Annual kWh	27	--
Lake Charles		
Peak kW	15	--
Annual kWh	31	--

* Data from Huang et al., 1987. Assumes an increase of 3 trees per house.

** Data estimated from Taha et al., 1988. Assumes an increase from 0.25 to 0.40 in the albedo of the surroundings.

† Canopy savings are annual savings. Albedo savings for the period from July 9 to July 12.

Table 3. Annual Cooling energy savings and reductions in released carbon from heat island mitigation using trees and white surfaces.[a]

(assuming 100 million trees, and light-colored houses, streets, and parking lots)

	Residential			Small Commercial			Large Commercial			Total	
	Energy (%)	Energy (10^{15} Btu)	Carbon (M Tons)	Energy (%)	Energy (10^{15} Btu)	Carbon (M Tons)	Energy (%)	Energy (10^{15} Btu)	Carbon (M Tons)	Energy (10^{15} Btu)	Carbon (M Tons)
Cooling Energy Use		1.2	36		0.75	24		0.75	24	2.7	84
Heat Island Portion[b]	15	0.18	5	10	0.08	2	3	0.02	1	0.27	8
Direct Savings	10[c]	0.12	4	4[d]	0.03	1	0	0.0	0	0.15	5
Indirect Savings	20	0.23	8	12	0.09	3	5[e]	0.04	1	0.36	12
Total Savings	30	0.35	12	16	0.12	4	5	0.03	1	0.51	17

a. Production of carbon (as CO_2) from a peak power plant assumes 11,600 Btu/kWh sold, and ~14,500 Btu/lb. of carbon.

b. We assumed that the overall heat island effect on the cooling energy use is 10%. We estimate that the effect of heat islands to be largest (15%) on residential, moderate (10%) on small commercial, and small (3%) on large commercial buildings.

c. **Residential.** We assumed 3 trees (plus light surfaces) for 50% of our 50 million air conditioned homes, so 75 million trees (plus light surfaces).

d. **Small Commercial.** We assumed 30% coverage by trees (25 million more trees).

e. **Large Commercial.** We assumed no additional trees.

Table 4. Cost-effectiveness, energy savings, and carbon reduction of urban trees and light-colored surfaces compared to other conservation and power generation strategies

Strategy	CCE * (¢/kWh)	CCC * (¢/lb C)	ΔE (Quad/yr)	ΔC (M Tons/yr)
Conservation (Direct + Indirect Effect)				
Urban Trees/ Light Surfaces (direct CO_2 sequestered)	0.2-1.0	0.25-1.25	0.5	17 (0.65)
Efficient Electric Appliances †	2	2.5	0.6	21
Efficient Cars ††	4.2 (50¢/gal)	8.3	2.8	60
New Generation				
Coal Power	8	Base Case	—	Base Case
Nuclear Power	11	4	—	60

source : Akbari et al. 1988.

* CCE is the Cost of Conserved Energy and CCC is the Cost of Conserved Carbon.

† Improved standards as defined by National Appliance Energy Conservation Act (NAECA).

†† Improved car efficiency from 26 mpg to 36 mpg.

Figure 1. Wind Speed Reductions for Different Canopy Densities as compared to a Control Site with no Trees or Buildings

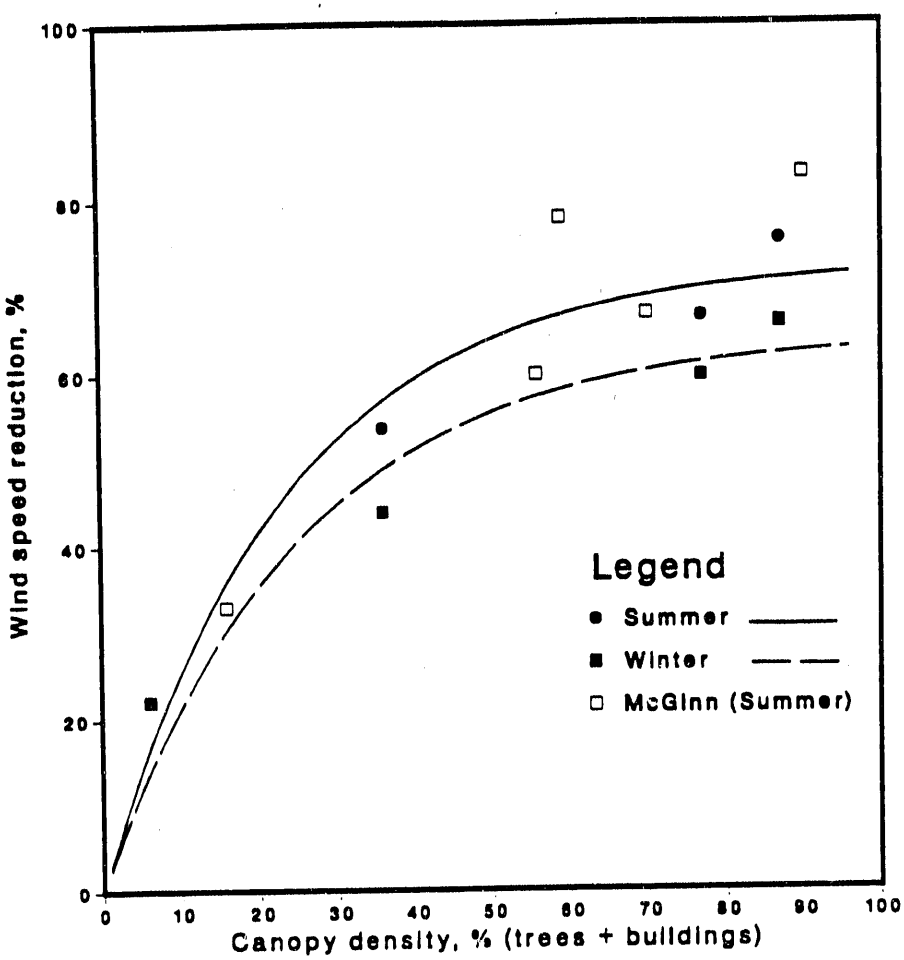
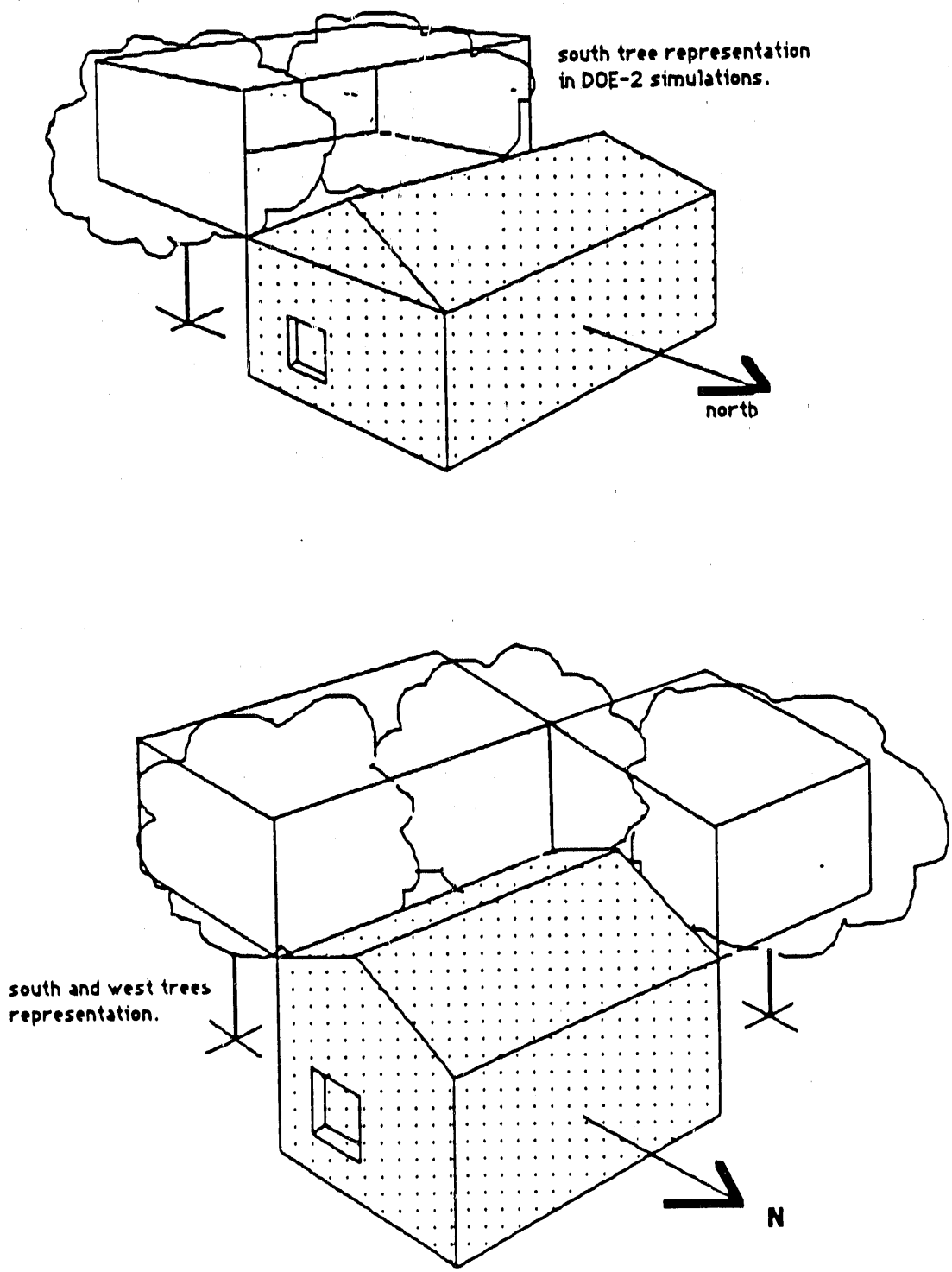


Figure 2. Tree canopy shade modeling used for DOE-2.1D simulations



DATA AND ANALYSIS METHODS AVAILABLE TO CONDUCT ENVIRONMENTAL AND ENERGY ASSESSMENTS OF TREE-RELATED UTILITY PROGRAMS

Jeanne M. Clinton, Principal
Julie E. Hashem, Consultant
Barakat & Chamberlin, Inc.

In light of increasing public concern about environmental quality in general and global climate change in particular, increased attention is being paid to tree planting as a way to improve atmospheric conditions. Many utility commissions, utilities, and public interest groups are interested in determining whether tree planting programs are a cost-effective means of incorporating environmental and other social considerations into utility resource planning.

The decision about whether or not to implement a tree planting program is affected both by environmental factors and other community concerns. This decision includes weighing a tree planting program's implementation costs and its possible effects on electric service reliability (more trees may result in more downed power lines) against its potential tree-related benefits, including reduced atmospheric carbon dioxide levels, decreased peak (cooling) loads, increased environmental quality resulting from decreased supply-side emissions, increased property values (and, potentially, property tax revenues), and improved quality of life. Tree planting may be an alternative to costly mechanical carbon absorption and sequestering processes, a high-visibility way to improve a utility's public image, and a way to generate community goodwill.

METHODOLOGICAL APPROACHES AND FINDINGS

Barakat & Chamberlin has worked with utilities and forestry organizations to assess the costs and benefits of urban tree planting, and recently performed an assessment of environmental and other social impacts of a utility's tree management program. We have found that a definitive quantitative assessment of the potential costs and benefits is not straightforward. However, we have conducted a comprehensive review of pertinent technical publications and journals and have identified a variety of factors for consideration in tree program decision

making. In the following pages, we will briefly discuss each of these factors, focusing on the data that are available, the methods for obtaining these data, and how the data might be applied to utility decision making.

Value of Service Reliability

One of the major causes of electrical service interruptions is trees interfering with the power transmission and distribution systems. Branches or stems rubbing against power lines can cause short circuits, particularly when they make contact with more than one line. Trees that are blown over in storms can disconnect lines, and roots can interfere with underground lines. Tree-related outages affect public safety by interrupting service to safety equipment (for example, fire alarms, emergency medical equipment, and traffic lights). They also affect commercial and industrial users, which suffer business losses when materials spoil or production time is lost, and residential users, who may be inconvenienced. To address potential safety and service problems, utilities remove or control vegetation near power lines. It is appropriate to consider the value of reliable electric service (or, conversely, the cost of unreliable service) where tree planting programs have the potential to disrupt electric service.

A recent article summarized the outage cost estimates from a variety of North American valuation studies over the past 15 years (Caves, Herriges, and Windle 1990). For the residential sector, outage cost estimates were generally between $0.09 and $14.61 per kWh unserved (1986 dollars). For the industrial sector, outage cost estimates were generally between $1.27 and $9.56 per kWh unserved. For the commercial sector, outage cost estimates generally ranged from $5.02 per kWh unserved in retail services to $21.73 per kWh unserved for office buildings.

Two types of valuation methods are commonly in use to estimate service reliability: proxy methods and survey methods. Proxy methods look at the damages and inconvenience that customers incur during a service interruption. For example, one proxy method is based on the cost of providing backup generator power. Survey methods—the most popular way of assessing damages and inconvenience—generally involve asking a sample of customers to estimate the costs they incurred from service interruptions or how much they would be willing to pay to avoid service interruptions.

For applicability to tree planting program evaluation, value of service data should be adjusted to account for the probability of tree-related interruptions. This probability should be based on such factors as the frequency of storms, the proximity of the proposed tree locations to power lines, and the blowdown characteristics of the tree species chosen for the program. As a general rule, the price of electricity for a given utility is the minimum value for estimating the value of service because this price is also the incremental avoided cost to the user of foregoing that unit of consumption.

A more direct way to evaluate the potential costs associated with tree planting is by reviewing a utility's actual expenditures for responding to tree-related outages. For example, one northeastern utility spent $1.4 million on restoring service in 1989 ($.0002 per kWh of service restored, or $2.94 per customer). Ideally, utilities should evaluate the maintenance costs for areas with species and density characteristics that are similar to those of the tree planting program. The utility can then estimate potential service-related costs associated with tree planting by looking at that fraction of the service restoration expenditures resulting from trees of similar characteristics, location, and density to the plantings proposed.

Atmospheric Carbon Dioxide Reduction

In recent years, public concern with atmospheric carbon dioxide levels has increased. According to various global climate change models, the increased use of fossil fuels and deforestation are raising atmospheric carbon dioxide concentrations, which is expected to cause a serious increase in the earth's average temperature. Potentially, tree planting can counter this effect and can serve as a means of addressing regulatory requirements for emissions control.

Tree planting can affect atmospheric carbon dioxide levels both directly and indirectly. Trees directly sequester carbon through photosynthesis. Trees indirectly affect carbon dioxide levels because tree canopies increase shade, thus reducing building cooling loads. Reduced building cooling loads affect power generation levels, which in turn affect power plant emissions.

Estimates show that one hectare of rural forest directly absorbs 6.5 tons of carbon annually (Chernick and Caverhill 1989, 61–64). Per-tree estimates show a range of 4 to 13 pounds of carbon per year. To estimate the number of trees necessary to offset power plant emissions, it is necessary to estimate the amount of carbon

emitted in the form of carbon dioxide for each kWh of electricity generated. Generally speaking, this amount varies from 0.5 pounds of carbon per kWh generated by natural gas-fired plants, to 1 pound of carbon per kWh generated by coal-fired plants (Rosenfeld 1988; Akbari et al. 1988). Assuming that the national average fuel mix is approximately 50% coal and 50% oil and gas (Akbari et al. 1988), this results in an average emission of 0.8 pounds of carbon per kWh of generated power. If on average one forest tree sequesters between 4 and 13 pounds of carbon, and on average 0.8 pounds of carbon are associated with each kWh of power generation, one forest tree can offset the carbon associated with 5 to 16 kWh of power produced.

Because of the additional potential of urban trees to reduce the combustion effects of fossil fuels for electricity production through reduced building cooling loads, urban trees can be between 10 and 20 times more effective than rural trees in reducing atmospheric carbon dioxide levels (Akbari et al. 1988). Other estimates are more optimistic. For example, one study (McPherson 1990) estimates carbon savings to be some 408 pounds per tree, 97% of which is assumed attributable to cooling-related avoided emissions.

The magnitude of carbon reduction for an individual utility is affected by its particular fuel mix and the characteristics of the tree program it is considering. Adjustments can be made to the sequestering assumption based on tree size and growth rate. The rate and magnitude of carbon sequestering can determine whether a utility decides to plant seedlings or to invest in larger trees.

Building Cooling Load Effects

Planting trees around a residential or small commercial structure can alter the energy balance and cooling requirements for that structure. Tree canopies decrease residential cooling loads directly through shading and wind reduction and indirectly through evapotranspiration and the cooling of urban heat islands. Trees also affect cooling loads because they reduce the temperature of adjacent sidewalks and other pavement. For a consumer, a decreased need for building cooling can mean a smaller electric bill. For a utility, trees can offer a means of load management at system peak. According to the American Forestry Association, three trees properly planted around the home can reduce air conditioning needs by 10 to 50%. Research undertaken at Lawrence Berkeley Laboratory (Huang, Akbari, and Taha, n.d. [1989]) provides region-specific data

about the potential cooling effects from varying tree canopy coverage in the United States.

A specific example of the magnitude of this effect is illustrated by an analysis of a Tucson mesquite planting program (McPherson 1990). McPherson estimated that average annual kWh savings for direct shade are 61 kWh per tree and evapotranspirational benefits are 227 kWh per tree.

In general, building cooling load effects vary widely in magnitude among service areas. They are most significant in warmer climates that have larger cooling loads and when applied to residential areas. Building cooling load effects have limited applicability to larger commercial buildings because in general, trees cannot be located to significantly shade rooftops or multistory walls. Further, unlike residences, cooling loads in many commercial buildings are largely tied to the internal heat generation of people, processes, and equipment loads. The potential for achieving significant load reductions from tree planting is also dependent on the percentage of currently unshaded housing and small commercial units in a market area, urban growth patterns, and the estimated per-unit cooling savings appropriate to a climatic region. In the right conditions, urban forestry programs can represent a long-term energy conservation and load management strategy.

Improved Environmental Quality

By serving a demand-side management function, urban trees improve environmental quality not only through carbon dioxide emissions avoidance but also through the avoidance of other supply-side emissions such as sulfur dioxide, sulfates, and particulates. This improvement can be quantified by looking at the reduced power generation associated with tree-induced cooling savings. Given an increasingly restrictive regulatory environment where, for example, utilities must comply with the more stringent and potentially costly provisions of the new Clean Air Act, the attractiveness of tree planting programs is enhanced.

Environmental quality can also be improved through the removal of particulates (for example, dusts and pollens) and through stormwater runoff control. One tree can remove between 42 and 400 pounds of particulates from the air (McPherson 1990). An associated value can be estimated by considering the avoided cost of particulate control through such means as road paving. Annual dust control costs determined by this means can be on the order of $0.12 per pound of particulate

matter (McPherson 1990, 5). Similarly, the cost of reducing stormwater runoff can be estimated by examining the avoided cost of stormwater control, where applicable. The absorption capacity of the type of tree considered for planting can be used as a means for estimating the amount of stormwater control that will be avoided. For Tucson, the average annual avoided cost savings for dust and stormwater control were estimated at $4.16 (34.7 lbs.) and $0.18 (73 gal.) per tree (McPherson 1990, 8). The applicability of these factors to other areas is highly dependent on local conditions.

Tree Planting and Maintenance Costs

For large scale plantings in more rural locations, the cost of establishing commercial tree plantations is a reasonable proxy for the cost of tree planting programs. Recent estimates of the costs of establishing forest plantations vary from $230 per hectare to slightly more than $1,000 per hectare, depending on the region (Calwell 1990, 7). If land acquisition costs are included, start-up costs for tree plantations in the United States are estimated at $800 per hectare ($320 per acre). Assuming amortization over 40 years and 300 trees per acre, $0.29 per year per tree is a reasonable estimate of the cost of rural tree planting for large scale power plant emissions offsets. Assuming that one tree offsets between 4 to 26 kWh per year, tree planting costs are in the range of $.011 to $.073 per kWh. Assuming minimal maintenance, costs per surviving tree are probably considerably higher.

In general, urban trees are considerably more costly to plant and maintain than rural trees because of their more scattered locations, a tendency to plant larger trees, and their proximity to buildings, roadways, sidewalks, and utility lines. Species selection is particularly important because it affects such factors as trimming frequency and watering needs. We reviewed a variety of urban tree planting programs and found that annual costs are often in the range of $10 to $75 per tree.

Planting and maintenance costs can vary widely depending on several factors: the cost of local labor, water, economies of scale, local climate, the characteristics of the species chosen, tree size, and planting location. Local nurseries, tree plantations, forestry departments and parks and recreation departments are valuable sources of information for estimating costs.

Valuing Quality of Life

Many people argue that visual contact with trees improves the quality of life and benefits a person's psychological and physiological well-being. Trees can provide desirable visual barriers against urban landscapes, reduce unwanted urban noise, reduce stress, improve postoperative recovery times, contribute to positive recreational experiences, and generally cause people to "feel good." Although there are many arguments in favor of trees, most tend to be intuitive. The amount of quantitative research available on this topic is limited.

The strongest quality of life benefits are derived from human access (visual or proximal) in heavily urbanized areas. Larger trees are generally more effective than smaller trees in evoking a positive reaction (Ulrich 1990, 26). Denser vegetation in urban settings evokes negative reactions because of concerns about personal safety and security. The understory openness associated with larger or more scattered trees is generally preferred (Ulrich 1990, 26).

Attempts to quantify the argument that trees are beneficial to people generally use one or more of three methods. The first method involves exposing subjects to a variety of scenes, usually in the form of pictures, and asking them to rate their reactions and feelings on a numerical scale. The second method involves exposing subjects to a similar variety of scenes and measuring their physiological responses (for example, heart and breathing rates). The third method involves estimating in dollar terms the amount of money that people are willing to pay to enjoy urban trees. This method accomplishes its purpose through such means as surveys or by looking at travel costs to parks as a measure of willingness to pay. In general, the dollar values generated by these methods are high. However, there is some question about whether it is realistic or appropriate to translate subjective values into dollars given the potential sources for bias (Schroeder 1986, 56). Consequently, quality of life benefits will probably be less important than other factors when a utility weighs the decision about whether to implement a tree planting program.

Effects of Trees on Property Values

Trees can have a significant effect on property values. Two primary methods are available for assessing the value of urban trees. The real estate sales method involves comparing the selling prices of properties that are similar except for tree

cover and to attribute the difference in value to the trees. Using the real estate sales method, trees have been found to add as much as 6% to 9% to the value of homes in Connecticut (Morales 1980). Trees have been found to add between 13% and 21% to the value of a typical Austin home (Austin ReLeaf 1990). Alternatively, the individual tree evaluation method involves a qualified professional evaluating a single tree and assigning a dollar value. For example, the International Society of Arboriculture's *Guide for Valuation of Landscape Trees, Shrubs, and Other Plants* suggests a basic value of $27 per cross section square inch, with adjustments made for species, size, location, and condition.

Increased property values represent both a benefit to homeowners and a potential boost in local property tax revenues. In general, trees add more value in areas where they are less abundant. The values they add depend on the size and the species of the trees involved.

ENVIRONMENTAL REQUIREMENTS IN RESOURCE PLANNING

Utility commissions are increasingly requiring that utilities reflect environmental and other social costs in their planning and decision making—whether the issue at hand is new generation, the siting of transmission lines, conservation programs, or routine utility operations. Procedures for addressing social costs in utility planning processes are rapidly evolving. A recent study (Pace University Center for Environmental Legal Studies 1990, 565) shows that 29 states have adopted or are considering some action to incorporate environmental externality costs into utility planning or bidding processes. The trend in the way that environmental externality costs are incorporated has been to attempt to estimate economic values for various impacts. Many states now require the use of environmental cost "adders" to supply-side resources, a discount or credit to demand-side resources, or the quantification of the estimated costs of environmental impacts using emissions mitigation techniques. Many other states require a qualitative consideration of environmental impacts.

Tree planting programs provide a potential means for addressing externalities in utility planning. They offer a means for mitigating energy-related emissions, for managing peak loads, and for considering community preferences and effects. Tree planting programs offer a means for regulatory compliance, environmental improvement, and positive public relations.

COMMENTS AND CONCLUSIONS

This paper illustrates the types of factors that decision makers will want to consider as they decide whether to implement tree planting programs and the type of information and analytic methods available to assess those factors. We have illustrated a number of the evaluation means that are available.

One way to integrate potential tree-related data into a cost-effectiveness analysis is to use an adaptation of the economic-ecologic model that was applied to the Trees for Tucson/Global ReLeaf program (McPherson 1990). The model accounted for planting locations, planting rates, growth rates, and mortality rates in its calculation of cooling savings estimates and avoided costs for dust and stormwater runoff control. It did not consider factors such as property value effects and quality of life impacts. Utility planners need to incorporate other factors such as energy savings, load shapes, avoided generation costs, retail electric rates, and service reliability effects. Local governments might also want to consider water use and street and sidewalk maintenance costs.

The magnitude and applicability of individual factors can vary significantly among service areas. The factors and methods that an individual utility will apply in its own planning is affected by its climate, fuel-mix, and region-specific factors. Climate can be a variable both in its effects on cooling loads and in the growth rates and characteristics of the trees that will be planted in conjunction with the program. Reduced peak (cooling) loads can free up needed capacity in warmer climates. Fuel-mix is a variable because it affects a utility's emissions offset requirements. Region-specific variants include tree planting and maintenance costs, urban development patterns, and real-estate costs.

Despite difficulties in quantifying various factors, trees have a number of significant environmental and social effects, including service reliability, atmospheric carbon dioxide reduction, improved environmental quality, decreased cooling loads (and consequent decreased electricity bills), increased property value effects, and improved aesthetics. Other community effects might include increased property tax revenues, increased street and sidewalk maintenance costs, and economic stimulation. Where tree planting and maintenance is less costly than power plant control equipment and any potential loss to consumers in service reliability, then a utility might not only reap a financial benefit, but also profit from improved relations with environmentally concerned citizens and regulators.

Overall, a tree-planting program evaluation should account for economics, environmental and other social factors, multiple constituencies, and a provision for monitoring and management. If tree planting programs prove to be a cost-effective means of incorporating environmental and social considerations into utility resource planning, regulators may want to consider incentives for expanded forestry activities as a means of supply-side mitigation and particularly urban forestry as a means of demand-side management.

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INTEGRATING COMPETITION INTO LEAST-COST PLANNING

Dr. John H. Chamberlin, Executive Vice President
Ms. Dana Toulson, Principal
Barakat & Chamberlin, Inc.
Oakland, California

Summary

Natural gas and electric utilities have always competed for market share, but in recent years, their rivalry has taken an new turn: utilities are being asked to promote the use of their competitors' services through the use of fuel-switching demand-side management programs. However, these fuel-switching programs may be promoting the very inefficiencies their proponents hope to discourage, and they may provide some utilities with an unfair competitive advantage.

This paper addresses the issue of the appropriateness of fuel-switching programs in the context of least-cost planning and inter-utility competition. It argues that although inefficiencies probably exist, they result in large part from inconsistent pricing of gas and electric services. Inconsistent pricing distorts both the competitive playing field and the long-term energy choices made by consumers.

By introducing for all energy sources a consistent pricing framework based on marginal costs, inefficiencies will be eliminated, gas and electric utilities will compete on an equal footing, and consumers will have the last word on the true cost or resource advantage of a particular appliance type. There may remain the potential for societal gains associated with fuel-switching; however, this issue can only be assessed within a comparable energy price environment.

To Switch or Not to Switch

Throughout their histories, natural gas and electric utilities have competed for market share. This competition has involved the use of a combination of builder incentives, advertising campaigns, and direct rebates on appliance purchases. More recently, utilities have tried to encourage the use of their particular product through the promotion of more efficient technologies.

However, competition has taken a new turn with the development and implementation of least-cost planning. Through fuel-switching demand-side management programs, regulators have asked some utilities to promote the use of their *competitors'* product. For example, some commissions have ordered summer-peaking electric utilities to develop incentive programs that encourage the use of gas air conditioning.

Proponents defend fuel-switching on grounds of societal efficiency, saying that without these programs, society's overall fuel-use mix will suffer from large inefficiencies. Opponents, however, object to mandates that provide competitors with an unfair advantage.

Recent commission decisions seem to validate opponents' concerns. For example, when the Idaho Public Utilities Commission early last year approved Idaho Power's "Good Cents" builder-incentive program, the PUC ordered that incentive payments should only reimburse builder expenses associated with meeting a higher energy-efficiency standard. "Amounts paid in excess of incremental cost increase the possibility of fuel-switching and may prejudice consumers against the use of natural gas," the commission wrote. "In this circumstance, a conservation program could turn into a load-building or promotional program."[1] In another case, the Florida Public Service Commission rescinded an order that required the state's electric utilities to encourage natural gas use as a way to promote conservation. The commission noted that "although it may be true that the increased use of natural gas ... may reduce the peak demand of electric utilities, there are other means by which this can be accomplished."[2]

We agree. Consumers should be permitted to make energy-purchasing decisions that are consistent with economic efficiency and societal least-cost planning principles. The term "economic efficiency" means that limited resources like electricity and gas are used in a way that provides the maximum value to society as a whole. Under perfectly competitive market conditions, prices serve this allocation function by equating the cost of providing additional supplies with the demand for a particular service or product. In a regulated market, regulators promote economic efficiency by designing rates that result in the same or nearly the same level of consumption that would have occurred under competitive market conditions. It is important to note that the emphasis here is not on the rate level or method employed, but on how customers respond to the prices they face to make rational purchase decisions.

Is there economic efficiency between gas and electric rates? The extent to which rates promote efficiency depends in large part on their relationship to *marginal costs*. Where there is significant fuel-substitution potential (e.g., chillers, cogeneration, heat pumps), the most important consideration from the perspective of economic efficiency is the relationship between gas and electric rates and marginal costs.

The societal efficiency of fuel-switching depends on the relative cost and performance of the end-use technology *and* the relative marginal costs of both electric and gas service. To date there has been little work done to establish a standard framework for calculating gas marginal costs. For example, only a handful of states —Massachusetts, New York, Oregon, New Hampshire, California, and the District of Columbia—have investigated natural gas marginal costs. This does not necessarily mean that gas rates are any less efficient than electric rates, given that utilities cannot charge more than their actual revenue requirements. However, it is difficult if not impossible to

determine whether the claims of societal efficiency associated with fuel switching are valid. It is also difficult to determine whether the relative prices of electricity and natural gas in a given service territory are leading consumers to make efficient choices between competing end-use technologies. Therefore, the first step should be to restructure natural gas utility rates.

A Gas Marginal Cost Model

To prove our point, we wanted to test the efficiency of existing rates between competing gas and electric utilities. We developed a planning model for identifying the marginal costs of an integrated gas supply/distribution firm, and we applied the model to an actual local distribution company (LDC) that competes with an electric utility whose rates are based on marginal costs. (Although we developed our framework independently, it proved to be very similar to the approach taken in Massachusetts.)

The model works by dividing gas distribution activities into commodity, peaking, demand, and customer cost categories and identifying how each of these costs vary with an increase in load.

Marginal commodity costs are the costs of purchasing or producing an additional therm of gas for a typical day in each month. A computer model determines how the LDC's sources of supply and storage options would be dispatched to meet monthly loads.

Marginal peaking costs are expenses related to peak-day capacity requirements, including the costs of additional storage capacity needed for peaking service and the costs of the incremental transmission and distribution capacity required to deliver additional therms to customers on peak-demand days.

Marginal demand costs are the expenses related to maintaining seasonal reliability, including incremental storage and the pipeline demand charges associated with increases in seasonal loads.

Marginal customer costs are defined as the costs of providing service to an additional average customer. These costs include investments in service lines and metering equipment and the expenses related to billing and customer accounting. We developed a marginal cost value using a regression analysis that relates changes in the number of customers to changes in costs.

We applied the model to an actual gas utility that has large, temperature-driven winter loads.[3] The gas utility's rates are based on embedded costs, and a fuel adjustment clause tracks changes in purchased gas costs. The competing electric utility is summer-peaking, and its rates are based on marginal costs. In addition, the electric

utility's rates are inverted for most customer classes and they are seasonally differentiated—that is, they are higher in the summer than in the winter.

Using publicly available data, we estimated the system marginal costs for the LDC. We found that they exceeded embedded costs by about 28% when marginal customer costs were included and by about 7% when marginal customer costs were excluded. More important, we found that the long-run marginal costs of serving winter loads are roughly three times higher than the marginal costs of providing service in the summer. This answer is consistent with common sense: winter loads are greater, heating loads are not needed in the summer, and the size of the storage and pipeline facilities and distribution plant are designed to serve winter loads.

However, in contrast to the wide differential in long-run marginal costs between serving winter and summer loads, the rates in place for the gas utility were constant over the year. The only variation came through the fuel adjustment clause, which lagged two months behind the actual prices the gas utility paid to pipeline suppliers. Thus, in 1989 the differential between summer and winter rates never exceeded 10%. This differential was nowhere close to the 300% difference that the marginal cost analysis called for.

This analysis led us to conclude that, at least in this service territory, consumers faced inefficient price signals because when they must choose between purchasing a gas or an electric appliance, consumers consider both the initial cost of the appliance and the effect of the appliance on their monthly utility bills. Given the large difference between the gas marginal costs and the price signals implicit in the LDC's rates, it is highly unlikely that these decisions are consistent with the value of energy resources for society as a whole.

Extrapolating the Results

The results of this analysis apply to two competing utilities located in a relatively small geographic location. Are these results also valid for other utilities? Because it is impractical to compare marginal costs for every utility in the country, we looked for other more readily available indicators. The most obvious is the extent to which gas utilities offer seasonal rates to reflect energy cost differences. Generally, seasonally differentiated gas rates are not as common as they are for electricity.

According to a 1989 American Gas Association survey of 87 gas utilities,[4] a little more than one in three of the utilities responding offered seasonal rates. Almost 45% of the responding companies offered gas air-conditioning rates, reflecting "the lower costs of providing this off-peak service." A recent Gas Research Institute survey of utilities by geographic region showed that electric utilities in every region of the United States had a seasonal variation in residential rates.[5] However, seasonal rate structures for gas utilities are not as widespread, particularly in the Midwest. We also used the Gas Research Institute study to compare the residential electric and gas rates in the top ten

major metropolitan areas in the United States.[6] Eight out of 11 electric utilities had seasonally differentiated rates, but only half of the 12 gas utilities used seasonal pricing.

The data suggest that fewer gas rates reflect the energy cost variations that utilities may be experiencing. As a result, customer fuel choice may be inefficient throughout the country; and in one region, the Midwest, these inefficiencies may be significant.

Conclusion

We conclude that the potential societal gains from fuel-switching programs cannot be assessed until the rates of competing gas and electric utilities are developed under a comparable framework. Given this background, fuel-switching makes little sense. After correcting inefficiencies by moving gas prices closer to marginal costs, further analysis may then prove that societal benefits exist. However, implementing fuel-substitution programs without first introducing a consistent pricing framework could lead to movement in the wrong direction.

Correcting rates is easier said than done, especially given the progress to date in developing gas marginal costs. Our approach is therefore a long-run solution. In some jurisdictions there may be a need or a justification to go forward with fuel-switching programs without clear quantitative analysis. When this is so, electric and gas utilities should develop and pay for programs jointly if both benefit. No utility should be asked to foot the bill for subsidizing the competition.

In addition, if electric and gas least-cost planning processes are separated and joint program development is not possible, some mechanism should be set up to allow the electric utility to share in the benefits it has transferred to the gas utility as a part of a fuel-switching program and vice versa. (It would be interesting to see how both gas and electric utilities might react to fuel-switching initiatives under these circumstances.)

Rather than mandating fuel-substitution programs, utility regulators should introduce a consistent pricing framework based on marginal costs for all energy sources. By using consistent pricing signals, inefficiencies will be eliminated, gas and electric utilities will compete on an equal footing, and consumers will have the last word on the true cost or resource advantage of a particular appliance type or source of energy.

NOTES

1. Idaho Public Utilities Commission, Order No. 22888.

2. Florida Public Service Commission, Order No. 22586.

3. See "Rebuttal Testimony of John H. Chamberlin," Public Service Commission of Maryland, Case No. 8251.

4. American Gas Association, "Gas Distribution Industry Pricing Strategies: 1989 Update," *Financial Analysis* (September 1989): 18–19.

5. Lynda J. White, Steven R. Cumbow, and Kim L. Sumner, *Electric and Gas Rates for the Residential, Commercial, and Industrial Sectors: 1990*, 2 vols. (Chicago: Gas Research Institute, May 1990): 11.

6. The major cities in the top ten metropolitan areas are New York, Los Angeles, Chicago, San Francisco, Philadelphia, Detroit, Boston, Dallas, Houston, and Miami.

Whose Crystal Ball Should We Use?
Is Fuel Switching in the Public Interest?

Presented at the

Third

National Association of Regulatory Utility Commissioners

National Conference
on

Integrated Resource Planning

by

Geoffrey C. Crandall
MSB Energy Associates, Inc.
7507 Hubbard Avenue, Suite #200
Middleton, Wisconsin 53562-3135
608/831-1127

Anita Fenichel
Maryland Public Service Commission
231 East Baltimore Street
Baltimore, Maryland 21202-3486
301/333-6000

Santa Fe, New Mexico
April, 1991

Slide #

I. Introduction and context of issue

Description of the issue

1-3 Gas Research Institute estimates that natural gas could displace 75,000 megawatts of electricity by the year 2000

Contentious issue is now before commissions in the context of rate cases/IRP-gas and/or Electric/F&PPAC cases/promotional practices and economic development cases disallowance and prudency reviews/QFs contract approval requests/conservation expense program design cases, etc..

Many commissioners and staff are dealing with this now - it's unavoidable for most other PUCs

II. Definition of Integrated Resource Planning

4-5 "Assessment of all reasonable supply-and-demand options against a broad set of cost and benefit factors"

III. Regulatory treatment of Fuel Switching

- Defining "fuel switching"

- Understanding the nature of fuel switching

6-9 - Application of benefit/cost methodology to capture the economic effects of end-use

- Measures and programs

- Use of California PUC *Standard Practices Manual* method

- Identification of savings potential from Michigan Electricity Options Study/LBL analysis

Slide #

IV. Case Studies:

Electric add-on heat pump proposed rebate program

Oil-to-Electric - characteristics of the proposed program

Application of economics including the California *Standard Practices Manual* methodology

10-16

Gas-to-Electric Electrotechnologies application - Engineering/BTUs assessment (Source BTU)

Application of California PUC *Standard Practices Manual* methodology

Electric-to-Gas Domestic hot water application - Engineering/BTUs assessment (Source BTU)

Economic Analysis - application of California Public Utility Commission *Standard Practices Manual* methodology

V. Selection and Decision Analysis - Criteria and Methods

Quantifiable analysis using California *Standard Practices Manual* with or without externalities adder

Engineering analysis (including BTU input/output method)

17-18

Economic analysis - use of Maine PUC Chapter 380 or California (STPM) methods. Non-quantifiables need to be considered even if difficult to monetize. These could include the long-term availability and price of gas/oil/electricity, diversity of supply/environmental impact/jobs/local economy/ other

Reliance on foreign energy supplies

VI. Alternative approaches:

- Review work underway now or done by other public utility commissions and utilities

19-22

- Wisconsin Public Service Commission 05-U-I-103

- Maine Public Service Commission Docket No. 87-261 and 88-111

Slide #

- Michigan Public Service Commission, *Michigan Electricity Options Study*, Work Group II, Vol. III 8-1 through 8-7 (Lawrence Berkeley Laboratory)

- Rhode Island 1990 Fuel-Switching Task Force draft report

- Central Vermont Collaborative - VPSB-5270

- Joint natural gas and electric planning

VII. Regulatory and political realities

Need to encourage the wise use of energy and preservation of finite fuels

Need to develop consistent long-term energy strategy

Force utility to pay their customers to switch to their competitors' fuel?

Switching from one fuel to another is different than conservation

Widely divergent analyses

Tendency to use an opportunity to build load

23-31 Is it important to treat gas and electric IOUs "the same"?

Need for commission to have more staff to handle these complex issues

Interrelationship with non-regulated fuels and fuel supplies

Highly contentious issues - no easy answers here

Hard for PUCs to get a handle on this, especially when dealing with non-regulated fuels, no gas IRP, and no national/state policies and plans

VIII. Need NARUC/DOE action to establish gas and oil avoided-cost method

32-34 DOE/NARUC need to develop methodology for fuel switching and publish a new issue (Vol. III) of the *Integrated Resource Planning Handbook*

IS FUEL SWITCHING IN THE PUBLIC INTEREST?

by

Geoffrey C. Crandall - MSB Energy Associates, Inc.

&

Anita Fenichel - Maryland Public Service Commission

WHY IS THIS AN IMPORTANT REGULATORY ISSUE?

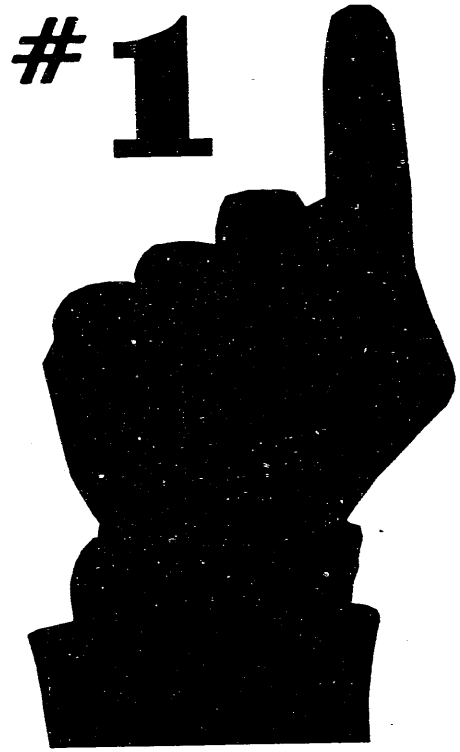
ISSUE KEEPS RE-APPEARING IN : GAS , ELECTRIC AND COMBINED IRP/ RATE CASES/ CONSERVATION PROGRAM DESIGN/ PROMOTIONAL PRACTICES/ETC

NEED TO INCORPORATE EFFECTS INTO STATE COMMISSION AND UTILITY ENERGY PLANNING

DOES FUEL SWITCHING FIT INTO AN IRP STRATEGY?



#1



DEFINITION OF

INTEGRATED

RESOURCE

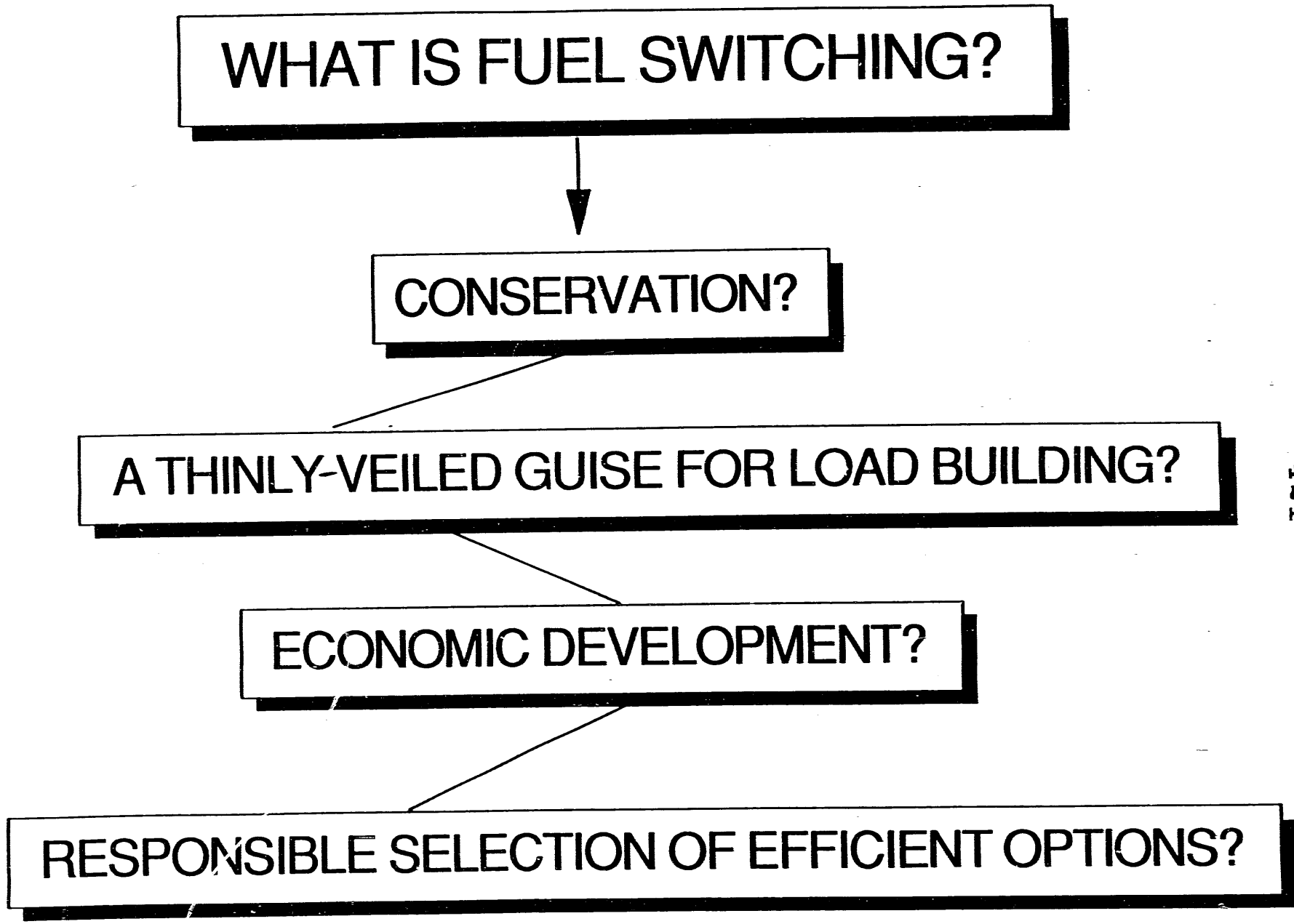
PLANNING

I. DEFINITION OF INTEGRATED RESOURCE PLANNING

A. **DEFINITION:** Process to assess all reasonable supply and demand options against a broad array of cost and benefit factors

IRP is not the same as conservation.

FUEL SUBSTITUTION


WHAT IS FUEL SWITCHING?
CONSERVATION?
A THINLY-VEILED GUISE FOR LOAD BUILDING?
ECONOMIC DEVELOPMENT?
RESPONSIBLE SELECTION OF EFFICIENT OPTIONS?

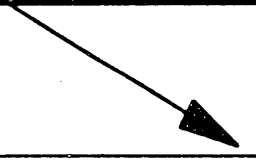
FUEL SWITCHING ISSUES:

WHICH CUSTOMERS PAY AND WHAT AMOUNT FOR PROGRAM OPERATION?

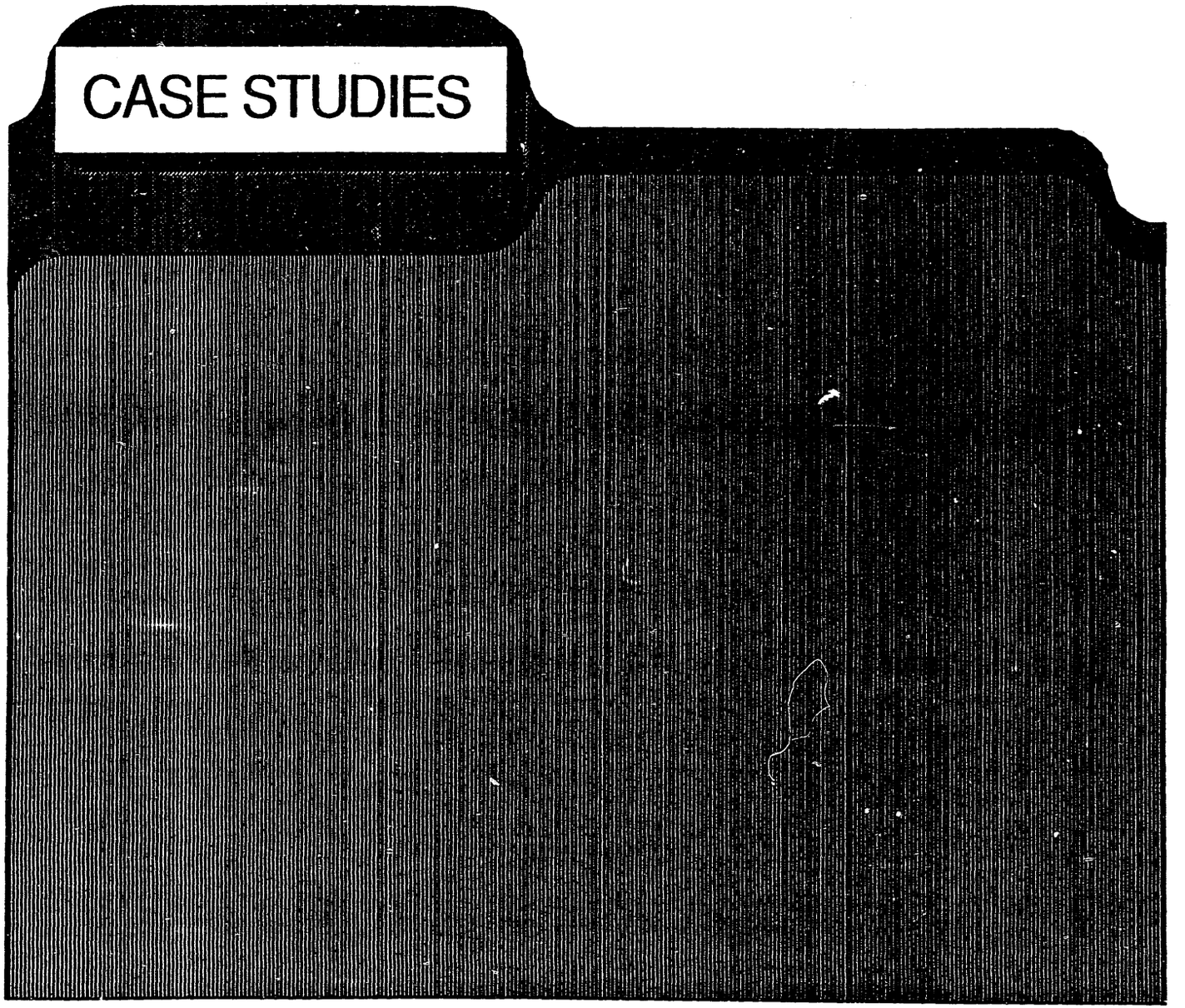
HOW DOES A PUC DECIDE WHAT COMBINATION DELIVERS THE OPTIMAL SOCIETAL BENEFIT?

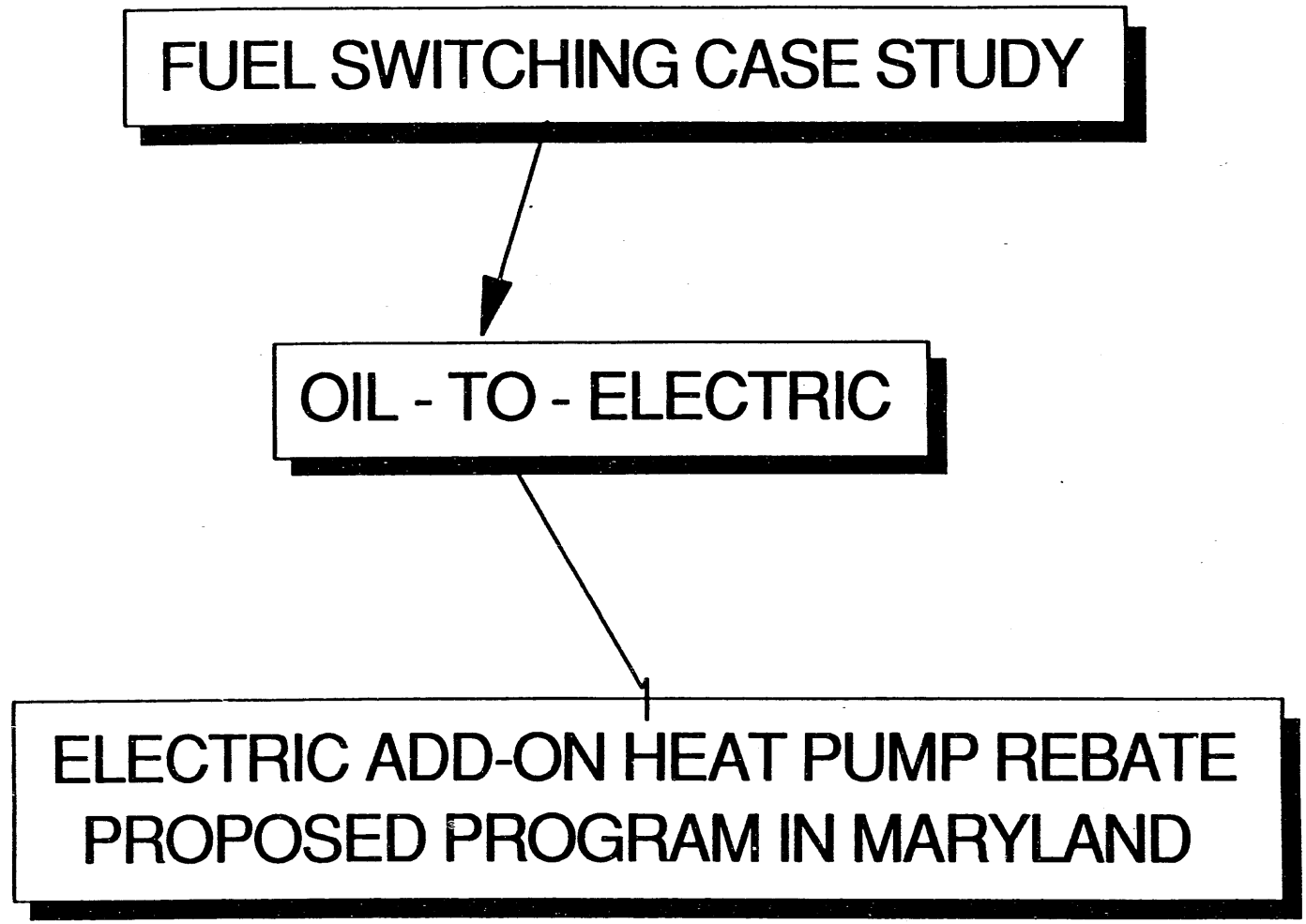
FUEL SWITCHING ISSUES:

APPLICATION OF ECONOMIC TESTS AT

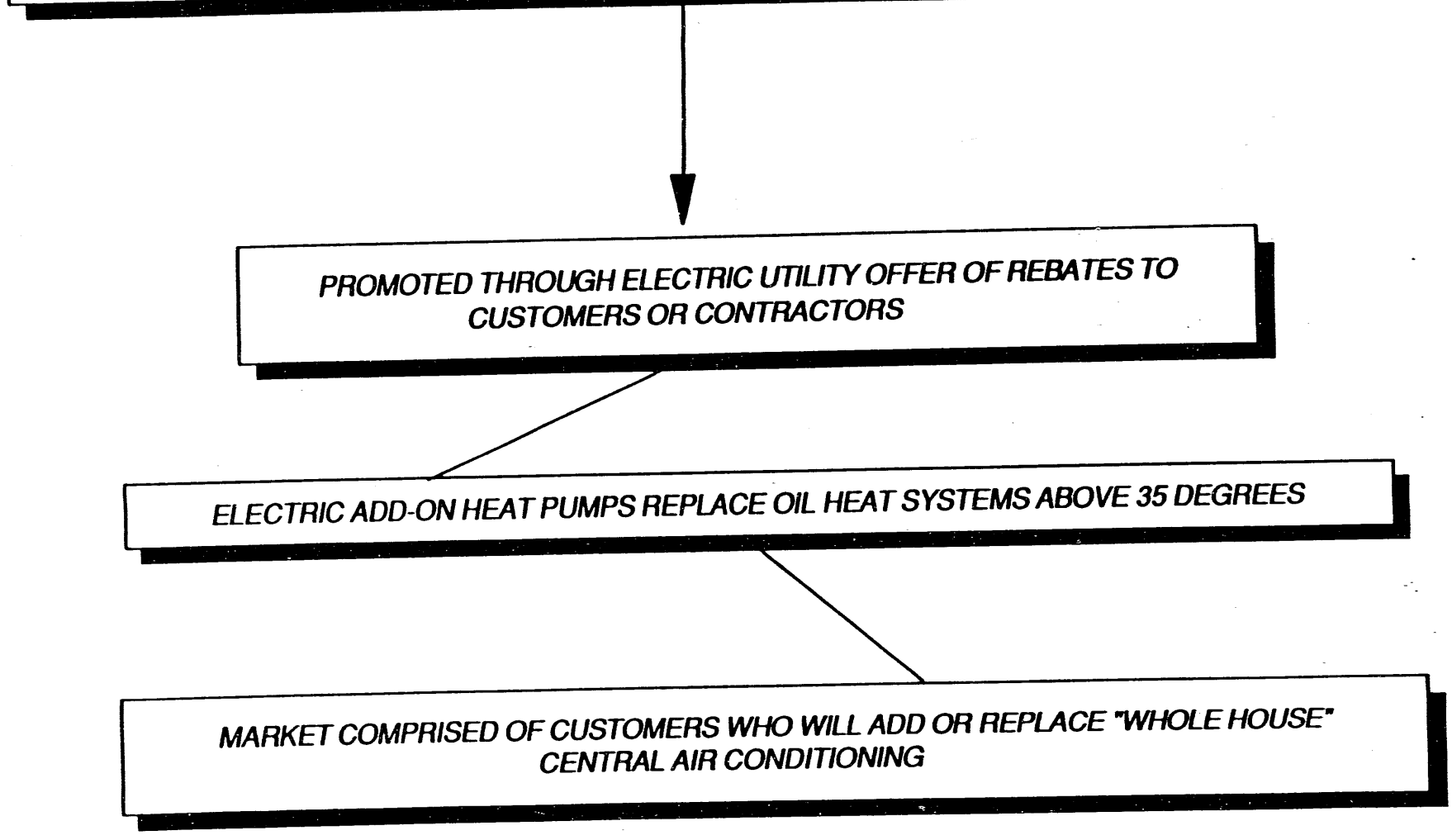


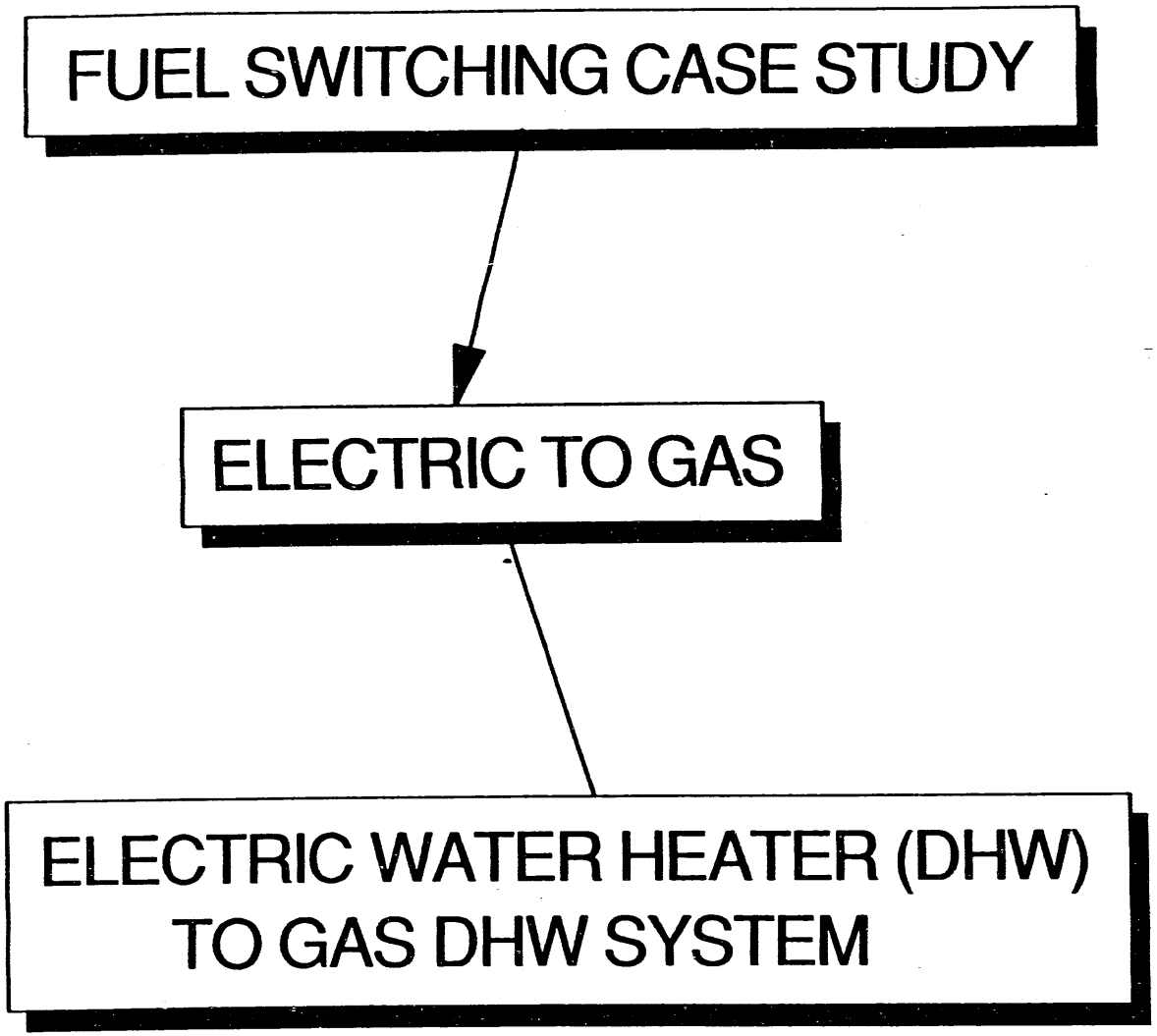
MEASURE/PROGRAM/SYSTEM LEVEL


CASE STUDIES

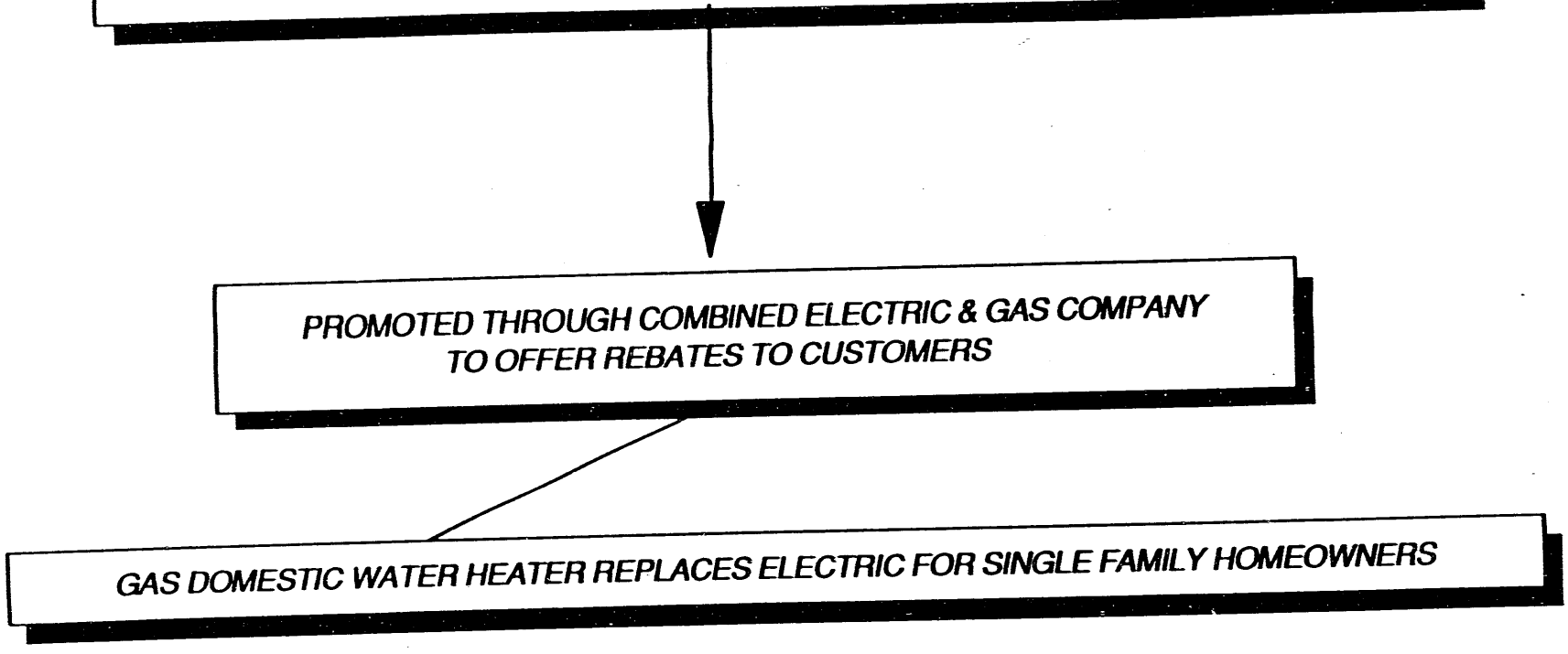

FUEL SWITCHING CASE STUDY
OIL - TO - ELECTRIC
ELECTRIC ADD-ON HEAT PUMP REBATE
PROPOSED PROGRAM IN MARYLAND

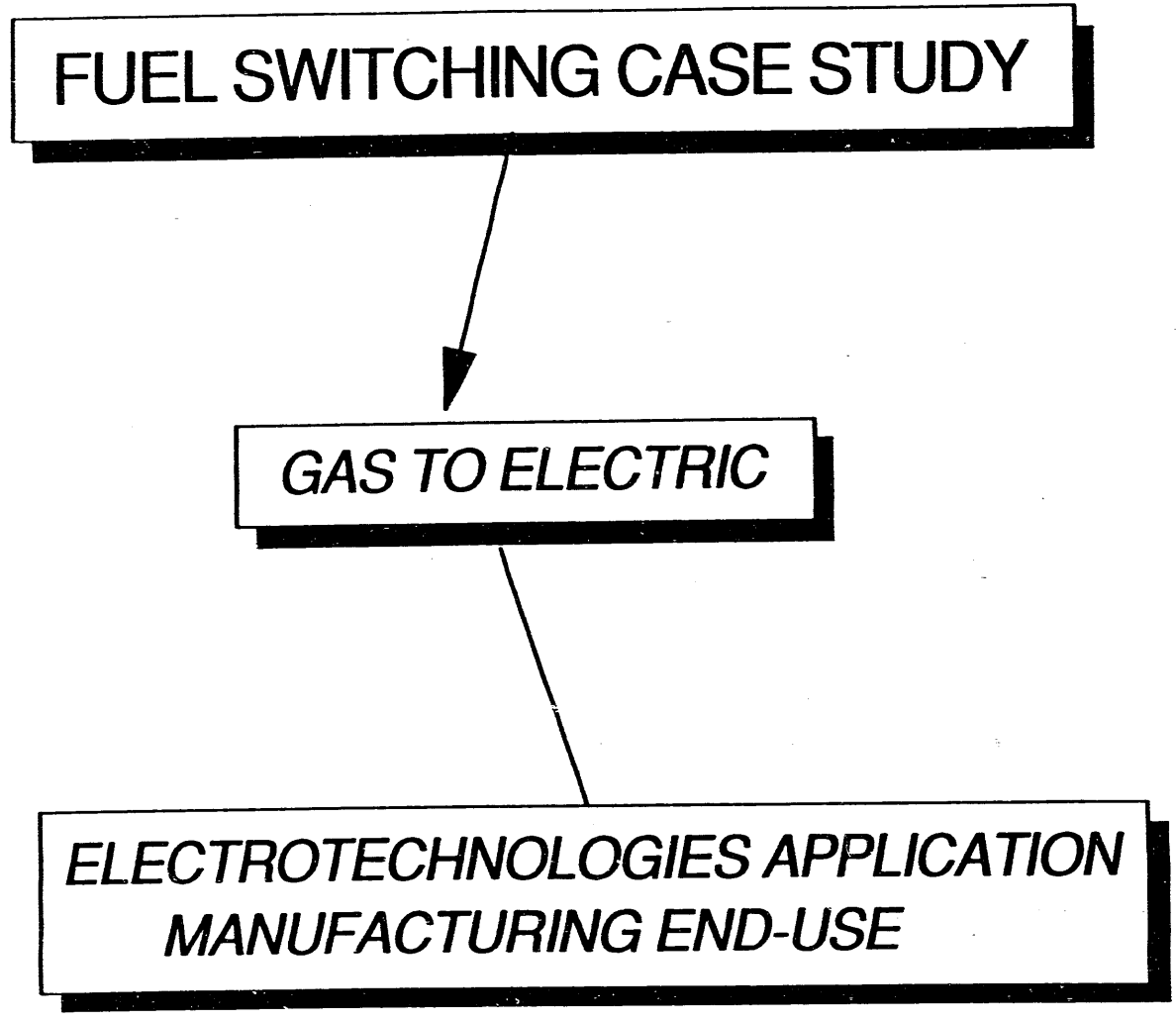
HEAT PUMP PROGRAM CHARACTERISTICS

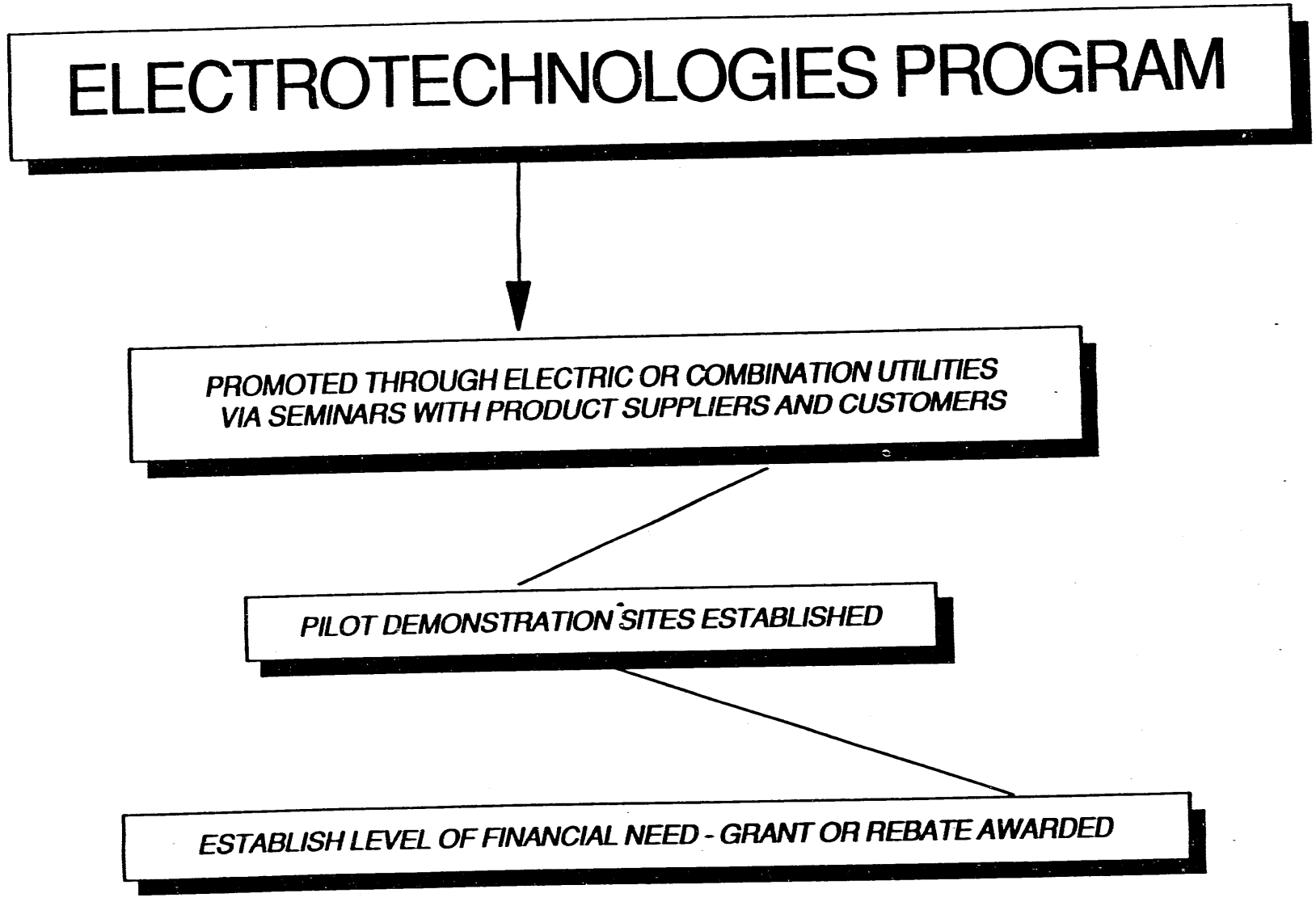



FUEL SWITCHING CASE STUDY
ELECTRIC TO GAS
ELECTRIC WATER HEATER (DHW)
TO GAS DHW SYSTEM

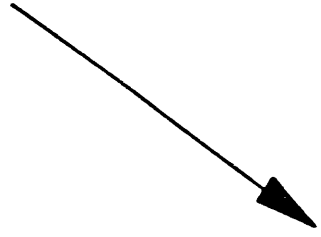
ELECTRIC-TO-GAS DHW PROGRAM




FUEL SWITCHING CASE STUDY
GAS TO ELECTRIC
ELECTROTECHNOLOGIES APPLICATION
MANUFACTURING END-USE

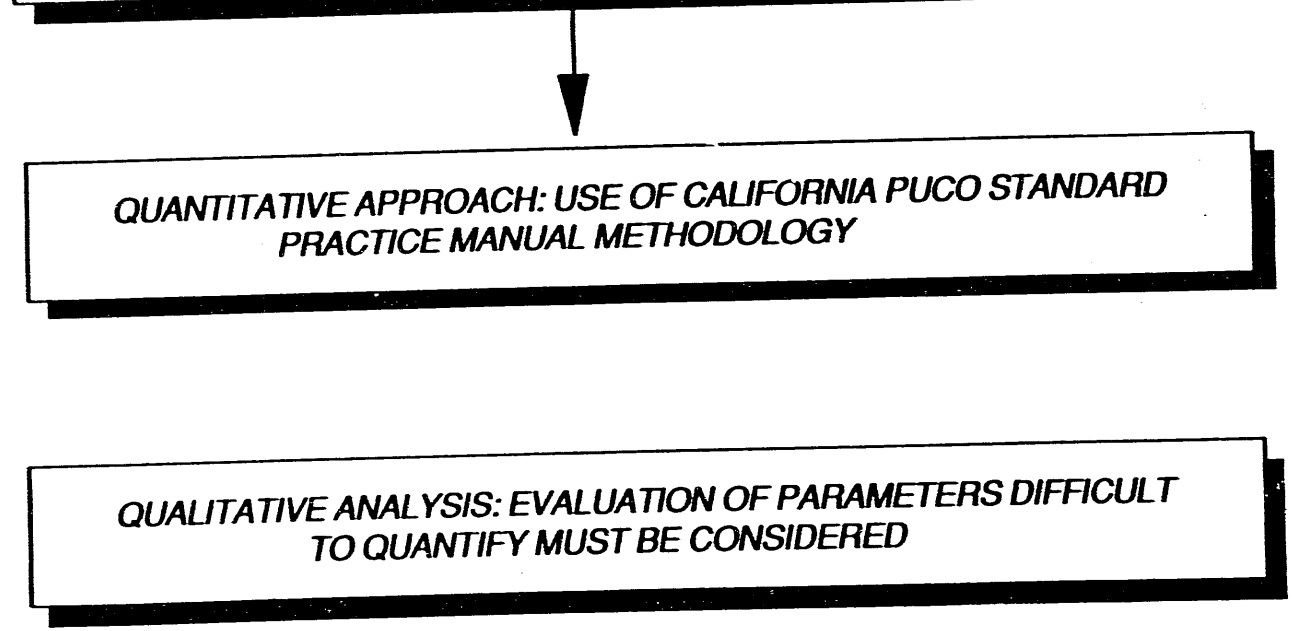

ELECTROTECHNOLOGIES PROGRAM
PROMOTED THROUGH ELECTRIC OR COMBINATION UTILITIES VIA SEMINARS WITH PRODUCT SUPPLIERS AND CUSTOMERS
PILOT DEMONSTRATION SITES ESTABLISHED
ESTABLISH LEVEL OF FINANCIAL NEED - GRANT OR REBATE AWARDED

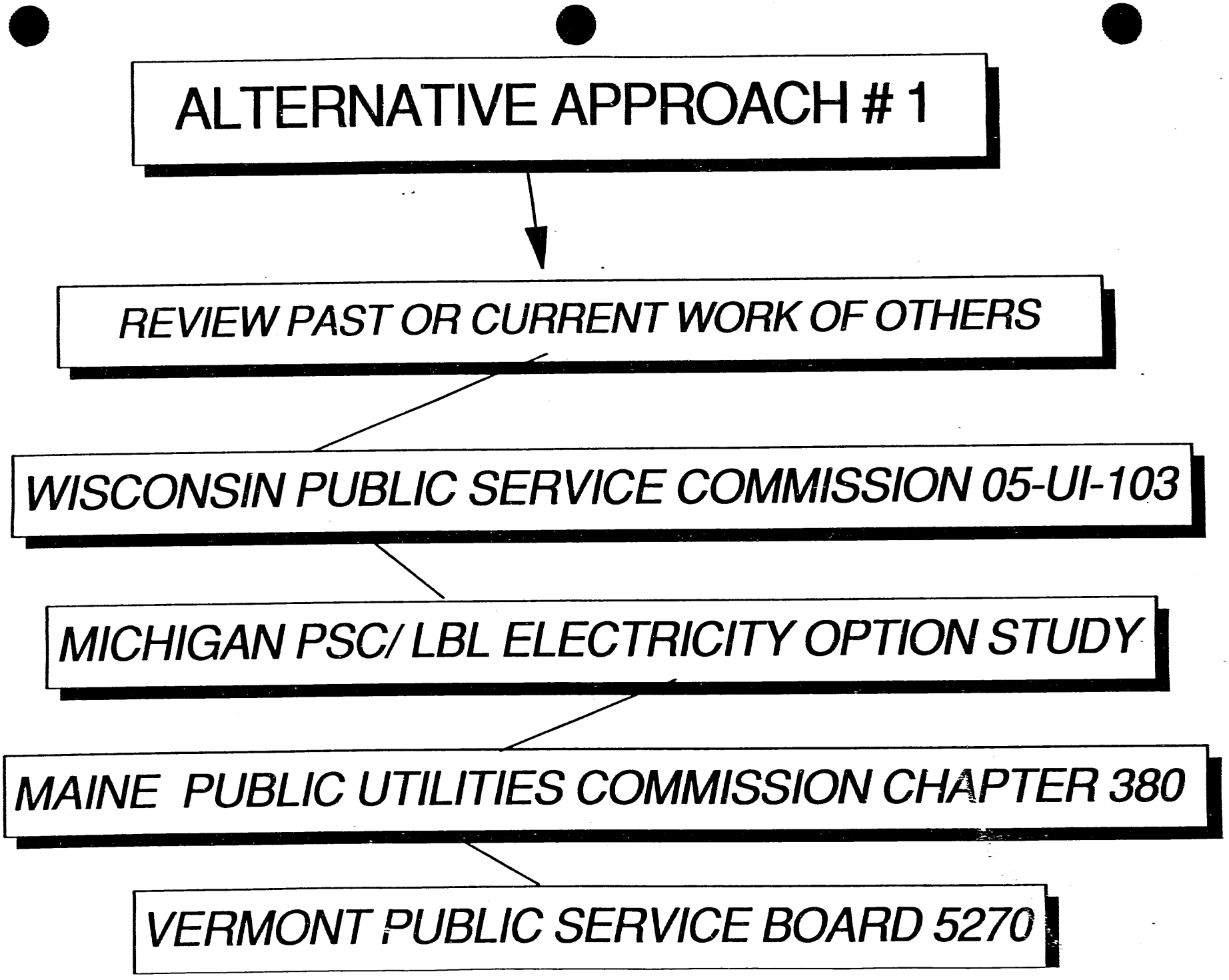
SUGGESTED CRITERIA FOR REGULATORS TO HANDLE FUEL SWITCHING OPTIONS

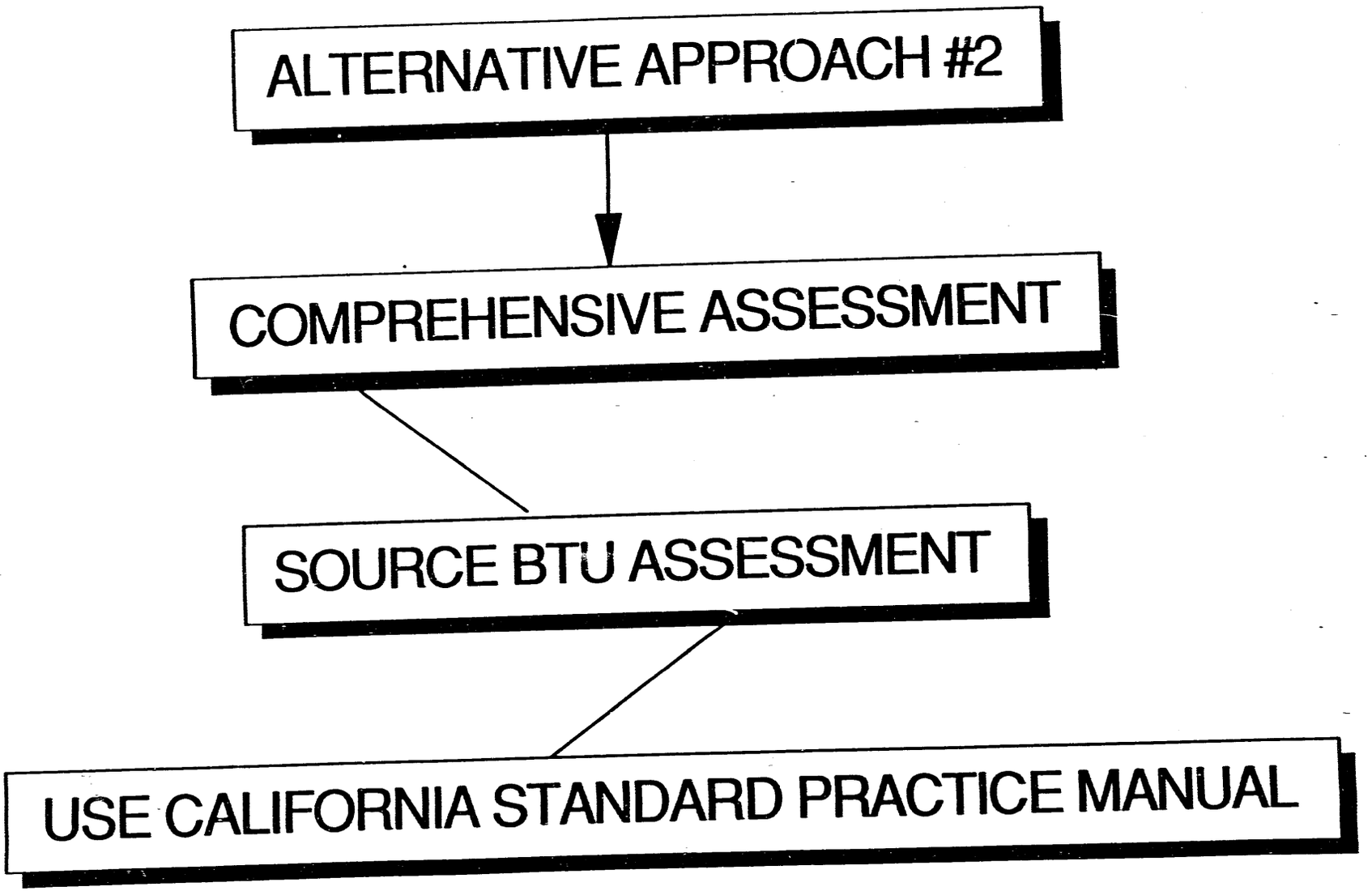


IN THE SHORT TERM:
WHEN YOU DON'T HAVE THE LUXURY OF TIME

EVALUATION OF REASONABLENESS OF PROPOSED PROGRAMS

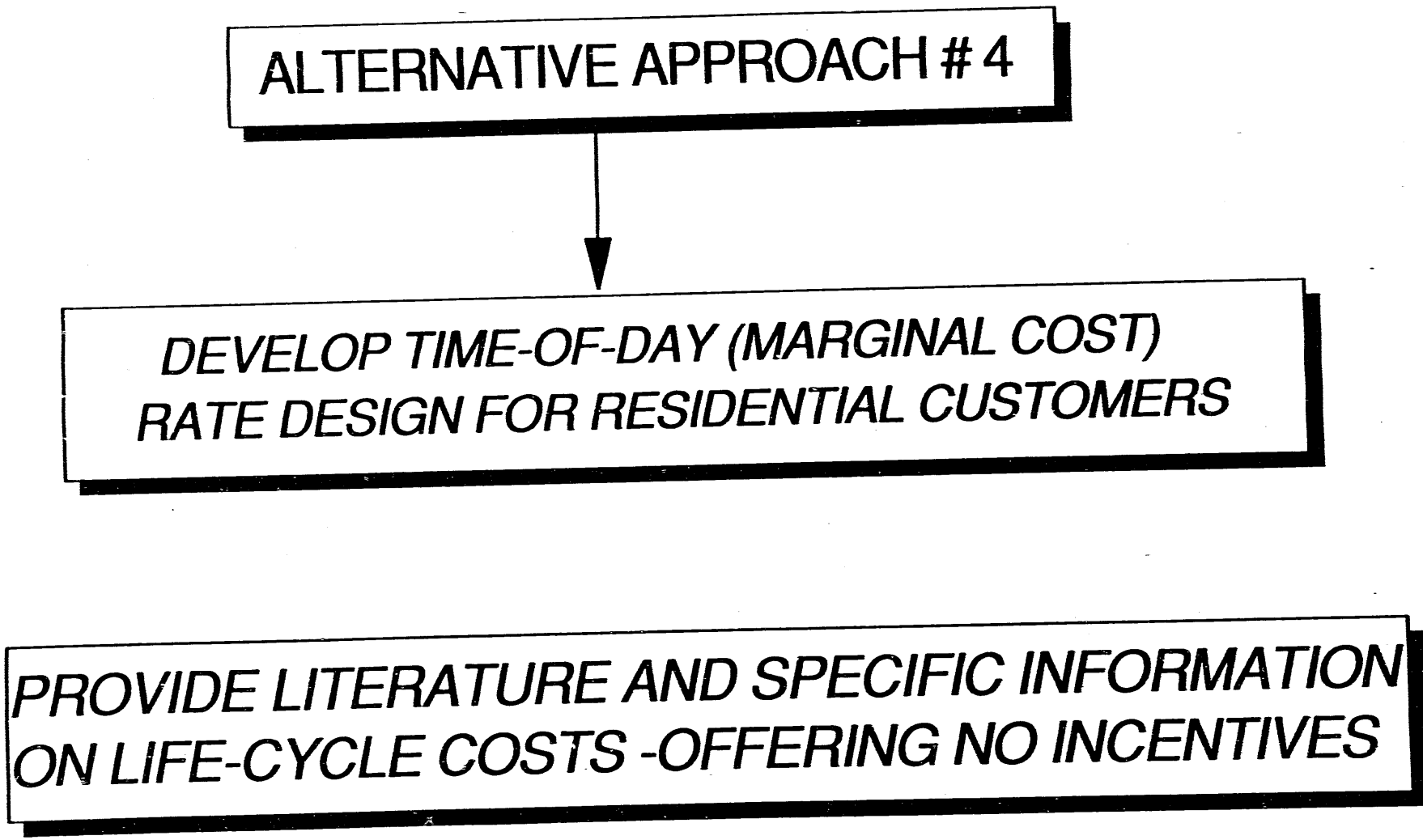



ALTERNATIVE APPROACH # 1
REVIEW PAST OR CURRENT WORK OF OTHERS
WISCONSIN PUBLIC SERVICE COMMISSION 05-UI-103
MICHIGAN PSC/ LBL ELECTRICITY OPTION STUDY
MAINE PUBLIC UTILITIES COMMISSION CHAPTER 380
VERMONT PUBLIC SERVICE BOARD 5270

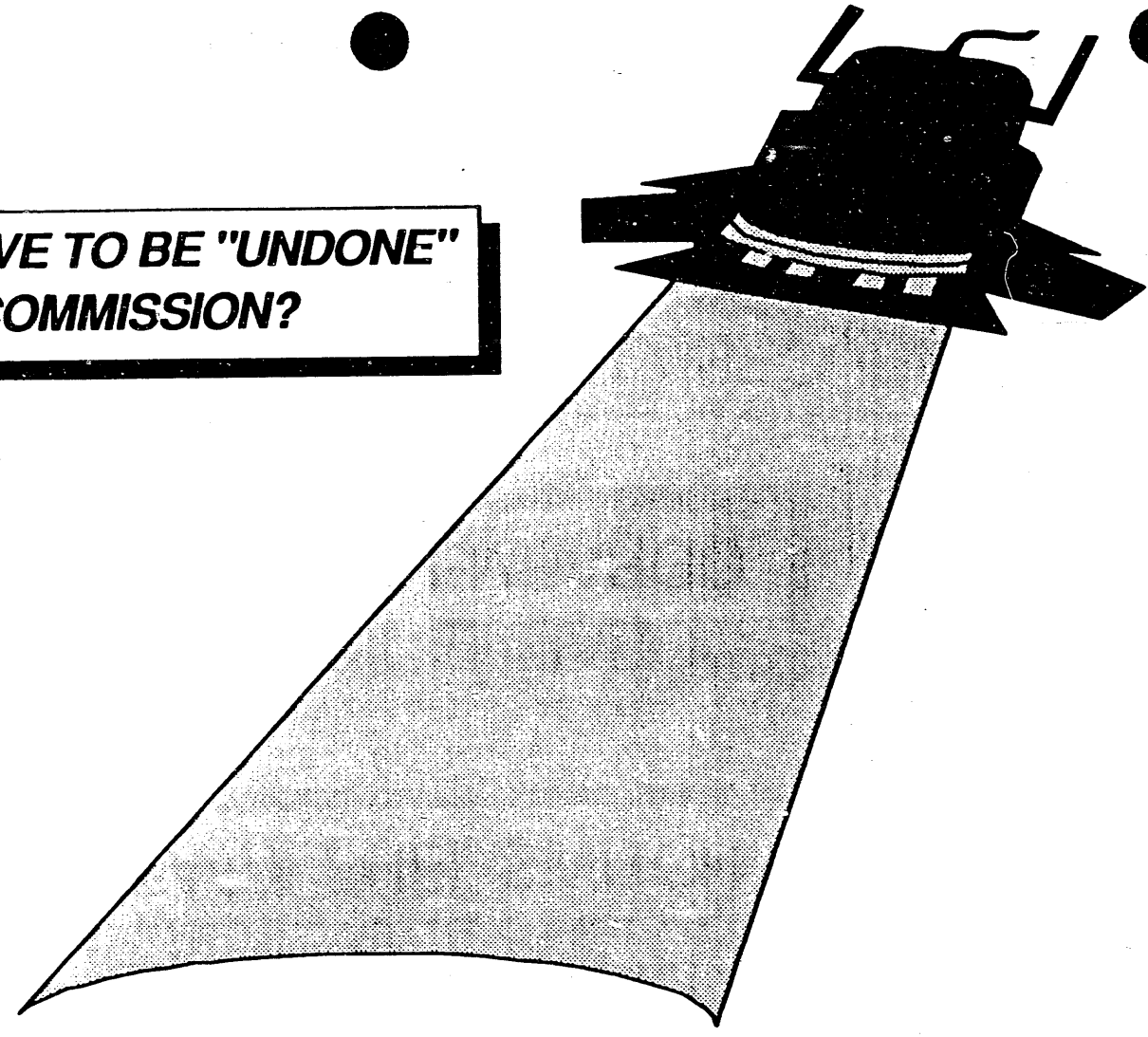

ALTERNATIVE APPROACH #2
COMPREHENSIVE ASSESSMENT
SOURCE BTU ASSESSMENT
USE CALIFORNIA STANDARD PRACTICE MANUAL

ALTERNATIVE APPROACH #3

PUC MANDATE ELECTRIC AND GAS UTILITIES TO DEVELOP AN OVERALL ENERGY PLAN JOINTLY


ALTERNATIVE APPROACH # 4
DEVELOP TIME-OF-DAY (MARGINAL COST)
RATE DESIGN FOR RESIDENTIAL CUSTOMERS
PROVIDE LITERATURE AND SPECIFIC INFORMATION
ON LIFE-CYCLE COSTS -OFFERING NO INCENTIVES

WILL ALL THIS HAVE TO BE "UNDONE" BY THE NEXT COMMISSION?



LONG-TERM PRICE & AVAILABILITY

1967-1970 "ELECTRICITY TOO CHEAP TO METER"

1970- CLEAN AIR ACT FUEL SWITCH COAL-TO-OIL

1973 ARAB OIL EMBARGO

1974 FUEL SWITCH OIL-TO-COAL (SECURITY, ETC)

1977 WINTER GAS DIVERSIONS

1978 NO GAS PROMOTION

1978 PASSAGE OF FUEL USE ACT-NO NAT GAS

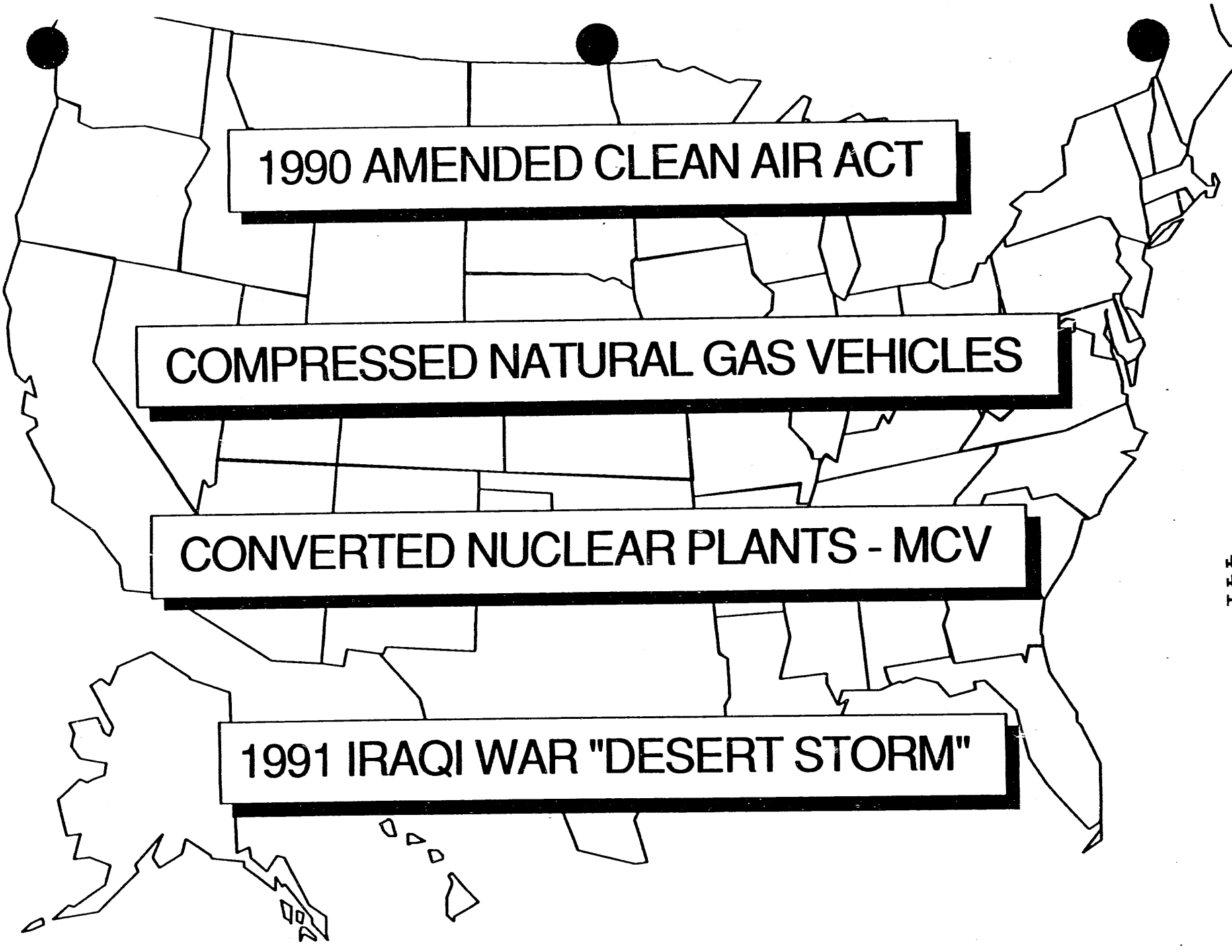
1983-85 REPEAL FUA PROLIFERATION OF QF'S/IPP'S

PROLIFERATION OF COMBUSTION TURBINES

LOW FRONT-END CAPITAL COST

FUEL IS A PASS -THROUGH ITEM

BURNING GAS IS GREAT "ENVIRONMENTALISM"

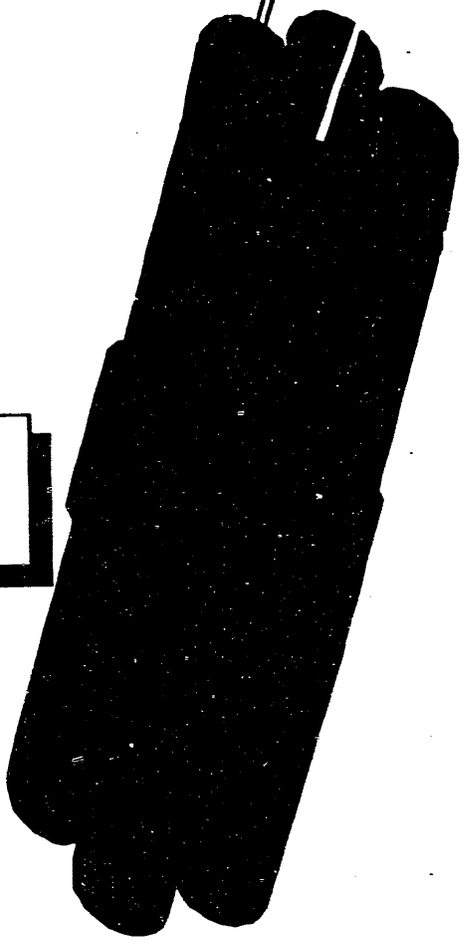

1990 AMENDED CLEAN AIR ACT
COMPRESSED NATURAL GAS VEHICLES
CONVERTED NUCLEAR PLANTS - MCV
1991 IRAQI WAR "DESERT STORM"

POLITICAL

&

REGULATORY

CONSIDERATIONS



FUEL SWITCHING & SUBSTITUTION

HAVE BEEN ABUSES

LOAD BUILDING/RETENTION IS PRIMARY MOTIVATOR

CONSERVATION IS AN AFTERTHOUGHT IN THIS ARENA

TECHNICAL ANALYSES ARE WIDELY DIVERGENT

INEQUITABLE TREATMENT OF GAS AND ELECTRIC IOU'S

THE JOURNEY INTO NON-REGULATED FUELS COUNTRY

ANTI-TRUST COMPLICATIONS WITH NON-REG'S

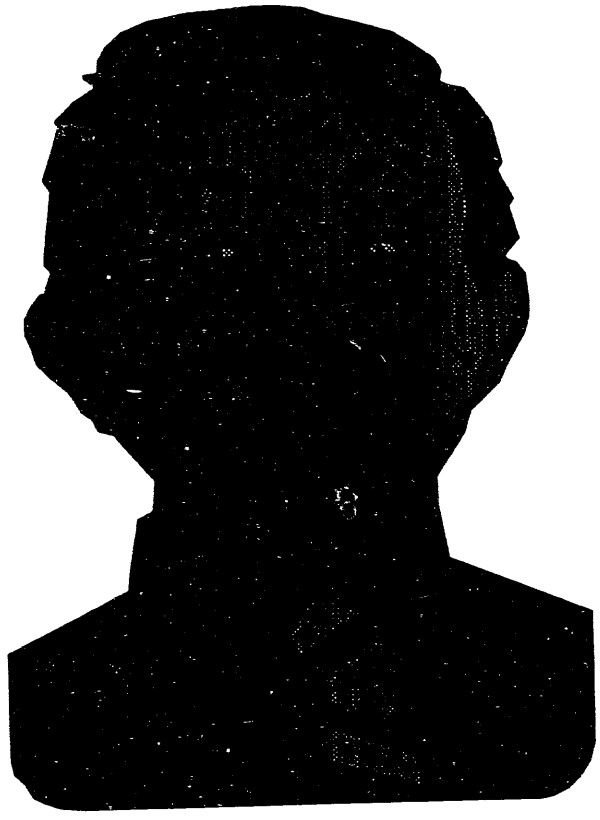
ANTI-COMPETITVENESS IMPACT OF FUEL SWITCHING

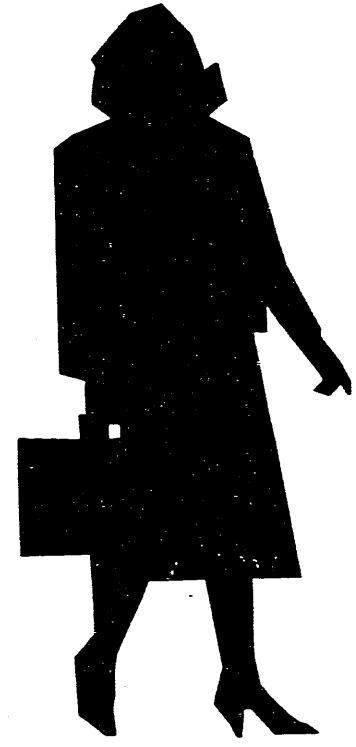
NEED FOR MORE FTE'S AND RESOURCES

MAKE TOUGH DECISIONS ABOUT FUTURE AVAILABILITY

BALANCE LONG-AND SHORT-TERM BENEFITS

ACTIONS MAY CONTRADICT EARLIER POLICY





HMMM.. WHAT'S THE NEXT STEP?

WHERE DO WE GO FROM HERE?



ACTION ITEM #1: NARUC/DOE ESTABLISH AN OIL & NATURAL GAS AVOIDED COST METHODOLOGY

ACTION ITEM #2: NARUC/DOE ESTABLISH FUEL SWITCH METHODOLOGY

WHERE DO WE GO FROM HERE?

ACTION ITEM #3: PUBLISH VOLUME 3 OF THE NARUC CONCEPTUAL AND METHODOLOGICAL ISSUES IRP PLANNING HANDBOOK

ACTION ITEM #4: INCREASED COORDINATION BETWEEN NARUC CONSERVATION AND GAS COMMITTEES



Madison Gas & Electric

NARUC

3RD NATIONAL CONFERENCE ON INTEGRATED RESOURCE PLANNING

APRIL 8 TO 10, 1991

SANTA FE, NEW MEXICO

FUEL SWITCHING:

A WINNING STRATEGY FOR

COMBINATION UTILITIES

CLAIRE K. FULENWIDER

MADISON GAS AND ELECTRIC COMPANY

FUEL SWITCHING:

A WINNING STRATEGY FOR COMBINATION UTILITIES

I. Fuel Switching Decision Criteria
   - The Customer's
   - The Utility's
   - The Regulators

II. The Winners
   - Likely Winners
   - How Not to Cross Subsidize

III. Marketing the Winners

FUEL SWITCHING DECISION CRITERIA

THE CUSTOMER'S CRITERIA

- Same as for any Energy Decision

- Reasonable Cost
  - Payback of Less than Five Years if Residential
  - Payback of Less than Two Years if Commercial/Industrial

- Highest Value
  - Reliability
  - Convenience
  - High Comfort Level

- Participant Test
  - Preferred Option
  - Economics Payback (first cost--inc. rebates vs. lower total bill)
  - Externalities (clean air, cleanliness, convenience)

DECISION CRITERIA

GAS UTILITY CRITERIA

RATEPAYERS TEST

- Nonparticipant (ratepayer, no loser) Test = Increased Revenues + Lower Per Unit Costs

- Considers as Costs:
  - Incremental Capital: Main, Lateral, Meter
  - Incentives - Rebates, Financing, etc.
  - Program Costs
  - Capacity Costs
  - Commodity Costs

- Considers as Benefits:
  - Increased Revenues
  - Capacity Savings
  - Commodity Savings
  - Capital and O&M Savings

- Externalities
  - New Technology
  - New Market
  - Appeal to Customers
  - Environmental Impacts
  - Regulatory Attractiveness

DECISION CRITERIA

THE COMMISSION'S

- Economic Tests less Clear
  - Impact on Other Regulated Fuel
  - Revenue Requirements Test or Total Resource Test

- Additional Costs
  - Electric Lost Revenues
  - Electric Rebates

- Additional Benefits
  - Capacity Savings
  - Production Cost Savings

(For all intents and purposes, electric lost revenues cancel gas increased revenues)

- Externalities
  - Environmental

REGULATORY CRITERIA

Total Resource

Benefits
Gas Capacity Savings
No Bill Savings
Electric Capacity Savings
Electric Commodity Savings
Customer Savings
- Capital Cost
- Operating Costs

Noncombustion Credit, 15%
No Added Revenues

Costs
Program Costs
Gas Capacity Costs
Gas Commodity Costs
Customer Costs
No Rebates
No Lost Revenues

Revenue Requirements

Benefits
Electric Capacity Savings
Electric Commodity Savings
Noncombustion Credit, 15%
No Added Revenues
No Bill Savings

Costs
Program Costs
Rebate Costs
No Lost Revenues

DECISION CRITERIA

UTILITY CRITERIA - ELECTRIC

- Revenue Requirements Test

Savings	Costs
Capacity	Rebates
O&M Savings	Program Costs
Equipment Savings (T&D)	Lost Revenue Does Not Count

THE WINNERS

- Likely Winners
- How Not to Cross Subsidize

AVOIDING CROSS SUBSIDIZATION

1. Select low annual load factor electric options.
2. See if conversion to gas passes or comes close to passing participant test.
3. Perform electric revenue requirements test to screen option.
4. If option passes, perform electric nonparticipant test to be sure rate impact is lower than rate of inflation or some other acceptable proxy.
5. Test gas conversion value to utility with nonparticipant test.
6. If passes "5," see if value (benefit) indicated in "5" + "3" is enough to move the market (pass the participant test).
7. If yes, set minimal needed incentive.
8. Assign up to 5 years marginal gas revenue (NPV) to rebate. Take remainder needed from "3." Any good promotional program should pay back in five years or less.

LIKELY WINNERS

Predicting the Winners

- Look for Low Annual Electric Load Factor Options
- Converted to High Annual Load Factor Gas Options
- Cost-effective, Attractive Customer Options

PREDICTING THE WINNERS

Electric to Gas	Gas Participant	Gas Nonparticipant	Electric Nonparticipant	Electric Revenue Requirement	TR Test
Residential Water Heating	P	P	F	P	P
Residential Space Heating	P	P	F	F	F
Multifamily Space Heating	?	P	F	F	F
Residential Air Conditioning	F	F	P	P	PP
Commercial Air Conditioning	?	P	P	P	P
Residential Cooking	P	?	F	P	F
Commercial Cooking	P	P	F	P	F

MARKETING THE WINNERS

- Stress the Customer Benefits
- Price to Move the Market and Still Maximize Utility Benefit
- Sell Internally to Build Company Support
- Empower your Field Representatives; Give Them On-the-Spot Sales Power
- Emphasize Noneconomic Benefits that Appeal to Customer
  - Contribution to Environment
  - Innovation
  - Capacity Availability for Others
- Always Play to Win/Win
- Focus your Efforts; Go for the Winners

MARKETING IS EVERYBODY'S BUSINESS

- Marketing is Broad-Based and Multifaceted
- Input is Essential from Many Areas
- Marketing Needs to be Integrated, Not Isolated
- Much is at Stake

GAS VERSUS ELECTRIC PROGRAMS

	Electric	Gas
Program Description	High Efficiency Air Conditioning Small Commercial	Residential Space Heating Conversion
Program Type	Conservation	Sales Promotion
Added Customer Cost	$360	$350 to $350
Customer Savings	$100/Year	$270/Year
System Benefit (Nonparticipant Test)	$102/Year Savings/ Customer for 20 Years	$200 Added Marginal Revenues/ Year/Customer
Rebate Range	$102 to $360	Up to $200

SPACE COOLING EXAMPLE

Replace 900-ton cooling load with gas-driven chillers. Defer 590 kW and 531,000 kWh/yr.

Utility Benefit	(Present Value Over 20-Year Life)
Avoided Electric Cost to Serve	$361,000
Revenue Over 20 Years Disincentive	(312,000)
Total Avoided Electric Cost	49,000
Markup for Gas Service	93,000
TOTAL Utility Benefit	$142,000

Customer Benefit	(Present Value Over 20-Year Life)
Electric Bill	$312,000
Gas Bill	(256,000)
Equipment Cost (Incremental)	(110,000)
TOTAL Customer Benefit Cost	$(54,000)

CUSTOMER NEEDS

Lower Customer Costs

Meet End-Use Requirements Efficiently

Education/Caring

Help Customers Control Bill

Customer Service

UTILITY NEEDS

Improve Customer Relations

Load Retention

PROFITABILITY

Improve Load Factor

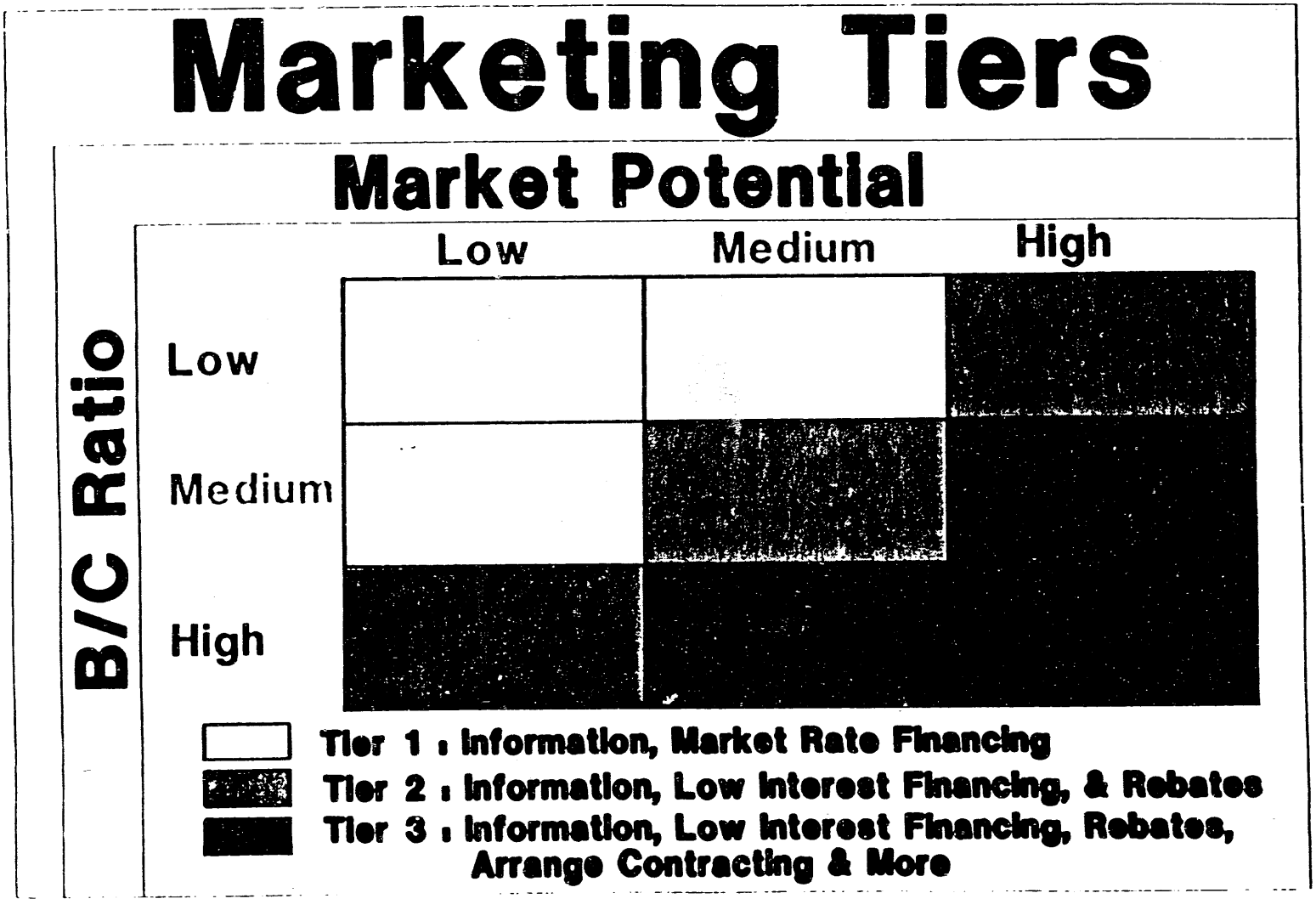
Lower Capital Costs

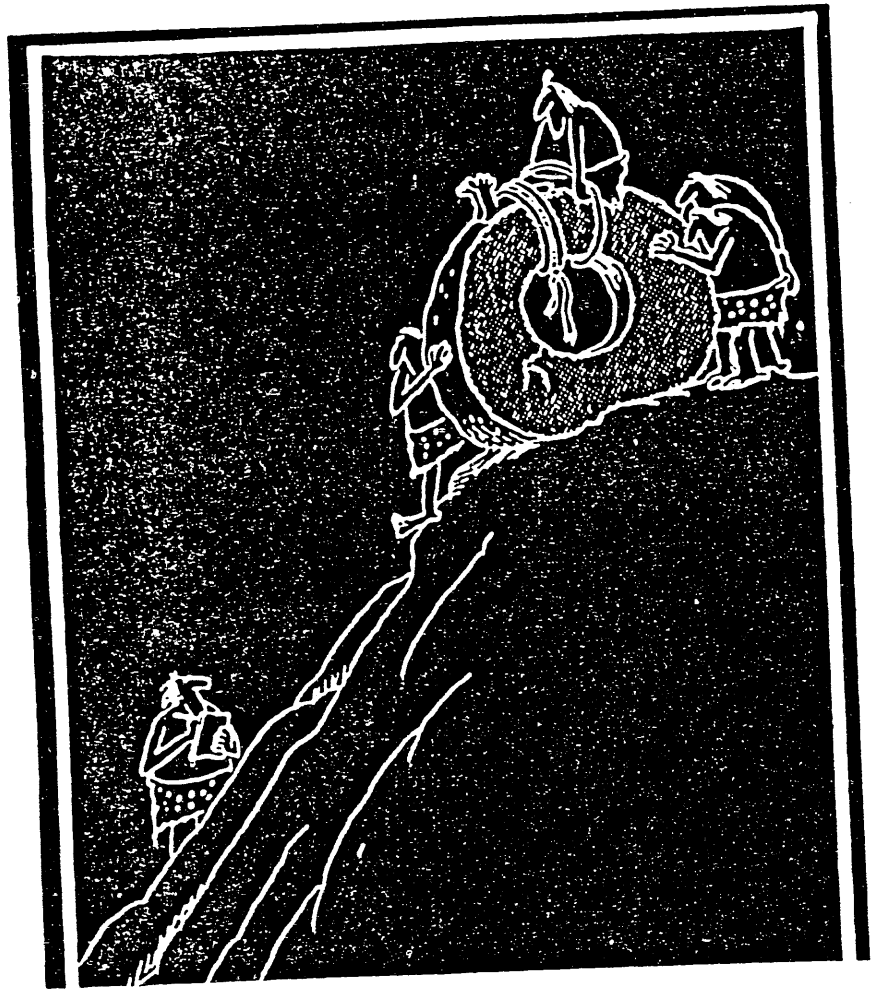
More Customers

Lower Fuel Costs

Either Defer Plant or Buy Smaller Share

Marketing Tiers





Early experiments in transportation

TAKING THE NEXT STEP: INTEGRATING ENVIRONMENTAL COSTS INTO UTILITY RESOURCE PLANNING

by

Shepard Buchanan and Elizabeth Bowers*

A. Introduction

Levelized utility and environmental costs are useful for comparing the cost-effectiveness of resources, but a clearer picture of how total social costs are affected by including environmental costs in resource planning becomes available only when a systems-based approach is used. Different resource strategies must be compared to discern the real impact of environmental externality costs on the merits of resource decisions.

In this paper we look at four resource strategies: Least Utility Cost, Least System Cost, Conservation and Renewables, and Fuel Switching. We then describe how applying quantified environmental externality costs affects the economic and environmental effects of each strategy. We also describe how the total cost of environmental externalities depends upon the nature of a utility's power system and how it interacts with neighboring power systems. We then report the power rates, total system costs, and pollutant emissions for each strategy. Finally, we provide some additional thoughts on the advantages of examining environmental externalities in the context of the whole power system.

B. Single Resource Versus Integrated Systems Approach

Most work in the area of quantifying environmental externalities has focused on determining the appropriate method for quantifying externalities (control, damage, offset, or mitigation costs) and on developing the cost estimates to apply in resource evaluation and selection. Once developed, the externality cost estimates are added to a resource's internal

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* The authors are economists at the Bonneville Power Administration. They gratefully acknowledge David Teuscher, also of the Bonneville Power Administration, for providing the computer modeling of the resource strategies outlined in this paper. The views expressed in this paper are those of the authors and do not necessarily reflect the views of Bonneville Power Administration. This paper is presented at the National Association of Regulatory Commissioners Conference on Integrated Resource Planning held in Santa Fe, New Mexico, April 8-10, 1991.

costs to determine that resource's total cost. This approach results in a more accurate representation of a resource's true cost.

The single resource costing approach is inherently limited, however, as it does not evaluate the resource and its quantified externality costs in the context of the utility's power system. A systems-based approach accounts for how the operations of the existing resources change as new resources are added. System costs and net environmental externality costs depend upon how a utility's power system operates as a whole.

The Bonneville Power Administration (BPA) has developed draft environmental externality cost estimates for its resource planning. The estimates are applied on a $/mWh basis by resource type. In our analysis we apply quantified environmental externality costs in a systems-based approach which is best understood against the backdrop of the characteristics of BPA's power system, BPA's cost-effectiveness test for resource additions, and BPA's principal resource planning model.

Cost-Effectiveness Test

The cost-effectiveness test that BPA uses in resource planning evaluates a resource (or a combination of resources) based on its effect on total system costs as the resource operates within the regional energy system. The cost-effectiveness test, as prescribed by the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[1], requires BPA to consider potential resource additions based on their total system costs, including quantified environmental costs and benefits. This approach is consistent with BPA's dual roles of Federal agency and regional utility partner.

For a resource to be considered cost-effective according to the Northwest Power Act, it must be forecast to: 1) be reliable and available within the time it is needed; and 2) "meet or reduce electric power demand at an estimated incremental system cost no greater than that of the least cost similarly reliable and available alternative measure or resource, or any combination thereof."[2] "System cost" is defined to include all direct costs of a measure or resource over its effective life. This includes, if applicable, the cost of distribution and

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1 The Pacific Northwest Power Planning and Conservation Act, Public Law 96-501, Section 3(4)(A)(ii). The Northwest Power Act authorizes BPA to acquire power resources to serve the loads of its wholesale and industrial customers.

2 Ibid

transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, fuel costs, and quantified environmental costs and benefits.

A resource meets the cost-effectiveness test by having a lower present value system cost than what the system cost would be if it were not acquired. A resource is considered not cost-effective if there is an alternative, including the status quo, that would result in a lower present value system cost.[3]

BPA's cost-effectiveness test evaluates a resource based on how it would operate within the regional power system instead of evaluating a resource in isolation. In addition to direct project costs (including environmental costs), resource characteristics considered in the cost-effectiveness test include dispatchability, load uncertainty, unit size, resource lead-time, reliability, seasonality, project life, and secondary energy. System characteristics considered are the effects of resources on system reliability, synergistic effects among resources; hydro-system operating constraints; annual and seasonal variations in resource outputs and loads; changes in the costs of operating existing resources; and so on.

The BPA System

BPA's hydro-based power system is unique. The system includes 30 federal hydro-electric facilities (22,239 MW) within the Columbia and Snake River systems. BPA's capacity (23,665 MW) and firm energy (8,353 aMW) are approximately half of the regional total. Because BPA's system is primarily hydro--approximately 87 percent of BPA's energy production is hydropower with most of the rest nuclear--BPA could be described as capacity-rich and energy-poor. The system allows BPA to meet huge capacity demands by storing and then releasing water through the hydroelectric dams but the energy availability is limited to the amount of water flowing through the system each year.

BPA also owns and operates nearly 15,000 circuit miles of transmission lines throughout Oregon, Washington, Idaho, and Western Montana. There are 183 points of interconnection in BPA's transmission system. BPA also exchanges power with British Columbia, California, and the Southwestern States. Existing and planned interties with California total more than 7000 MW of capacity.

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[3] Bonneville Power Administration, "Draft Cost Effectiveness Methodology, 1987 Resource Strategy," Bonneville Power Administration, Portland, Oregon, December, 1986.

ISAAC

To perform the analysis of system effects resulting from the integration of environmental costs we used a decision analysis model called the Integrated System for Analysis of Acquisitions, commonly known as ISAAC. ISAAC was developed cooperatively by the Pacific Northwest utility community and is used by BPA and the Northwest Power Planning Council as a principal tool for resource planning analyses.

ISAAC simulates the effects of different resource decisions by acquiring resources in response to various load forecasts; operating the power system; and calculating costs, ensuing rates, and BPA's revenue requirements and net cash flows. The model simulates how loads and load forecasts evolve over time, making annual resource acquisition decisions in response to load forecasts. Each pass through the entire model period (1991-2050) is one game.

In each game the model acquires resources by first making a load forecast and testing whether existing resources are sufficient to meet loads. If not, ISAAC selects new resources from a "resource stack" with priorities specified by the user. ISAAC selects new resources in amounts sufficient to meet the forecast load according to the user-specified priority. ISAAC will turn to lower priority resources if the lead-times for the higher priority resources are too long to enable them to come on-line when needed.

ISAAC is designed to simulate the effects of resource decisions specified by the user and, therefore, does not optimize the acquisition of resources--that optimization is left to the user. Different resource strategies are tested by manipulating the priorities and supply of resources in the resource stack. ISAAC sometimes overbuilds and sometimes underbuilds because actual loads obtained each year are determined randomly. Thus, it simulates the costs of making "wrong" decisions in response to long-term load forecasts.

ISAAC is designed for risk analysis: it produces both an expected value estimate of the impacts of an alternative resource strategy and estimates of the likelihood that the cost and rate impacts of any particular action might be much higher or lower than the expected value estimate. This provides information about the relative riskiness of the alternative actions.

In simulating the effect of resource decisions, ISAAC explicitly handles uncertainty by introducing randomness through several variables. Randomness is exhibited in the regional load forecast, the amount of water available to the

hydro-system each year, and aluminum prices.[4] Each game uses a new series of random selections of values for those variables that are uncertain. Usually many games are run to ensure that a wide range of uncertainty is modeled, and the probability of different outcomes can be determined. One can also analyze single games or single values of random variables to test the effects of a resource decision under specific conditions.

Expected values, such as those reported here, are computed by averaging the outcomes of 100 games. Results are reported in real 1988 dollars, except as otherwise noted. BPA uses a 3 percent real discount rate, a 5 percent annual inflation rate, and real cost escalation of varying amounts for fuel and capital costs. Results are reported for the Pacific Northwest region as a whole, although we model different resource decisions made only by BPA. Therefore, the investor-owned utilities in the region make essentially the same resource acquisitions across all alternatives. This enables us to isolate the effect of BPA decisions without interfering with the strategic resource decisions of other regional parties.[5]

Modeling Environmental Costs

BPA developed a postprocessor for ISAAC to calculate the environmental costs of each strategy. Environmental costs were not included as resource costs in the ISAAC model itself. To do so would have resulted in using those costs to dispatch resources during the model's resource operations phase. Although the analysis of total cost dispatch would have been interesting, we did not wish to pursue it for this study. Our reasoning is that dispatchers are not likely to take external costs into account when determining which resources to operate. Therefore, determining an optimal system that includes variable environmental costs results in a system that would be optimal only under circumstances that would not actually occur. We would have designed a system for dispatchers who would operate differently from the model's dispatchers.

The postprocessor is little more than a counter, and is easily developed. It first totals the operation of each resource in each year in each game and multiplies that total by the environmental cost specific to that resource. (See Table 1.) This yields an annual environmental cost by resource for each

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[4] Aluminum prices affect loads of aluminum producers who account for approximately 30 percent of BPA's sales.

[5] The resource acquisition decisions of other regional parties are held constant, but because the integrated regional system is dispatched on an economic basis, BPA's resource acquisition decisions may affect how other parties operate their resources, and may affect the export and import decisions of all parties.

game. The annual costs are then escalated by the forecast rate of annual population growth, approximately 1 percent. This serves as a reasonable proxy for the real increase in environmental damage expected to occur over time. Costs for all resources are summed and discounted in the usual way to produce a present value of environmental costs for each game. Finally, the environmental costs for all games are averaged to produce an expected present value of environmental costs for each strategy.

C. The Analysis

Alternatives

We tested four resource plans or strategies to determine the system impacts of integrating environmental costs into the planning process.

1. Least Utility Cost[6]--This base case strategy is designed to produce the lowest costs for the region's utilities and ratepayers. It considers all costs to the region except environmental externality costs. Different priorities of the resources available to ISAAC are assigned until a schedule of resources producing the lowest expected present value of utility costs is found. This would be the least-cost path of resource acquisitions if environmental costs were not taken into account.

2. Least System Cost--This strategy is designed to produce the lowest expected present value of all system costs, including environmental costs. It is found by testing different combinations of resource priorities and choosing the one producing the lowest expected value of system costs.

3. Aggressive Conservation and Renewables--This strategy tests the effects of increasing the amount of conservation and renewable resource additions. For conservation we increase the available quantity of energy savings from high efficiency appliances and the available quantity of new and existing commercial and industrial conservation measures. Those measures are assigned significantly higher costs. For renewables no change in the supply functions are made, but geothermal, solar, and wind resources are given a higher priority in the resource stack. This results in earlier development of those resources, delaying, or

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[6] We use the abbreviated term "utility costs" to refer to system costs minus environmental costs, but we remind the reader that this measure accounts for all resource costs, including costs borne by end-users for demand-side investments and load curtailments. The term "system costs" refers to all regional costs, including environmental costs.

reducing the amount of fossil fuel and other high environmental cost resources acquired compared to the Least Cost strategies.

4. Fuel Switching--Fuel switching does not appear to qualify as a resource under the Northwest Power Act, the enabling legislation for BPA's resource acquisitions. Consequently, fuel switching actions are not normally considered to be available as resources for BPA's planning purposes and are not part of our other strategies. Nevertheless, the thermodynamic efficiencies gained by direct application of fuels to end-uses should produce economic and environmental benefits. By using fuels more efficiently to meet end-use needs, less fuel must be purchased and fewer emissions are created. Because BPA has large transmission interconnections to other parties on the West Coast, saved energy--combined with BPA's extensive hydropower system--can always be used to displace fossil fuel generation somewhere on the West Coast system.

   For this alternative we use supply functions representing switching new and existing residential space and water heating applications to natural gas. The supply functions account for all consumer costs, including the cost of capital investments in new appliances and the costs of fuel purchases. The environmental costs reported for this strategy also account for incremental emissions from end-use applications of natural gas.

Environmental Costs

BPA's draft estimates of the environmental externality costs focus on plant operations, four airborne pollutants--nitrogen oxides (NOx), sulfur oxides (SOx), total suspended particulates (TSP or particulates), and carbon dioxide (CO2)--and land and water effects. To derive values for NOx, SOx, and particulates, BPA estimated the economic costs to society caused by damage from these pollutants. BPA's estimates assess the economic value of human health risks, visibility reductions, materials damage, and crop and timber damage caused by these pollutants. A value for CO2 emissions is derived from the cost of capturing CO2 by planting trees. Our rule of thumb when developing our estimates is to choose the lower of damage or control costs as the cost of the pollutant. We believe that this approach best represents the choices that an efficient utility would make. The estimates used in this study are shown in Table 1.[7]

[7] BPA has issued draft environmental cost adjustments for use in its resource planning processes. Those cost adjustments are the basis for the costs shown here but do differ slightly. The costs and supporting documentation are available from BPA by calling (503)230-3478.

D. Results

System Costs

Table 2 shows the change from the base case strategy (Least Utility Cost) in expected net present value of system costs for each of the three alternative strategies. For each strategy the internal costs and the environmental costs were calculated and then summed to obtain the total system costs.

When compared to the internal costs of the Least Utility Cost base case strategy, (which, by definition, has the lowest internal costs), the Conservation and Renewables strategy is the most expensive (plus $61 million) with the Least System Cost strategy following close behind (plus $29 million). Although neither cost is significantly higher considering the long study period and the "noise" inherent in any modeling, the direction of change is consistent with our expectations. Internal costs for the Fuel Switching strategy are significantly less (minus $663 million) than those for the base case. This occurs because BPA currently does not treat fuel switching as a resource so fuel switching options are not available in the base case. As a result, when the relatively inexpensive fuel switching options are included, internal costs are actually less than in the base case.

Although the Conservation and Renewables strategy has the highest internal cost, its associated environmental costs are the lowest--the cost to the region of adverse effects on the environment created by an aggressive Conservation and Renewables strategy is $500 million less than the costs of the environmental effects caused by the Least Utility Cost base case. In addition to the Conservation and Renewables strategy, the Fuel Switching and the Least System Cost strategies are also less expensive than the base case when evaluated on environmental costs alone (minus $92 million and minus $33 million, respectively).

The overall ranking of resource strategies changes when environmental costs are added to internal costs. The Least System Cost strategy is only slightly cheaper ($4 million) when environmental costs are included. Fuel Switching is the most economically efficient strategy having total system costs $755 million lower than the base case. The Conservation and Renewables strategy is the next most efficient strategy at $439 million less than the base case. This was an unexpected result because we had not found this strategy in our initial iterative search for the Least System Cost strategy.[8] One

[8] The reader is reminded that the initial search for a Least System Cost strategy did not examine fuel switching options.

reason we had not illustrates the importance of system integration considerations. The Conservation and Renewables strategy acquires geothermal at costs of 45-80 mills/kWh, wind at 57 mills/kWh, and solar at 84+ mills/kWh. These costs are much higher than other resource costs; for example, nuclear costs are approximately 38 mills/kWh. The short lead time and small unit sizes of these resources result in a relatively small internal cost penalty for "wrong" resource decisions because resources can be easily matched to load conditions. Their low environmental costs produce significant benefits resulting in large system cost savings.

Rates

Table 3 shows forecasted expected power rates in nominal dollars and the percent change in BPA's wholesale power rates from the Least Utility Cost base case strategy for each alternative strategy. From a rate effects perspective, the only resource strategy that results in a significant increase through 2010 is the Conservation and Renewables case--2.8 percent higher than the base case in 1997, 5.8 percent higher than the base case in 2003, and 5.7 percent higher than the base case in 2010. (These increases are not additive). Although rates would increase slightly, consumer bills would increase by a lesser amount. Aggressive conservation investments are made in all economic sectors, so all consumers would have opportunities for reducing energy consumption to offset most of the higher rate effect. The Fuel Switching case results in a small increase (0.4 percent) in the wholesale power rate over the base case in 1997. By the year 2010, however, the wholesale rate actually decreases by 0.7 percent compared to the base case rate. Long-term wholesale rates for the Least System Cost strategy track the rates under the base case although there is a small increase in the near term.

Emissions

The emissions of selected pollutants--sulfur oxides, nitrogen oxides, particulates, and carbon dioxide--associated with each strategy are shown in Table 4. Reductions of emissions from the base case strategy also are shown. Because emissions change from year to year, one year--2010--was selected to illustrate the emissions caused by the resource infrastructure developed under each strategy.

The emissions are those associated with natural gas-fired cogeneration, natural gas-fired combined cycle combustion turbines, coal plants, and, for the fuel switching alternative, incremental emissions from residential natural gas-fueled space and water heating. The estimates are based on expected quantities of emissions from all regional fossil fuel-fired resources decremented by displacements of California resources

from export sales. We assume that the displaced California resources are natural gas-fired combustion turbines, recognizing that some portion of those resources probably would be less efficient gas and oil boilers.

Each of the resource strategies results in reduced emissions; in some cases the reductions are substantial. None produce significant reductions for SOx or TSP. This is simply because BPA does not build coal plants (the only major source of those pollutants) in any of the games tested in ISAAC. BPA has sufficient quantities of other, cheaper resources to meet loads under any of the load conditions tested.

The Least System Cost strategy reduces NOx emissions by about 3 percent compared to the Base Case and CO2 emissions by nearly 5 percent. The emissions reductions result from a slight increase in the acquisition of nuclear generation (WNP-1 and -3), reductions in combustion turbine and cogeneration operations, and increased sales to California.

The Conservation and Renewables strategy produces nearly double the emissions reductions as the Least System Cost strategy. The greater additions of conservation and renewable resources produce no emissions and result in BPA avoiding the acquisition and subsequent operation of 300 average megawatts of combustion turbines. Also, the alternative produces a resource mix capable of sustaining, on average, an additional 300 average megawatts of power sales to California.

Finally, the Fuel Switching strategy produces emissions reductions about halfway between the previous alternatives, except for CO2. Fuel switching reduces the need for new resources and permits the displacement of existing resources. The nature of BPA's system is such that all load savings result in fossil fuel displacement somewhere on the West Coast. BPA's hydro-system is flexible and the transmission interties are large enough that a market for surplus or secondary energy nearly always exists, permitting regional or California utilities to displace their high cost fossil fuel resources. CO2 emissions are not reduced as much as in the previous alternatives because the fuel switching does increase those emissions from residential space and water heating appliances. After accounting for increases in that sector, CO2 emissions are reduced by about 3 percent compared to the base case strategy.

E. Implications and Next Steps

Our results have shown that rate shocks do not necessarily result from including the costs of environmental externalities in resource planning. Although additions of conservation and renewables to a resource portfolio may result in longer-term rate increases, a one-for-one increase in higher consumer

electricity bills will not result. The combined decrease in need for electricity from conservation investments along with a decrease in consumption due to the higher electricity rates both would tend to mitigate possible increases in electricity bills.

In our analysis there is a small increase in the present value of direct costs to ratepayers for the Conservation and Renewables and Fuel Switching strategies. These costs are far outweighed, however, by the reduction of one-half to three-quarters billion dollars of adverse environmental effects that the region would otherwise incur if it pursued a resource strategy selected on the basis of direct costs only. Consequently, "ratepayers-as-citizens" actually would receive enormous benefits.

Comparisons between the Least Utility Cost and the aggressive Conservation and Renewables strategies show that a small investment in conservation and renewables can result in large environmental benefits. The reductions in adverse environmental effects from pursuing conservation and renewables that we have quantified in this analysis will increase as more of the total fuel cycle costs of energy resources are included in externality estimates. In addition to conservation and renewables, the utility industry may need to consider non-traditional alternatives such as fuel switching as a means to reduce further the costs society pays for electric generation.

Sales to California provide economic and environmental benefits to both regions. The Pacific Northwest obtains additional revenues from sales of power which is surplus to its needs while California is able to displace higher cost thermal resources. In some cases, exchanges of energy permit displacement of some thermal resources in the Pacific Northwest.

Our estimates of the value of displaced environmental costs in California are overly conservative because we assume that only natural gas-fired combined cycle combustion turbines are displaced. To the extent that oil-fired units and low efficiency gas boilers are displaced, the environmental benefits obviously would be higher. Also, we use the environmental costs of combustion turbines located in the Pacific Northwest as a proxy for California's costs. If the actual California costs were higher, the benefits of interregional sales also would be greater.

A natural extension of our systems-based analysis of environmental externalities is to look at total cost dispatch. BPA will examine this issue in future planning processes.

BPA is currently looking at ways to refine its modeling of the environmental effects of sales to the Southwest States. BPA can integrate environmental externalities into its recently developed Power Marketing Decision Analysis Model (PMDAM) to estimate more accurately the West Coast emissions of air pollutants and other environmental effects. PMDAM models the decisions of all parties separately and has much greater detail on the operation of actual resources than ISAAC. The model is even capable of estimating and optimizing emissions in airsheds specified by the user. BPA hopes to explore these possibilities with interested parties in both regions to determine whether mutually beneficial power and resource strategies can be developed.

F. Summary and Conclusion

Our analysis shows significant potential benefits from integrating environmental costs into resource planning activities. Through our systems-based approach we are able to identify two strategies providing large benefits to the Pacific Northwest region. These benefits are not obvious from an examination of resources' levelized costs; they become evident only after performing a systems-based analysis.

By emphasizing conservation and renewable resources, significant environmental benefits could accrue to the region. Our analysis shows that for a small increase in internal costs, the region would gain a $500 million environmental benefit. This means that by paying slightly higher utility bills, regional citizens would pay much lower costs for medical bills, taxes, and recreational opportunities, and would maintain a higher quality of life. Citizens in other regions whose utilities would have increased opportunities to purchase BPA's low cost power would also benefit from utility savings and improved environmental quality.

By pursuing fuel switching opportunities, ratepayers and citizens in the Pacific Northwest would enjoy substantial economic benefits. Even after accounting for increased payments to gas utilities, ratepayers would be faced with costs nearly $700 million lower than in the base case strategy. While the environmental benefits are not especially large, they nevertheless represent an improvement over the base case strategy. And because the Pacific Northwest historically has enjoyed low electric rates and is located near abundant Canadian gas supplies, there are significant fuel switching opportunites available to the region.

While the modeling of environmental costs in utility resource planning may sometimes be complex, it is essential for

obtaining a clear picture of the effects of using environmental costs in resource decision-making. The development and use of stand-alone levelized environmental costs in utility resource planning is a significant step forward. Integrating those costs into utility resource system planning as we have done here is the next step.

Table 1

ENVIRONMENTAL COST ADJUSTMENTS

Resource Type	(1988 $/mWh)
Pulverized Coal	$9.60
AFBC Coal (Fluidized Bed)	$8.50
IGCC Coal (Coal Gasification)	$8.00
Natural Gas-Fired Combined Combustion Turbine	$4.10
Nuclear	$3.70
Natural Gas-Fired Cogeneration	$2.20
New Hydro Facility	$2.00
Additions to Existing Hydro Facility	$1.00
Geothermal	0
Wind	0
Solar	0
Conservation	0

- These adjustments are subject to change based on an on-going review and are in real levelized 1988 $/mWh. The adjustments are modifications of BPA's Draft Environmental Cost Adjustments released on February 22, 1991. These values do not constitute BPA's position on environmental cost adjustments but are intended to approximate current estimates.

- Explanatory documentation of these adjustments can be obtained by calling BPA's document request line. Call 1-800-841-5867 (Oregon), 1-800-624-9495 (other western states), and 503-230-3478 (elsewhere).

Table 2

Expected Net Present Value of System Costs 1/

(Millions 1988$)

Alternatives 2/	Change From Base Case		
	Internal Costs	Environmental Costs	Total System Costs
Least Utility Cost (Base Case)	---	---	---
Least System Cost	+29	-33	-4
Conservation and Renewables	+61	-500	-439
Fuel Switching	-663	-92	-755

1/ System costs are for all parties in the Pacific Northwest Region, computed as expected values for 100 games of ISAAC (see text). Model period is 1991 through 2050.

2/ Alternatives are described in text.

Table 3

BPA Wholesale Power Rates 1/

(Nominal Rates in 1988 mills/kWh)

Alternatives 2/	1997	Percent Change From Base	2003	Percent Change From Base	2010	Percent Change From Base
Least Utility Cost (Base Case)	28.5	---	39.6	---	60.0	---
Least System Cost	28.6	+0.4%	39.9	+0.8%	60.0	0%
Conservation and Renewables	29.3	+2.8%	41.9	+5.8%	63.4	+5.7%
Fuel Switching	28.6	+0.4%	39.7	+0.3%	59.6	-0.7%

1/ Wholesale power rates are charged to BPA's preference customers. Rates reflect capacity and energy charges.

2/ Alternatives are described in text.

Table 4

Emissions in 2010 of Selected Pollutants 1/

(In Tons) 2/

Alternatives 3/	Sulfur Oxides (SOx)	Change From Base Case	Nitrogen Oxides (NOx)	Change From Base Case	Total Suspended Particulates (TSP)	Change From Base Case	Carbon Dioxides (CO2)	Change From Base Case
Least Utility Cost (Base Case)	25,992	---	61,072	---	3,912	---	23,996,000	---
Least System Cost	25,641	-351	59,023	-2,049	3,860	-52	22,849,000	-1,147,000
Conservation and Renewables	25,422	-570	57,373	-3,699	3,827	-85	21,883,000	-2,113,000
Fuel Switching	25,545	-447	58,337	-2,735	3,845	-67	23,204,000	-792,000

1/ Emissions vary by year. The last year of the planning period (2010) was selected because it represents the resource infrastructure resulting from the resource alternatives.

2/ Emissions include all regional emissions from fossil fuel plants (combustion turbines, coal plants, and natural gas-fired cogeneration) decremented by displacements of California natural gas-fired combustion turbines.

3/ Alternatives are described in text.

THE ISSUES AND IMPLICATIONS OF VALUING ENVIRONMENTAL EXTERNALITIES

Fred Mobasheri, Ph.D. and Robin J. Walther, Ph.D.
Southern California Edison Company

Abstract

Resource planning decisions -- decisions that affect the timing, quantity, and mix of the electric utility's resources -- are generally recognized to have environmental implications. However, until recently the objective of resource planning was viewed as ensuring a reliable electricity supply at the lowest possible cost. As long as the utility was complying with existing regulations, the utility as well as the utility's regulator were not expected to take into account other environmental implications.

Pushed in part by advocates for conservation and renewable resources, this situation is changing. Increasingly, regulators and utilities are being asked to explicitly consider the environmental implications of their decisions. The environmental benefits of displacing existing fossil-fired generation by conservation, renewables, and clean-burning new fossil-fired generation are being considered and weighed against the costs of these resource options.

This move away from consideration of only compliance and mitigation costs in the development of utility resource plans has not been accompanied by a consensus on the best way to incorporate environmental considerations into resource planning. Initially, consideration of environmental effects was limited to the resource acquisition process, and more specifically, to the evaluation of resource bids. Now the discussion has progressed to the incorporation of environmental considerations in determining when to add new resources.

This presentation focuses on the issues and implications associated with the incorporation of environmental externalities in the determination of resource need. Potential implications of introducing environmental externalities are identified, including added capacity requirements, changes in the utility's resource mix, higher cost capacity, higher customer rates, and environmental benefits. An example is presented to illustrate these potential implications. The sensitivity of the results to changes in fuel prices is also discussed.

Southern California Edison Company

Issues and Implications of Valuing Environmental Externalities

by
Fred Mobasheri and Robin J. Walther
Southern California Edison Company

NARUC's Third National Conference on Integrated Utility Planning
Santa Fe, New Mexico
April 8-10, 1991

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Resource Planning Decisions

Timing	When should resources be added?
Quantity	How much is needed?
Mix	What resources should be added?

Criteria for Resource Additions

Criteria	Driving Forces
Reliability	Capacity need
Economic	Capacity need Fuel savings
Socioeconomic	Capacity need Fuel savings Environmental benefits

Socioeconomic Criteria

- Adopted by Massachusetts, Nevada, and California Energy Commission for timing and quantity of resource additions
- Primary emphasis on valuation of residual air emissions

Potential Implications of Introducing Environmental Externalities in Planning

- Added capacity
- Change in resource mix
- Higher cost capacity
- Higher customer rates
- Environmental benefits

AG1

Example to Demonstrate Potential Implications

- Methodology
- Assumptions
- Results

Example to Demonstrate Potential Implications - Methodology

- Example utility
- Criteria for resource additions
- Resource additions, cost, and benefits
- Sensitivities to fuel price uncertainties

Example to Demonstrate Potential Implications - Simplifying Assumptions

- Focus on changes in timing and mix of supply-side resources
- Demand-side resources taken as given
- Valuation of externalities limited to air emissions
- Simplified spreadsheet analysis used to assess net benefits

Example to Demonstrate Potential Implications -
System Assumptions

Unmanaged Customer Demand	
1992 level	20,000 MW
Annual growth rate	3%
Managed Customer Demand	
1992 level	17,000 MW
Annual growth rate	2%
Existing system	
Total resources	21,000 MW
Gas-fired steam resources	10,000 MW
Average heat rate for gas-fired steam resources	11,000 Btu/kWh

4055

Example to Demonstrate Potential Implications -
Economic Assumptions

Utility's economic carrying charge rate	17%
Natural Gas	
1992 price (1992 $)	$3.6 per MMBtu
Annual escalation rate	8.3%
Annual escalation rate for capital, O&M, and emission values	5%

Example to Demonstrate Potential Implications -
Resource Options

	Fossil-fired	Renewable/Alternative
Resource Option	Gas-fired Combined cycle	Geothermal Wet steam
Capital costs (1992 $)	750 $/kW	2650 $/kW
O&M costs	0.2 ¢/kWh	1.0 ¢/kWh
Capacity factor	65%	65%
Heat rate	8200 Btu/kWh	not applicable

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Example to Demonstrate Potential Implications -
Emission Assumptions

	Value (1992 $/Ton)	Emission Rates for Gas-Fired Steam Generation (lb/MMBtu) New Combined Cycle Unit	Existing System
NOx	$21,000	0.018	0.023
SOx	$21,000	0.001	0.001
PM-10	$14,000	0.002	0.002
ROG	$6,000	0.005	0.005
Carbon	$33	30.0	30.0

Example to Demonstrate Potential Implications -
Criteria for Resource Additions

Criteria	Resources Additions
Reliability	Gas-fired combined cycle
Economic	Gas-fired combined cycle
Socioeconomic	Renewable/alternative resources

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Example to Demonstrate Potential Implications -
Capacity Additions

	Reliability	Economic	Socioeconomic
Capacity Additions (MW)			
1992-2001	2,400	3,200	4,000
2002-2011	5,200	5,400	5,600
2012-2021	6,400	6,600	6,800
1992-2021	14,000	15,200	16,400
Reserve Margin	16%	20%	24%

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Example to Demonstrate Potential Implications -
Capacity Additions Above Reliability Requirement

	Capacity Additions (MW)	
	Economic	Socioeconomic
1992-2001	800	1600
2002-2011	200	400
2012-2021	200	400
1992-2021	1,200	2,400

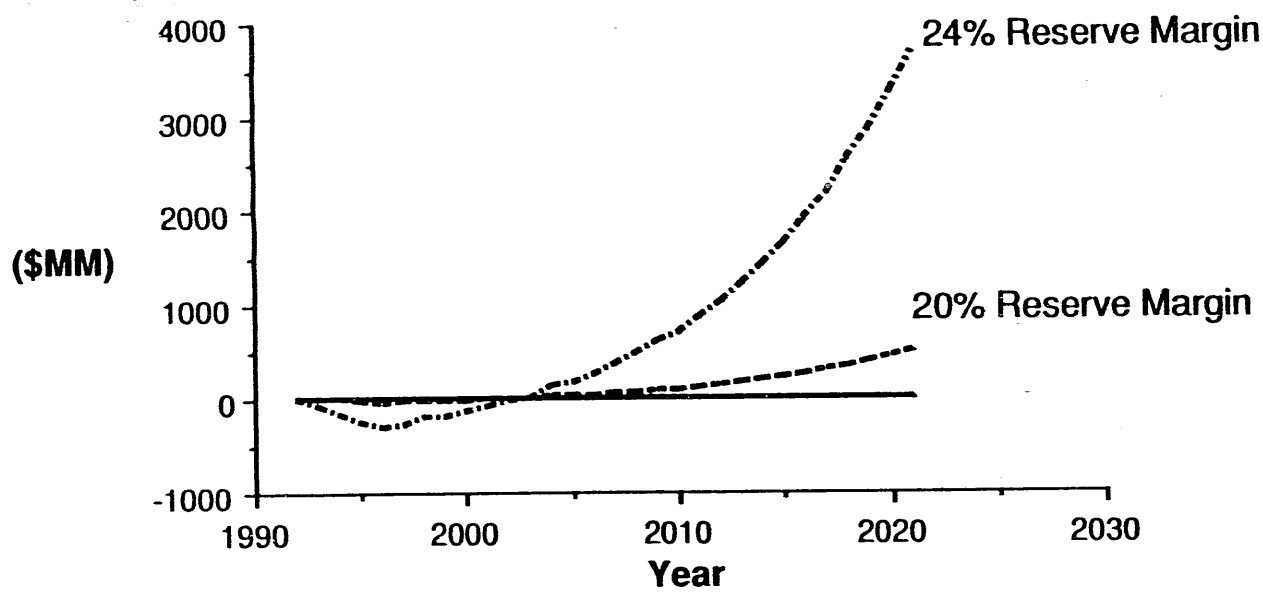
Example to Demonstrate Potential Implications -
Costs and Benefits Above Reliability Requirement

(Present value of 30 year cost stream in 1992 MM$)

	Economic	Socioeconomic
Costs		
Capital cost	740	5,470
Operating and maintenance	10	810
Benefits		
Fuel savings	760	6,140
Emission benefits	110	850
Net Benefits with		
Fuel benefits	10	(140)
Fuel and emissions benefits	120	710

Example to Demonstrate Potential Implications -

Annual Net Benefits with Fuel and Emission Benefits



Example to Demonstrate Potential Implications -
Summary of Base Case Results

- If utility does not value environmental externalities, utility would add gas-fired resources for reliability and possibly for fuel savings
- If utility values environmental externalities, utility would accelerate capacity additions with R/A resources
- Building based on socioeconomic criteria results in 1600 MW of additional R/A capacity additions in first 10 years
- 1600 MW of R/A resources means (1992 $ present value):

- additional investment	$2.9 Billion
- additional O&M	$0.3 Billion
- fuel savings	$2.0 Billion
- environmental benefits	$0.4 Billion
- net benefits with fuel and emissions	-$0.8 Billion
- rate increase	$1.2 Billion

EXHIBIT 55

Example to Demonstrate Potential Implications -
Fuel Price Sensitivity

	Annual escalation rate
Base case natural gas price	8.3%
No real price escalation	5.0%

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Example to Demonstrate Potential Implications -
Effect of Lower Fuel Prices

(Present value of 30 year cost stream in 1992 MM$)

	Economic	Socioeconomic
Costs		
Capital cost	740	5,470
Operating and maintenance	10	810
Benefits		
Fuel savings	490	4,020
Emission benefits	110	850
Net Benefits with		
Fuel benefits	(260)	(2,260)
Fuel and emission benefits	(150)	(1,410)

Example to Demonstrate Potential Implications -
Summary of Fuel Sensitivity Results

- Lower fuel prices reduce cost-effectiveness of accelerated resource additions
- For low fuel escalation case, fuel benefits of accelerated resource additions do not offset capital costs
- Lower fuel prices reduce cost-effectiveness of R/A resources relative to gas-fired resources
- For low fuel escalation case, fuel and emission benefits of R/A resources do not offset capital and operation cost

Summary

- Including environmental benefits in resource planning will:
  - increase reserve margins (i.e. higher capacity additions overtime)
  - advance the building of capacity several years earlier than needed for reliability
  - lead to the building of more costly renewable resources
- Moving need forward adds to the utility's risk because of uncertainty and reductions in flexibility
- In an uncertain environment, shortening the lead time and postponing decisions is a desirable strategy
- Added costs and increased risks should be balanced against environment benefits

INCORPORATION OF ENVIRONMENTAL EXTERNALITIES INTO INTEGRATED RESOURCE PLANNING

Jennifer Fagan and Rodney Stevenson[1]

INTRODUCTION

In recent years, supply side dominated traditional electric utility planning has been evolving into a much more comprehensive integrated resource planning (IRP) process. IRP has several purposes, including: balanced assessment of supply and demand side resource options, explicit consideration of resource choice feedback effects, expansion of decision criteria to include social impacts and environmental effects, and increased public involvement in the development of the resource plan.

Effective incorporation of externalities into integrated resource planning (IRP) is very important. The environmental consequences of various resource options are substantial. The nature of the environmental effects varies considerably among the alternative supply and demand side options. Incorporation of environmental considerations into IRP, however, is very difficult. There is substantial disagreement on the nature and consequence of the various environmental hazards. Tracking hazard to harm can be very difficult - especially for latent arising chronic harms that may have multiple causes. Also, environmental stake holders are not as easily identifiable as

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1. Fagan is Manager, Demand Side Planning at Wisconsin Power & Light Co.; Stevenson is Professor of Business, Professor of Environmental Studies, and Executive Director, Wisconsin Public Utility Institute at the University of Wisconsin, Madison.

other stake holders (investors, customers, employees, etc.) and lack equivalent voice. Unfortunately, the standard feedback control management practices ("if it's not broke - don't fix it") are ill-suited for treatment of many environmental stresses. Environmental problems that may pose the greatest danger (such as global warming) are ones for which there is the greatest uncertainty; and by the time that it becomes clear that "it's broke" it may be too late to "fix it."

Planning methods, resources, and processes developed for the more limited needs of traditional utility planning are not immediately adaptable to addressing environmental externalities in an appropriate manner. Effective incorporation of environmental externalities into IRP requires:

1. Identification of the environmental externalities of concern.
2. Assessment of the environmental impacts of the different resource options.
3. Integration of environmental considerations with other decision objectives of interest (rate levels, job creation, etc.).

To be able to accomplish these tasks in an appropriate manner requires:

1. Sufficient resources (human and other) to conduct analyses.

2. Appropriate structural organization within the utility to allow for effective information flows from analysts to decision makers.
3. A facilitating process for public decision making that provides for appropriate public input and information sharing.

IDENTIFICATION OF EXTERNALITIES

An initial step in the process of incorporating environmental externalities into IRP is to determine which environmental issues are to be considered. Electric power environmental externalities include an extensive range of actual and potential hazards (SO_x, NO_x, CO, CO_2, particulates, trace metals, toxics, ionizing radiation, PCBs, EMF, etc.). Hazard exposure may occur through all media (air, water, and terrestrial). Hazard exposure can lead to a wide variety of harms (health impacts, loss of biodiversity, natural resource damage, aesthetic impairment, etc.).

The list of environmental concerns that utilities consider with respect to evaluation of the various resource options tends to be driven by government requirements - if the regulatory commission tells the utility that an environmental factor has to be evaluated, it will be -- otherwise it most likely will not be considered. The absence of a clear method or process for identifying an appropriate set of environmental factors to consider for resource option evaluation means that there are likely to be various unnecessary factors that will be evaluated

and some potentially important issues that will not be considered.

Identifying an appropriate list of environmental problems to address is not only a problem for electric utility planning. Environmental agencies have similar problems. The recent efforts of the Environmental Protection Agency, however, may provide better guidance on identifying major environmental problems. (See EPA, 1987 and EPA, 1990)

ASSESSING EXTERNALITY CONSEQUENCES FOR RESOURCE OPTIONS

Various methods have been used to assess the externality consequences of alternative resource options. These methods range from a simple listing of hazards and harms to a more sophisticated scoring and weighting system for environmental threat characterization. Usage of the various methods in the decision making process varies, as discussed in the following section. Three methods will be discussed in this section: EIS type listing of hazards and harms, monetization of potential environmental damage, and qualitative scoring approaches.

Listing - the EIS Approach

With the EIS approach, the environmental impacts associated with a major action (e.g., building a power plant) and its viable alternatives are cataloged. For an actual CPCN request for building a specific project, the material included in the required EIS will be very extensive. For resource option

consideration, a much more limited cataloging of effects would be undertaken. With the EIS type approach, basic information is provided but there is no formal assessment of the relative magnitude of the actual or potential environmental harms.

Monetization Approaches

With the monetization approach, one attempts to 'cost out' the various environmental stresses. Three approaches have been used to monetize the various types of externalities: a cost-adder approach, an avoidance-cost approach, and a damage-cost approach.

The cost-adder approach uses a simple percentage multiple of the direct cost of the resource option to reflect the cost of environmental harm. No explicit attempt is made to estimate either the cost of abatement or damage. The cost-adder value can be added to the direct cost of a resource option to reflect the total social cost of the option. For example, if the cost of a coal fired power plant is $1,000/KW and the adder percentage is 15%, then the coal plant would be treated as having a 'total cost' of $1,150/KW for option comparison analysis.

The cost-adder percentage is generally prescribed by the state regulatory commission. The levels of cost-adder percentages that are either in use or under consideration range from 10% to 25% (see Table 1). In Wisconsin, the utilities are required by the Public Service Commission to apply a 15 percent cost-adder to supply-side options. Generally, there is only

minimal analytical support for the cost-adder percentage level. The adder percentage that the PSC of Wisconsin has required state utilities to use for option choice analysis was recently thrown out by the Courts because of a lack of a evidentiary information in the record to support the appropriateness of a 15% level. (Brown County Circuit Court Case Nos. 89-CV-716 and 89-CV-309)

Table 1

Cost-Adder Approach

CURRENT

User	Value
Wisconsin utilities	15%
Oregon utilities	10%
Northwest Power Planning Council	10%

PROPOSED

User	Value
California utilities	10% - 25%
Iowa utilities	10%
Vermont utilities	15%

The avoidance-cost approach uses as the measure of environmental impact the cost of equipment that would be required to prevent the externality from occurring. For example, for SO_2 mitigation, the avoidance cost-based approach would assign the externality a value based upon the cost of outfitting or retrofitting a generation plant with scrubbers. Table 2 presents a comparison of avoidance-cost estimates of externalities from

New Source Performance Standards (NSPS) power plants. (See Koomey, J., 1990) The values labeled "Typical Externality Costs" are at about the mid-point of the range of estimates which have been developed in various studies over the past few years. Utility management is more likely to accept avoidance-cost results since the method focuses on costs that the utility would incur if it was required to reduce or eliminate a particular type of environmental hazard. However, the costs of reduction or elimination for various types of hazards, such as EMF, are currently unknown.

The damage-cost approach seeks to obtain direct estimates of the effects of environmental damage. Damages can be denominated in terms of human lives lost or degraded due to illness, the value of lost economic activity, the customer's willingness-to-pay to avoid the externality, and other similar measures. Unfortunately, linking hazards to harms is very difficult and the magnitudes of various types of potential damages are unknown or in dispute.

Damage based monetization frequently yields results that are very different from cost-based monetization. For example, some of the air-quality related externalities can be controlled at relatively low costs. Without controls the health impacts of degraded air quality would be severe. Conversely, for less well understood categories of externalities such as electromagnetic fields (EMF) the cost of prevention may be substantially higher than the as of yet uncertain damage cost. Table 3 presents

Table 2

Avoidance Cost Estimates for Externalities from New NSPS Power Plants

Resource: Gas-fired Combustion Turbine

Externality	Typical Estimates Cost	Typical Estimates % of Total	High Estimates Cost	High Estimates % of Total
SO_2	0.00	0%	0.00	0%
NO_x	0.40¢	3%	2.77¢	20%
SO_2 + NO_x	0.40¢	3%	2.77¢	20%
CO_2	1.19¢	9%	1.19¢	9%
Total	1.59¢	12%	3.96 ¢	29%

Resource: Conventional Coal-fired

Externality	Typical Estimates Cost	Typical Estimates % of Total	High Estimates Cost	High Estimates % of Total
SO_2	0.31¢	4%	0.55¢	7%
NO_x	0.83¢	10%	5.78¢	70%
SO_2 + NO_x	1.14¢	14%	6.33¢	76%
CO_2	1.58¢	19%	1.58¢	19%
Total	2.71¢	33%	7.91¢	95%

Source: Schilberg, G.M., J.A. Nahigian and W.B. Marcus, "Valuing Reductions in Air Emissions and Incorporation into Electric Resource Planning: Theoretical and Qualitative Aspects" (re: CEC Docket 88-ER-8), JBS Energy, Inc., for the Independent Energy Producers, August 25, 1989.

damage based estimates of externalities from new NSPS coal-fired generation. (See Cavanagh, et al, 1982) Although the damage based "Best Estimate" is similar to the avoidance estimates shown in Table 2, the high end of the range greatly exceeds any of the avoidance-cost estimates.

Table 3

Damage-Cost Estimates for Externalities from Conventional Coal-Fired Generation

Human Health	1.22¢
Property Damage	0.02¢
CO_2 - Property Damage	0.01¢
CO_2 - Famine	1.87¢
Best Estimate	3.12¢
Range	0.045¢ to 32.0¢

Source: Cavanagh, Ralph, Margie Gardner and David Goldstein, "Part IIIA2E: Environmental Costs" in A Model Electric Power and Conservation Plan for the Pacific Northwest, Northwest Conservation Act Coalition, 1982.

Avoidance-cost and damage-cost monetization methods of environmental impact assessment have been used primarily with air quality concerns. Air quality-related impacts are generally better understood and their quantification is relatively more straightforward than with the other areas of environmental degradation. Less well understood are impacts associated with water quality, electromagnetic fields, and land use, though some utilities have attempted to monetize these categories as well.

Qualitative Scoring

The intent of qualitative scoring is to provide an overall

index of the environmental consequence of a particular resource option. The scoring approach starts with a rather extensive list of specific types of externality threats. Table 4 lists environmental externalities considered in the qualitative scoring

Table 4

Environmental Externalities Considered in Qualitative Scoring Process by Wisconsin Power and Light Company

- Electromagnetic Fields (EMF)
- SO_2 Emissions
- NO_x Emissions
- CO_2 Emissions
- Particulates
- Land-Use Impacts
- Surface Water Quality
- Ground Water Quality
- Non Hazardous Solid Waste
- Hazardous Waste
- Use of Nonrenewable Fuels
- Aesthetic Impacts
- Chlorofluorocarbons (CFCs)
- Radon Accumulations
- Long-term Health Effects

process by Wisconsin Power and Light. A score is ascribed for each externality factor for each of the various options. Wisconsin Power and Light, for example, uses a generic zero-to-four range with the lower bound (zero) representing the most negative impact.

The individual externality scores for a given option are combined into an overall score. Many utilities apply differential weights (percentages) to the various externality

scores before aggregation. The weights reflect an assessment of the relative importance of factors such as the health and economic impacts associated with the externality and the costs of controlling the externality. For example, a weight of .1 for CO_2 and .2 for SO_2 reflects an assessment that SO_2 is considered to be twice as much of a concern as CO_2. As shown in Table 5, externalities related to air quality and EMF are typically assigned larger weights than other types of externalities. Table 5 presents the weights assigned to various types of externalities by three utilities. The relatively large weights for air quality and EMF reflect the current concern over the health and economic impacts of global warming, acid rain, and EMF.

METHODS FOR INCORPORATING ENVIRONMENTAL ASSESSMENTS INTO THE RESOURCE OPTION CHOICE PROCESS

After assessing the environmental effects of the various resource options, it is necessary to incorporate the results into the decision making process. Three methods of incorporation are used: fatal-flaw screening, benefit/cost evaluation, and multiattribute utility decision analysis. In this section we describe how externality concerns are treated in each of the methods.

Fatal-Flaw Screening

The purpose of fatal-flaw screening is to identify resource

Table 5

Comparison of Weights Assigned to Various Types of Externalities

Category	New England Electric	Wisconsin Electric	Wisconsin Power & Light
Air Emissions:			
SO_2	12.6%	6.3%	3.3%
NO_x	6.5%	5.9%	3.3%
N_2O	2.6%	--	--
CO_2	12.6%	5.5%	3.3%
Particulates	6.6%	5.9%	3.3%
Toxics	8.6%	--	--
Methane	2.5%	--	--
Other	0%	9.2%	13.7%
Subtotal Air	52.0%	32.8%	26.9%
Water Emissions	16.0%	8.1%	6.6%
Solid/Hazardous Waste	14.4%	10.4%	6.6%
Other:			
Transmission (EMF)	10.8%	4.6%	3.3%
Fuel, Land Use, Water Consumption, and Visual	6.7%	11.6%	6.6%
Socioeconomic Impacts	1.7%	29.2%	50.0%

options that have unacceptable environmental consequences that have been determined to be unacceptable. The options with a fatal-flaw are excluded from the resource option choice set. Table 6 presents the screening forms used by Northern States Power Company.

Inputs for fatal-flaw screening typically come from the EIS type listing analysis. Since a purpose of the screening analysis

is to find a relatively low cost way for excluding options that would ultimately not be acceptable, the more extensive costing analysis or scoring analyses are not performed on the environmental attributes of the resource options with fatal-flaws.

Table 6

Externality Screening Forms for Northern States Power Company

HEALTH

	None/ No	Slight	Moderate	Significant	Great/ Yes	Quantity
Particulate Emissions						
Toxic Emissions						
Carcinogenic Emissions						
Radon/Indoor Pollution						
Hazardous Waste Discharges						
Proximity to Population Centers						
Electromagnetic Fields						

FATAL FLAW? (Characteristic which could outweigh everything else)

ENVIRONMENTAL

	None/ NO	Slight	Moderate	Significant	Great/ YES	Quantity
Wetland Impacts						
Forestry Impacts						
Agricultural Impacts						
Recreation Area Impacts						
Engangered Species Habitat Impacts						
Water Quality Impacts						
Surface						
Groundwater						
Acid Deposition Impacts						
Fish/Wildlife Impacts						
Aesthetic/Viewshed Impacts						
Noise Level Impacts						
Construction Impacts						

FATAL FLAW?

Benefit/Cost Analysis

A common method of resource option assessment is the benefit/cost approach. Benefits reflect the cost savings of adopting a given option relative to a default or "business as usual" base case. Costs include the capital and operations costs (and for DSM, incentive payments) as well as the environmental consequences. Generally, options with a benefit/cost ratio less than one would then be excluded from further analysis. The benefit/cost ratios of the remaining options can serve as an ordering guide for purposes of final resource set selection.

Monetization is the environmental assessment information source that is most commonly used with this method of resource option analysis. The avoidance-cost or damage-cost of damage measures are typically added to the direct cost of the option to achieve a total cost for a given option. Cost-adder values will either be treated as an addition to the direct cost of the option or as an adjustment to the benefits of that option or other options.

Results of the qualitative scoring method can also be used in benefit/cost assessment. Wisconsin Power and Light, for example, incorporates the environmental consequences through a process of increasing the benefit levels for the non-combustion resource options. WPL benchmarks the externality score benefit credit received by the average non-combustion option at 15% (the cost-adder savings of not using a combustion supply-side resource). WPL compares the scores of various demand-side and

supply-side options with the average score and scales the credits accordingly; specific adjustments for non-combustion options range from a low of 7 percent for gas fired combined cycle generation to a high of 24 percent for advanced refrigeration and heat pump water heater (demand-side) options. Table 7 presents information on externality scores and benefit/cost ratio adjustments for various options. The benefit/cost adjustment can be added to the initial benefit/cost ratio to obtain a total benefit/cost ratio. The total benefit/cost ratio is the basis for accepting or rejecting options.

Table 7

Wisconsin Power and Light Company

Externality Scores and Benefit-Cost Ratio Adjustment for a Selection of Resource Options

	Externality Score (points)	Benefit-Cost Ratio Adjustment
Supply Options		
Gas Combustion Turbine	120	+ 0.10
Gas Combined Cycle	104	+ 0.07
Baseload Coal	73	+ 0.00
Reconductor Lines	153	+ 0.15
Demand-Side Options		
Efficient Room A/C	158	+ 0.18
High Efficiency Ballasts	165	+ 0.19
Agricultural Time-of-Day Rate	143	+ 0.14

Some utilities use a hybrid combination of weighted environmental scores and monetization information The "hybrid"

approach combines the advantages of the scoring methods with the advantages of the monetization methods.

Multiattribute Decision Analysis

The multiattribute decision analysis method is a more sophisticated method of evaluating the relative desirability of alternative resource options when there are several objectives to be considered. The underlying assumption is that decisions are made based on a set of objectives. Various objectives that may include project cost, flexibility, environmental effects, local job creation, etc.

The objectives are stated in terms that can be measured (attributes). For each objective, the options are scored to assess the relative levels of objective attainment. The scores for the objectives are weighted and combined into a single value. Weights for the various objectives reflect the individual preferences of the decisionmakers for that attribute relative to all others.

Some utilities have used multiattribute decision analysis to identify their preferred resource plans. Because the multiattribute decision analysis process is relatively complex, few utilities have attempted to use this method to incorporate externality concerns into their choice of resource options.

The main advantage of multiattribute decision analysis is its quantitative, systematic treatment of decision making criteria. The method relies on the relative weights that

decision makers attach to the objective criteria and it forces these weights to be applied to corporate objectives in a very explicit, systematic manner. The main disadvantage is that the process is relatively complex and requires explicit revelation of objectives and relative weights.

Method - Adoption Considerations

Adoption of externality assessment methods should be in accord with the following criteria:

1. The approach should provide a level playing field in its treatment of supply-side and demand-side options.
2. The method should be reasonably consistent with the corporate decision making process.
3. The method should minimize subjectivity and individual bias when calculating the value of externality adjustments and weighting factors.
4. The method should foster giving the greatest attention to the most important externalities.

RESOURCES, STRUCTURE, AND PROCESS

Proper identification and analysis of environmental consequences are necessary for effective integration of environmental externalities into IRP -- but not sufficient. Effective integration into IRP also requires adequate attention to resources, structure, and process.

Resources include both staff and what staff needs to do its job. Conducting environmental assessment requires a sufficient

number of trained environmental professionals. As it would be inadvisable to have accountants design power plants or engineers manage financial reserves, so is it inadvisable to have environmental assessment undertaken by those who have not been sufficiently trained to the area. The utility needs to have a sufficiently large enough core of environmental scientists and other environmental professionals to conduct environmental effects identification and analysis studies. And the environmental staff needs to have sufficient resources available to it so that it can carry out its responsibilities. While the utility can often rely on consulting services to provide access to highly trained environmental professionals, the utility and the communities of interest for which it is responsible would be ill-served by over-reliance on outside sources of professional expertise. The utility needs to have an internal environmental staff.

Equally important with having a core staff of environmental professionals in the utility is having them properly situated within the structure of the utility so that their work can be effective. While there are a variety of feasible structural arrangements, certain structural concerns need to be considered. The environmental core should be organized so as to have a clear identity and mission. The environmental group should be afforded a reasonable degree of independence from those responsible for developing and implementing either the supply side or demand side resource options. The environmental group should be at a

sufficiently high enough level within the company to be able to have attention and access to top management and planners. Further, the placement of the environmental group should be such as to facilitate the group's involvement early in the development of resource option sets and at the point of selection of the resource set that will be proposed for implementation.

Integration of environmental concerns into IRP goes far beyond the activity of the utility. Several groups are involved in the resource planning decision-making process: utilities, governmental agencies (PSCs, FERC, NRC, EPA, etc.), third party organizations, independent power producers,and utility customers. Traditionally, the process that has been used to provide for public input in the decision making process has been the quasi-judicial litigated regulatory process. The litigated process effectively places the various parties in the position of adversarial opposition. The result of the traditional regulatory process is that information sharing is limited and the various parties find themselves migrating to polarized extremes. Little effort is made at consensus development. While the adversarial litigated process may have been sufficient for revenue requirements determinations, it is an impediment to the development of sensible integrated resource plans that adequately integrate environmental considerations. More innovation with process alternatives is needed to improve the planning process.

MANAGERIAL RESPONSIBILITY

Historically, regulatory commissions and, to a lesser extent, independent power producers, have been primarily responsible for seeing that externalities are considered when resource plans are developed. Although utility management should bear major responsibility for incorporating environmental externality concerns into IRP, they often do not. Many utility managers do not believe that externalities represent 'real' costs. Others believe that the responsibility for their incorporation lies with the government.

The failure of utility management in proactively accepting the responsibility for IRP environmental consideration can adversely affect the well-being of the utility. The potential financial consequences of failure to appropriately consider environmental effects can be substantial. Financial harm can occur, for example, through impacts on the utility's emissions trading capacity and through impacts on utility rates if externalities are internalized by governmental requirements in the future.

The opportunity for a utility to engage in emissions trading came about as a result of the passage of the Clean Air Act of 1990. With the emissions trading program, utilities can either buy or sell emissions credits with other utilities or power generating entities. A decision to build a fossil-fuel fired baseload plant is a decision to either (a) purchase more emissions credits if the utility is in a deficit position; or (b) sell fewer emissions credits if the utility is in a surplus

position.

If externalities eventually drive up the utility's costs, the consequences are twofold: (1) the utility will select a mix of resources which is not "least-cost"; and (2) the utility will incur the added costs associated with externalities. These added costs will either be borne by shareholders (in which case earnings are eroded) or ratepayers (in which case the utility's competitive price position is weakened). In either case, the resources added were non-optimal from the viewpoint of society, utility shareholders or utility ratepayers.

Table 8 illustrates the financial consequences of a utility failing to take externalities into account in the planning process. It is assumed that the externalities eventually become a part of the utility's costs. In this example, a medium sized utility chooses to build a coal plant on the premise of lower costs, and does not incorporate the effects of externalities into its decisionmaking process. Three cleaner burning alternatives are available at costs which appear to be higher: a gas-fired combined cycle plant, a transmission line addition paired with a hydroelectric power purchase, and additional demand-side management. As the table shows, the financial consequences to the utility can be considerable in the short-run: in the high externalities adjustment case, a decision to build a transmission line and purchase hydroelectric power could result in average rate levels which are approximately 8 percent lower than those which result from the decision to build coal.

Table 8

Failure to Include Externalities in IRP Decisions: Financial Consequences

Resource Costs
Given Various Externality Adjustments:

Adjustment:	None		Low		High	
Resource	%	Cents	%	Cents	%	Cents
Coal	0%	4.3	33%	5.7	95%	8.4
CTs (Gas)	0%	11.0	12%	12.3	29%	14.2
Combined Cycle	0%	5.4	17%	6.3	44%	7.8
Transmission/ Purchase	0%	5.0	10%	5.5	20%	6.0
Demand-Side	0%	8.0	--	8.0	--	8.0

Cost and Rate Penalty Associated With Building Coal

Externality Adjustments	Preferred Option(s)	Cost Penalty ($ per year)	Rate Increase Implied
Low	Transmission/Purchase	$ 4 million	.7%
High	Demand-Side	$ 8 million	1.3%
	Transmission/Purchase	$48 million	8.4%
	Combined Cycle	$12 million	2.0%

COMMITMENT

It's all too easy to pass the buck with regards to environmental assessment. The adverse consequences of unwise resource choices may not be clearly obvious and may not manifest for several generations. In such an environment there is a familiar litany of denials:

-It's not a problem.

-It's not a major problem.

-We don't know how much of a problem it is.

-But it's not my problem.

-It's not my major problem.

-It's not a problem that I know how to handle.

A convenient means of passing the buck is to limit explicit consideration to environmental concerns to only those for which the government has by rule or law required explicit consideration; and then consider only to the level prescribed by the law.

Effective incorporation of environmental externalities requires many things. But the threshold requirement is for each of the various parties (and especially utility management) to take proactive responsibility for the quality of the environment. This means taking upon oneself the responsibility of protecting and promoting the interests of those who may never realize that their interests have been protected and whom we may never know.

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IMPRESSIVE PROGRESS SO FAR -- BUT EVEN MORE LEFT TO DO

Since 1979, the U.S. has gotten >7x as much new energy from savings as from <u>all</u> net increases in energy supply.

Of that new supply, more has come from renewables (now ~11-12% of total primary supply) than from nonrenewables.

Because of savings achieved since 1973, the annual U.S. energy bill has recently been ~$430 billion instead of ~$580 billion -- a saving of ~$150 billion per year, comparable to the Federal budget deficit.

However, if the U.S. were now as efficient as its competitors in Europe and Japan, it would be saving an <u>additional</u> ~$200 billion per year.

And simply choosing the best energy buys for the rest of this century could yield a cumulative net saving of several <u>trillion</u> of today's dollars -- enough to pay off the entire National Debt.

ENERGY EFFICIENCY FOR ECONOMIC COMPETITIVENESS

The energy now wasted in the U.S. each year costs:

- **more than the $10,000-per-second military budget**
- **about twice as much as the Federal budget deficit.**

The U.S. spends 11-12% of its GNP on energy, compared with 5% for Japan; this difference gives typical Japanese exports an automatic ~5% cost advantage.

Huge investments in needless energy supply, rather than in modernizing industry, are an even bigger handicap. Expanding the U.S. electric system costs ~$60 billion a year in private investment plus federal subsidies -- about the same as <u>total</u> annual investment in all durable-goods manufacturing industries.

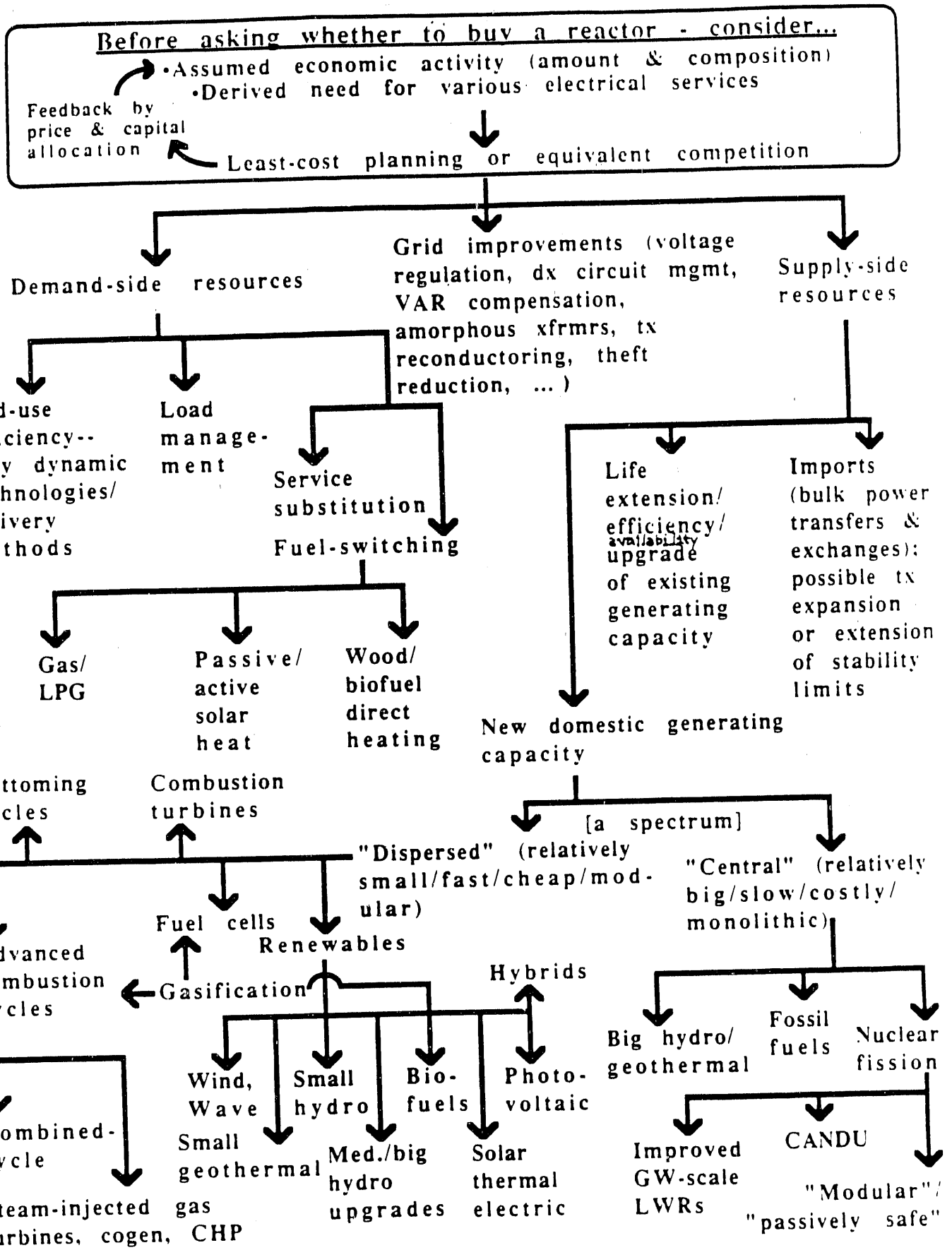
Japan is not only more energy-efficient than the U.S.; it is becoming even more efficient much faster. In four major industries, electric intensity per ton is falling in Japan but rising in the U.S. In 1986, a dollar of Japanese GNP used 36% less electricity than a dollar of American GNP. Official projections show this gap widening to 45% by 2000.

FOUR REVOLUTIONS IN ELECTRIC EFFICIENCY

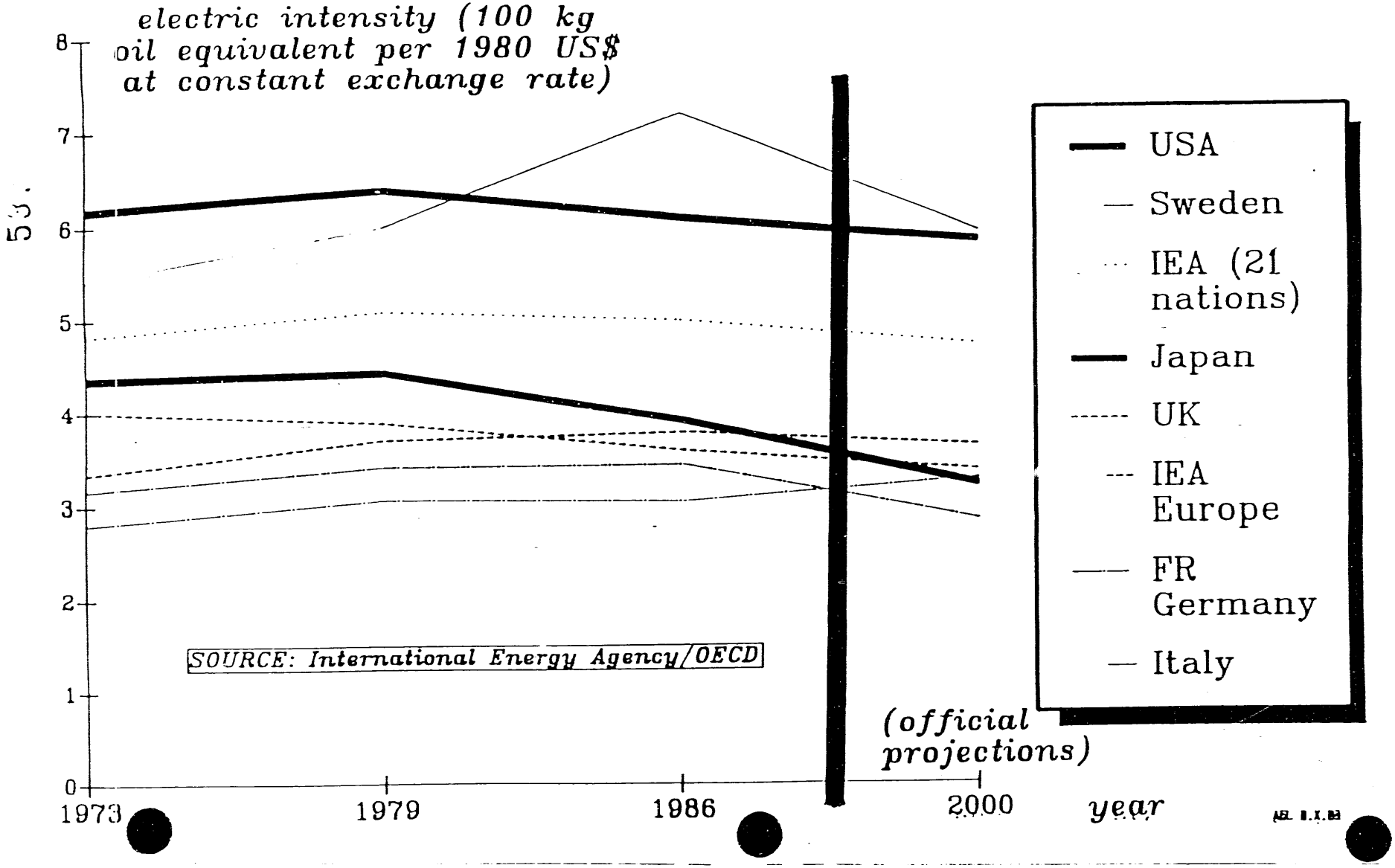
- New technologies for efficient end-use -- most of the best less than a year old -- can save twice as much electricity as five years ago, and at only a third the real cost;
- new implementation methods for financing and delivering those technologies are evolving just as quickly;
- utility regulation (price formation) is being rapidly reformed so as to reward utilities for efficient behavior;
- partly in response, utilities' mission and culture are changing profoundly and irreversibly.

These developments are occurring all over the world. They affect all kinds of utilities in virtually all kinds of societies. External events such as the post-1992 European market and environmental concerns seem bound to accelerate them.

Most fundamentally, they are driven by one basic fact: electricity is expensive, but efficiency is cheap, and the gap is widening. Customers will naturally want to buy less electricity and more efficiency; the only question is who will sell them the efficiency. It is sound business strategy to sell customers what they want before someone else does. Utilities' only choice is between participation and obsolescence.

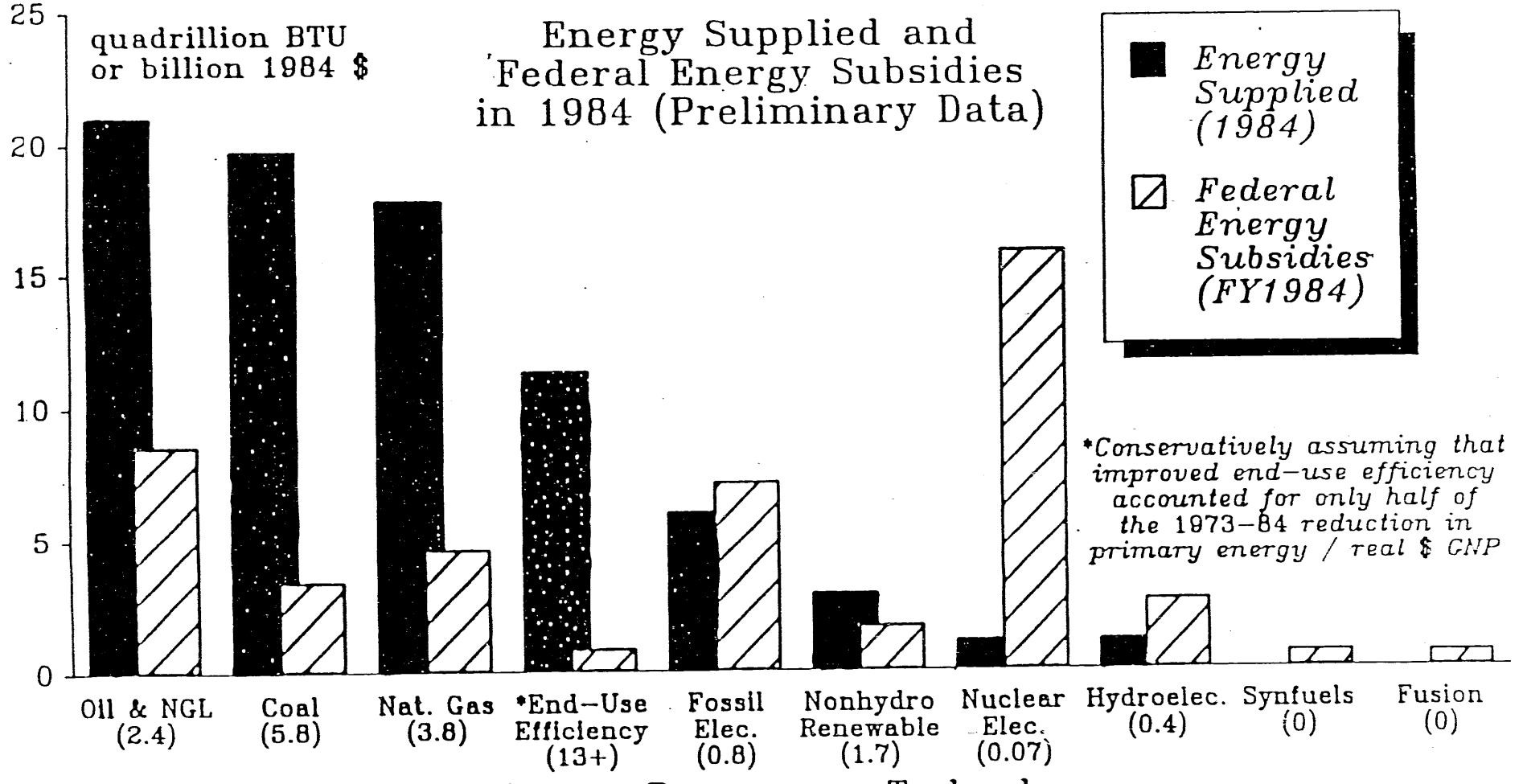

Before asking whether to buy a reactor - consider...
•Assumed economic activity (amount & composition)
•Derived need for various electrical services
Feedback by price & capital allocation
Least-cost planning or equivalent competition
Demand-side resources
Grid improvements (voltage regulation, dx circuit mgmt, VAR compensation, amorphous xfrmrs, tx reconductoring, theft reduction, ...)
Supply-side resources
nd-use fficiency-- ery dynamic echnologies/ elivery ıethods
Load manage-ment
Service substitution
Fuel-switching
Life extension/ efficiency/ availability upgrade of existing generating capacity
Imports (bulk power transfers & exchanges): possible tx expansion or extension of stability limits
Gas/ LPG
Passive/ active solar heat
Wood/ biofuel direct heating
New domestic generating capacity
Bottoming ycles
Combustion turbines
[a spectrum]
"Dispersed" (relatively small/fast/cheap/mod-ular)
"Central" (relatively big/slow/costly/ monolithic)
Fuel cells
Renewables
Advanced combustion cycles
Gasification
Hybrids
Big hydro/ geothermal
Fossil fuels
Nuclear fission
Wind, Wave
Small hydro
Bio-fuels
Photo-voltaic
Combined-cycle
Small geothermal
Med./big hydro upgrades
Solar thermal electric
Improved GW-scale LWRs
CANDU
"Modular"/ "passively safe"
Steam-injected gas turbines, cogen, CHP

International Trends in Electric Intensity of GNP

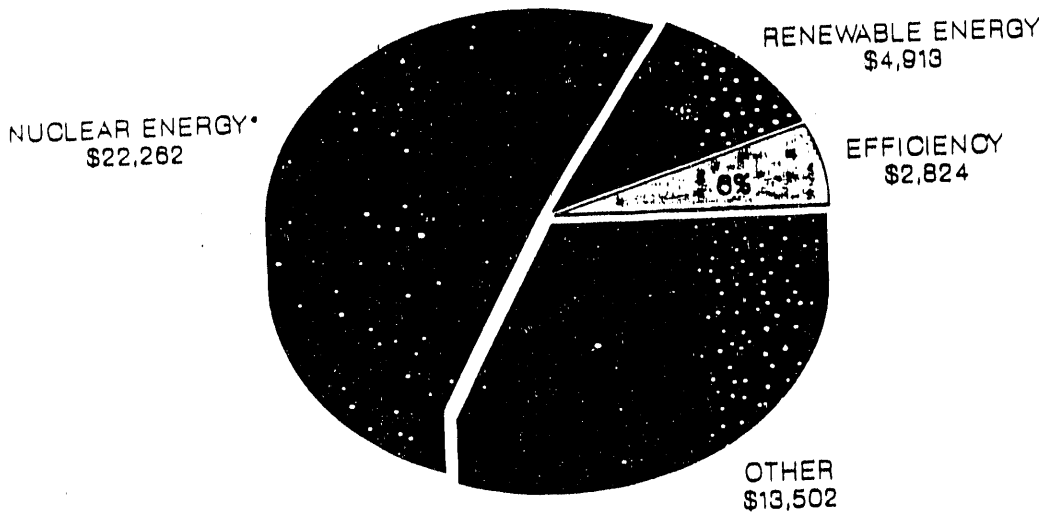


ELEVEN REASONS WHY WE'RE SAVING ELECTRICITY MORE SLOWLY THAN DIRECT FUELS

- Electricity is ~11x as heavily subsidized (as of 1984).
- Most electricity is sold at rolled-in prices, but most fuel prices are based on marginal cost.
- Long lead times further delay the price response to costly new power plants.
- Electricity is sold at declining-block tariffs far more often than fuels are.
- Most U.S. electric utilities are vigorously promoting new sales by every possible means.
- Traditional electric ratemaking [inadvertently] increases profits whenever electric sales increase.
- Most of the best ways to save electricity are much newer and less familiar than fuel-saving methods.
- Most electricity-using devices are specified or bought by people who want only to minimize first cost; far fewer electricity- than fuel-using devices are chosen so as to minimize life-cycle cost.
- Some important uses of electricity, such as space heating, look very cheap to their installer because their huge capital costs to society are socialized.
- Most RD&D on electric use, both government and private-sector, seeks and promotes new uses of electricity.
- Most U.S. utilities have no incentive, and little compulsion or inclination, for least-cost investments.

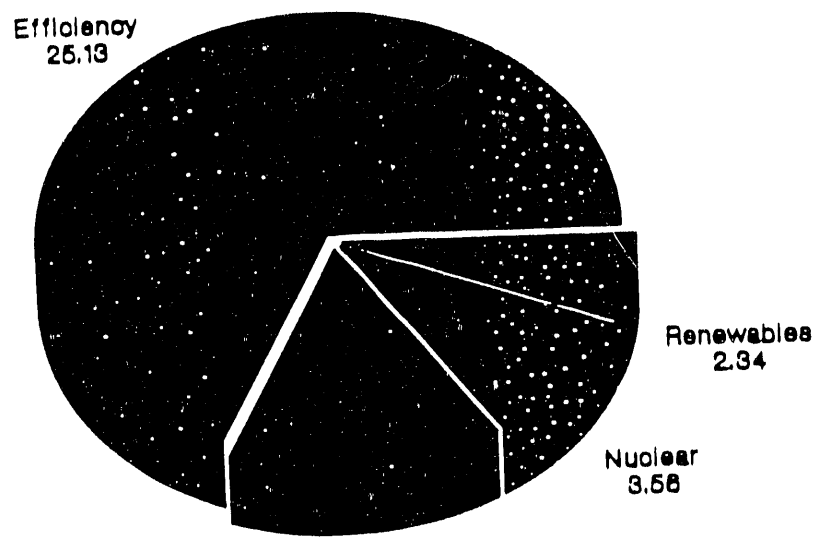

quadrillion BTU
or billion 1984 $
Energy Supplied and
Federal Energy Subsidies
in 1984 (Preliminary Data)
Energy Supplied (1984)
Federal Energy Subsidies (FY1984)
*Conservatively assuming that improved end-use efficiency accounted for only half of the 1973-84 reduction in primary energy / real $ GNP
25
20
15
10
5
0
Oil & NGL (2.4)
Coal (5.8)
Nat. Gas (3.8)
*End-Use Efficiency (13+)
Fossil Elec. (0.8)
Nonhydro Renewable (1.7)
Nuclear Elec. (0.07)
Hydroelec. (0.4)
Synfuels (0)
Fusion (0)
Energy Resource or Technology
(million BTU supplied per $ of subsidy)

FEDERAL ENERGY R&D SPENDING
($ Millions, FY73 to FY89)



SOURCE: CRS, 1982 CONSTANT DOLLARS.
* INCLUDES FISSION & FUSION

SOURCES OF EFFECTIVE ENERGY SUPPLY GAIN
Average Quads/Year 1973-1986



Not Shown: Oil/gas decline of 7.2 Quads
SOURCE: Rocky Mountain Institute

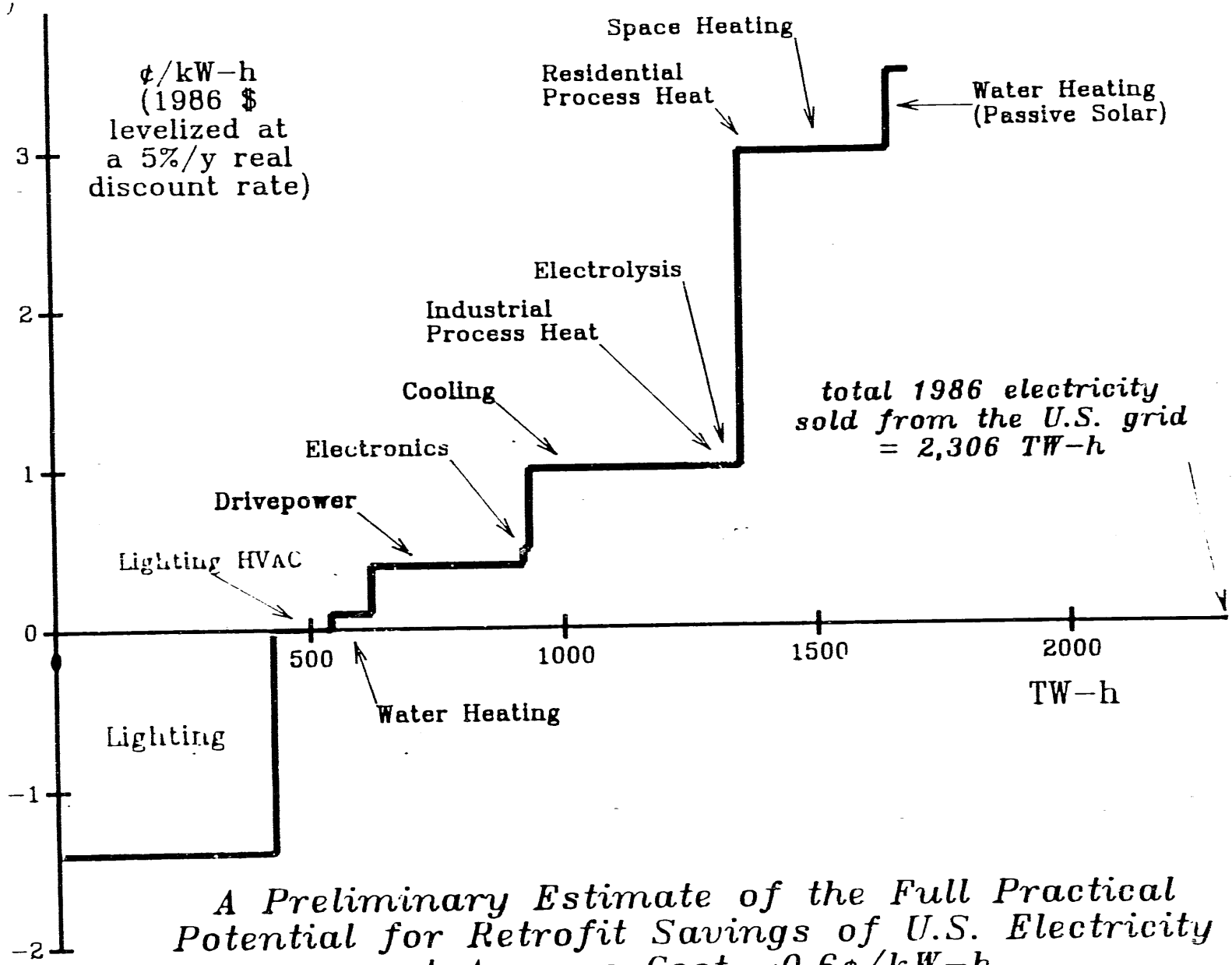
HOW MUCH ELECTRICITY COULD BE SAVED BY FULLY RETROFITTING THE CAPITAL STOCK OF THE U.S.?

- assessed by Rocky Mountain Institute, 1988-present
- measured cost and performance data
- data documented in very detailed COMPETITEK reports used by >190 utilities and related organizations in 31 countries; analysis undisputed so far
- ~1,000 kinds of commercially available technologies
- careful engineering into integrated packages of measures
- technical-potential analysis (100% market capture)
- no fuel-switching or load management
- compared with the 1986 U.S. capital stock
- all services unchanged or (often) improved
- finding: ~75+% potential saving @ av. cost ~0.6¢/kW-h
- even more could be saved at higher cost

In round numbers, the saving is in three equal parts:

- save 1/4 in lights (& associated net HVAC): ~92% saving @ -1.4¢/kW-h (<0 because of saved maintenance cost)
- save 1/4 in motor systems: ~50% saving @ <0.5¢/kW-h
- save >1/4 in everything else (building shells, household appliances, and commercial/industrial equipment): savings highly variable, often ~80+% @ ~0-2+¢/kW-h

This technical potential is like a mineral reserve profitably extractable with present technology. The fraction of this reserve actually recovered will be <100%, but recent microexamples of rapid 70-90+% recovery are encouraging.



A Preliminary Estimate of the Full Practical Potential for Retrofit Savings of U.S. Electricity at Average Cost ~0.6¢/kW−h

EXAMPLES OF MODERN ENERGY SAVINGS IN U.S. BUSINESSES

Southwire Corporation (the largest U.S. independent maker of rod, wire, and cable) cut its total energy use per kg of product by >50% in eight years -- reducing electric use per kg by ~40%, gas use per kg by ~60% -- and is continuing to save even more, still with two-year paybacks.

Compaq Computer Corporation cut kW-h/m^2-y by one-third in a recent ~100.000-m^2 office building, chiefly through lighting improvements, and is cutting it by half in the newest office, with paybacks of a few years. (The payback could well be negative if mechanical systems were properly downsized.)

In I.91, five engineering firms presented conceptual designs to retrofit 1.900 m^2 of the research office of Pacific Gas and Electric Company. This office used ~878 delivered MJ/m^2-y including 178 kW-h/m^2-y -- one-third more efficient than the U.S. office stock. The DOE-2-simulated energy savings, all cost-effective (some by a wide margin) from the utility's perspective, were 67%, 74%, 76%, 76%, and 87%. One design predicted an 85% electric saving at 2.1¢/kW-h -- a 3-year payback. All designs used off-the-shelf equipment and would greatly improve aesthetics and comfort. The best designs achieved ~27 kW-h/m^2-y via daylighting, ~1-3 W/m^2 artificial lighting (for 500 lux), superwindows (~0.7 W/m^2-K), COP>10 mechanicals, and ~2 W/m^2 office equipment. Measured data should be available by XII.91.

LIGHTING ENERGY SAVINGS

Lighting directly uses ~20% of U.S. electricity -- ~25% including net space-conditioning effects.

Half the lighting energy is used in fluorescent lights. Retrofitting advanced lamps, reflectors, ballasts, and controls typically saves ~70-90+% at an average cost ~0.5¢/kW-h.

A further ~42% of the energy goes to incandescent lamps, which can generally be replaced by diverse compact fluorescents ~4-7x as efficient. They last ~4-13x as long, and hence typically more than repay their cost via saved maintenance costs, making the electric savings better than free.

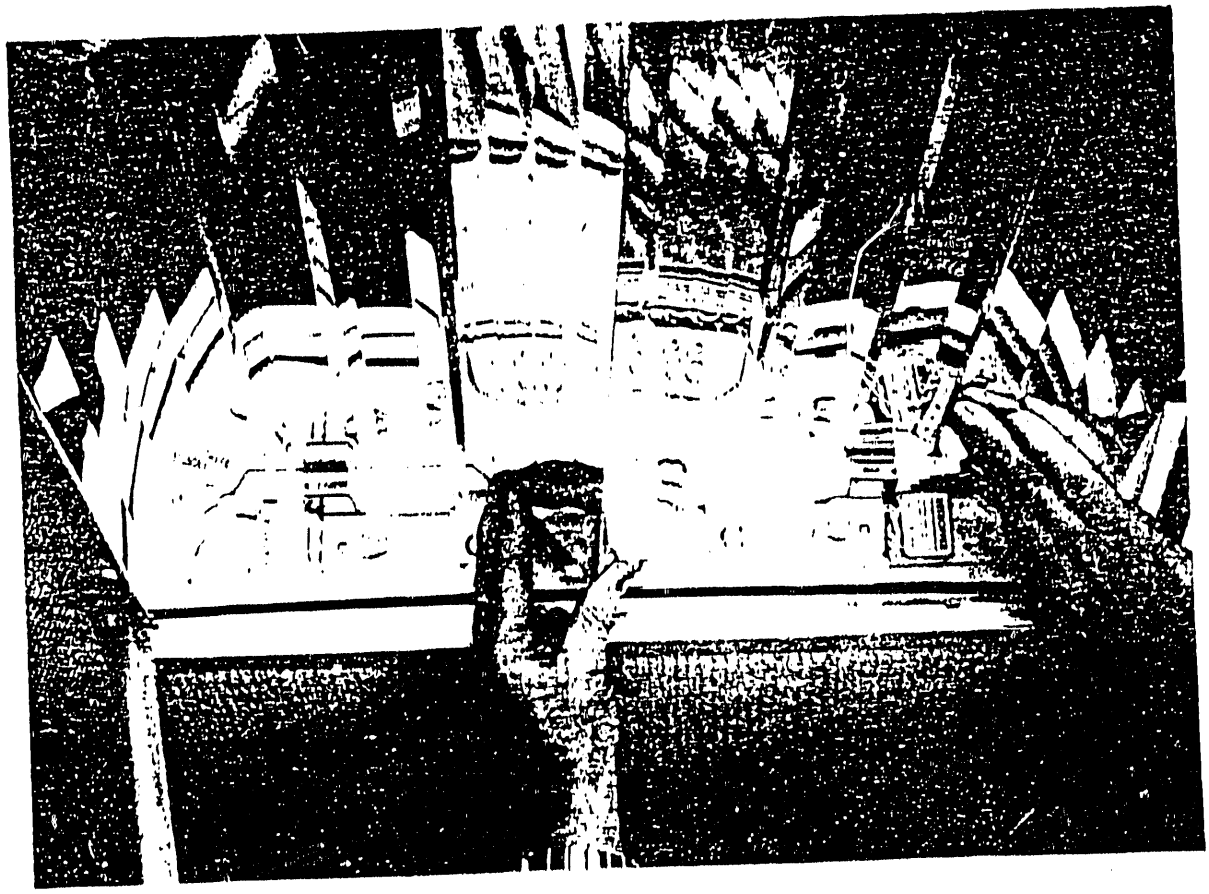
Based on measured and documented cost and performance data for the best devices commercially available in spring 1988, and adding small extra savings from improved maintenance practices and other minor measures, the total potential retrofit saving is ~92% of the direct lighting energy, at an average net cost of about -1.4¢ per saved kW-h (1986 $, levelized at a 5%/y real discount rate).

Including space-conditioning, the U.S. potential lighting saving totals ~120 GW. Saved operating costs exceed $30 billion/y. The same amount of light is delivered, but it looks better and you see better: less glare, more even distribution, nicer color, no flicker, no hum.

SOURCE: A.B. Lovins & R. Sardinsky, *The State of the Art: Lighting*, Rocky Mountain Institute/COMPETITEK Hardware Report, April 1988, 348 pp., citing primary sources.



Looking up into a two-lamp PowerMaster 90+. Note virtual imaging and the reflective end and trim details.

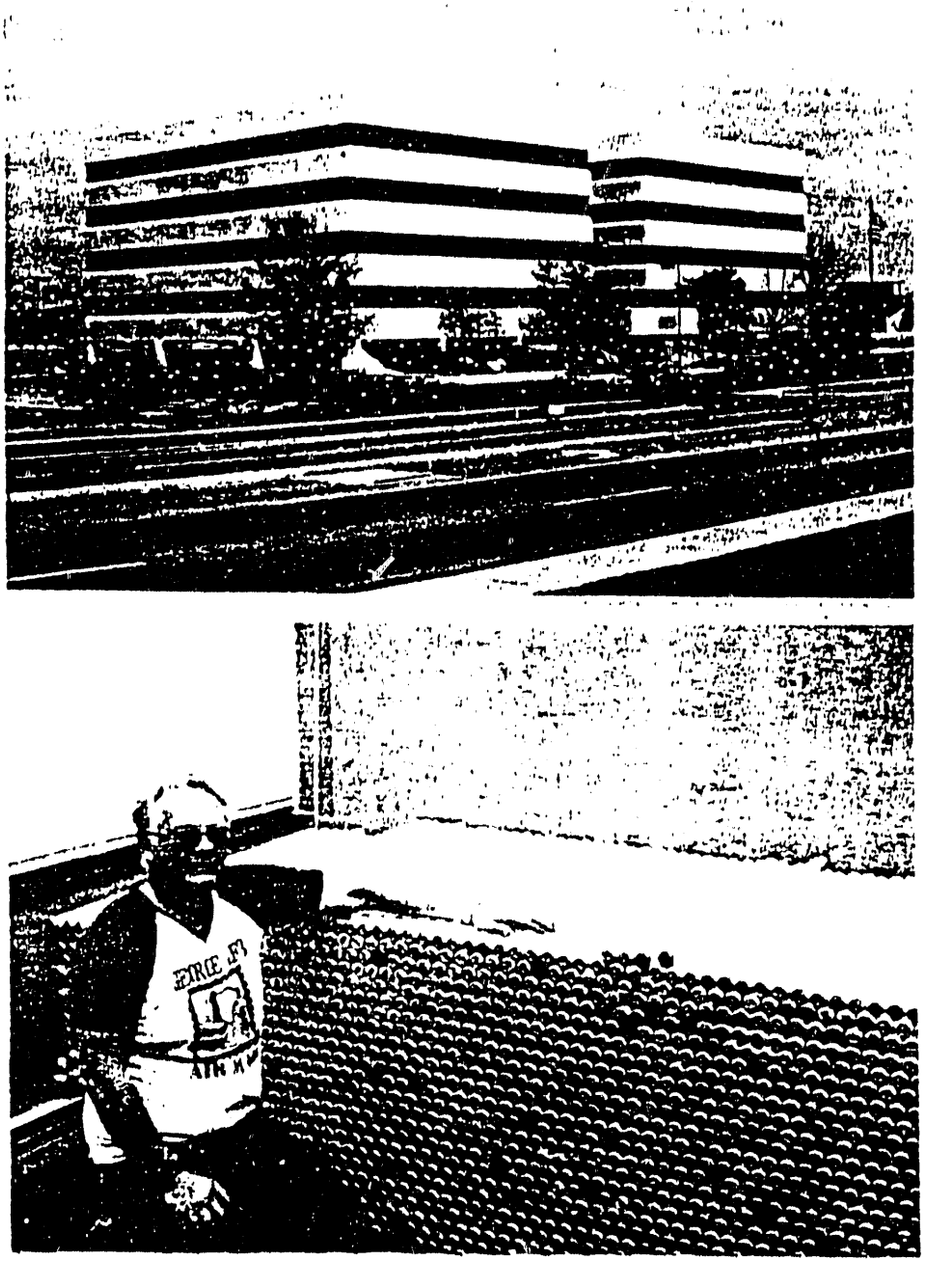


Installing an imaging specular-silver reflector, using Retroffer connectors to relocate the lampholders.

Photograph courtesy of Electronic Advanced Systems Corporation.

A reflector retrofit of this Illinois office building (top) removed half the lamps (bottom) while providing essentially unchanged illuminance. Each lamp represents a ~$25/y saving on electricity and maintenance.

Photo courtesy of Silverlight Corporation.



ELECTRONIC BALLASTS SAVE ELECTRICITY FIFTEEN WAYS

1. the ballast dissipates only ~2 W/lamp, instead of 8 with a standard or 3-4 with a high-efficiency magnetic ballast
2. the lamps are ~10-15% more efficient at high frequency

In the early '80s, these two "intrinsic" savings increased light per watt by 20-25%. But now the measured gain is >40% with several brands, >50% with some emerging designs.

In addition, remotely dimmable high-frequency ballasts offer thirteen more distinct kinds of measured savings:

3. new 4- or 6-lamp ballasts can save another ~1 W/lamp
4. abnormally low supply voltage reduces light output less
5. nonoptimal lampwall temperature reduces light output less (#4 + #5 save ~12½% by reducing design margins)
6. lamps are dimmed to match how much daylight is present (often saves 50+% in perimeter zones)
7. lamps are brightened as they dim with age (saves ~14%)
8. "tuning" the ballast gives less light where you need less (saves ~12-20%, excluding further task-lighting savings)
9. lamps turn off in empty rooms (often saves ~25-50%)
10. lamps turn off after hours unless you turn them back on
*11. people can adjust ambient light to the levels they want (several experiments suggest possible 20+% savings)
*12. lamps can gradually be slightly dimmed at peak periods
*13. the ballast can de-energize itself when a lamp fails
*14. dimming better maintains output (and lamp life)
*15. high frequency may maintain light output ~2-5% better

*Conservatively, these five savings aren't shown in the total.

HOW ENERGY SAVINGS BUILD UP WITH ELECTRONIC BALLASTS

Based on the best measured data, and scoping uncertainties:

	CUMULATIVE REDUCTIONS IN DIRECT WATTS PER USEFUL FOOTCANDLE
intrinsic lamp & 4-lamp-ballast savings only	20-31%
include voltage & lampwall-temp. stability (12½%)	30-39%
include compensation for lumen depreciation (14%)	40-48%
include task-tuning (12-20%)	47-58%
include occupancy & scheduling controls (25-50%)	60-79%
include daylight-dimming (25-90%)	70-98%

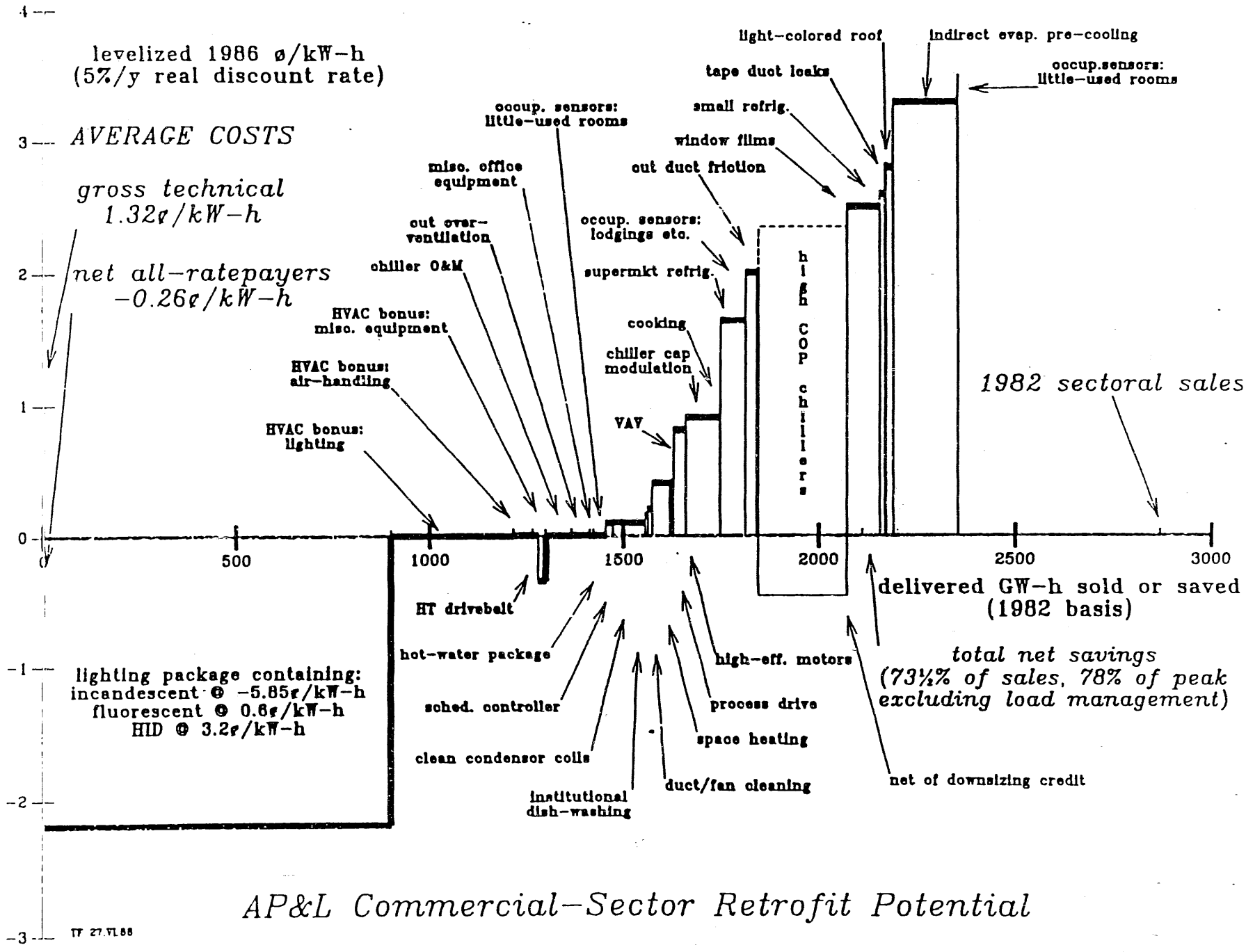
The combined savings under four conditions (with some of the most efficient ballasts on the 1988 market) are thus:

core zone, no daylighting, no control opportunities	30-39%
same plus lumen compensation & task-tuning	47-58%
whole plan area controlled, half 50% daylit	70-84%
whole plan area controlled and 50-90% daylit	80-98%

The third (underlined) value is typical of most retrofits.

But that's just the ballast and control savings! In addition, better lamp phosphors can reduce W/fc by ~15%; imaging specular reflectors, ~35-50%; IES-recommended ambient light levels and task-lighting, ~20-60+%; polarizing lenses, usually ~40-50%; lighter-colored finishes and furnishings, ~10-30+%; extending the daylit perimeter zone, ~10-20+%; and improved lighting maintenance practices, ~10+%.

Furthermore, each 3 kW-h of saved lighting energy saves ~1 additional kW-h of net space-conditioning energy; each 2 peak kW, ~1 peak kW of space-cooling energy.



AP&L Commercial-Sector Retrofit Potential

MEASURED ENERGY INTENSITIES OF COMMERCIAL BUILDINGS
(site BTU/ft^2-y, with electricity @ 3,413 BTU/kW-h)

U.S.: average office	built 1901-1920	84,000
	built 1974-1979	167,000
	built 1980-83	120,000
	in 1983 stock	123,000
world: median of 103 relatively efficient offices, av. 249,000 ft^2, built ~1980-85		62,000
Fresno CA: typical 20,000 ft^2 Title 24/1984 office		46,300

Yet the best mid-1980s offices use ~5-25% as much as the stock average, the higher level being more typical of hot, humid climates:

Austin TX, 14,600-ft^2 office:	39,800
Norfolk VA, 250,300-ft^2 office:	37,900
Jackson MS, 465,300-ft^2 office:	37,300
Los Angeles CA, 4,800-ft^2 clinic:	36,300
Van Nuys CA, 258,200-ft^2 office:	31,300
Denver CO, 9,000-ft^2 office:	30,700
Jamaica, 108,000-ft^2 office:	25,365
Menlo Park CA, 22,000-ft^2 office:	~16,000
Brisbane AU, 227,600-ft^2 office:	15,300
San Pasqual CA, park visitor center (simulated):	13,860
Mt. Airy NC, 13,500-ft^2 library:	13,500
Tokyo JP, 40,600-ft^2 office:	11,200
Old Snowmass CO, 4,000-ft^2 multipurpose:	<2,000-14,000

Most of these exemplary buildings, other than the best six, took little advantage of modern lighting technology to reduce internal loads and heat gains. Reported paybacks on the marginal capital cost of the savings shown range from negative to about two or three years.

SOURCES: average U.S. data from DOE/EIA-0318(83), IX.86, at 22; 103-office median from M.A. Piette *et al.* in *Procs. 13th Ener. Technol. Conf.* (Washington DC, III.86) at 1260; Fresno simulation from California Energy Commission; other data from LBL-19413, IV.85, except:

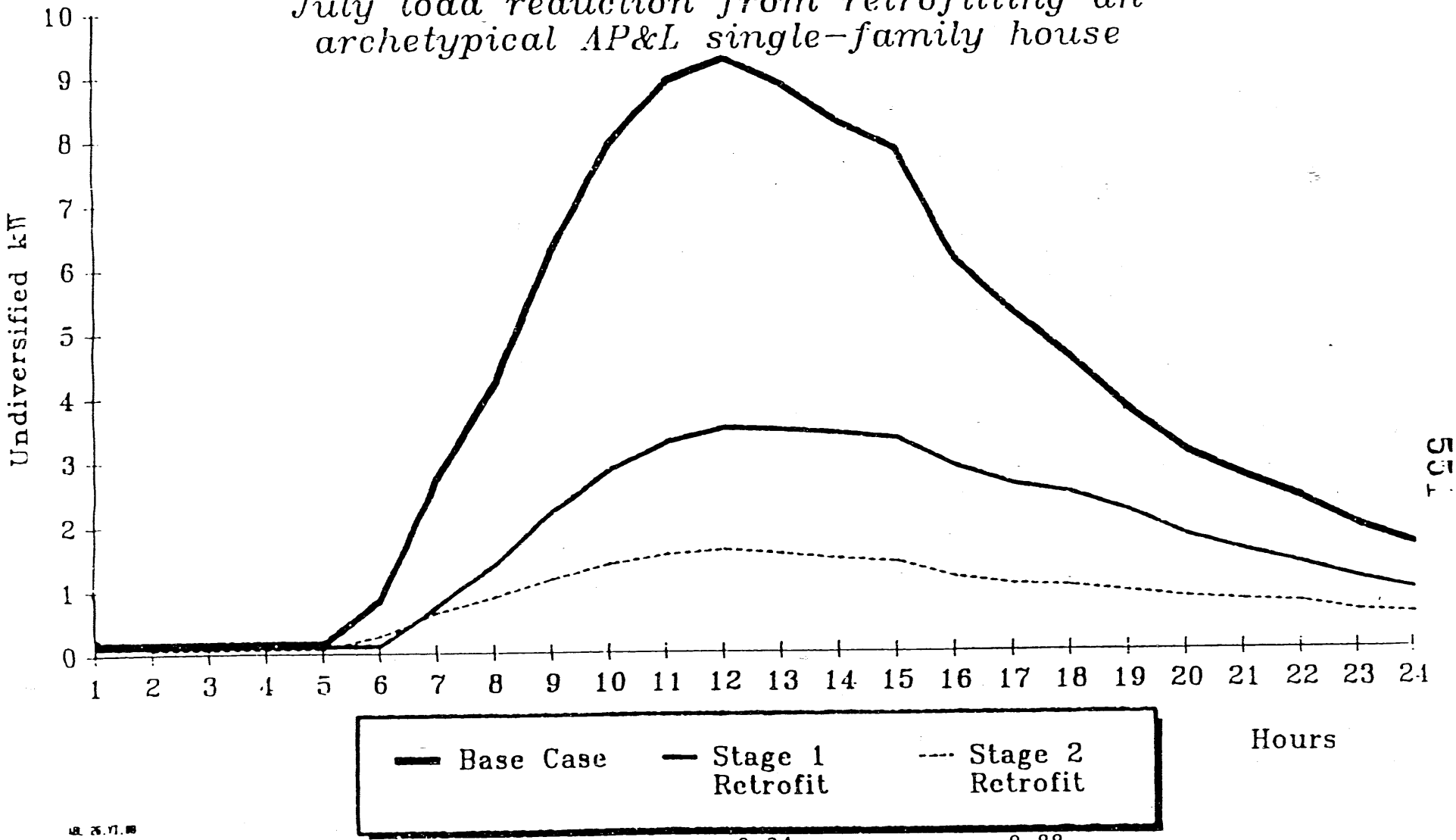
(a) Jamaica preconstruction simulation from F.S. Dubin & L. Sauerwein, *Procs. 1984 ACEEE Summer Study on Energy Efficiency in Buildings* at D-193ff; intensity is 23,000 BTU/ft^2-y excluding convenience outlets; Dubin reports [personal communication 12.XI.87] that actual performance matches this simulation and results will be published.

(b) Menlo Park datum from Donald Aitken [personal communication, VI.86].

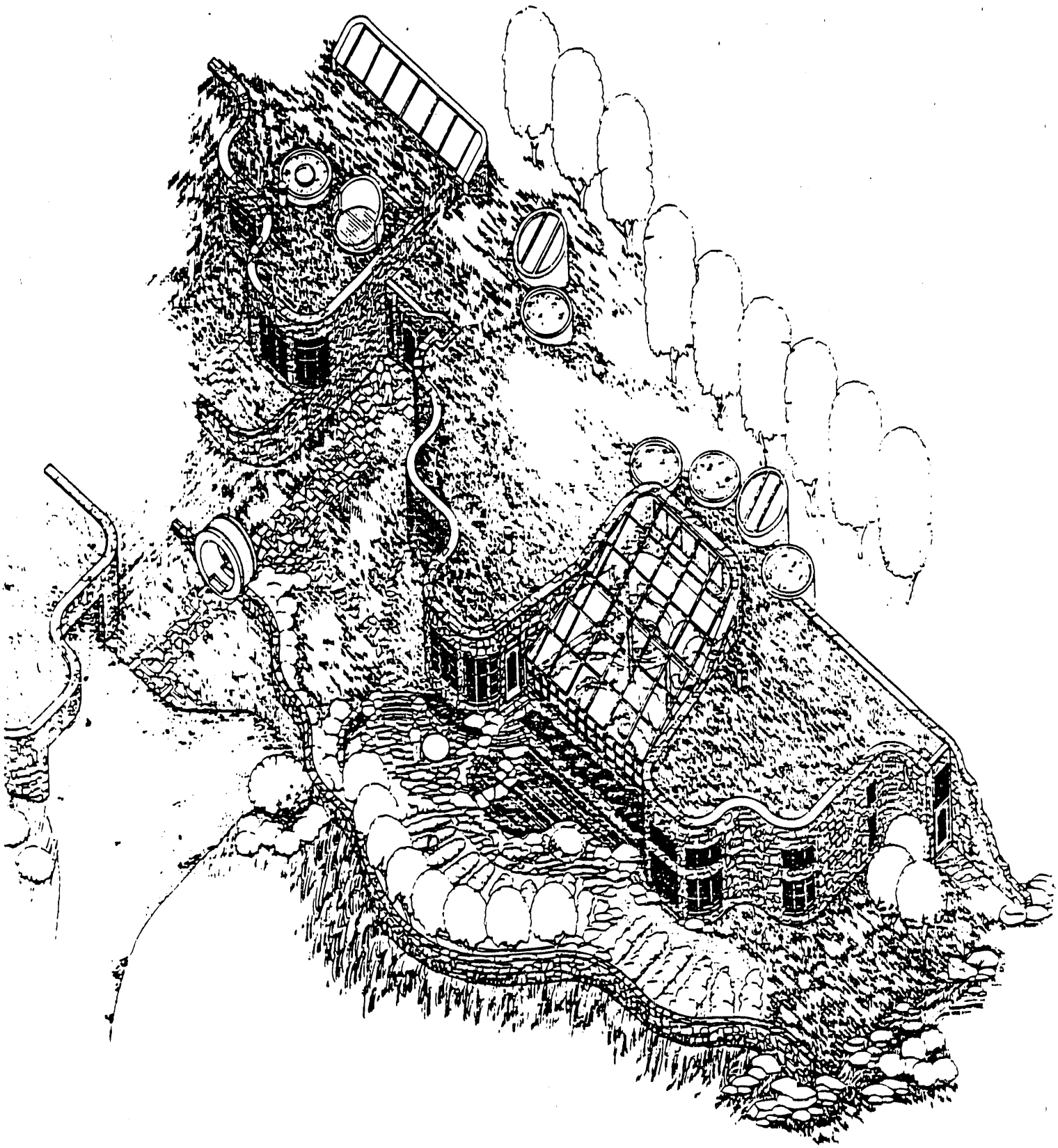
(c) San Pasqual simulation from Keniston & Mosher AIA; performance estimated similar.

(d) Old Snowmass measurements from A.B. Lovins's 1985-87 billing data; climate is ~8,700 heating and a few hundred cooling Fahrenheit degree-days per year; roughly half the plan area is office space and the rest a home/bioshelter. Site energy <2,000 BTU/ft^2-y includes all comfort, light (0.01-0.02 W/ft^2), and controlled ventilation; 6,000 includes all convenience outlets (mostly office equipment for ~25 people); and 14,000 adds 8,000 propane (cooking, ~HW backup). Heating is passive via R-5.4 and -8.3 glazings.

July load reduction from retrofitting an archetypical AP&L single-family house



Annual load factor	0.25	0.34	0.88
% kW-h/y saving	-	50%	77%
% kW_p saving	-	62½%	83%
Av. net 1986 ¢/kW-h cost	-	0.67	1.59
Simple payback (8¢/kW-h)	-	1.2 y	4.0 y (new: 2.1 y)
Same incl. gas (50¢/ccf)	-	1.1 y	2.9 y (new: 1.4 y)



An efficient cold-climate building (1984)

House/bioshelter/Rocky Mountain Institute headquarters,
A.B. Lovins *et al.*, Old Snowmass, Colorado 81654-9199, USA

Site: western Colorado, 39½°N, 2165 m elevation, dry climate
continuous midwinter cloud for 39 d has exceptionally occurred
~4900 C°-d/y (@ 21°C); 99% design temp. ~-25°C
observed low temp. -44°C; -40° is observed almost every winter

Form: 1-story, 40-cm curving slipformed masonry walls, 50 t oak beams
372 m^2 floor incl. 84 m^2 central greenhouse, 102 m^2 windows

Envelope: k (W/m^2K): perimeter skirt ~0.22, flat roof <0.09, walls 0.14
windows typically 1.05 COG, best units currently installed 0.47
uncontrolled infiltration <0.1 ach, 6 air-to-air heat exchangers

Measured electric efficiency: >95% daylit + artificial ~0.1-0.2 W/m^2
efficient lights & appliances cut household use to ~110-130 av W
(~10% of national norm, smaller fraction of local norm)
heat exchangers use ~200-250 av W (9-10 mo/y), 2 process pumps
~100-140 av W, office equipment (34 staff) ~560-670 av W
total electric use ~1.1 av kW, >50% for office equipment

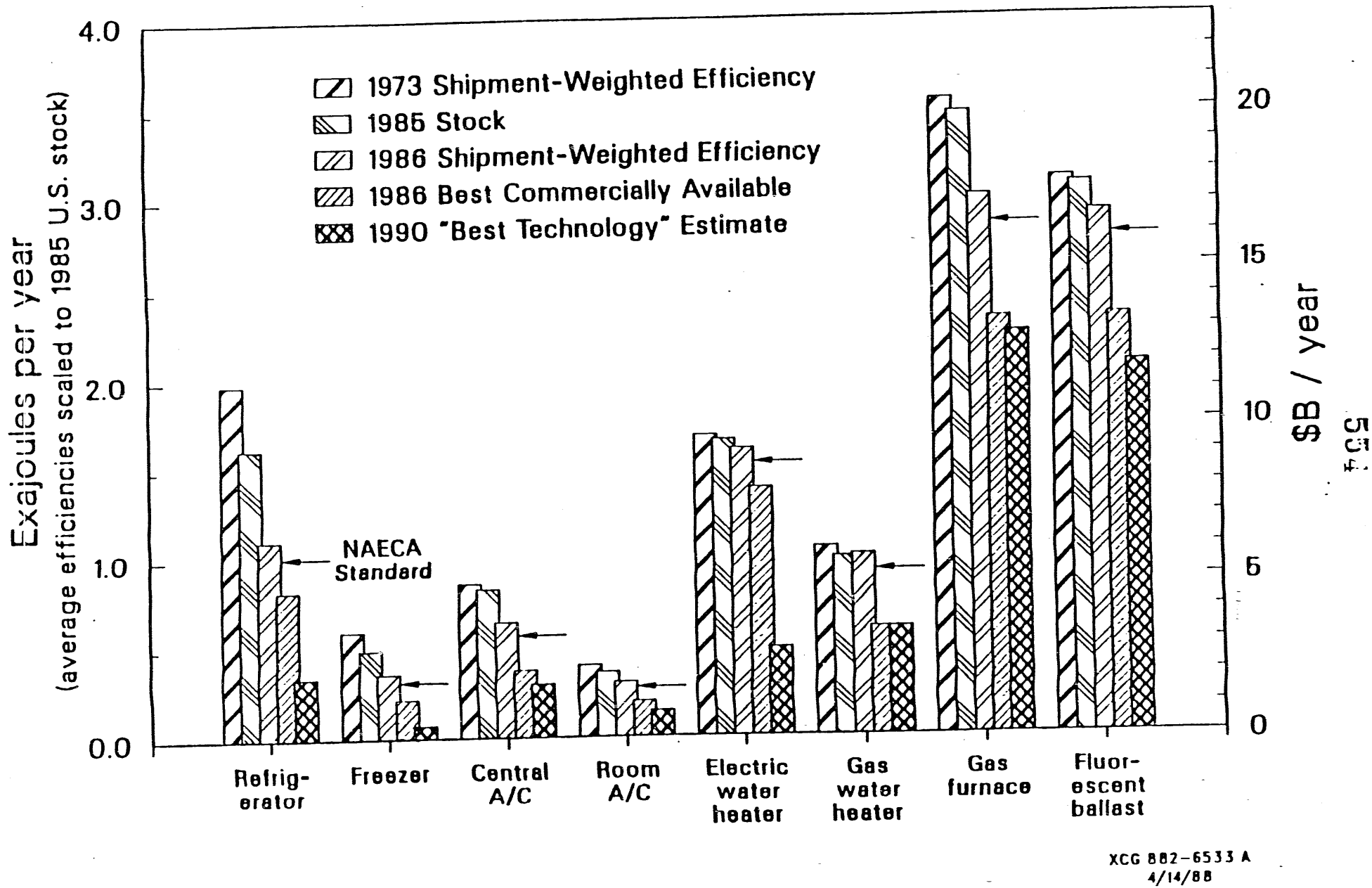
Measured thermal performance:
comfort is maintained with no conventional heating system
central greenhouse achieves a semitropical climate year-round
occasional minor operation of 2 woodstoves, for both backup and
aesthetics, amounts to <1% of local norm for heating use
~99+% solar water heating with 11.9 m^2 active solar panels, passive masswall preheater, and 5 m^3 hot-water storage
total site energy use <8 GJ/y without, ~59 GJ/y with, office eq't.

Measured cost-effectiveness:
net marginal cost of >99% space-heating savings: <0
total net marginal cost (to save >99% of space & water heat,
>90% of electricity, and >50% of water): ~$16/$m^2$
simple payback against the most cost-effective mix of the normal
local fuels (electricity, propane, & wood): ~10 months

Update: Significant further improvements could be achieved in shell performance, chiefly through newer k ~ 0.45 W/m^2K superwindows, at trivial extra cost. Minor further improvements in electric efficiency could also be cost-effectively achieved. The water-heating solar-panel area could be reduced ~2x through recent collector advances.

Great aesthetic flexibility is available with little change in energy use. Similar energy performance can be achieved in essentially any climate, with any built form desired, with paybacks on the order of one year. A 2.1-kW_p photovoltaic system is being added.

Trends in U.S. Appliance Efficiency



ELECTRONIC OFFICE EQUIPMENT

- most Americans who work now work in offices
- 1 screen per 2.5 officeworkers in 1990, 1:1.1-1.2 by ~1995
- info. tech. is ~50% of U.S. plant-&-equipment investment
- often the fastest-growing load in the fastest-growing sector
- ~12+ GW or ~63 TW-h/y (1990, incl. HVAC); x2 in <5 y
- low-diversity onpeak summer load that drives HVAC peaks
- critical load for office design: high new/retrofit HVAC costs
- very low saturations outside OECD -- catch it now!
- abysmal data on equipment stock and end-use allocations
- surveys assume nameplate demand, typically ~2-5x actual
- low awareness/cooperation by many makers/vendors
- efficiency not marketed except indirectly (e.g., laptops)
- severe split incentives in choosing, buying, and operating
- very poor user awareness, complicated by myths
- no labelling/standards/incentives, few standard tests
- but ~6-y computer life, so innovation can saturate quickly
- technical potential to save ~60-70% short-term, ~80-90% longer-term, of total (not per-device) electric usage -- or ~96+% per device -- at zero marginal cost or less
- surprise: this is true not just of computers but also of imaging equipment (computer printers, high-speed digital printers, photocopiers,...) -- many important new imaging technologies (high- and low-speed, color and B&W)
- can save ~9+ GW of 1990 load, + ~15-25 GW in the '90s
- synergistic blend of hardware/software/operating changes
- high efficiency comes with major non-energy advantages
- extraordinarily rapid technological evolution
- vital to support, not inhibit, the technical brilliance and entrepreneurship that created this unique industry

Major Industrial Drivepower Savings

Motor choice
- Conventional high-efficiency induction motors
- New types (RE-Fe-B permanent-magnet, amorphous-Fe, high-speed homopolar, reluctance,...)
- Correcting past rewinds' core damage
- Correcting gross oversizing
- Improving synchronous & DC motors & MGs

Motor controls
- Variable-frequency electronic drives (several types)
- "Power-factor controllers" / soft-start devices
- Fast controllers (axial/centrifugal turbomachines)
- Switching, cycling, scheduling, & load management

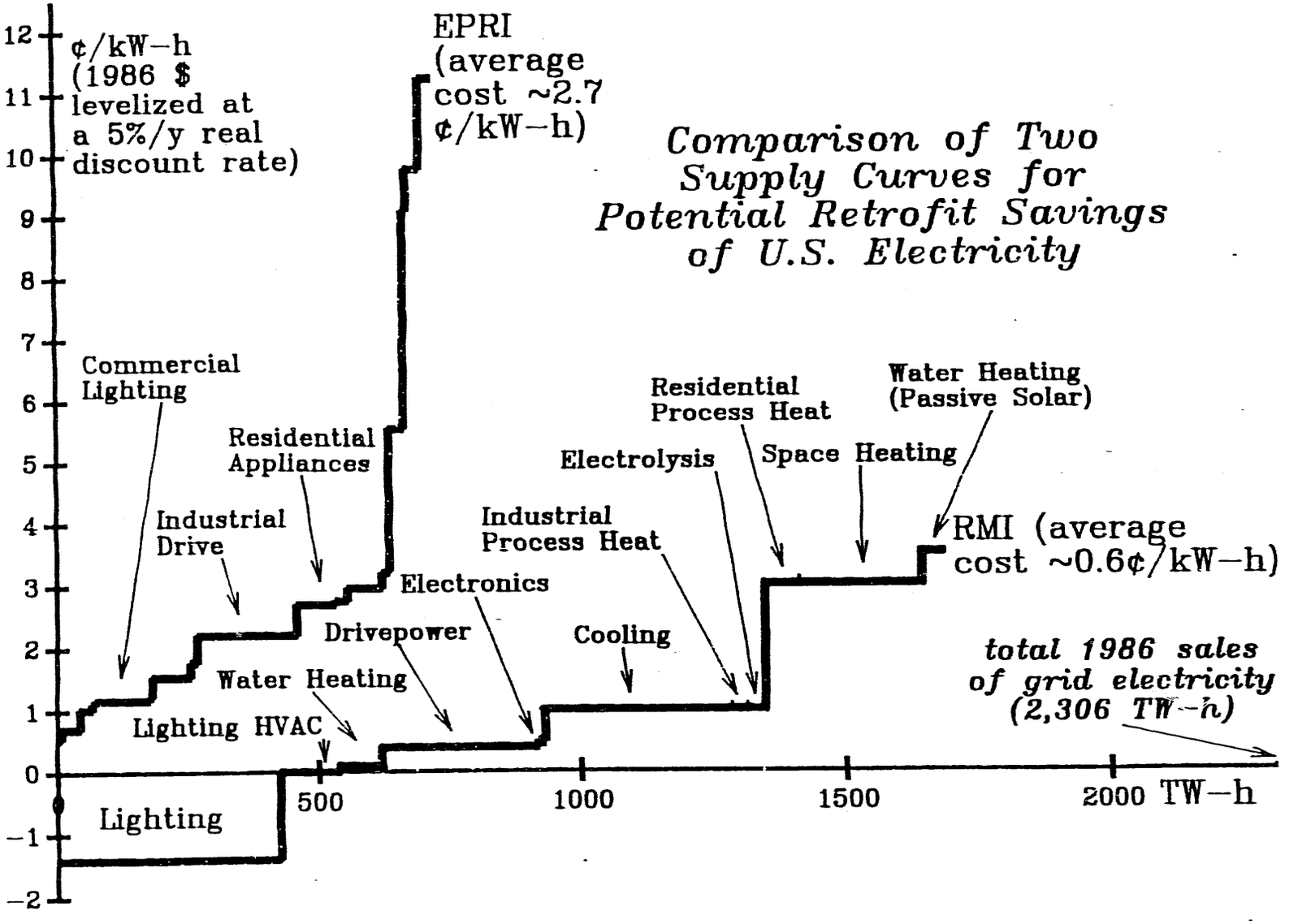
Electrical tuneups
- Phase balancing (under dynamic conditions)
- Correcting power factor near or at load terminals
- Improving local power quality & voltage stability
- Reducing in-plant distribution losses

Mechanical tuneups
- Drivetrain efficiency (belts, gears, bearings,...)
- Advanced lubricants, better lubrication techniques
- Cooling, cleaning, & maintenance practices

Management, acquisition, monitoring, recordkeeping

Total U.S. retrofit drivepower savings potential:
- ~44±16% (more recently, ~50% -- EPRI agrees)
- @ average cost <0.5±0.15¢/kW-h,
- or ~80-190 (prob. ~160) GW + $25-50 billion/y,
- with ~1¼-y average payback @ 5¢/kW-h

+ downstream process/control savings, hydraulics,....


Comparison of Two Supply Curves for Potential Retrofit Savings of U.S. Electricity
¢/kW–h (1986 $ levelized at a 5%/y real discount rate)
EPRI (average cost ~2.7 ¢/kW–h)
RMI (average cost ~0.6¢/kW–h)
total 1986 sales of grid electricity (2,306 TW–h)
Commercial Lighting
Residential Appliances
Industrial Drive
Electronics
Drivepower
Water Heating
Lighting HVAC
Industrial Process Heat
Cooling
Electrolysis
Residential Process Heat
Space Heating
Water Heating (Passive Solar)
Lighting
12
11
10
9
8
7
6
5
4
3
2
1
0
–1
–2
500
1000
1500
2000 TW–h

WHY DO ASSESSMENTS OF POTENTIAL ELECTRIC SAVINGS DIFFER?

RMI's estimate is ~2x as big as EPRI's, at severalfold lower average cost; but most of the difference is methodological, not substantive. The reasons for it appear to include:

1. Methodological differences. RMI's inclusion of saved maintenance costs makes lighting retrofits cost -1.4¢/kW-h instead of +1.2¢/kW-h, making a 50% electrical saving free. EPRI excludes, but RMI includes, 9-15% savings expected by 2000 from prices, government standards, and existing utility programs. EPRI counts only savings potentially achievable by 2000, while RMI counts full long-term potential. EPRI's curve is near the lower end of a 20-percentage-point uncertainty range, but RMI's curve is a central case.

2. Modernity of technologies assumed. Most of the best electricity-saving technologies are <1 y old. Using 5-year-old data makes the savings half as big and ~3x as expensive.

3. How fully the technologies are characterized. Are all 10 measured (or 15 identified) savings mechanisms for electronic ballasts counted, or only 2-3? a few motor-system measures, or all 35? (EPRI agrees the latter can save ~2-3x more electricity, at ~5x lower cost, than its curve shows.)

4. Synergisms. Detailed whole-system engineering can cut costs severalfold through interactions between measures. That's what makes the motor-system savings so cheap.

5. Disaggregation. Including many small savings as well as a few big ones often doubles the total quantity of savings.

6. Accounting differences. RMI uses 1986 dollars and levelizes at a 5%/y real discount rate; others may differ slightly.

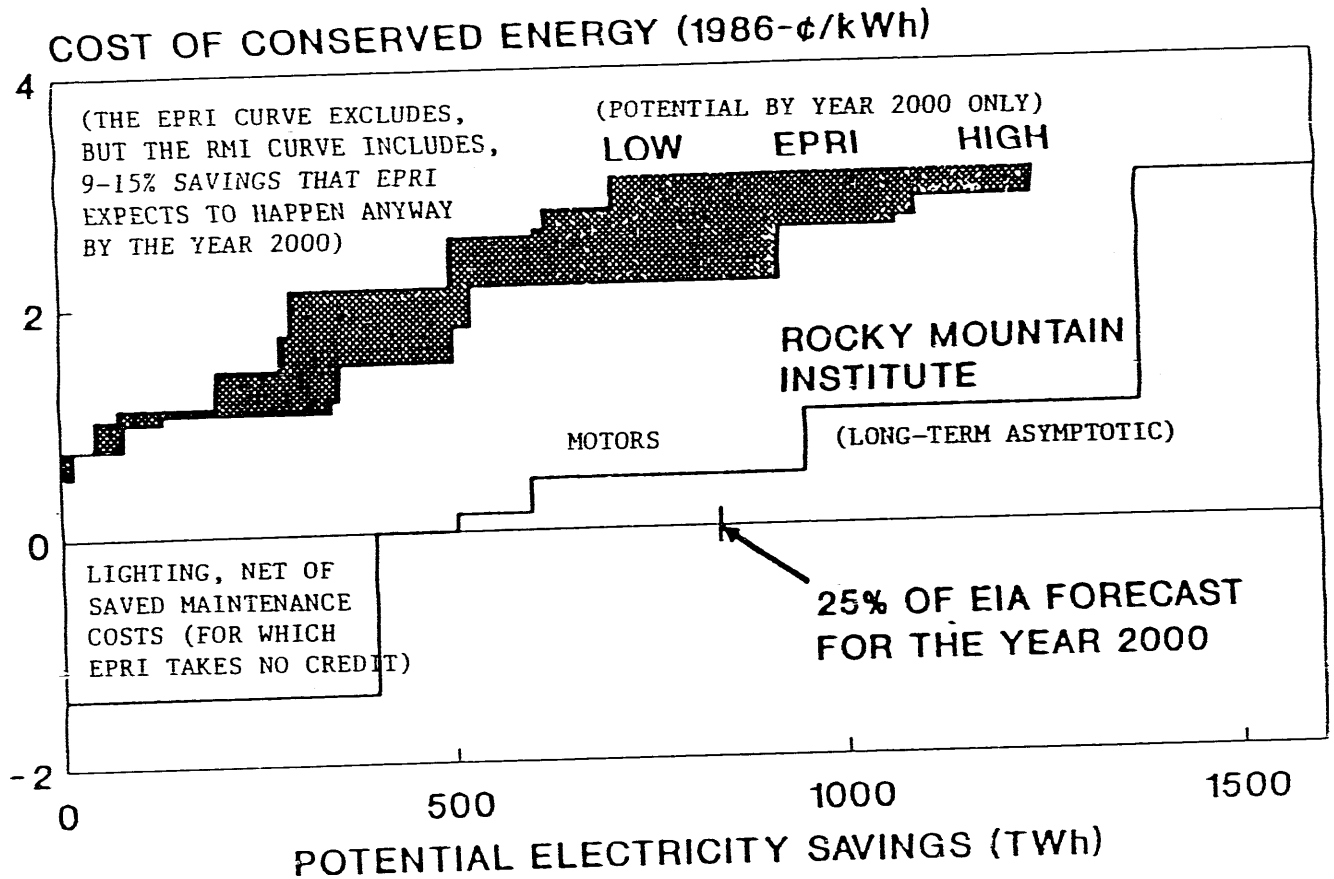


Fig. 12. **Estimates from EPRI and RMI of potential electricity savings in the U.S. as a function of the marginal cost of conserved energy.**

Source: Eric Hirst, "Possible Effects of Electric-Utility DSM Programs, 1990 to 2010," ORNL/CON-312, Oak Ridge National Laboratory, Oak Ridge, Tennessee, January 1991.

LESS ELECTRICITY CAN PROBABLY BE SAVED IN WESTERN EUROPE AND IN JAPAN THAN IN THE U.S.A., AND AT HIGHER COST, BUT THE DIFFERENCE IS PROBABLY NOT IMPORTANT

Among salient examples of recent, highly detailed analyses using present technology:

- **the Swedish State Power Board (Vattenfall) has identified, with several-year-old technology, a potential to save half of Swedish electricity at an average cost ~1.3¢/kW-h (1986 US$);**
- **the Technical University of Denmark has found a potential to save half the electricity used in all Danish buildings at an average cost ~0.6¢/kW-h, or three-fourths at ~1.3¢/kW-h;**
- **the Housing and Environment Institute (Darmstadt) has described a potential to save 80% of the electricity used in West German households (including cost-effective fuel-switching) at an average cost repaid in ~2.6 years.**

Naturally, the size and cost of potential savings require detailed analysis in each end-use, sector, and country; but these examples suggest an important and attractive potential even in the most energy-efficient countries.

COMPARISON OF TWO ECONOMIC "LENSES"

- Vattenfall
- Holmen Paper Company

--> Improve 16 pumps
- Initial use = 9000 MWh/year ~ 1800 Single-family homes

	Vattenfall	Holmen
Real Discount Rate	5%	20%
Required Discounted Payback Time	10 years	2 years
Savings Potential in One Plant	3500 MWh/y (38%)	600 MWh/y (7%)
Cost of Conserved Energy	1.4 cents/kWh	2.5 cents/kWh
Cost of New Supply	(~ 6 cents/kWh)	

Note: The Holmen method transforms a 5-year simple payback into a perceived payback of > 50 years!

IMPLEMENTING NEGAWATTS

OLD METHODS: finance or market negawatts

- Public information (exhortation and education)
- Targeted technical information (builders, designers)
- Low- or no-interest loans (usually for weatherization)
- Gifts ("full financing"--cheaper than loans)
- Rebates (targeted, or generic for <u>any</u> kW_p or kW-h)
  - To buyer, seller, other trade allies, combinations
  - Coupled with scrappage of old devices
  - For beating minimum equipment standards
- Equipment leasing (20¢/lamp-month...)
- Third-party investors and utility service companies

NEW METHODS: make a market in negawatts

- Competitive bidding processes
  - Industrial modernization grants
  - Generalized ("all-source") auctions
- Fungible savings (with transmission credit?)
  - Wheeling between customers, utilities, & nations
  - Arbitrage between cost of megawatts & negawatts
- Negawatt/megawatt spot, futures, & options markets
- Peak-load covenants traded in secondary markets
- Efficiency cross-marketing
  - By electric utilities
  - By gas utilities
- Performance-linked hookup fees for new buildings
- Targeted mass retrofits, esp. of commercial lighting

plus sales/profits decoupling, exemplary rewards,
and predictable cost recovery to utility
plus quality control, tariff reform, barrier removal,....

AN ELECTRICITY-SAVING SUCCESS STORY

Of ~141 GW of U.S. electrical savings achieved during 1973-83, EPRI ascribes 13 GW to demand-side management programs and 128 GW to "composite price effect," though in practice the two are very hard to distinguish. (An additional 100-GW load reduction from lower-than-expected economic growth has been factored out.) Yet the actual potential saving is enormously larger. An existence proof, not even using the latest techniques:

When Southern California Edison Co.'s peak load was ~14 GW in the mid-1980s, SCE was reducing its long-term (10-y) forecast peak load by nearly 1.2 GW/y -- ~45% through its own programs, costing 0.3¢/kW-h for efficiency and \$30-odd/kW_p for load management, and ~55% through state programs, mainly building and appliance standards, which cost the utility nothing. Absent this state action, SCE could have achieved similar results at program costs of about zero to ~0.6¢/kW-h.

If <u>all</u> Americans saved electricity at the <u>same speed and cost</u> at which the ~10 million people served by Southern California Edison Company actually <u>did</u> save electricity during 1983-85, then national forecast needs for long-run power supplies would decrease by ~40 GW <u>per year</u>. The total program cost for utilities to achieve those savings would then average ~0.1-0.2¢/kW-h -- about <u>one percent</u> of the cost of new power stations.

Responses to Bidding RFP's

	Requested (Megawatts)	Responses	Ratio Resp./Req.
California	330	3,580	11
Del/MD	100	830	8
Florida	440	1,989	5
Hawaii	646	3618	6
Indiana	160	750	5
Maine (1984-1989)	1160	6245	5
Massachusetts	834.7	11,794	14
Nevada	125	3200	26
New Hampshire	50	557	11
New Jersey	270	768	3
New York	150	1,425	10
Ohio	100	1,075	11
Texas	25	136	5
Vermont	290	1,466	5
Washington	100	1,241	12
TOTAL	4780.7	38674	8

Percentage of Gross Revenues Spent to Save Electricity by Selected U.S. Utilities

	1990	1991	1992	1993
New England El. System	3.8%	>5%	~6%	~7%
Central Maine Pwr. Co.	~7%			
Burlington El. Dept.	~7%	rising		
Ctrl. Vermont Pbl. Srv.	~5-7%			~14%
Bonneville Pwr. Admn.*	4.1%	5.8%	~7%	8%
Pacific Gas & El. Co.**	2%	>2%	more...	

**Bonneville, a large (mainly hydro-based) Federal wholesale utility operating under strict least-cost investment criteria, has allocated 83% of its 1992-93 resource acquisition budget to end-use efficiency and only 8% to new supply. Its expanding understanding of demand-side opportunities continues to push off supply expansions into the indefinite future, always beyond the horizon of the resource plan.*

***PG&E, the largest U.S. investor-owned utility (with a large hydro/geothermal resource base), expects to get 2.5 GW, or at least 75%, of its projected 1990-2000 marginal resource needs from demand-side options, and all the rest from private, alternative, renewables-plus-advanced-gas-cycle supplies. For the first time in four decades, PG&E has not a single central thermal plant in its resource plan.*

22 TESTS OF UTILITY PHILOSOPHY

PRODUCT	commodity (kW-h)	energy services
SERVING	ratepayers	customers
ATTENTION	top line	bottom line
MAXIMIZE	kW-h sales	customer satisfaction
MINIMIZE	price	bills (= price x use)
FUTURE NEEDS	fate	choice
BEHAVIOR	forecast & build	optimize demand & supply
PRINCIPLES	accounting	economics
DECISION RULE	asset utilization	economic dispatch
OVERCAPACITY	unamortized investment	sunk cost
MKT. SEGMENTATION	core/peripheral	differing needs
PRICING	inverse-elasticity	nondiscriminatory
BYPASS RESPONSE	sweetheart rates	targeted efficiency
EFFIC'Y. EMPHASIS	cosmetic	strong
EFFICIENCY/COGEN	threat	opportunity
NATURAL GAS	competitor	complement
CULTURE	engineering	entrepreneurial
STYLE	by the book	ready, fire, aim
SPEED OF LEARNING	decades	months
INTERNAL INCENTIVES	punish/ignore failure	reward success
EXTERNAL RELATIONSHIPS	adversarial	collaborative
RELATIONSHIP BETWEEN OWN BUSINESS INTERESTS AND CUSTOMERS'	zero-sum	win-win

THE ONE-NEGATON-CO_2 LAMP

A single 18-watt compact fluorescent lamp, producing the same light as a 75-watt incandescent lamp for ~13 times as long, directly saves 570 delivered kilowatt-hours over its 10,000-hour lifetime. The lamp will thus

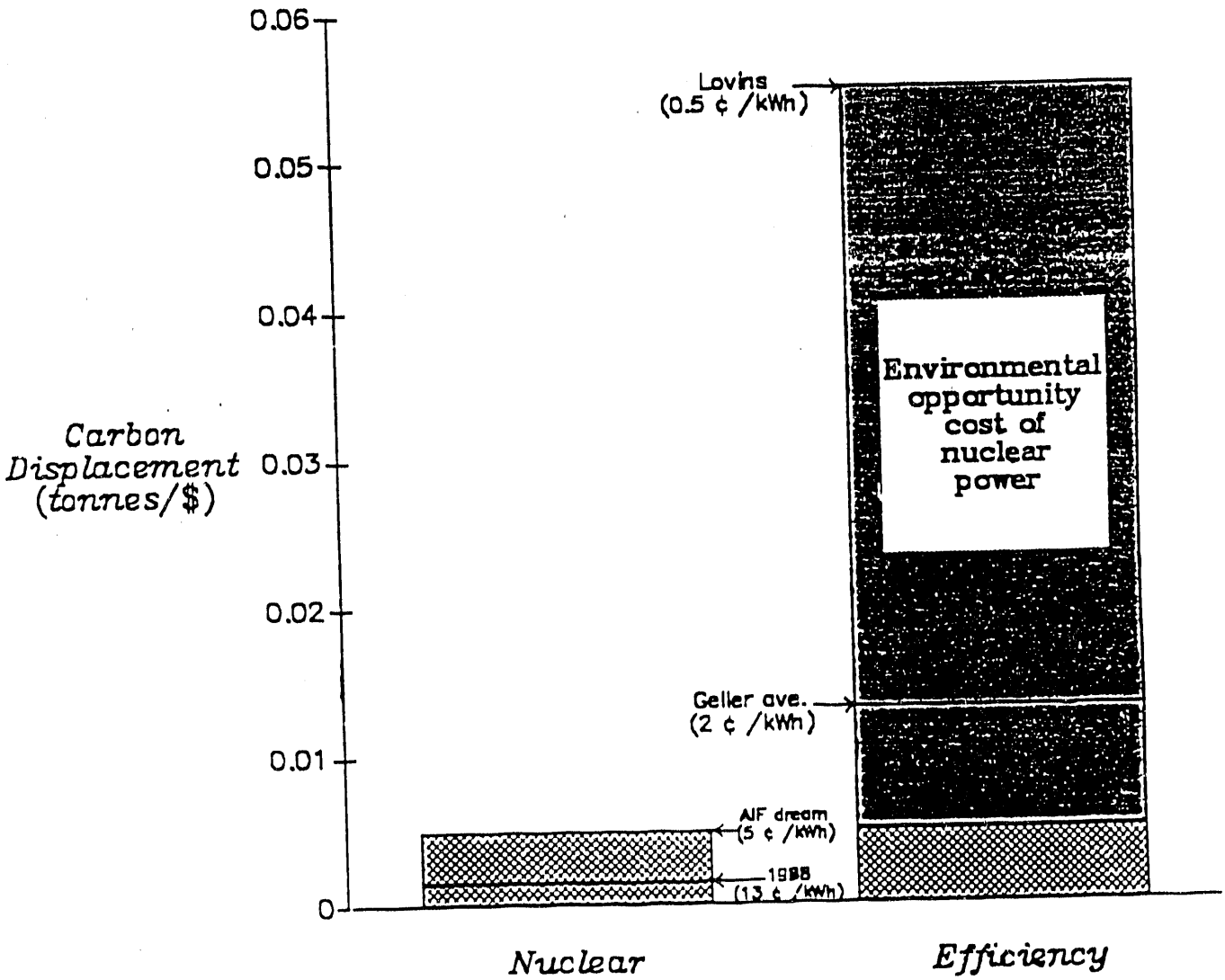
- avoid the emission from a typical U.S. coal plant of
  - a ton of CO_2, which adds to global warming, and
  - ~8 kg of SO_2, which contributes to acid rain, plus NO_x, heavy metals, and other pollutants; or
- avoid the production by a typical nuclear plant of
  - half a curie of strontium-90 and cesium-137 (two major components of high-level waste) and
  - ~25 mg of plutonium -- equivalent in explosive power to 0.4 ton of TNT, or in radiotoxicity, if uniformly distributed into human lungs, to ~2,000 cancer-causing doses; or
- avoid the consumption by a typical oil-fired steam plant of 200 l (1¼ bbl) of oil -- enough to run a U.S. family car 1,000 miles, or to drive a superefficient prototype car entirely across the U.S. and back.

Yet the lamp, typically retailing for a price of ~$12-18 and costing much less to make, saves

- the cost of a dozen ordinary lamps and their installation labor (typically totalling ~$20), plus
- ~$20 worth of utility fuel, plus
- ~$200-300 worth of deferred supply capacity.

Thus the lamp offers major environmental benefits together with tens of dollars' increased wealth and hundreds of dollars' increased capital availability.

Relative Efficacy of Nuclear and Efficiency Investments for Abating Carbon Dioxide



Global Warming: Hopeful Examples

Sweden

In April 1989, the Swedish State Power Board published, shorn of the usual disclaimer, a description of how moderately efficient use of electricity, fuel-switching, and environmental dispatch could simultaneously

- support a ~50% increase in real GNP by 2010;
- handle a phaseout of nuclear power (~50% of supply);
- reduce utilities' CO_2 output by a third; and
- reduce the direct economic cost of electrical services by almost $1 billion per year

-- in a country that is already among the most energy-efficient in the world, and has much heavy industry and a severe climate. The assumed electrical savings, too, appear understated in light of the latest U.S. analyses.

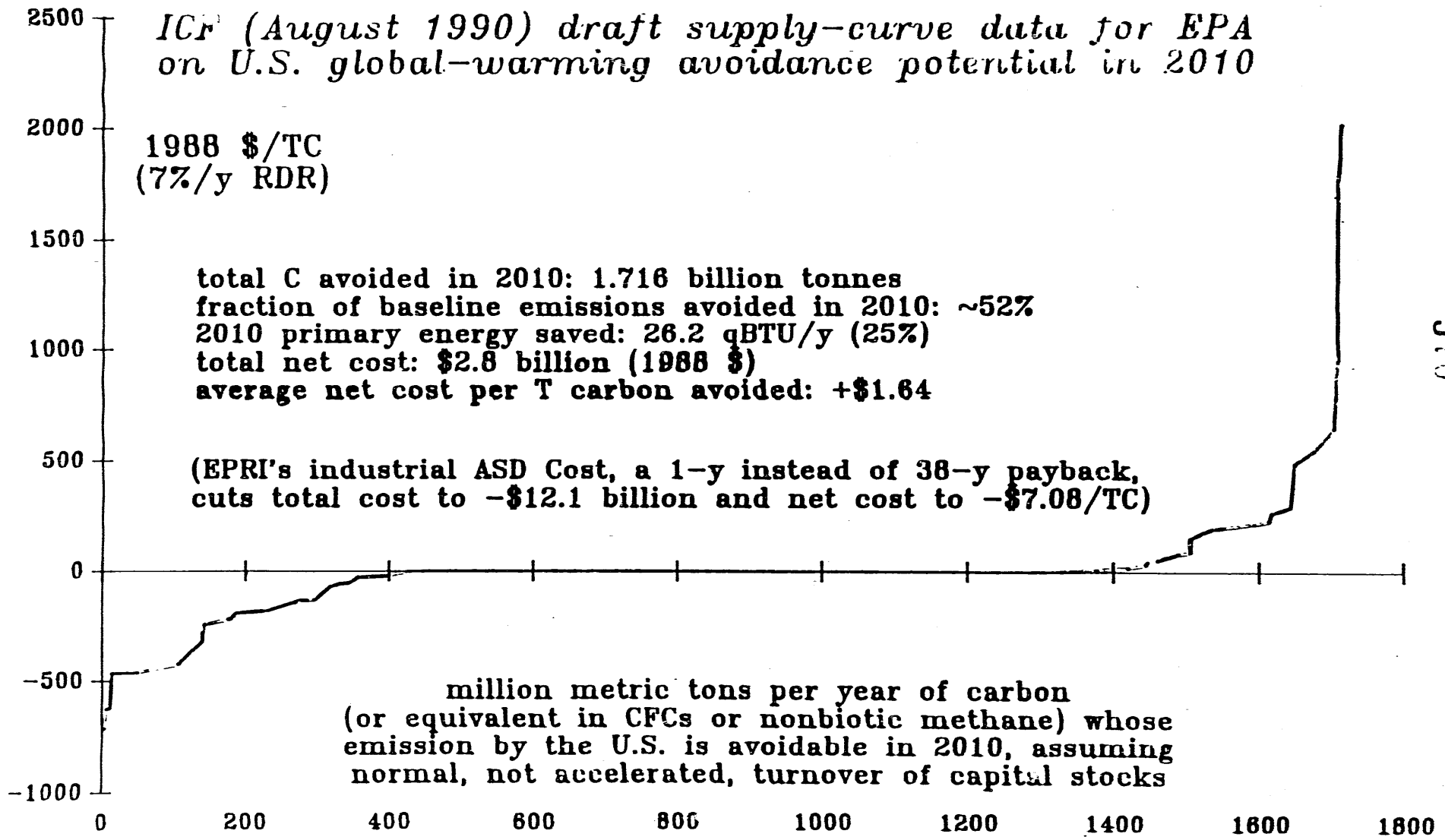
World

A 1981 study for the Umweltbundesamt (reprinted by Rocky Mountain Institute in 1989) assumed a world

- with a ~2080 population of 8 billion people,
- with a 1975 FR German standard of living worldwide,
- hence with five times the 1975 Gross World Product (a tenfold increase in developing countries), yet
- using energy in a way that saves money, with 1980 prices and technologies.

Such a world would use only a third as much total energy as today; and those needs could be entirely met by renewable sources available, and cost-effective on the long-run margin, in 1980. (If the same analysis were redone today, its results would be even more favorable.)

ICF (August 1990) draft supply-curve data for EPA on U.S. global-warming avoidance potential in 2010



ENERGY EFFICIENCY FOR ECONOMIC DEVELOPMENT

A nine-year weatherization program by Osage Municipal Utilities, Osage, Iowa (pop. ~4,000) reduced the utility's costs so much more than its revenues that it was simultaneously able to:

- **prepay all its debt,**
- **build up a multi-million-dollar cash surplus,**
- **have five rate cuts, totalling 32% real, in five years,**
- **thereby attract two big factories to town, and**
- **keep >$1,000 per household per year recirculating in the local economy -- money that had earlier gone out of town, and usually out of state, to buy utility inputs -- and thereby create what a Wall Street Journal reporter found was an oasis of relative prosperity amid regional hard times.**

Energy Efficiency and Fair Development

Rich countries today are on average nearly three times as energy-efficient as poor ones -- even though typical rich countries can at least quadruple their present energy efficiency at costs far below today's energy prices.

Thus, if poor countries became as efficient as rich ones now should be, leapfrogging over our mistakes, poor countries could use the same amount of energy as now to run an economy ten times as big as now -- while the rich countries dramatically decreased their own energy use.

Doing this right the first time -- building energy efficiency, and indeed resource efficiency generally, into their infrastructure from scratch -- will require all countries to be more sophisticated buyers and more consistent users of efficient technologies. It will also require rich countries to set a good example, and to export and transfer their most, not their least, efficient technologies. (They now prefer to export devices too obsolete to sell in their home markets -- an immoral export akin to that of deregistered pesticides.) Doing all this will not be easy.

But the alternative is to continue to stifle development by spending too much on unnecessary energy supply, leaving too little money to buy the things which were to use the energy. High levels of energy efficiency are a prerequisite to both sustainable development and a liveable world.

DESIRABLE RATEMAKING PRACTICES

- Minimize bills, not rates. Screen only for economic efficiency, and promote distributional equity through program design.
- Decouple return from sales, e.g., by an ERAM-like mechanism.
- Let utilities predictably keep part of what they save -- even if the present-valued revenue requirements they're reducing are those of a different [gas or electric] utility in your jurisdiction.
- Provide predictable, timely recovery of reasonable program costs; expensing may be preferable to rate-basing.
- Consider and try novel (e.g., Moscovitzian) mechanisms.
- Reward customers/utilities for saving energy, not for spending money; don't constrain those rewards in size or (usually) in duration.

DESIRABLE REGULATORY SIGNALS

- Help utilities rethink their mission and support cultural change.
- Enforce internal consistency.
- Encourage and reward entrepreneurship and boldness both by and within utilities: "Ready, fire, aim." "Let's try it this week."
- Develop collegial processes and relationships.
- Renounce excessive precision in analysis and evaluation.
- Expect and celebrate a reasonable number of failures.
- Do diverse, microvariable experiments in parallel, and develop flexible, adaptive organizational structures which learn quickly. "How can we learn as much as possible this month about how to excite our customers?"
- Keep current during extremely fast hardware evolution, lest you have to re-retrofit later. "If we can't afford to do it right the first time, how come we can afford to do it twice?"
- Provide consistent signals to utilities/customers.
- Pay attention to quality control and information feedback. Information is cheap and powerful.
- Use attractive and exciting terms; avoid turn-off words.
- Emphasize market processes, bottom-up organizing, and respect -- treating customers as mature, honest, and responsible.
- Keep it simple.

IF CUSTOMERS SAVE ELECTRICITY, MUST RATES RISE?

Assume a utility which sells 100 kW-h/y at a rate of 10¢/kW-h (5¢ fixed costs plus 5¢ operating costs) for a revenue requirement of $10/y. (These particular figures, chosen for arithmetic convenience, aren't important to the policy conclusion. Note that in this example, too, average price, 10¢, exceeds short-run marginal cost, 5¢.)

1. An oversimplified initial assumption: Suppose the utility gives the customer a widget which instantly doubles end-use efficiency. Suppose the widget costs 2¢/kW-h saved. Now the utility is selling:

50 kW-h/y el. @ 15¢/kW-h (10¢ fixed, 5¢ op.)	=$7.50/y, plus
50 "kW-h/y" eff. @ (say) 2¢/"kW-h"	=$1.00/y
for a total revenue requirement of	$8.50/y

The societal surplus of $1.50/y comes from providing 50 kW-h worth of energy services at an operating cost 3¢/kW-h (= 5¢ - 2¢) lower. Note that the utility recovers all its fixed costs by raising rates 50%, from 10¢ to 15¢/kW-h, as some utilities fear--but bills fall by 15%.

2. Now let's make that assumption more realistic in two ways:

A. Suppose that doubling the customer's efficiency doesn't take place overnight, but requires 15 years, during which the net plant in service depreciates by half. Thus when sales drop by half, so do fixed costs as old bonds mature, so the fixed charge remains 5¢/kW-h. (The depreciation income needn't be reinvested in replacement plant, because the demand which that plant would serve no longer exists.)

B. Suppose that the utility's original 5¢/kW-h operating cost was an average: its generation was half @ 7¢/kW-h and half @ 3¢/kW-h. When demand is halved, the utility backs out the 7¢ plant and keeps the 3¢ plant. Assuming the widget is still unamortized after 15 y--an unusually expensive efficiency measure--the utility is now selling:

50 kW-h/y el. @ 8¢/kW-h (5¢ fixed, 3¢ op.)	=	$4.00/y, plus
50 "kW-h/y" eff. @ 2¢/"kW-h"	=	$1.00/y
for a total revenue requirement of		$5.00/y

If the resulting societal surplus of $5.00/y were, for illustration, split evenly between ratepayers and shareholders, the average ratepayer's bill would fall by 25%, while net for common would about triple.

Thus, unless a utility saves electricity extremely rapidly, it should not need to raise its rates (¢/kW-h) to cover fixed costs out of fewer kW-h sold, for three reasons:

1. "Fixed" costs are not fixed; they slowly decline with depreciation.
2. Demand growth preserves revenue streams; they simply come from different customers, and no capacity is idled.
3. In addition, saved operating costs (whenever it's cheaper to save electricity than to run the marginal existing plant) can be used to pay fixed costs. This is especially rewarding because the cashflow of saved operating costs is front-loaded: you buy the cheapest savings first, and uses them to back out first those plants which cost the most to run. Such a cashflow is ideal for prepaying debt. The resulting avoidance of interest accrual typically increases the present value of the saved operating costs by about a third.

Thus one can save electricity without raising rates (¢/kW-h), as long as the speed of the saving is less than the depreciation rate (suitably adjusted to distinguish generation from grid investments), plus the rate of growth in service demand, plus an allowance for the ability to apply saved operating costs to prepaying debt and hence reducing fixed costs, plus any allowance for new wholesale export opportunities. In many systems, just the first two of these four terms add up to roughly 5%/y--as fast as the average California utility has in fact been saving electricity in recent years, and much faster than many other utilities think their customers can save.

Moreover, even if very rapid savings did require temporarily higher rates,

4. the rates would have been still higher with inefficient end-use, because then rising demand would have driven new plant construction at high marginal costs and risks; and
5. energy-service bills would still go down, because consumption would fall more than price rose. BILLS ARE ALL THAT MATTER TO THE CUSTOMER. For the utility, all that matter are PROFITS, which equal bills or revenues (i.e., price times consumption) MINUS COSTS. Decreasing the costs more than the revenues increases the profits; it's then up to the regulators to let the utility keep part of those increased profits.

The bottom line: efficiency programs are very unlikely to raise rates in practice, and even if they did, bills would still go down.

Thus when we remember that "fixed" costs are not fixed, but slowly fall with depreciation, we see that by saving electricity at a speed no greater than the depreciation rate, both bills and rates can decrease. Yet even if rates did rise, that would be OK as long as bills fell--as long, that is, as the electrical saving were the least-cost resource for the system to acquire. Any criterion based on rates will cause economically inefficient investment. Why? Because in economic terms, energy services delivered to customers are a joint product of two factors of production: electricity, and the efficiency of using it. When we consider rates rather than bills, we are tacitly rolling the cost of one factor (efficiency) into the price of the other (electricity). This bizarre practice conceals a money-saving opportunity: raising total factor productivity by selling the customer a mixture of less of the costly input (electricity) and more of the cheap input (efficiency).

3. What if demand grows while we're saving electricity?

Suppose that during the 15-year period of implementing the doubling of end-use efficiency, demand for electrical services grows by, say, 15% (i.e., at 0.9%/y). Then after 15 years, the utility is selling:

57½ kW-h/y el. @ 8.52¢/kW-h (5¢ fixed, 3¢ op. for the first 50 kW-h/y, 7¢ op. for last 7½ kW-h/y)	=	$4.90/y, plus
57½ "kW-h/y" eff. @ (say) 2¢/"kW-h"	=	$1.15/y
for a total revenue requirement of		$6.05/y

In contrast, if end-use efficiency hadn't doubled, then on two conservative assumptions (the original plants which supplied 100 kW-h/y still have enough spare capacity to supply 115 kW-h/y, and that marginal generation can be done at the original marginal cost of 7¢/kW-h), the utility's sales would have been:

115 kW-h/y el. @ 9.61 ¢/kW-h (4.35¢ fixed, 3¢ op. for the first 50 kW-h/y, 7¢ op. for last 65 kW-h/y) = $11.05/y,

maintaining the $5/y surplus of the previous case. Note, however, that the fixed costs of $5.00/y after 15 years' depreciation have been spread over the increased sales of 115 kW-h/y, with no provision for reinvestment in replacement plant which, without the doubled efficiency, is much more likely to be required. It would therefore be more realistic to count a fixed cost of at least $5.75/y, increasing the surplus to $5.75/y (or more if marginal construction costs more). We also haven't credited the utility with possible revenue-earning opportunities in the bulk power market if it saves more/faster than others.

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1776 Massachusetts Ave., N.W. • Washington, D.C. 20036
Phone: (202) 452-1999
Fax: (202) 296-7365

THE NATIONAL ENERGY STRATEGY: A CRITIQUE

Christopher Flavin
Vice-President for Research
Worldwatch Institute

Paper presented to

Third National Conference on Integrated Resource Planning

Sponsored by

National Association of Regulatory Utility Commissioners

Santa Fe, New Mexico

April 8-10, 1991

Recycled Paper

Introduction

Three severe oil shocks in 17 years are a clear warning that the world cannot continue indefinitely along a path of petroleum dependence. The ultimate constraint is physical--oil supplies are finite--but the immediate limits are geographical and political: nearly two-thirds of the world's proven oil reserves are in the volatile Persian Gulf region. Since 1985, presidents Bush and Reagan have presided over a 60 percent rise in U.S. oil imports, hastening the arrival of the next great oil crisis.

An even more fundamental limit on fossil fuel use is the atmosphere's capacity to cope with the burden of nearly 6 billion metric tons of carbon emissions each year. Scientists working with the United Nations-commissioned Intergovernmental Panel on Climate Change predict that these emissions will warm the atmosphere at an unprecedented rate, and may eventually undermine the economy itself.

Combustion of all the world's remaining fossil fuels would raise the concentration of carbon dioxide as much as tenfold, compared with the mere doubling that now concerns scientists. Stabilizing the climate will ultimately require reducing global carbon dioxide emissions by 60 to 80 percent. Slowing global warming inevitably means placing limits on fossil fuel combustion; the longer we wait, the more difficult the task will be.

The United States is the country most responsible for the world economy's dangerous dependence on Persian Gulf oil and for the emerging threat to the global climate. With just 4 percent of the world's population, the U.S. consumes 24 percent of the world's oil and produces 22 percent of the carbon dioxide from fossil fuel combustion. These lopsided figures are powerful evidence of the crucial role the U.S. government could play in addressing the world's energy problems.

The National Energy Strategy

The Bush Administration has been at work on a National Energy Strategy throughout the past two years, and so was well positioned to reevaluate and redirect the country's energy systems. Unveiled just before the end of the Gulf War in late February, the Bush energy strategy has turned out to be a major disappointment--more likely to lead the country backward to the energy sources of the fifties, than forward into the twenty-first century. Indeed, the Bush energy policy is a prescription for greater dependence on foreign oil, higher emissions of greenhouse gases, and lagging economic competitiveness with the rest of the world.

The strategy document is marked by disingenuous language, fabricated projections, and a failure to squarely confront any of the country's main energy problems. It is particularly notable that at a time when 22 other nations have adopted targets to limit their emissions of carbon dioxide, the Bush energy strategy does not even specifically state how much carbon emissions will increase as a result of its policies.

As described by Secretary of Energy James Watkins during the first months of the Bush administration, the National Energy Strategy was intended to "establish clear goals for our future and provide a yardstick to measure forward movement." Upon releasing the interim report last year, Secretary Watkins asserted that the clearest single message he heard during a year's worth of hearings was the need for the U.S. to spur energy efficiency throughout the economy.

Yet the Bush energy strategy contains no clear goals, and lacks any sense of vision. Most of the modest energy efficiency proposals that were contained in the draft of the energy strategy that was prepared by the Department of Energy were dropped by John Sununu who led the White House effort to eviscerate it. What remains is a supply side-oriented relic of energy policies past.

Energy Policy and Global Warming

The United States currently emits 22 percent of the world's carbon dioxide from fossil fuels--the largest single contributor to greenhouse heating of the earth's atmosphere. Under the NES, U.S. emissions of carbon dioxide, the leading greenhouse gas, would increase by 26 percent between 1990 and 2010. Additional increases in carbon emissions would occur until at least 2030, the final year for NES projections. Meanwhile, Germany, a leading industrial competitor of the United States, plans to cut emissions by 30 percent by 2005.

The NES projects that U.S. coal use will rise by 47 percent between 1990 and 2010, with oil and gas consumption rising 13 percent and 22 percent respectively. The NES downplays the U.S. role in reducing global carbon emissions by stating that developing countries are producing growing levels of carbon dioxide emissions.

This cynical effort to blame the victim ignores the fact that the overwhelming bulk of the carbon dioxide comes from the United States and other industrial countries. That the nearly 4 billion people who live in developing countries may one day emit as much carbon dioxide as 250 million Americans is a curious excuse for inaction.

Energy Policy and Oil Dependence

The Bush energy strategy's failure to seriously address the threat of global warming is only one of several shortcomings. The NES is comprised of an outdated set of legislative proposals, most of them unlikely to significantly reduce oil imports or reduce uneconomic energy consumption. No clear goals or measures of progress have been suggested. Furthermore, the document lacks a clear presentation of the facts and assumptions that lead to the rosy projections found in nearly every section.

The administration contends that oil imports will remain stable, due to increased domestic production and greater "conservation." Nearly all of the

additional production of 3.8 million barrels of oil daily--equivalent to a 40 percent increase in current U.S. oil production--is projected to come from enhanced recovery from existing fields and from the nation's pristine coastlines and wilderness areas. Most of this enormous amount of oil is presumed to flow as a result of government sponsored research and development.

From the analysis presented, it is unclear how this will occur, and under any reasonable oil price scenario, it is almost certainly an overestimate. In any case, the energy strategy itself points out that domestic oil production does virtually nothing to shield the U.S. economy from the shock of suddenly rising oil prices--Texas and Alaska crude will rise in price just as rapidly as Middle Eastern oil.

On the "conservation" side, the Administration claims that oil consumption will be reduced by 3.4 million barrels a day compared to the current policy base. The NES claims some savings from slightly higher fuel efficiency, but most of the "conservation" comes from the use of alternative transportation fuels, and from fuel switching in the electric power industry. In other words, this is not efficiency at all, but again more supply. Moreover, there is little guarantee that the so-called flexible fuel vehicles will actually use non-petroleum fuel. And only 4.3 percent of U.S. electricity was derived from oil in 1990, leaving little room for oil displacement. The savings figure is therefore a fiction.

The section of the Arctic National Wildlife Refuge that would be drilled under the Administration's proposal is an ecologically fragile stretch of Alaskan coastal plain. The Interior Department's mid-range estimate of the oil in the Refuge is only 3.6 billion barrels--as much as the United States consumes in six months. Peak production is projected to reach 870,000 barrels daily, a pumping rate that would drain the field in about ten years.

The United States is now losing nearly half that much production each year. Contrary to wishful estimates contained in the NES, U.S. oil production will decline during the 1990s. Interior Department figures show that of the country's 13 largest oil fields, 7 are at least 80 percent depleted. The U.S. oil industry understands these trends and invested over half its exploration budget overseas last year--up from one-third in the mid-eighties. Contrary to the assertions contained in the NES, this energy strategy would lead to a sustained and dangerous increase in U.S. oil imports.

DOE's new budget also reflects old priorities. Over 60 percent of its proposed 1992 funding goes to nuclear weapons production and cleanup. Remaining funds are concentrated on fossil fuels and nuclear technologies. The $274 million to be spent on all energy efficiency research and development in 1992 is less than the U.S. military spent on cruise missiles alone during the Gulf War. Meanwhile, the administration has called for real cuts in the 1992 budget for renewable energy research and development. The "balance" that the administration claims to have achieved in its energy strategy is not apparent in its own budget.

The Role of Energy Efficiency

Practical, cost-effective, and quick ways to enhance energy efficiency and bring about an economic boon are available. Together, these approaches can achieve a 20-percent cut in industrial country carbon emissions by the year 2010, helping to slow global warming. Yet the efficiency provisions in the National Energy Strategy are largely limited to calls for more studies or continued support for existing programs. This retreat on efficiency is all the more surprising given the Bush Administration's own lavish rhetorical support of energy efficiency.

U.S. automobiles go nearly 50 percent further on a gallon of gasoline now than they did in 1974, and each new car expels 2,000 fewer pounds of carbon each year. And although the Bush Administration has decided to oppose efforts to pursue them, auto improvements can advance much further. A report by the Lawrence Berkeley Laboratory found that a standard of more than 40 miles per gallon is not only feasible but cost-effective. Engine and other design modifications would cost $500 per car, but the gasoline savings would total $2,000 over the life of the car. Improving new-car fuel economy to 40 mpg could reduce U.S. oil consumption by nearly three million barrels a day by 2005, equivalent to about two-fifths of the fuel now used by U.S. automobiles.

In the United States, total electricity use could be cost-effectively cut 40-75 percent, according to the California Energy Commission. On a per kilowatt-hour basis, electricity saved through efficiency costs about the same as fueling and operating a coal power plant (2 cents/kwh), and far less than building a new power plant (4-6 cents/kwh). By improving the efficiency of refrigerators, lights, and other electric appliances, the indirect environmental effects, including carbon dioxide emissions, could also be cut.

Efficiency gains in lighting, which accounts for one-quarter of the electricity used, could be dramatic and easy to achieve, yet the National Energy Strategy would prohibit standards on lighting products. Replacing the lighting fixtures in commercial buildings with improved fluorescent bulbs and electric current regulators could cut their electricity use by 75 percent.

In homes, the simple act of exchanging incandescent bulbs for compact fluorescent bulbs, which use only 16 watts to provide the same amount of light as a 60-watt incandescent bulb, would substantially reduce power consumption. Each fluorescent bulb saves about $30 worth of electricity over its typical 10,000-hour lifetime. The U.S. Environmental Protection Agency should be congratulated on its recent initiative to encourage the use of efficient lighting by U.S. corporations, a voluntary program that could have a larger impact than any efficiency measure in the NES.

By encouraging these and other cost-effective technologies, the United States could cut its projected annual carbon emissions by more than 20 percent by the year 2010, and in so doing save about $35 billion annually. This alone would not be enough to stabilize the climate, but it would be a critical step in reversing the dangerous growth in worldwide carbon emissions. Measures of this type are conspicuously absent from the Bush energy strategy.

The National Energy Strategy states that, "investments in electricity conservation and efficiency should be allowed to compete fairly with electricity supply options." This is a laudable aim, but the NES would do little to accomplish it, planning only to conduct minimal research and to assist states that are engaged in integrated resource planning. Indeed, it is unclear how the administration expects to achieve the stated goal of 45,000 megawatts of additional electric efficiency by 2010. While there is much efficiency that the states will likely accomplish on their own, the federal government will have to come up with a much more powerful program of financial support if it is to substantially assist these efforts.

Energy Prices

Another means of reducing carbon emissions is to consider the full environmental, social, and national security costs associated with using them. Everything from the cost of the war in the Gulf to the health costs of air pollution would need to be included in the price of oil if is to reflect its true costs. By some calculations, this would make a barrel of oil worth $100. Yet unless some of these costs are included, the world will continue to overuse fossil fuels, and bear these costs indirectly.

Air pollution from automobiles, for example, is estimated to add more than $40 billion to annual medical bills, according to the American Lung Association. Including such costs in the price of energy would allow markets to more accurately determine the least expensive means of meeting energy needs. Governments could accomplish this by taxing energy to incorporate environmental costs into the price paid by consumers.

A 1990 study by researchers at Pace University in White Plains, New York, reviewed various estimates of the environmental costs of electricity technologies. The study found that electricity from coal would need to be priced at least 100 percent higher to cover its environmental costs, chiefly those resulting from air pollution-related damage. Oil-generated electricity would need to rise at least 50 percent, and natural gas much less.

Seventeen U.S. states are already incorporating environmental costs in their regulation and planning of electric utilities, though at levels far below those that might be justified. European countries are also beginning to account for the costs of pollution, primarily through increased taxes. Sweden, for example, proposed taxing sulfur and nitrogen oxide emissions in April 1990; the following month, France instituted a tax on sulfur dioxide emissions. Italy started taxing low-sulfur fuels at half the rate of high-sulfur fuels in July 1990. No such encouragement is found in the NES.

Another way of reflecting environmental costs is a broader energy tax linked to emissions of carbon dioxide. Such a tax would directly incorporate the anticipated costs of global warming in the prices paid for energy. Carbon taxes are fast becoming a reality in Europe. Both Finland and the Netherlands introduced such a tax in 1990, and Sweden and Norway levied them in January 1991. Germany, Italy, Japan, Switzerland, and the European Community are also weighing carbon taxes.

While most of the taxes proposed so far are relatively small, a larger tax of at least $100 per metric ton of carbon would be needed to significantly redirect energy trends. While this may seem like a huge sum, most countries including the United States already tax gasoline at an effective rate of more than $100 per metric ton. Indeed, Italy's current gasoline tax of $3.50 a gallon is equivalent to a carbon tax of more than $1,400 per metric ton.

Higher energy taxes can translate into investments in thicker home insulation, improved windows, more efficient vehicles, and compact fluorescent lighting. They also encourage the development of independent, decentralized, and less carbon-intensive generating technologies, such as solar, wind, and geothermal energy. In order to prevent any overall increases in the tax burden and to preserve the equity of the tax code, it is logical to enact an offsetting decrease in social security and income taxes.

The United States now has the lowest energy prices of any major industrial country. While everyone likes the notion of low energy bills, this is a fool's paradise. If we don't start paying a realistic price now, we will inevitably pay for it later through oil price induced recessions, lagging economic competitiveness, and a damaged environment. Raising energy prices should be an immediate national priority.

The Vision Thing

Its hard to ask for directions when you don't know where you're going. President Bush's new energy strategy is particularly flawed in its view of the long-run energy future. The administration's plan assumes that as late as 2030 the United States will be as dependent on dirty, insecure fossil fuels as it is today. While some increases in hydropower and alternative fuels production is assumed, virtually no significant additional contribution from solar energy, wind power, or geothermal energy is included in the National Energy Strategy projections for 2030.

Yet even the U.S. Department of Energy has recently estimated that the United States has an abundance of renewable energy sources. The country's annual influx of accessible renewable resources, for example, is more than 200 times its use of energy, and more than 10 times its recoverable reserves of fossil and nuclear fuels. According to a new study by U.S. government scientific laboratories, renewables could supply the equivalent of 50 to 70 percent of current U.S. energy use by the year 2030.

Contrary to the assumptions of the Bush strategy, steady advances have been made in a broad array of new energy technologies that would allow the world to greatly increase its reliance on renewable resources. The cost of solar thermal power has fallen 66 percent, wind power 75 percent, and photovoltaic electricity 90 percent over the past decade.

Many of the machines and processes that could provide energy in a solar economy are now almost economically competitive with fossil fuels, and rapid commercial development of several of these technologies is expected during the

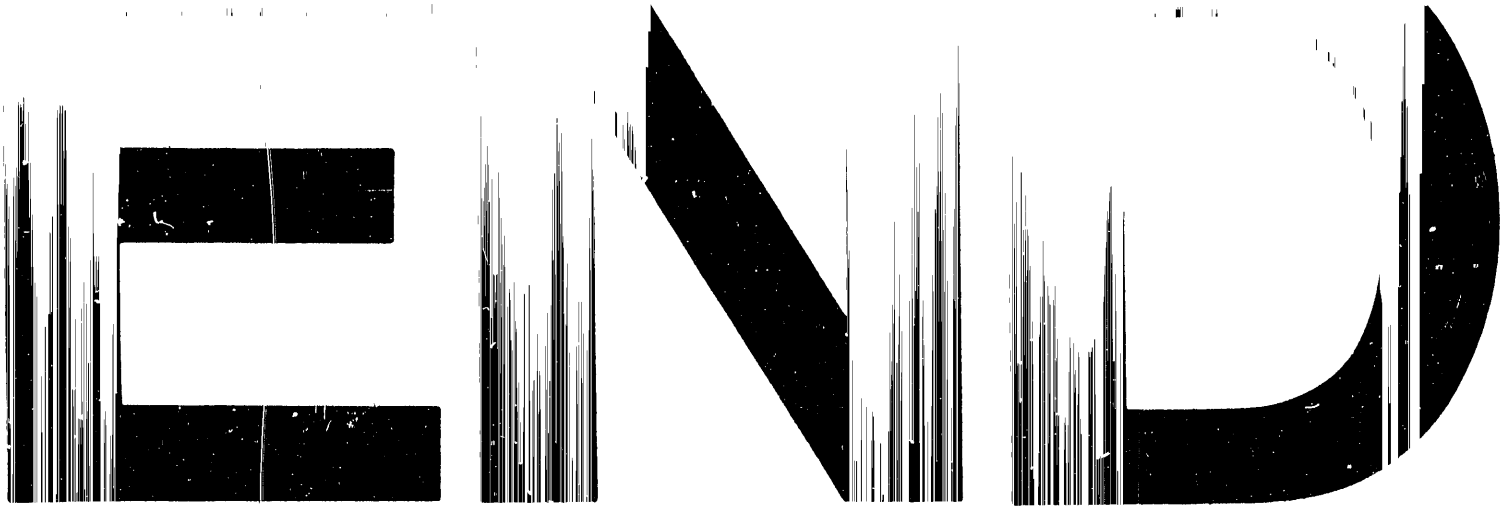
next decade--particularly with government support. Indeed, the progress to date would have been far more rapid if it were not for a 70-percent decline in oil prices between 1980 and 1986, and a comparable cut in U.S. government support during the same period.

The real challenge ahead is not technological. The greater task is to overcome narrow economic interests, and revamp policies to create sustainable energy systems. Raising energy prices is one essential tool. However, regulatory reform in the electric utility industry is a second important ingredient. In the past, utilities have been encouraged to build large new power plants, many of them fossil-fired. Recently, utilities in some parts of the country have increasingly turned to investments in improved energy efficiency and to buying power from independent producers of wind, biomass, and solar power--energy sources that do not add to the carbon dioxide in the atmosphere.

The federal government could do much more to assist the states that are pioneering new ways of setting utility rates of return, or factoring environmental costs into the planning of new power plants. New York, for example, is experimenting with a substantial charge against proposed new coal-fired plants. Such policies can increase competition, and lead to a future in which most new power plants involve renewable energy.

Congress would also be wise to look skeptically at the administration's proposal for reforming the public utility holding company act. The administration proposal could well end up giving utility monopolies carte blanche to build large, over-priced, environmentally damaging coal-fired plants, with little state regulatory oversight. This proposal could actually reduce competition, squeezing out small, innovative independent producers of renewable energy, reversing the progress of the past decade.

A renewable energy future might take decades to achieve, but it is now clearly achievable. The question is whether the country can summon the political will to begin a transition that is in some sense inevitable. President Bush would have us stay with fossil fuels until oil price increases and rapid climate change undermine the economy. The alternative is as obvious as the sunshine: an immediate and orderly start on an energy future based on energy efficiency and renewable energy resources.



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