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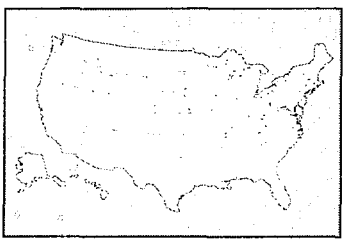
Survey of State Regulatory Activities on Least Cost Planning for Gas Utilities



Applied Science Division
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National Association of
Regulatory Utility Commissioners

April 1991

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Survey and Analysis of State Regulatory Activities on Least Cost Planning for Gas Utilities

March 1991

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MASTER

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Survey and Analysis of State Regulatory Activities on Least Cost Planning for Gas Utilities

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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 at each PUC was conducted by The Fleming Group (a sub-contractor to LBL), between September and November 1990. Written summaries were then prepared and sent to respondents and Commission chairs for verification and revision (see Appendix B).

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 (see Fig. ES-1). 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.

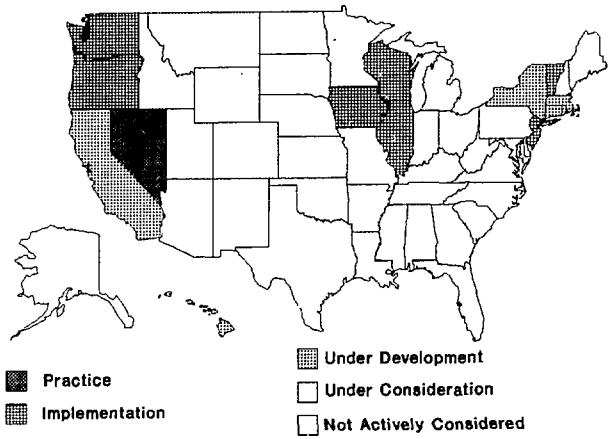
- Twenty-nine PUCs report that gas LCP is not actively being considered. Eighteen of these states indicated that utilities develop gas conservation programs on a voluntary basis. About one-third of these states indicated that integrated resource planning processes for electric utilities are in various 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).

Figure ES-1
Status of Gas LCP Regulations and Practices



- 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 types 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 preferred 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 eight 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, Nevada, 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 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. Incorporating the concept of meeting customer energy service needs entails a recognition that customers' costs must be considered along with the utility's costs in the economic analysis of energy options. 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 prudence 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 U.S. Department of Energy, 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.

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, i.e., least-cost planning (LCP) regulations, gas DSM programs, review of gas purchasing policies. The initial telephone survey was conducted by TFG and consisted of an extensive list of open-ended and multiple choice questions on various topics (see Appendix A for survey instrument). Based on responses from contacts, LBL/TFG prepared written summaries for each state, which were then sent back for verification and revisions. In addition, these draft summaries were sent to the chair of the PUC in that state. Typically, summaries were sent to 2-4 people at each Commission. We ultimately received comments back from about 45 states. Appendix B includes the written summary for each state.

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

Categorization of LCP practices necessarily involves some degree of subjectivity and judgment. Moreover, there has been significant controversy regarding the most appropriate method to utilize in assessing the status of state PUC least-cost planning practices for electric utilities, as evidenced by the discrepancies between Electric Power Research Institute (EPRI 1988) and the National Association of State Utility Consumer Advocate (Mitchell 1989) surveys which were published in 1988 and early 1989 respectively. In our survey, we attempted to adapt the EPRI ranking system 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? (see Appendix A). 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.

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.

In contrast, the NASUCA survey, conducted by Mitchell and Wellinghoff, asked structured questions of PUC personnel, which used a more rigorous and formal definition of LCP that identified practices that are "full-featured" from both a regulatory framework and utility planning perspective. They argued that the EPRI survey used much looser evaluation criteria which allowed states to be classified as having implemented LCUP even though one or more necessary procedural components were lacking. Components of their "full-featured" LCP process include: (1) A utility planning process that is established through statute, regulation, or case precedent in which the electric utility periodically submits for public review and comment a long-range IRP plan. The IRP plan must include a comprehensive analysis of demand and supply resource options available to meet or alter

forecasted demand, (2) the LCP process must be subject to public review, e.g., formal hearing where other parties can comment on the utility's plan and present alternative positions, (3) PUCs must integrate utility ratemaking and construction permit processes with the LCP process, e.g., future resource acquisitions such as construction of new power plants must be part of an approved LCP plan before they can proceed (Mitchell 1989).

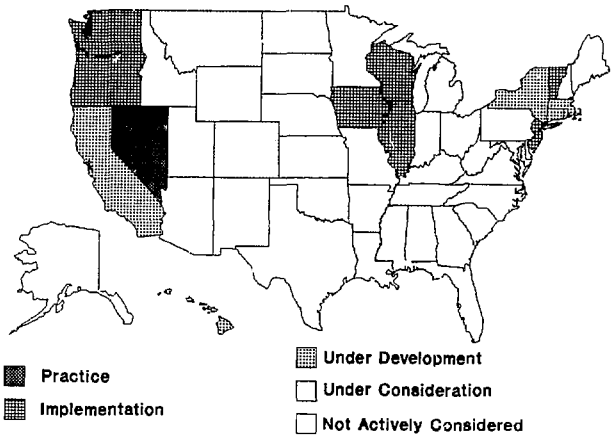
We think that the NASUCA approach has significant merit in assessing regulatory practices and processes related to electric resource planning, which are relatively mature in many states, have evolved over a decade, and where there are examples of utility IRP plans and decisions affected by the LCP process. However, gas integrated resource planning is by all accounts a new phenomenon and thus, our primary purpose is to identify states that are active in developing a gas LCP approach. One of our goals is to highlight the varying approaches that PUCs take to regulatory review and oversight of the elements of gas resource planning: long-range IRP plans, integration of supply- and demand-side resource options, assessment and implementation of gas DSM programs, and review of gas supply purchase practices. Given the relative immaturity of gas IRP, a primary objective of the survey is to compile and synthesize information on these topics and identify areas for future work that are needed to advance the state-of-the-art. 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

PUCs were asked if their state had a requirement for least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities as well as sources for the LCP initiative, e.g., state law, PUC order, utility proposal. Those PUCs that indicated that LCP was not actively considered or under consideration or rejected were also asked if there were particular reasons why LCP requirements had not been developed for gas utilities.

Twenty-nine 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 considering or developing LCP requirements for electric utilities and that they wanted to

Figure 1
Status of Gas LCP Regulations and Practices



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.

We categorized seven 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 (see Appendix B for individual

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

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

state summaries). Among this group, about half of the PUCs have made substantial progress in terms of developing a formal regulatory framework. 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 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 (CPUC 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

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

an ambitious conservation plan, parts of which have been approved, which includes a budget of up to $60 million over the next five years.

- **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 having 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 are being promulgated as a result of a PUC order. In 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.

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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	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.

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

- **Nevada** - Least-cost planning requirements were developed as a result of electric LCP/IRP requirements, and a 1987 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] Gas utilities serving northern Nevada are required to file a LCP in January 1992. Nevada's LCP regulation requires gas utilities to develop ten-year forecasts, three year action plans, and to include detailed assessments of the technical and market potential of conservation by end use, descriptions of proposed programs, and detailed cost/benefit analyses.

- **District of Columbia** - In March 1988, the District of Columbia 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 cost, 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 (ICC) promulgate a rulemaking procedure (this ended in January 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]

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

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

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 ICC 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 has proposed specific guidelines and requirements for the implementation of energy efficiency programs that apply to both electric and gas utilities which meet goals articulated in recent legislation passed by the Iowa General Assembly (Iowa Department of Commerce 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 Board and utility staff, Department of Natural Resources, and members of the Consumer Advocate Division of the Department of Justice (Smith 1990a). Under the Board's 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 Board expects gas utilities to file their first DSM plans by July 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 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.

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

- **Oregon** - In April 1989, the Oregon Public Utility Commission (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 yet 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 its LCP requirements for all major electric and gas utilities (Vermont Public Service Board 1990). The Board 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 provides 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 a projection of spot market versus long-term purchases for both firm and interruptible markets and 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 plan outlining the specific actions to be taken by the utility in implementing the long-range least-cost plan (Washington 1987).

One gas utility, Washington Water Power, has submitted a least-cost plan to the Commission, which will be set for hearing in April 1991. The other three gas LDCs are expected to file their plans in 1991.

- **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 an annual 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 is 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, summarize PUC respondents' assessments 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 assessments 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 tended 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 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, the State Energy Office, Department of Public Utility Control, the Office of Consumer Council, CAP agencies and community groups.

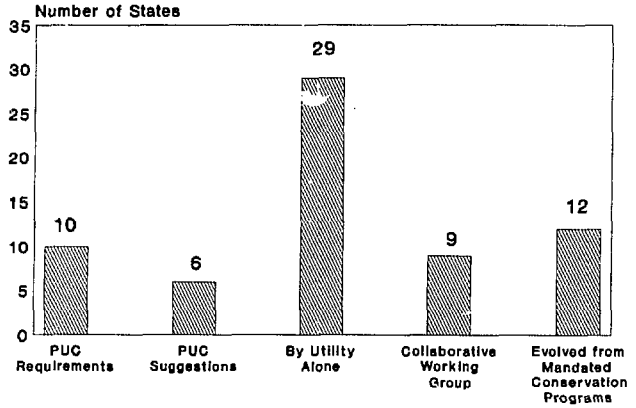
- **District of Columbia** - A collaborative group composed of staff from District of Columbia Natural Gas, Commission staff, DC Energy Office, Office of People's Counsel, and consultants developed 22 pilot DSM programs encompassing all sectors, which are currently being implemented.

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

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

[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



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 (the Residential Conservation Service audit) or initiated as a result of state statutes. For example, Oregon requires that utilities offer low-interest financing for conservation measures to residential customers (see Appendix B). States such as New Jersey, which are developing gas IRP processes, reported that utilities have offered gas conservation programs which have been operating for many years (since 1982 in New Jersey).

Finally, several PUCs reported that energy conservation goals for natural gas utilities have been developed either through PUC order or state statute. The Florida Energy Efficiency and Conservation Act (FEECA), (Florida 1989) mandated conservation activities for electric and large gas utilities, although the focus has been on electric utilities in part because only one gas utility (Peoples Gas System) was large enough so that participation was required. In its Order requiring an integrated least-cost plan, the District of Columbia Public Service Commission (1988) established very ambitious conservation targets to be achieved by 1998:

Residential Sector:	25% usage reduction
Multifamily Sector:	35% usage reduction
Commercial Sector:	18-25% usage reduction
by end use:	30% heating
	70% cooling
	20% water heating
	20% cooking

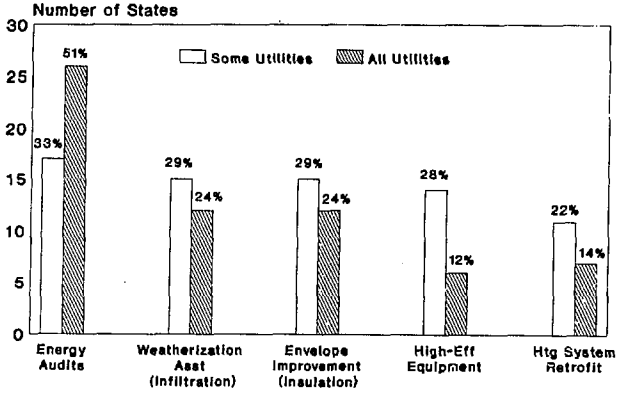
Types of DSM Programs

PUCs were also asked to describe the types 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, e.g., 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). It should be noted that these types of rates often serve a load retention purpose, either on their own or as part of a package of discounts. In some cases, interruptible rates are offered based on competitive market considerations rather than as a conscious strategy to control gas loads. Thus, it can be argued that interruptible gas rates should not always be viewed as a DSM option. 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 types 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

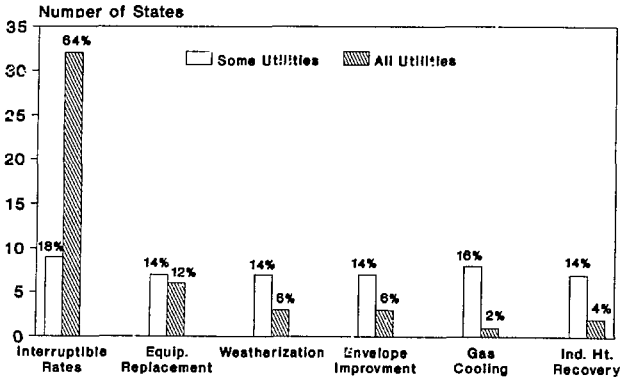
Figure 3
DSM Programs Offered by Gas Utilities
(Residential Customers)



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 (see Appendix B for gas utilities that were most active in DSM in each state).

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 locations with 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 few 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

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



utility DSM efforts.[12] Again, most PUCs were able to provide only a qualitative indication of the scope of DSM activity in terms of the number, type and scale of programs. 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.

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

Gas utilities that were identified by PUCs as active in demand-side management often were combination utilities. 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 represent about 41% of the gas utilities in the 15 most active states (30 of 73) 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 sold only 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).

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 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 vary among PUCs and utilities. For example, different analytic techniques and methods have been used to value 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

[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).

long-term contracts. Various names are sometimes associated with the different economic perspectives, although this is mostly a matter of convention.[14]

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	1
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	30

[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.

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 to customers.

[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.

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 of DSM programs is often not a major issue because gas DSM programs either do not exist or are quite small. A number of PUCs responded that gas utilities often favored the non-participant's test, but were either required to look at other economic perspectives, e.g., societal, or that PUC staff considered these other perspectives in their economic evaluation of DSM programs. In six states where gas LCP is currently not actively being considered or developed, two PUCs, Maine and Pennsylvania, indicated that utilities perform cost/benefit evaluations of proposed DSM programs, while the Utility Cost and Ratepayer Impact Measure tests are used by utilities or PUCs in four other states (Table 5). 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" (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. 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	X		yes, emphasis on TRC test
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

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 incremental costs that are avoided by gas utilities by these types of

programs. Only eight PUCs indicated that gas utilities or PUCs 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 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 and gas inventory charge, which is a negative component when evaluated in this context.

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

- **Wisconsin** - As part of an investigation on interfuel substitution, Commission staff has reviewed various approaches that can be used to calculate avoided gas costs, which were grouped into four general methods: average cost methods, generic method, load curve segmentation, and planning model methods (Kaul 1991).[16] Several Wisconsin utilities have used average cost methods as a proxy for avoided costs, but Commission staff has argued that average cost methods are less desirable because they do not reflect incremental costs. Table 6 provides a brief description of each method, while Table 7 summarizes strengths and weaknesses of each approach. The generic method draws heavily on approaches that have been used to determine avoided electric supply costs in which the capacity cost of a peaking plant is used as a proxy for all capacity costs and all remaining costs are treated as energy costs. However, it is unclear if a generic method can be developed that is

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

[16] The load segmentation curve approach has also been referred to as the "Targeted Marginal Approach" and was utilized in avoided gas cost valuation in a recent study of the DSM programs of New Jersey electric and gas utilities (RCG/Hagler Bailly 1990).

Table 6. Methods of Calculating Gas Avoided Costs

Method	Description
Average Cost Methods	These proxy methods divide sales into aggregated gas costs to get an average. This can be done on an annual or a seasonal basis and can be used just for commodity costs or can average both commodity and capacity costs together.
Generic Method	This approach designates one option for incremental capacity cost and one option for incremental commodity cost. For example, the capital cost associated with an LNG plant may be used as a proxy for capacity avoided costs. Utilities would use that cost as a proxy for avoided capacity costs, regardless of the supply option they actually choose to purchase. Similarly, an index of spot and long-term gas prices can be used as a proxy for avoided commodity costs.
Load Curve Segmentation	This method divides a load duration curve into segments, such as peak, heating, shoulder and base, and then determine which segment will realize the next increment or decrement of load. The costs associated with the next increment of supply are used as the avoidable costs. The next supply option to be added or dropped sets the system avoided cost.
Planning Model Methods	These methods use a gas dispatch model to develop a base case that optimizes supply purchases assuming demand levels without demand-side programs. The demand impacts of programs are then included. The supply modeling is redone and the costs of the two runs are compared. The difference in costs is used to calculate the avoided cost.[a]

Source: Adapted from J. Kaul, "Testimony of James Kaul," Wisconsin Public Service Commission, Docket D%-UI-103, Exhibit JK-1, Schdule 2, January 25, 1991.

[a]It is important to note that demand-side programs can either reduce or increase sales, depending on whether they are encouraging cost-effective conservation or conversion from alternate fuels to gas because it is a lower cost energy service.

Table 7. Methods of Calculating Gas Avoided Costs: Strengths and Weaknesses

Method	Strengths	Weaknesses
Average Cost	Easy to calculate Inexpensive LDCs familiar with method	Does not produce incremental costs
Generic Method	Manageable calculations Based on publicly available data Produces one set of costs for all LDCs	Allows for no differences between utilities Hard to know which commodity costs to include in index
Load Curve Segmentation	Easy to calculate Inexpensive Fits individual LDC needs Designates incremental costs	More appropriate for capacity than commodity costs Could produce wide variation in costs over time
Planning Model	Calculates individual LDC avoided costs Appropriate for both capacity and commodity costs	Difficult to use Costly Existing models have limitations

Source: J. Kaul, "Testimony of James Kaul," Wisconsin Public Service Commission, Docket D5-UI-103, Exhibit JK-1, Schedule 2, January 25, 1991.

widely applicable to the unique operating circumstances of local gas distribution companies. Planning model methods rely on long-range gas dispatch models that analyze gas supply options and adjust gas dispatch to incorporate gas efficiency programs. Scenarios that do not include conservation can then be compared with costs of scenarios that do include gas efficiency programs to determine the value of these programs. While this approach is theoretically appealing, existing long-term gas models are difficult to use and are not yet widely utilized by gas utilities for this type of analysis. Load curve segmentation methods are simplified marginal approaches which utilize the current gas supply plan and determine where the plan is likely to change on the margin because of gas DSM programs.

Cost Recovery of DSM Programs

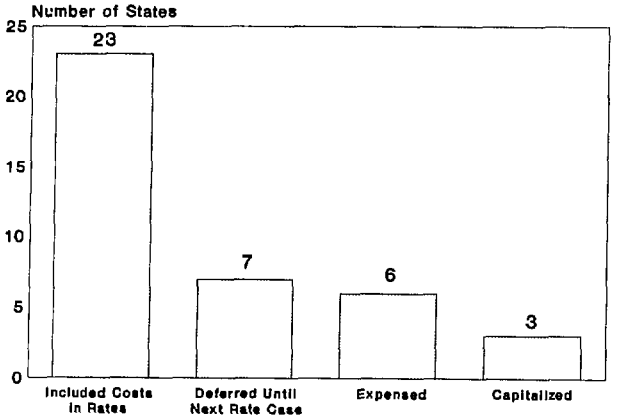
PUCs report that DSM program costs of gas utilities are recovered through various methods. Most PUCs tended to give general responses, with 23 PUCs stating that program costs were included in rates (see Figure 5). Seven PUCs said that cost was deferred until the utility's next general rate case.[17] Six PUCs noted that DSM program costs were expensed and treated as general administrative costs. Several PUCs (see Appendix B, Illinois) reported that various types of DSM program costs received different cost recovery. Typically utility administrative costs were expensed while other program costs, such as customer incentives for efficient equipment, could be capitalized. Fourteen PUCs, all from states that are not actively considering gas LCP, did not respond to this question, often because gas utilities did not have significant DSM programs.

Financial Incentives to Utility Shareholders for Promoting Gas Energy Efficiency

PUCs were also 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" (Moskovitz 1989). Although the analysis and examples were drawn primarily from the context of electric utilities, the underlying argument appears to apply to the economic incentives faced by most gas utilities as well. Thus far, PUCs that have attempted to reward utilities for effective implementation of IRP and DSM have focused principally on developing incentive mechanisms for electric utilities. A recent study found that PUCs in 17 states have adopted regulations or procedures for electric utilities that either overcome disincentives (by allowing ratebasing, adjustments for

[17] States are Iowa, Nevada, New York, Rhode Island, Vermont, and Washington and the District of Columbia.

Figure 5
DSM Program Cost Recovery



"lost revenues", or decoupling utility earnings from sales) or provide various types of bonuses for exemplary DSM programs (Hirst and Goldman 1990).

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 8). 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."[18] For programs classified as customer equity and service programs, PG&E's shareholders will retain 5% of the actual program expenditures as an incentive.[19] 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

[18] 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.

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

Table 8. 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	≈4.0	NA
Cost-Plus Programs	-	$23.6
Expected Earnings	1.5	$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 expected gas earnings are estimates, based on discussions with PG&E.

that actual program costs do not exceed planned program costs.[20] A penalty mechanism that would reduce earnings for poor performance is also included (CPUC 1990).[21]

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, Nevada, New Jersey, and the District of Columbia. For example, the Iowa Utilities Board has proposed that utilities be granted a reward if the benefit/cost ratio for their overall DSM plan exceeds 1.25 (based on a societal test adapted from the California Standard Practice Manual) and the utility expends more than 75% of the spending level approved by the Board. Similarly, a penalty will be imposed if benefit/cost ratios that are less than one are achieved or if the utility expends less than 75% of the spending level approved by the Board (Iowa 1990b).

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 example, in 1986, it was estimated that about 5% of the U.S. commercial floor space was cooled by natural gas, which competes against various electric space cooling alternatives (AGA 1988a). Gas industry representatives, such as the American Gas Association (AGA) have argued that gas cooling represents a cost-effective option that can either improve utility load profiles or reduce an electric utility's summer peak load in areas with near-term capacity shortfalls (AGA 1988b). Thus, PUCs increasingly face requests by gas utilities for special air conditioning rates for commercial customers or rebates to encourage space cooling installations.[22] Fuel substitution policies also arise in the residential DSM programs of electric and gas utilities that provide customers with financial incentives to purchase high-efficiency equipment, such as heat pumps or gas condensing furnaces.

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

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

[22] An AGA study (1988a) estimated that 20 gas utilities offer a reduced gas air conditioning rate as well as rebates to encourage commercial space cooling installations; rebates ranged from $50 to 230/ton.

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.[23]

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, Vermont, and Wisconsin) 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. Fuel substitution issues are often quite controversial. For example:

- 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.[24]

- **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.

- **In Massachusetts,** the PUC stated that Boston Gas may challenge a number of conservation measures proposed by Massachusetts Electric on the grounds that they

[23] 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, then 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 are dependent on the perspective of the respective gas or electric utility (See CPUC and CEC, "Standard Practice Manual",1987 for more discussion.)

[24] 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.

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, 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. Rhode Island has a Fuel Switching Task Force which consists of gas and electric utilities, PUC staff, and the Energy Office. Initially, they have focused on electric and gas cooling options.

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).[25] 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 by-product 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).

A 1987 study by American Gas Association (AGA) documented the development of so-called "least-cost" purchasing requirements in a number of gas-consuming states.

[25] 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.

These purchasing requirements typically obligated LDCs to buy the least expensive gas available consistent with providing reliable service (Smoot 1987).[26] "Least-cost" purchasing requirements were an issue for AGA primarily because they pose increased financial risks for LDCs in the event that PUCs determine that gas utilities acted imprudently and impose cost disallowances.

In May 1988, the Interstate Natural Gas Association of America (INGAA 1988) conducted a survey of PUC staff in 29 states on state prudence policies regarding gas purchasing practices of LDCs. The INGAA study found that:

- Only two of the 29 states had formal prudence guidelines, Pennsylvania and Iowa. PUCs generally prefer not to have specific guidelines because it allows flexibility to respond to market and regulatory changes and the facts in a particular case. However, fourteen states noted that they used unofficial, unpublished prudence guidelines.

- Fourteen states have some form of least-cost purchasing rules which were based on statute in eight of these states.[27] Two states, Massachusetts and North Carolina, have adopted or were considering "best-cost" purchasing policies which emphasize price and security.

- PUCs disallowed purchased gas costs for three types of imprudent actions: bad buys, i.e., price too high for a specific contract; bad strategy, i.e., LDC used wrong supply strategy, but prices of individual contracts were appropriate; and bad operations i.e., questions about system operation.

- Some PUCs were developing additional oversight mechanisms to augment traditional prudence review such as review of gas supply plans (11 states), pre-purchase approvals (4 states) and regulatory policies regarding LDC transportation.

In this survey, our intent was to followup on the AGA and INGAA studies, but not attempt a comprehensive treatment of issues related to regulatory review of gas purchase policies of LDCs. We asked a series of questions on this topic which allowed us to determine changes in regulatory activities that have occurred since the AGA and INGAA studies. For example, we asked respondents if PUCs conducted prudence reviews of gas

[26] The AGA study reviewed statutory provisions, regulations, and case law in some detail for the following states: California, Illinois, Iowa, Maryland, Michigan, Nevada, New York, Ohio, Pennsylvania, Virginia, Washington, West Virginia, and Wyoming. Other states included in the analysis were Indiana, Massachusetts Mississippi, North Carolina, Texas, and Wisconsin.

[27] Alabama, Arkansas, Connecticut, Illinois, Iowa, Massachusetts, Michigan, New York, Ohio, Pennsylvania, Utah, Virginia, Washington, and West Virginia.

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 prudence reviews of gas purchases. Among those states that conduct prudence reviews, Figure 6 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 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 prudence reviews (Connecticut, Massachusetts, Michigan, Texas).

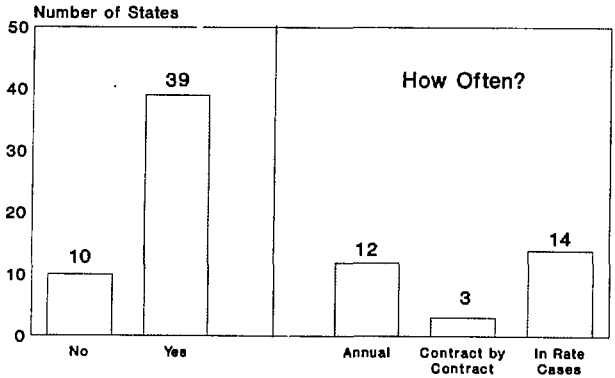
- Thirteen states indicated that they have adopted "least-cost" purchasing rules, either because of state statute, PUC order or rulemaking, or implicitly through practice (see Table 9).

- With a few exceptions, PUCs generally indicated that there was no relationship between prudence 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 9). Discrepancies exist because of methodological differences, because this survey was conducted 2-3 years after those studies and because we used an expanded sample compared to the INGAA report. We relied primarily on respondent answers and did not conduct a detailed and independent review of state statutes and case law as was done in the

Figure 6
39 PUCs Conduct Prudency Reviews
of Gas Purchases



AGA study. Several state PUCs (e.g., District of Columbia and Nevada) that have adopted least-cost purchasing requirements since the INGAA study 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 (see Appendix B, section V of each state). Table 10 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 types of topics mentioned and our categorization scheme will help in interpreting the issues identified by state PUCs:

Procurement includes issues related to supply options available to LDCs, choice of suppliers, portfolio mix;

Table 9. 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 Smoots 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).

Table 10. Key Regulatory Issues Identified by PUCs

	SUPPLY ONLY									LCP AND DSM							
State	Procure-ment	Transport-ation	Supply Relblty	Pipeline Addition	Bypass	Prudence Review	Dereg-ulation	FERC/ Jurisd.	Rates	LCP	DSM	Load Forecast	Envr.	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	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	Procure-ment	Transport-ation	Supply Reblity	Pipeline Addition	Bypass	Prudence Review	Dereg-ulation	FERC/ Jurisd.	Rates	LCP	DSM	Load Forecast	Envr.	Promo Practices	Fuel Subst.	Electric Only	None
Kansas					X	X	X		X								
Kentucky		X			X				X								
Louisiana																	X
Maryland	X																
Michigan		X	X													X	
Maine		X									X						
Minnesota						X		X									
Missouri		X			X	X		X									
Mississippi					X												
Montana			X													X	
N. Carolina				X		X											
N. Dakota	X				X												
Nebraska																	X
New Hamp.		X								X	X						
New Mex.																	X
Ohio		X							X								
Oklahoma																	X
Penn.											X						
S. Carolina	X				X												
S. Dakota																	X
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	4	2	5	4	7

Transportation includes topics related to transportation customers, open access, obligation to serve these customers, re-entry and exit fees;

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;

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

Deregulation/Unbundling - refers to unbundling of gas rates and services for non-core customers;

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

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

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, prudence 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 policies (6), 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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APPENDIX A

SURVEY QUESTIONNAIRE

February 1991

State

Letter sent to:

Contacts:

Amount of natural gas sold in '87 _____

Percentage of U.S. Total _____

Heating Degree Days _____

Gas Utilities, Sales Revenue, Customers

I. The status of state PUC least-cost regulation and practices for gas utilities.

1. Does the state of XXX require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities?

2. For all responses describe the current situation in more detail in your state with respect to IRP for gas utilities:
[Interviewer will check off categories and then classify.]

Not actively considered	Under consideration	Under development	Implementation	Practice
___ not at present time	___ staff\ commissioner discussion	___ active consideration	___ PUC requirements in place	___ plan includes provisions for review and evaluation of demand and supply options of LCP/IRP
___ internal staff discussion	___ next step - formal development	___ workshops\ working groups	___ formal plans submitted by utilities	___ LCP/IRP programs are in place and running
___ commission or legislative interest	___ discussion in legislature	___ met with utility's executive	___ regulations in effect	___ utilities have completed 1 or more LCP/IRP cycles
___ internal discussion re: planning process	___ other _____	___ PUC\ legislative requirements under development	___ legislation in effect	
___ other _____	_____	___ legislation pending	___ other _____	
_____		___ other	_____	
_____ Rejected				

3. **If not actively considered** or **under consideration** - Could you discuss some of the reasons why LCP requirements have not been developed/adopted for gas utilities in your state?

____ Surplus supply conditions
____ Don't know
____ Rejected for electric
____ Rejected for gas
____ Other

4. Describe.

5. **If under development, in implementation,** or **in practice,** what is the source of the regulatory requirement for your state's LCP\IRP? Check all that apply.

	Date
____ Legislative Initiative	_____
____ Rate Case Decision	_____
____ PUC Order	_____
____ PUC Regulation	_____
____ Utility Proposal	_____
____ Other-_____	_____

6. How did the requirement develop?

____ Grass roots, or Popular Advocacy
____ Legislative Initiative
____ PUC Staff Proposal
____ Rate Case
____ PUC Order
____ Other - _____

7. Describe.

8. Are all gas utilities subject to the same LCP/IRP requirements?

9. If No - Which gas utilities are required to prepare an IRP/LCP Plan?

10. Which of these are combined (gas and electric) utilities?

11. What percentage of gas sales in the state is subject to LCP/IRP requirements?

____ None
____ Calculate from sales est._____
____ Other- _____

12. May we have a copy of these utilities integrated resource plans?

13. May we have a copy of the legislation or PUC order requiring LCP/IRP Plans?

14. Please discuss the steps used in the IRP process or resource planning for gas utilities, specifically with respect to consideration of DSM options.

15. Which of these iterative steps are included?(Interviewer check steps and number in sequence.)

____ End-Use Load Forecasting
____ Identification of DSM Scenario
____ Estimation of conservation impact (technical and market potential)
____ Modified Peak Day and Sales Forecast
____ Revision of Gas Supply Requirements
____ Revision of Cost of Service
____ Calculate Change in Sales
____ Combination for Integrated Plan
____ Continue steps to achieve equilibrium
____ Other -_____

16. Has your state developed energy conservation goals for natural gas utilities?

17. Does the state require that target levels of conservation be achieved by a certain date?

18. Describe

II. The type and extent of natural gas DSM programs in effect, including fuel substitution.

19. How are DSM programs currently developed by gas utilities in your state?

____ PUC Requirement
____ Suggestions by PUC
____ By utility alone
____ Collaborative Working Group
____ Evolved from earlier utility conservation programs
____ Other- _____

20. Please describe the type of DSM programs that have been implemented by gas utilities in each customer class?

DSM Programs	Utilities		
Residential\Multifamily	All	Some	None
Energy audits; Informational	____	____	____
Weatherization Assistance (infiltration measures)	____	____	____
Envelope improvements (insulation measures)	____	____	____
Financial incentives for high efficiency equipment	____	____	____
Heating system retrofits	____	____	____
Fuel substitution	____	____	____

Other _____

Commercial/Industrial

	All	Some	None
Replace with high efficiency equipment	____	____	____
Weatherization	____	____	____
Envelope Improvement	____	____	____
Gas Cooling rebates	____	____	____
Fuel substitution	____	____	____
Interruptible rates	____	____	____
Industrial Heat Recovery	____	____	____
Other _____			

21. Which gas utilities in your state have the most comprehensive DSM programs?

22. Presently, at what stage of development are gas utility DSM programs in your state?
____ A few pilots
____ Pilot programs in many areas
____ Some full scale, some pilots
____ Mostly full scale
____ Other _____

23. Does your state offer financial incentives to gas utilities to encourage conservation?

24. If Yes, please describe. (Note any shareholder incentives.)

25. Could you discuss how the costs of DSM programs are recovered by gas utilities?
____ Deferred until next rate case
____ Included In Rates
____ Implied Prudent Recovery
____ Administrative - expensed
____ Program costs - capitalized
____ Other

26. Describe.

27. Has your PUC adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution by customers?

28. Describe.

29. Has your PUC required electric utilities to encourage gas use for particular end-uses?

30. If Yes - For which gas end-uses?
    _____ Residential Heating
    _____ Residential Hot Water Heating
    _____ Other residential -_____
    _____ Commercial Cooling
    _____ Commercial Cooking
    _____ Commercial Heating
    _____ Other commercial -_____
    _____ Industrial

31. Have gas utilities intervened or opposed electric utility DSM programs that offer rebates or financial incentives for high efficiency equipment that potentially competes with gas-fired equipment?
_____ High-efficiency Heat Pumps
_____ Water Heating - Direct Control
_____ Residential Electric Thermal Storage
_____ Other

32. Describe

III. Economic tests used to evaluate gas utility DSM programs.

33. What economic tests are used by gas utilities to measure DSM program cost effectiveness?
_____ Utility Revenue Requirements Test
_____ Ratepayers Impact Measure Test (No Losers Test)
_____ Total Resource Cost Test
_____ Societal Test _____ Other_____

34. Are gas utilities required to use certain criteria in screening DSM options?

35. If Yes, What screening criteria are used?
    _____ Cost effectiveness
    _____ Energy conservation potential
    _____ Required lead time
    _____ Lifetime of option
    _____ Free ridership
    _____ Cream skimming
    _____ Other _____

36. If No, have they developed or proposed criteria?

37. One important element involved in quantifying the benefits of DSM programs and supply acquisition is a determination of the long-term costs that are avoided by gas utilities by these type of programs. Has the PUC or gas utilities in your state developed a methodology to estimate the avoided costs of new gas supplies?

38. Please describe the approach
39. If yes, can we get a copy of order, decisions or utility filings?

40. Have gas utilities in your state developed estimates of long-run marginal costs?

41. If Yes, briefly describe your conclusions.
42. May we have a copy of your marginal cost study?

43. What methods do gas utilities use to value the benefits of DSM programs?

____ Wholesale Rate ____ Retail Rate ____ Avoided Gas Cost
____ Other _____

44. Describe

IV. Relationship between prudency reviews of gas utility purchasing practices and IRP/LCP initiatives.

45. Could you describe your PUC's approach to oversight of distributor gas purchasing practices, with respect to specific types of prudence "standards" and reviews?

____ Prudency review (in fuel cost adjustment hearings)
____ Pre-contract approval
____ No approval
____ Reviewed in rate cases
____ Other

Please Explain.

46. Does your PUC conduct a prudency review of gas purchases?

47. If Yes - How often?

	All	Some	None
Annually	____	____	____
Contract by contract as new supplies are negotiated	____	____	____
In Rate Cases	____	____	____
Other	____	____	____

48. Has your state adopted specific criteria, rules, or guidelines that are used in prudence reviews of gas purchasing policies?

49. If Yes, please describe:

50. Has your state adopted some form of "least-cost" or "best-cost" purchasing rules? ("best-cost" policies explicitly emphasize price and security of supply; however, reliability is not ignored and assumed as a given in least-cost purchasing requirements).

51. If Yes- What is it based on?
_____ based on state statute
_____ PUC order/rulemaking
_____ Other _____

52. Does your state PUC require gas utilities to file gas supply plans in advance of purchases?

53. If Yes - By what authority?

54. What is the relationship between the prudency review process and the LCP\IRP process?
_____ None
_____ None - it is a separate activity from LCP\IRP.
_____ They are linked. How? _____

55. Could you discuss recent trends in the relative mix of long-term, short-term and spot supplies for your state's gas utilities?

V. Projections of state commission activity over the next 5 years.

56. Do your gas utilities forecast any increases in gas demand during the next 5-10 years or major capacity additions to the existing gas transportation system (i.e., pipeline additions)?

57. Please explain.

58. Discuss the future direction of gas utility regulation in your state. What are the key regulatory issues facing gas utilities? (List in rank order.)

59. What activities do you expect your PUC to conduct in the area of integrated resource planning for gas utilities?

60. What is the size of the PUC Staff working on gas LCP\IRP? _____

61. List any independent research planned by staff.
62. Describe

APPENDIX B

STATE SUMMARIES

ALABAMA

Gas Utilities Serving State (gas-only or combination)

1) Alabama Gas Corporation (Alagasco) (regulated - gas only)
2) Mobile Gas Service (regulated - gas only)

All other regulated utilities each serve less than 500 customers. Alagasco serves the majority of the state.

I. Status of state PUC least-cost regulation and practices for gas utilities

Alabama does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. With Commission oversight, the gas utilities participate voluntarily in a collaborative approach to demand-side management (DSM) programs. The Commission considers Alagasco to have a strong DSM program in place, and Mobile Gas is following closely behind. If Alagasco ever decides to cease implementation and practice of DSM programs the Commission would consider intervening. Concerned primarily with guaranteeing an adequate and reliable supply of natural gas, the Commission has focused on a "portfolio approach" with natural gas utilities.

Alagasco and Mobile test DSM measures using a conservation impact estimate taking into account technical and market potential. Utility forecasting also incorporates conservation measures. Conserved energy in current DSM programs amounts to < 0.5% of total sales and is not significant to offset supply requirements. No target levels or conservation goals are set by the state for conservation of natural gas. All DSM programs are developed solely by the gas utility companies.

II. Type and extent of natural gas DSM programs (including fuel substitution)

All natural gas utilities have provided energy audits and informational materials for residential and multifamily customers. The two major utilities (Alagasco and Mobile Gas) offer weatherization assistance, envelope improvements, financial incentives for high efficiency equipment, heating system retrofits, and fuel substitution opportunities.

In the commercial\industrial sector, all gas utilities offer interruptible rates. One large scale and some small scale gas cogeneration projects are underway.

According to Mr. Reed, Alagasco offers the most active DSM programs of all the gas utilities in the state. They presently have some full scale and some pilot programs in effect.

DSM costs incurred for providing audits, weatherization assistance, or other conservation measures are recovered through the utilities rates. Fuel substitution has not been recognized through a formal Commission policy. The Commission does not require electric utilities to encourage gas use for any particular end-uses. Hearings have been pending for two years on fuel substitution policies.

The gas utilities have intervened in the promotional practices of the electric utilities. In particular, the electric utilities' program which encourages: 1) all-electric households; and, 2) the promotion of high-efficiency electric heat pumps.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The Commission does not require the gas utilities to use certain criteria in screening DSM options, nor has the Commission developed or proposed criteria. The gas utilities currently use the ratepayers impact measure (RIM) test to evaluate DSM program cost effectiveness.

A methodology to estimate the marginal costs of new gas supplies has been developed by the gas utilities. The methodology presently used entails determining the price of gas as if all supplies had been bought from the pipeline and then determining the spot market price purchases and comparing the differences. To value the benefits of DSM programs, the gas utilities employ the wholesale rate.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

A state statute gives the Commission authority to pre-approve contract purchases before gas utilities exercise the contract. However, gas utilities are not required to file supply plans in advance of purchases, but they do provide informal briefings to the Commission. No formal prudence reviews are required in Alabama. The state has not adopted specific criteria, rules, or guidelines for prudence reviews. Natural gas purchases and the bidding process are reviewed every month by the Commission.

There has been a trend toward spot market purchases over the past ten years. Within the past five years the gas utilities fluxed between reliance on long-term, short-term, and spot supplies. Over the past three years, Mobile Gas Service has had heavy reliance on the spot market.

V. Future PUC activities and key regulatory issues

Gas utilities forecast no significant increases in demand during the next 5-10 years or any major capacity additions to the existing gas transportation system. A steady 1%-2% growth in demand is projected.

The key regulatory issues facing gas utilities are:

1) competition between electric and gas for new residential markets; and,
2) the potential conflict between spot market purchases versus firm purchases.

There is no Commission staff research presently being conducted in regard to integrated resource planning for gas utilities.

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ALASKA

Gas Utilities Serving State (gas-only or combination)

1) Enstar Natural Gas (gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/integrated resource planning (IRP) has not been required by the Commission for natural gas utilities. Enstar Natural Gas is currently developing some preliminary least-cost planning measures. No energy conservation goals for natural gas utilities are in effect.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Enstar voluntarily provides informational materials regarding energy conservation and the efficient use of natural gas for residential and commercial customers. Advertising costs for energy information can be recovered through the utility's rates. No other conservation programs are offered by gas utilities in Alaska. Very few interruptible rates are offered to commercial customers. Enstar is in a growth mode and has been active in hooking up new customers for the past five years.

No formal policy or rules regarding DSM programs encourage fuel substitution. However, last year the Staff asked the Commission to examine load forecasting issues for electric and gas utilities. A fuel substitution policy may be under advisement some time in 1991. Chugach Electric Company with subsidized federal funds, encouraged conservation, energy awareness, and conversion of electric space heating to more efficient gas heating between 1985-1989. This program helped alleviate the capacity crunch experienced by Chugach.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No economic tests are used by gas utilities to measure DSM program cost effectiveness due to the non-existence of natural gas DSM programs.

Most electric generation is fired by natural gas with gas supplies from Enstar and directly from the producer. In the last year Enstar has experienced competition from other suppliers, and the Commission has had to determine a methodology for avoided costs of new gas supplies. An avoided gas methodology had been determined for cogeneration projects and this methodology will be applied similarly for natural gas utilities on a case-by-case basis. The Commission outlines avoided costs methodology for cogeneration projects in the Alaska Administrative Code (3AA 50.770, April 1989). Long-run marginal costs have recently been under consideration.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Prudence reviews of gas utilities purchases are conducted on a case-by-case basis. There are no specific criteria, rules, or guidelines that are used. However, the Commission relies on a series of case laws which specify that the Community as a whole must benefit. Contract terms must be reasonable with explanations of why the company agreed to the contract terms.

The Commission does not require pre-approval of supply contracts. Enstar is locked into a long-term supply contract until the year 2030 with renegotiation scheduled for 2010. The contract is somewhat flexible, specifying that the utility may reduce its take-or-pay requirements, and reduce its purchase of gas if the utility looses a non-core customer.

V. Future PUC activities and key regulatory issues

Key regulatory issues facing the gas utility in Alaska are:
1) Threat of bypass;
2) Transportation costs; and
3) Certification requirements as the gas utilities move into new service areas.

No formal research on natural gas LCP is being conducted by the Commission staff, but the staff does follow activity in other states.

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ARIZONA

Gas Utilities Serving State (gas-only or combination)

1)	Southern Union Gas Company	(gas only)
2)	Southwest Gas Corporation	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/integrated resource planning (IRP) is not required for gas utilities. There has been internal staff discussion, however, the staff has been occupied with electric LCP/IRP.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The Commission does not require the gas utilities to implement conservation or DSM programs.

There are no formal policy or rules regarding DSM programs that may encourage fuel substitution by customers. However, Southwest Gas registered a complaint with the Commission regarding Arizona Public Service's rebate program to builders or customers of dual fuel homes. Arizona Public Service wanted to restrict rebates (e.g., heat pumps and load control devices) to all-electric customers. This policy by Arizona Public Service would preclude dual fuel customer eligibility for a rebate, and encourage the development of all-electric homes. A settlement was reached between Arizona Public Service and Southwest Gas in which Arizona Public Service agreed to provide rebates for dual fuel and all-electric customers.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The Commission staff has not evaluated or required specific economic tests to evaluate gas utility DSM programs.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Prudence reviews are conducted by the Commission. The gas utilities file an Annual Procurement Plan with the Commission. The Plan includes forecasted demand accompanied by explanations of the sources of supply and expected cost. No pre-approval of contracts is required. Purchase gas adjustment (PGA) reviews are held according to provisions stipulated by the Commission upon review of the annual procurement filing.

The Commission is in the process of establishing specific criteria and guidelines for PGA reviews in response to a Southwest Gas Corporation rate case of August 1989 which involved affiliated interest in purchasing (Docket No. U-1551-89-102 & 103, Decision No. 57075).

The majority of gas purchases have involved spot purchases and short-term contracts. A small quantity of the gas supply is arranged through long-term contracts.

V. Future PUC activities and key regulatory issues

The key regulatory issue facing gas utilities involves procurement policies. It is possible that the Commission would extend the electric utility LCP/IRP to include natural gas, however, no immediate action is planned.

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ARKANSAS

Gas Utilities Serving State (gas-only or combination)

1)	Arkansas Louisiana Gas Company/ARKLA	(gas only)
2)	Arkansas Western Gas Company	(gas only)
3)	Arkansas Oklahoma	(gas only)
4)	Associated Natural Gas	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Although there has been internal staff discussion regarding least-cost planning (LCP)/integrated resouree planning (IRP) for natural gas utilities, Arkansas does not require LCP/IRP for natural gas utilities at the present time. Commission regulations have concentrated on ensuring that gas utilities purchase the least-cost gas supplies.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The Arkansas Commission is expressly authorized by statute to propose, develop, solicit, approve, require, implement and monitor energy conservation programs and measures by utility companies.[1] Some natural gas utilities provide: energy audits; weatherization assistance; and, envelope improvements for residential/multifamily customers. Weatherization expenses may be recovered through gas utility rates. Some of the natural gas utilities offer interruptible rates to their commercial/industrial customers.

Any fuel substitution which takes place in the residential/multifamily or commercial/industrial sectors is solely the result of competition between the gas and electric utilities to gain market share and not a formal Commission policy or DSM initiative.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The gas utilities in Arkansas are not required to use any specific criteria in screening DSM options. The Commission is not aware of any criteria that the utilities would use. Neither the Commission nor the gas utilities have developed a methodology to estimate the avoided costs of new gas supplies.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Arkansas Commission does not conduct prudence reviews on a regular basis. The Commission is currently involved in a review in a special ARKLA docket bifurcated into two

[1] Arkansas Statute No. 23-3-401, 1977.

phases. Phase I of the docket was not a routine review and involved only specific contracts. Phase II will involve ARKLA's overall gas purchasing practices. The state has not adopted specific criteria, rules, or guidelines that are used in prudence reviews of gas purchasing policies. The Commission does not require gas utilities to file gas supply plans in advance of purchases.

State statute requires gas utilities to purchase the most advantageous gas supply, however, the statute does not discuss any specific criteria regarding "least-cost" or best-cost" purchasing rules.

The Commission does monitor the trends in the relative mix of long-term, short-term and spot supplies for Arkansas' gas utilities.

V. Future PUC activities and key regulatory issues

The gas utilities of Arkansas do not forecast any increases in gas demand during the next 5-10 years or major capacity additions to the existing gas transportation system. Presently, there has been much activity in pipeline construction in Arkansas, but it is not all attributable to LDCs. Arkansas Energy Resources is building an interstate pipeline. NOARK, a privately held company, has recently gained approval to construct an intra-state pipeline.

Future regulatory issues addressing natural gas utilities will be:
1) developing gas purchasing standards and incentive programs for LDCs; and,
2) integrated resource planning for natural gas utilities.

Integrated resource planning for natural gas utilities may well be an issue in the next year or so.

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CALIFORNIA

Gas Utilities Serving State (gas only or combination)

1) Pacific Gas & Electric	(combination - gas & electric)
2) Southern California Gas Company	(gas only)
3) San Diego Gas & Electric	(combination - gas & electric)
4) Southwest Gas Company	(gas only)
5) CP National	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

In 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. The California Energy Commission (CEC, not the PUC is responsible for long-term energy planning. Long-range supply and demand-side options are included in the Biennial Fuels Report prepared by the California Energy Commission (CEC). The long-term demand forecast includes the effects of existing gas DSM programs and state building standards for new construction. Utilities are not required to evaluate all cost effective options, only those implemented. Utility DSM programs are monitored by the PUC. DSM programs are evaluated by the PUC using The California Standard Practice Manual for Cost Effectiveness, which is applied to both gas and electric utilities. About 97% of all natural gas sales are subject to this program evaluation requirement. These cost effectiveness tests were developed by PUC and CEC staff. 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.

II. Type and scope of natural gas DSM programs (including fuel substitution)

In California, utilities normally propose DSM programs during their general rate cases, which occur every three years. In August 1989, a collaborative working group was formed consisting of electric and gas utilities, the Division of Ratepayer Advocates (DRA), California Energy Commission (CEC), and a broad-based group of other stakeholders. In 1990, the Collaborative group produced a report ("An Energy Efficiency Blueprint for California") which produced recommendation for expanded DSM programs and incentives for utility shareholders.[2] In August 1990, the CPUC approved expanded DSM programs for both electric and gas utilities.[3]

All gas utilities in California have DSM programs which include energy audits, weatherization assistance, building envelope improvement, and heating system retrofit programs for their residential and multifamily customers. Additionally, a few utilities also have financial incentives for high efficiency equipment, fuel substitution, and new construction programs. In the

[2] Report of the Statewide Collaborative Process, "An Energy Efficiency Blueprint for California", January 1990.

[3] California Public Utilities Commission (CPUC), Decision 90-08-068, August 29, 1990.

commercial and industrial markets, all gas utilities have DSM programs which include high efficiency equipment replacement, interruptible rates, and gas end-use energy audits. A few utilities also have weatherization assistance, building envelope improvement, gas cooling rebates, fuel substitution, industrial heat recovery, and new construction.

Pacific Gas & Electric Co., and Southern California Gas Co. are considered to have the most active DSM programs in the state. Most DSM programs are running at full scale, with a few pilots.

As noted earlier, in August 1990, the CPUC approved incentive/penalty mechanisms to reward utility shareholders for vigorously and efficiently managing these DSM programs. "Shared savings" type incentives were approved for Pacific Gas & Electric (PG&E) and San Diego Gas and Electric (SDG&E) for certain energy efficiency programs, while a variable (and higher) rate-of-return was approved for Southern California Gas Company. SoCal will earn 14% of the program cost for "DSM resource programs," provided that actual program costs do not exceed planned program costs. A penalty mechanism that would reduce earnings for poor performance is also included.[4]

DSM programs costs are recovered in rate cases. Estimated program costs are funded in a balancing account and expensed. This procedure is usually approved by the PUC during a rate case.

There are no formal rules regarding DSM programs that may encourage fuel substitution by customers. The PUC has not required electric utilities to encourage gas use for particular end-uses, but has granted some limited approval for commercial cooling and agriculture pumping. Natural gas utilities have not intervened in electric cases, but electric utilities have intervened or opposed gas utility DSM programs that offer rebates or financial incentives for high efficiency equipment that potentially competes with electric equipment. This occurred in the spring of 1990 during the Southern California Gas Co rate case (Application No. 88-12-047).

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The gas utilities use any of four economic tests to measure DSM program cost effectiveness: the utility revenue requirements test; the ratepayers impact measure test, (also known as the "no losers" test); the total resource cost test; and the participant test. Additionally, a societal test may be used, which is a variant of the total resource cost test. The PUC uses these four tests as described in the "Standard Practice Manual" 2nd edition, revised in February 1989.

Gas utilities utilize the various economic tests specified by the Standard Practice Manual in screening DSM options. The PUC has not adopted a prescribed methodology to estimate avoided gas costs. 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

[4] California Public Utilities Commission (CPUC), Decision 90-08-068, August 29, 1990.

and general (A&G) expenses, PG&E compression losses as well as the forecast commodity price of gas, which is the most significant element.[5]

In a recent decision, the CPUC indicated its commitment to develop rates that are long-run marginal cost-based and has issued broad costing guidelines to be used by gas utilities, based on results of a lengthy proceeding (I.86-06-005) and series of workshops.[6] These guidelines specify methods that should be used by utilities to estimate LRMC for the following system components: customer-related, distribution, transmission (interstate, local, and "backbone"), and storage (seasonal and peaking). Utilities are expected to file new LRMC studies based on these guidelines.

IV. Relationship between prudence reviews of gas utility purchasing practices and integrated resource planning

The California PUC conducts an annual reasonableness review of all planned gas supply purchases for gas only utilities, such as Southern California Gas Co. Gas supply purchases of the combination utilities are reviewed during the electric cost adjustment account annually. There are no specific criteria, rules or guidelines that are used in prudence reviews of gas purchasing policies.

Recent trends in gas supply purchasing indicate an increase in long term contracts in the relative mix of long term, short term and spot market supplies.

V. Future PUC activity and key regulatory issues

Gas utilities forecast a significant increase in demand during the next 5-10 years, principally as a result of increased gas use for electric generation, cogeneration, and enhanced oil recovery. The 1990 California Gas Report (CGR), which is prepared and submitted annually by the state's gas utilities, forecasts a 16% increase in gas to be taken by the California utilities over the next five years. Moreover, pending air quality restrictions mandated by the South Coast Air Quality Management District (SCAQMD) may lead to an increase in gas use as a result of gas substitution of oil in an effort to improve local air quality in the Los Angeles air basin.

There is a general consensus on the need for additional interstate pipeline capacity to serve California and several pipeline projects are at various stages of acquiring permits and project development. The CPUC, in affirming the need for new capacity, ruled to "let the market decide." Proposed projects include new pipeline (Kern River, Altamont, WyCal, Mojave) or expansions of existing interstate pipelines (the El Paso expansion). Applications for these projects have been submitted and in some cases approved by FERC and the PUC (where necessary).

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[5] Pacific Gas & Electric Company 1990, "Annual Summary Report of DSM Programs 1989-1990 Technical Appendix," p.2.

[6] CPUC, D.90-07-055, "Order Instituting Investigation on the Commission's own motion into implementing a rate design for unbundled gas utility," July 1990; See also CPUC, D.90-01-021, January 1990.

The key regulatory issues facing gas utilities are:

1) degree or type of deregulation (e.g., proposals for capacity brokering of firm interstate transportation capacity, gas procurement policy and responsibility for noncore customers);

2) impact of additional interstate pipeline capacity; and,
3) environmental effects.

There are five FTE staff persons working on gas DSM. Currently no further activities are planned by the PUC in the area of natural gas LCP/IRP.

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COLORADO

Gas Utilities Serving State (gas-only or combination)

1)	Public Service Company of Colorado	(combination - gas & electric)
2)	Colorado Springs Department of Utilities	(combination - gas & electric)
3)	Greeley Gas Company	(gas only)
4)	KN Energy	(gas only)
5)	Peoples Gas Company	(gas only)
6)	Rocky Mountain Natural Gas	(gas only)
7)	Citizens Utility Company	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP) or integrated resource planning (IRP) for natural gas is under development. In the mid 1980s the PUC tried to implement LCP/IRP proceedings for electric utilities, but the utilities viewed LCP/IRP as a prerogative of utility managers. The Commission's awareness of LCP activity in other states, staff initiative and support from consumer advocacy groups led the PUC to conduct a two year study of LCP/IRP and to issue a policy document (Docket No. 90I-227EG, December 5, 1990). Electric utility representatives and Commission staff in collaboration with the Colorado Office of Energy Conservation, and the Colorado Office of Consumer Counsel have been instrumental in preparing the policy statement. The intent of the policy document is to make Commission regulatory objectives explicit and open to comment from all interested parties.

The Commission staff is relatively small and resources are limited, therefore, innovative and specific DSM programs must originate with Colorado utilities. The Commission's focus will be on electric LCP/IRP, with gas LCP/IRP following in about a year.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The Commission does not require any DSM programs. Any programs now in effect evolved from earlier conservation programs. Public Service Company of Colorado performs energy audits for its residential customers, and does make energy conservation information available. A fee is charged for energy audits. Interruptible rates are offered to commercial customers by all gas utilities. A hybrid electric/gas cooling pilot program was implemented by Public Service Company of Colorado to encourage commercial customers to switch to gas cooling during system peaks.

The PUC has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution, but a policy statement is expected to be issued. There are some experimental pilots in which combination utilities have encouraged electric customers to switch to gas use for a particular end use (i.e., commercial gas cooling and residential gas clothes drying).

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Economic tests and analysis methods used to evaluate DSM programs will be addressed in Commission hearings.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

All gas utilities file monthly gas cost adjustments. The Commission performs audits annually in which a prudence review may be included in the annual audit and hearing. There are no formal rules or guidelines that are used in prudence reviews of gas purchasing policies.

Many local distribution companies have been transporting gas themselves rather than engaging in long-term contracts.

V. Future PUC activities and key regulatory issues

The PUC staff does not follow gas forecasts at this time. The Trans Colorado Pipeline (scheduled completion in 1991) is being built by a group of utilities for the purpose of exporting gas out of the state. This pipeline is expected to eliminate the current gas supply bubble in Colorado.

The key regulatory issues facing gas utilities are:
1) Rules for transportation; obligation to serve; pricing; and, back-up service; and,
2) Conversion of pipelines to common carriers.

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CONNECTICUT

Gas Utilities Serving State (gas-only or combination)

1)	Connecticut Natural Gas	(gas only)
2)	The Southern Connecticut Gas Company	(gas only)
3)	Yankee Gas	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Connecticut has begun the development of a least-cost plan (LCP)/ integrated resource plan (IRP) process for all natural gas utilities. The Connecticut General Statute of 1989 requires gas utilities to file a ten year supply and demand forecast on an annual basis. The statute (Public Act No. 89-50) was a modification of a previous public act (No. 87-32). Along with gas supply information (i.e., estimates of peak loads, projected forecasts and sources of supply), the Act stipulates that gas utilities identify "specific measures to control load growth and promote conservation." [7]

The LCP/IRP initiatives were drafted by Commission staff and codified in the state legislature. All three major gas utilities are subject to the same LCP/IRP requirements. About 99% of all gas sold is subject to the ten year forecast requirement.

A consultant to the three utilities has prepared a draft management audit report entitled, "Assessment of Connecticut Gas Companies Integrated Planning Strategies and Practices." The final report is due January 1991.

Annual conservation planning for gas utilities with respect to DSM options proceeds along the following steps:

1) In a rate case, the utility proposes an annual conservation budget. The Commission determines the total conservation budget and, in some cases, may provide guidelines on how the money is spent.

2) Intervenor groups provide input and resolve differences through a " Conservation Collaborative Group" for each of the three gas utilities. The collaborative members include representatives from the utility, Office of Policy and Management (OPM), the State Energy Office, the Department of Public Utility Control, the Office of Consumer Council, CAP agencies, and community groups. The Group is monitored and coordinated by a Commission staff member. The resolution process involves:

   - creating a list of all possible residential conservation measures;
   - agreeing to specific measures and program design methodologies to be implemented;

[7] Open Docket No.90-10-01, which includes Commission review of "The Supply and Demand Forecast" of each utility.

- determining program design (i.e., time period; the cost to purchase and install any necessary equipment; the amount of estimated savings; and program delivery system. A cost/benefit ratio is also determined.

- The Group also must include estimated savings of each program, specifically: 1) how well the utilities have estimated projected savings versus actual savings; and, 2) after a heating season, the effect upon energy consumption is evaluated (the first heating season - 1989-1990 - has not been analyzed yet, evaluation is pending). Data is not available to adjust end-use estimates of conservation. The gas utilities have approached conservation in three ways: 1) help low-income customers conserve energy; 2) improve community relations; and, 3) save energy for all customers.

3) All collaborative members attempt to develop a consensus on how much of the total budget will be spent on any one DSM program, and file a report with the Commission of all programs agreed upon.

4) The Commission modifies, approves, or rejects the group's proposal. The Commission must approve the proposal for any programs to be implemented.

Connecticut is currently engaged in the fourth step for Connecticut Natural Gas (CNG) and Yankee Gas for the 1991 budget year. Southern Connecticut has yet to receive approval for all of its 1990 budget year programs. Programs have not yet been implemented for a full heating season, and therefore, program evaluation has not been fully implemented.

An iterative process used by the Collaborative Group includes provisions for: 1) estimating and validating screening model assumptions and demand reductions; 2) estimating the impact of DSM programs on supply plans; 3) designing future plans; and, 4) drafting appropriate documentation for regulators. Integration of DSM measures has not been included in utilities forecasting of supply purchases, although they are used to reduce future demand estimates.

The Connecticut DPUC concentrates on how much energy can be conserved through a given conservation budget rather than specific conservation targets. The DPUC approved a $950,000 conservation budget for Yankee Gas, an $875,000 conservation budget for Southern Connecticut, and a $769,000 conservation budget for CNG. These budgets are an annual allotment for each year starting in 1990 and every year thereafter until a new rate case is filed.

II. Type and extent of natural gas DSM programs (including fuel substitution)

DSM programs are currently developed through each collaborative working group with Commission approval. All gas utilities perform energy audits; provide informational material, weatherization assistance, and envelope improvements. CNG sponsors a set back thermostat program for space heating. CNG also combines its resources with community groups and other state energy agencies in order to provide extended conservation measures for housing rehabilitation projects. Yankee Gas has implemented direct installation of attic insulation in public housing, and low income heating. Southern Connecticut Gas sponsors community outreach programs that train and employ inner-city youths to install insulation and other weatherization measures. Incentives are currently not offered for heating system retrofits. Program approval of financial incentives for

high efficiency equipment for new gas customers was rejected because the Commission believes this would encourage additional gas load, and was not as cost beneficial as other opportunities.

Energy audits are performed for small commercial/industrial customers. Some sub-metering pilots allow larger customers to know how much gas they consume by end-use. Through this boiler inspector/maintenance program, gas utilities collect end-use data as well as provide information to customers on operating their equipment more efficiently. Interruptible rates are offered to all commercial/industrial customers with dual fuel capabilities. CNG will provide financial assistance for weatherization and envelope improvements if the cost-benefit ratio is greater than two.

Yankee Gas Company is reported to have the most effective DSM programs. All programs are limited by the company's total budget which is recovered in their base rates as a utility expense.

There is no formal policy or rules regarding DSM programs which would encourage fuel substitution by customers. Oil use has been discouraged, but the state has not outlined a policy recommending customers to switch to either gas or electric.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The utility revenue requirements test is the primary quantifiable economic test used to evaluate gas utility DSM programs. Three other tests (i.e., ratepayers impact measure, total resource cost, and societal) are also used to measure DSM program cost effectiveness. The gas utilities are required to conduct the above cost-effectiveness analysis as the first step in designing DSM programs. All gas companies collaborative groups adjust the results of the four quantitative tests by qualitative standards (i.e., providing the set-back thermostat program to low-income customers as opposed to non low-income). DSM programs are screened through the following criteria taking into account long-term revenue requirements over the lifetime of a measure and adjusted for qualitative factors: cost effectiveness; energy conservation potential; required lead time; lifetime of option; free ridership; cream skimming. The Southern Connecticut Gas Company uses its own version of the California Standard Practice Manual tests.

The Commission and the gas utilities have developed a simple, static methodology to estimate the avoided costs of new gas supplies. The Commission staff uses the following steps: 1) estimate how much gas is saved; 2) run an economic dispatch model for the gas supply portfolio; 3) estimate the marginal cost of gas, and identify the marginal supply - contract versus per unit mcf energy cost of the contract; and,4) include the per unit mcf savings which includes the utility avoided capacity costs. This avoided gas and capacity cost is used by the gas utilities to value and design the DSM programs until evaluation data becomes available.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Oversight of distributor gas purchasing practices is conducted through purchase gas adjustment proceedings. The Commission also performs management audits no less frequently than every six years, and is currently performing a conservation and load management audit. Rate cases

are done no less than every five years. There are legislative requirements (as referred to above in Section I) for management audits and rate-case reviews.

Supply contracts are reviewed as part of each rate case. No pre-approval is required. Spot supplies provide the primary source of summer gas (April 15 - October 15). From October 15 - April 15, firm supplies are relied on primarily with some LNG peaking support.

V. Future PUC activities and key regulatory issues

Iroquois, a Canadian gas project is constructing a new pipeline which will serve Connecticut.

Key regulatory issues facing gas utilities in Connecticut include:

1) Development of firm transportation rates;
2) Fuel substitution policies - Allowing preferential gas fuel expansion policy, decreasing the use of electric and oil, and increasing the use of gas for a cleaner environment;
3) Development of a gas dispatch pool;
4) Develop loss of load probability approach to gas; reserve requirements as opposed to the current design year process.

There is a staff of one (F.T.E.) working on gas LCP/IRP.

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DELAWARE

Gas Utilities Serving State (gas-only or combination)

1)	Delmarva	(combination - gas & electric)
2)	Chesapeake Utilities Corporation	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Delaware has no least-cost planning (LCP) or integrated resource planning (IRP) requirement for natural gas utilities. Presently, the Staff is working on LCP for the electric utilities. Natural gas LCP has been limited to internal staff discussion.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Demand side management programs (DSM) for natural gas utilities are not required in Delaware. Delmarva performs a "Total Home Comfort Audit" upon customer request which provides an analysis of a customer's heating and cooling system (i.e, cost of replacing with high-efficiency equipment; cost of operating present system vs. upgrade). No follow-up work after the initial audit is furnished.[8] Chesapeake Utilities Corporation does not offer energy audits or any other conservation programs to its residential customers.[9] Fuel substitution for residential/multifamily customers is encouraged by Delmarva and Chesapeake to the extent that it increases the gas utilities market share, not as a demand side management program.

The gas utilities advertise opportunities for commercial and industrial customers to install high efficiency natural gas equipment. The marketing departments of gas utilities promote fuel substitution. The Commission does not consider the above two programs to be DSM. Both utilities offer interruptible rates.

Any costs incurred by the gas utilities in implementing conservation programs could be included in the gas utilities operating and maintenance expenses, but this issue has not come before the Commission.

A formal policy or rules regarding DSM programs that would encourage fuel substitution by customers has not been adopted in Delaware. The Commission has not required electric utilities to encourage gas use for any particular end-uses. Gas utilities have not intervened in or opposed electric utility DSM programs that offer rebates or financial for high efficiency equipment that potentially competes with gas fired equipment.

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[8] Information on the Total Home Comfort Program was received via telephone interview with William Ferguson of Delmarva Power & Light on October 23, 1990.

[9] Tom Bacon of Chesapeake Utilities Corporation stated that Chesapeake does not offer any conservation programs for natural gas in its Delaware service territory (October 22, 1990).

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Delmarva performs no economic evaluation of its Total Home Comfort Audit Program. The Commission has not required economic tests to evaluate gas utility DSM programs.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Delaware Commission conducts annual fuel cost adjustment hearings for both Delmarva and Chesapeake. No specific criteria, rules, or guidelines govern gas purchasing policies. Least-cost or best-cost purchasing rules have not been adopted. Gas utilities are not required to file gas supply plans in advance of purchases, however, supply purchase information is reported in the annual filing. The amount of short-term gas purchase contracts has increased during the past three years.

V. Future PUC activities and key regulatory issues

Delmarva anticipates that the increase in natural gas demand over the next 5-10 years will be the result of gas-fired electric generation.

Activity regarding natural gas regulation will be limited in the near future due to the Commission's effort in developing and implementing an LCP/IRP for electric utilities. It is possible that natural gas LCP/IRP regulation will follow after the electric LCP/IRP is complete.

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DISTRICT OF COLUMBIA

Gas Utilities Serving State (gas-only or combination)

1) District of Columbia Natural Gas (DCNG) (gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

District of Columbia Public Service Commission Order No. 8974, of Formal Case (F.C.) 834, Phase II issued on March 16, 1988 requires DCNG to implement an integrated least-cost plan (LCP).

DCNG's Integrated Least-Cost Planning process includes the following steps:[10]

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;

The process is iterative to insure that all supply and demand options are evaluated on an ongoing basis. The iterative process includes: identifying a DSM scenario; forecasting DSM impacts according to end-use models; forecasting demand by end-use; matching the supply plan to demand; evaluating cost of supplying gas and the cost of the DSM scenario; calculating rate impacts; calculating the change in demand; and, identifying the optimal least-cost plan.[11]

DCNG's integrated least-cost plan also 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.[12]

Conservation goals for natural gas utilities were established in F.C. No. 834. However, these targets "are not requirements imposed by the Commission. If a utility and its working group find that certain targets are unachievable or uneconomic, the utility may explain these circumstances."[13]

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[10] District of Columbia Natural Gas, A Division of Washington Gas Light Company, Formal Case No. 834, Phase II, Integrated Least Cost Plan, Executive Summary and Plan, Volume I of XV, September 4, 1990, pp.17-18.

[11] Ibid, p. 19.

[12] Ibid, pp. 18-19.

[13] Public Service Commission of the District of Columbia, Opinion and Order, Formal Case No. 834, Phase II, Order No. 8974, March 16, 1988, p.62.

The Commission "expect(s) that the targeted reductions would be achieved"[14] by 1998. The targets are as follows:[15]

Residential Sector:	25% usage reduction
Multi-family Sector:	35% usage reduction
Commercial Sector:	18% - 25% usage reduction
by end use:	30% heating
	70% cooling
	20% water heating
	20% cooking

II. Type and extent of natural gas DSM programs (including fuel substitution)

DCNG offers energy audits for all residential customers. This program evolved from the earlier federal RCS program. DCNG's collaborative working group composed of utility representatives, Commission staff, the District of Columbia Energy Office (DCEO), the Office of People's Counsel, and consultants developed pilot DSM programs which are currently being implemented. Residential pilot programs include: weatherization assistance (insulation and infiltration measures); boiler/furnace replacement assistance and loan program; clock thermostat program; and, equipment grant program (water heaters, dryers, oven/range). DCNG also offers a Therm Buster program to its residential customers. This program provides a cash incentive to customers who decrease their therm usage over a specified period of time.

Audits are available to multi-family customers as well as boiler/furnace replacement, high-efficiency equipment grants, 3-5 cogeneration projects, and a pilot rehabilitation program. The Rehabilitation program provides a $500 per unit incentive to developers of low-income multi-family dwellings if high-efficiency boilers/furnaces are installed.

Commercial customers are offered energy audits, gas chiller incentives, weatherization assistance (insulation and infiltration), and loans for high-efficiency equipment. The utility has conducted surveys of cooking end-use in 200 area restaurants.[16] Interruptible rates are offered to all commercial customers.

Twenty-two pilot energy conservation programs are being implemented by DCNG. These include energy audit, education, weatherization, and equipment efficiency programs.

Currently, most of DCNG's DSM programs are on a pilot program basis. Future DSM programs will involve expansion and modifications of its pilot programs into full scale programs,

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[14] Ibid, p. 64.

[15] Ibid, pp.63-64.

[16] DCNG, Integrated Least Cost Plan, September 4, 1990, pp. 36-37.

and the addition of three new pilots: new commercial design; gas-fired generation; and, municipal boiler/furnace installation assistance.

Financial incentives to gas utility shareholders to encourage conservation are not offered, however, the Commission is presently considering this issue. Recovery for DSM program costs are reviewed in each rate case.

The Commission has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution.

DCNG has intervened in electric utility rate proceedings where it has argued against several electric utility DSM programs that offer rebates or financial incentives for high efficiency equipment that would potentially compete with gas-fired equipment (i.e., high-efficiency heat pumps, water heaters, and residential electric thermal storage). DCNG also intervened in the proceedings on PEPCO's 1990 Integrated Least-Cost Resource Plan.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

F.C. No. 834, Order 8974 specifies that "the all-ratepayers test serve as the predominant test in developing least-cost plans."[17] In Order 9627 the Commission noted that the "Commission-adopted All Ratepayers test does not authorize or provide for consideration of alternative fuels."[18] Utilities are also encouraged to use other tests in determining an appropriate mix of demand-side programs.

The Commission requires screening criteria of DSM options test for cost-effectiveness, energy conservation potential, free ridership, and cream skimming.

The development of a long-run marginal cost model is under development under the current LCP. Various methodological approaches are being discussed in the working groups. DCNG uses the wholesale rate of natural gas to value the benefits of DSM options when used in conjunction with the All Ratepayers Test.

Three separate PC-based models have been developed by DCNG as part of the preparation of the Integrated Least-Cost Plan. DCNG has developed a financial model, the Distribution Facility Simulator (DFACS), to estimate the non-gas cost of service for the District of Columbia. The DFACS model produces the net impact on rates and customer bills that results for proposed conservation incentives. The Gas Supply Model (ROGM) simulates an optimum long range gas acquisition strategy. The specific DSM programs to be implemented and the estimated level of

[17] F.C. 834, Order 8974, March 16, 1988, p.47.

[18] F.C. 834, Order 9627, January 10, 1991, p.2.

implementation are determined by the DSM Optima model. This model selects the least-cost mix of conservation and DSM programs required to meet predetermined therm savings targets.[19]

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

DCNG submits an annual Gas Procurement Report which provides an explanation of supply plans. The Commission also conducts rate case reviews any time DCNG requests a rate increase. Any irregularities may be reviewed in a rate case. An order is anticipated by the Commission in F.C. No. 874 on additional rules and guidelines for gas procurement practices.

LCP reviews are conducted independently of prudence reviews.

V. Future PUC activities and key regulatory issues

Key regulatory issues facing DCNG include:

1) Commission analysis of target conservation goals;
2) Evaluation of initial two-year pilot programs; and,
3) Interruptible and special contract customer considerations.

Future natural gas LCP/IRP activities will include the participation of all collaborative working groups to develop, monitor, and implement DSM programs. There are an estimated 2.25 FTE Commission staff members working on natural gas LCP. The Commission staff is conducting independent research on such areas as externalities and commercial fuel use.

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[19] District of Columbia Natural Gas, Integrated Least Cost Plan, Executive Summary and Plan, Vol.I of XV, pp.12-18, September 4, 1990.

FLORIDA

Gas Utilities Serving State (gas-only or combination)

1) Peoples Gas System, and nine other investor owned gas utilities (gas only)
2) Twenty-nine municipal gas utilities (gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Florida does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities, and the topic is not actively considered at this time. Florida has very few gas customers compared to electric customers - 350,000 gas customers to six million electric. Saturations are low for gas heating for residential and commercial customers. Only 25% of all gas sold in Florida is subject to PUC control. The remaining 75% is sold to transportation or industrial customers, or to municipal distribution companies. Industrial customers purchase gas directly from the pipeline. There is one gas pipeline serving most of the state, Florida Gas Transmission, which just became an open access transmission carrier this year.

II. Type and extent of natural gas DSM programs (including fuel substitution)

In 1980, the Florida Energy Efficiency and Conservation Act (FEECA) mandated conservation activities for electric and large gas utilities. Utilities must file a conservation plan with the PSC which indicates a company goal for each program, and allows for concurrent cost recovery of any conservation related expense. Gas utilities must sell at least 100,000,000 therms per year to be required to participate, and only one gas utility, Peoples Gas System, is that large. All gas DSM programs are designed to assist in controlling electric growth. As such, they are perceived by the smaller gas utilities as marketing programs. These other utilities have requested participation in the conservation programs cost recovery, and have programs similar to Peoples Gas.

In the residential/multifamily market, DSM programs include: energy audits; financial incentives for high efficiency equipment; heating system retrofits; some limited electric and oil substitution programs; and, gas cooling rebates. In the commercial/industrial market DSM programs include: high efficiency replacement equipment; gas cooling rebates; fuel substitution programs; and, small packaged cogeneration. All gas utilities have interruptible rates.

Most of the DSM programs are characterized as full scale programs, although the utility is testing two load-building pilot programs (gas space conditioning and small packaged cogeneration), and two utilities are considering programs to spur natural gas vehicle fueling station growth.

Conservation costs are recovered concurrently. Program costs are estimated every six months. These estimated costs are recovered in rates, and any reconciliation of balances is done at the six month interval.

The PSC formally encourages fuel substitution in Florida to cope with the rapid rise in electricity demand as a result of population growth. Natural gas is recommended whenever possible

to reduce the electric growth rate, especially in water heating, and for the northern third of the state, space heating. The 1989 revision to 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. The PSC retracted, avoiding a charge of violation of first amendment rights of the electric utility. That is, the argument that the electric utility cannot be forced to advertise a competitor's product without violating its right to free speech.

Electric utilities offer rebates or financial incentives for high efficiency equipment which potentially competes with gas-fired equipment. The gas utilities do not intervene because of the relative size difference between electric and gas utilities.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The investor owned utilities measure DSM program cost-effectiveness with two tests: utility revenue requirements test, which uses 10 years of program expenditures and 20 years of benefits; and the ratepayer impact measure test. A total resource or societal test is not used, because there is not enough gas demand for an equivalent mix of energy sources. Actual vs. estimated gas demand is measured using utility billing records. Gas utilities are required to monitor total end-use although these programs are not yet in place.

DSM screening criteria are not required by the PSC. The Florida PSC wants to avoid a formalistic approach to the analysis of DSM programs for gas utilities. There are no methodologies developed by the PSC or the gas utilities to estimate the avoided costs of new gas supplies, or long-run marginal costs.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives

The Florida PSC does not conduct a prudence review or approval of distributor gas purchasing practices. Florida Gas Transmission Co. is the only pipeline and it serves most of the state. Florida Gas Transmission Co. instituted open access on August 1, 1990. This change may result in some type of supply plan review procedure over the next 18 months. Gas utilities may only convert 20% of current sales this year, and another 25% in 1991, which could make the change to open access a more significant issue.

V. Future PUC activities and key regulatory issues

Demand for natural gas now exceeds pipeline capacity, but not supply. Florida Gas Transmission Co. is now trying to measure additional demand for current customers. The company is presently adding 100 MMCF a day to increase from 825 to 925 MMCF/day. Additionally, ANR Pipeline Company has indicated that it intends to refile an application to build a gas pipeline across the Gulf of Mexico.

The key regulatory issues facing gas utilities are:
1) Incentive rates for natural gas marketing programs;
2) Prudence reviews of supply planning portfolios; and,
3) Deregulation, or streamlining the regulation concerning interruptible rates in order to increase rate flexibility.

Little, if any, activity in IRP is planned for gas utilities due to the relatively small portion of sales subject to PSC control. There is the PSC staff equivalent of .5 F.T.E. assigned to gas conservation issues. No independent research is planned by staff.

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GEORGIA

Gas Utilities Serving State (gas-only or combination)

1) Atlanta Gas Light Company (gas-only)
2) United Cities Gas Company (gas-only)

All other natural gas distribution companies are small municipal utilities which are not regulated by the Commission.

I. Status of state PUC least-cost regulation and practices for gas utilities

The state of Georgia does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. Electric regulatory matters are a priority item at this time.

II. Type and extent of natural gas DSM programs (including fuel substitution)

No residential or commercial DSM programs are required by the Georgia Commission. Presently, Atlanta Gas voluntarily provides energy audits, and some limited weatherization assistance and envelope improvements to their residential customers, primarily for new construction. Interruptible rates are offered to commercial customers by both Atlanta Gas Light and United Cities. The Commission passed a promotional practices ruling (Docket #3618-U) in the Spring of 1989, which it rescinded on December 18, 1990. The Commission is restarting rulemaking proceedings on promotional practices which are intended to complement current efforts in LCP/IRP.

The Commission does not require electric utilities to encourage gas use for particular end-uses. The electric utilities filed pilot DSM programs in November 1990 which are being reviewed by the Commission staff. The gas companies have not submitted comments on the electric utilities' filed DSM programs. Commission action on the programs is expected prior to May 31, 1991.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No economic tests are used by gas utilities to measure any conservation or DSM program cost effectiveness, nor has the Commission proposed any. Gas utilities have not developed a methodology to estimate the avoided costs of new gas supplies.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Commission has no oversight authority over gas utility purchases. Commission authority extends only to operation and management reviews. If an issue does arise during a management review, the Commission does have general authority to conduct a review of any discrepancies. The Commission has no specific criteria, rules, or guidelines that would be used in reviews of gas purchases, nor has the Commission adopted any form of least-cost or best-cost purchasing rules.

Gas utilities are not compelled to file gas supply plans in advance of purchases. The gas utilities consider information on purchasing as proprietary and confidential. The Commission does have knowledge of the utilities supply forecast through each utility's annual filing. Mr. Cearfoss noted that in the past three years there have been increased purchases on the spot market.

V. Future PUC activities and key regulatory issues

Mr. Buckner stated that Georgia Power anticipates an increased use of natural gas to fire electric generation. The Commission is also examining the use of compressed natural gas (CNG) vehicles which would boost the consumption of natural gas.

Mr. Cearfoss noted that the Staff has expressed interest in natural gas least-cost planning, and that this could be a future regulatory issue facing gas utilities in the next 3-5 years.

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HAWAII

Gas Utilities Serving State (gas-only or combination)

1) GASCO - produces and distributes synthetic gas to the Hawaiian islands.

I. Status of state PUC least-cost regulation and practices for gas utilities

Hawaii has entered the first phase of establishing a framework for least-cost planning (LCP)/integrated resource planning (IRP) for both electric utilities and GASCO. Issues to be addressed include: resource options and evaluation methods; appropriate technical tools, data requirements, and budgetary considerations; relevant cost-benefit analysis (i.e., inclusion of externalities and other factors); and the commission role. Energy utilities are submitting the first framework draft after February 5, 1991. The Commission will require utilities to formulate and submit a plan one year after the framework has been approved. Hearings are scheduled for May 1991. End-uses for synthetic gas are residential and commercial cooking, water heating, industrial processing and outdoor lighting. According to the American Gas Association estimates, only 32,408,000 therms of gas were sold in Hawaii in 1987.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Due to the limited use of gas, no DSM programs are presently mandated by the Commission. DSM programs for gas may be addressed when the LCP/IRP framework has been determined.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

DSM cost-effectiveness tests and screening criteria have yet to be determined.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

GASCO is subject to rate reviews during each rate case. The Commission determines if proposed increases are fair and reasonable based on the justification presented. No formal least-cost or best-cost purchasing rules have been adopted.

V. Future PUC activities and key regulatory issues

Future PUC activities for gas are linked to the LCP/IRP docket.

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IDAHO

Gas Utilities Serving State (gas-only or combination)

1) Intermountain Gas Company (gas only)
2) Washington Water Power (combination - gas & electric)
3) Mountain Fuel Supply Company (gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Idaho does not require least-cost planning (LCP)/integrated resource planning (IRP) for natural gas utilities. There has been some internal staff discussion and the commissioners are aware that there is activity in other states. No pressure is present to implement conservation programs, and gas prices are deemed reasonable. Natural gas issues at the Commission have focused on supply side issues.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Docket Nos. U-1034-91 & 141 outlines Intermountain Gas Company's conservation conversion program which includes a $200 rebate to residential and multifamily customers for the installation of high efficiency furnaces. Washington Water Power suggested gas substitution of electric water heating as a way of reducing electric load. The Commission subsequently encouraged a water heater replacement program and a preferential rate for customers with both gas heat and gas water heating. Intermountain Gas Company offers a $100 rebate for electric to gas water heater conversions. All gas utilities offer interruptible rates to their commercial/industrial customers.

About five years ago Intermountain Gas intervened in an electric program which offered financial incentives for high efficiency heat pumps. Intermountain Gas' testimony was very limited, and the company acted more as an observer. There has been ongoing debate in the legislature regarding conservation and building codes. The gas utilities participated with electric utilities in securing passage of a more demanding code that will apply to all new housing starts in 1991. The gas utilities have cooperated with the Idaho Department of Water Resources, Energy Division, in a demonstration program to test the cost-effectiveness of model conservation standards (MCS) for gas homes.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Due to the fact that no DSM programs are required, no economic test are used to evaluate gas utility DSM programs. No avoided cost methodology or marginal costs estimates have been developed.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Natural gas supply contracts are subject to Commission approval, however no pre-approval is required. Prudence reviews are conducted, but no specific criteria, rules, or guidelines have been established. Idaho has only had open access for two years.

The trend of gas supply purchases is moving towards more mid-term contracts, high level of spot market activity, and little to no long-term contracts.

V. Future PUC activities and key regulatory issues

Intermountain Gas consumption has grown 3-5% per year since 1987 due to a strong economy and population growth. Eighty-five to ninety percent of the heating load in their service area is serviced by Intermountain Gas.

Key regulatory issues facing gas utilities include:

1) Deliverability of industrial gas supplies (i.e, for electric generation);
2) Industrial spot purchases and bypass issues in relation to obligation to serve core customers; and,
3) Fixed costs in regard to re-entry and exit fees.

LCP/IRP regulation is probably at the top of the Commission agenda in the next five years. The issue of reliability will be addressed first.

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ILLINOIS

Gas Utilities Serving State (gas-only or combination)

1)	Central Illinois Light Co.	(combination - gas & electric)
2)	Central Illinois Public Service Co.	(combination - gas & electric)
3)	Illinois Power Co.	(combination - gas & electric)
4)	Interstate Power Co.	(combination - gas & electric)
5)	Iowa/Illinois Gas & Electric Co.	(combination - gas & electric)
6)	Northern Illinois Gas Co.	(gas only)
7)	North Shore Gas Co.	(gas only)
8)	United Cities Gas Co.	(gas only)
9)	Peoples Gas, Light & Coke Co.	(gas only)
10)	Union Electric Co.	(treated as electric only, they have a small gas business in Illinois)

I. Status of state PUC least-cost regulation and practices for gas utilities

Illinois has a LCP/IRP rule in effect for natural gas utilities. The rule 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 1989), and that the Illinois Department of Energy & Natural Resources prepare a state-wide plan by January 1990 (filed January 16, 1990). This plan stipulates that individual utility plans must be consistent with the state plan. Hearings on the PUC rules concerning the state plan were completed in September 1990. PUC Commissioners voted on a final order on LCP/IRP on October 3, 1990.

Individual utility plans are due in January 1991. All 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. About 95% of all gas sold in Illinois is subject to LCP/IRP requirements.

The LCP/IRP plans are to be 10 year plans, including an initial two year period featuring pilot DSM program implementation. DSM program development begins with the utility preparing its own database of demand and supply options. End-use forecasting is not a requirement, but it is suggested for consideration by PUC staff. Demand forecasts are prepared for a 10 year period. Total demand is based on the design day temperature, which is defined as the coldest day in the last 100 years.

Gas utilities are using SEND OUT@, a commercial supply planning software tool, to develop their supply plans. The PUC does not have modeling capability in-house. The methodology used to calculate demand forecasts must be judged to be replicable by PUC staff.

DSM end-use program options are developed by the utilities with suggestions by PUC staff and a collaborative working group. The utility prepares an estimate of the conservation impact of the DSM program (technical and market potential); this is then 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.

Illinois established conservation goals for gas utilities in PUC dockets during 1983. Conservation goals are not a part of the current LCP/IRP initiative.

II. Type and extent of gas utility DSM programs (including fuel substitution)

All gas utilities provide energy audits and information programs. Weatherization assistance, envelope improvements, financial incentives for high efficiency equipment and heating system retrofits are provided by some, but not all, gas utilities for the residential/multifamily market. No gas utilities have fuel substitution programs as part of a DSM initiative.

In the commercial/industrial market, gas cooling rebates and fuel substitution programs are being considered as competitive promotional practices in Chicago. All gas utilities have interruptible rates, and some have high efficiency equipment replacement, weatherization, envelope improvement and industrial heat recovery programs.

DSM programs throughout the state are a mix of full scale and pilot programs. The most active DSM programs are thought to be at NIGAS, Illinois Power Co., and, Iowa-Illinois Gas Co.

Costs of DSM programs are recovered by expensing the administrative costs, and capitalizing the program costs and, in some cases, the monitoring equipment. In some cases, riders to a rate are filed by utilities for recovery of costs associated with specific customer groups. All capitalized costs are included in a rate request.

There is no formal policy regarding fuel substitution, and the PUC has not required electric utilities to encourage gas use for any particular end-uses. Gas utilities have not intervened or opposed electric utility DSM programs that offer rebates or financial incentives for high efficiency equipment that potentially competes with gas-fired equipment. However, they have been parties to formal cases, but have not presented evidence against such electric promotion. Neither have the electric utilities intervened against any gas promotions.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The PUC does not require any specific economic test to measure cost-effectiveness of DSM programs. However, gas utilities must justify the appropriateness of their choice of test. Likewise, there are no specific criteria required in screening DSM options. The PUC allows utilities to present any selection of programs, as long as they maintain consistency with the LCP/IRP. This is characterized as programs with the lowest present value revenue requirement (PVRR).

Avoided costs of new gas supplies, or marginal costs have not been developed by gas utilities or the PUC. All utilities use the contract price of firm supply - the wholesale rate - to quantify the benefits of DSM programs.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Illinois PUC conducts a prudence review of gas distributor purchasing practices annually, and in most rate cases, for all gas distribution companies. Although there are no specific rules, criteria, or guidelines used in prudence reviews, there is a general framework in which to judge the flexibility of any supply plan to the expected spot market price. Utilities are not required to file supply plans in advance of purchases. "Least-cost" or "best cost" purchasing rules are

expected to be included in the October 3 Commissioners decision. There is no relationship between the prudence review process and the LCP/IRP initiative.

Recent trends in the mix of long-term, short-term and spot supplies are reported to show an increase in the short-term contract and spot markets, and a decrease in long-term contracts.

V. Future PUC activities and key regulatory issues

Pipeline additions are not expected in Illinois. Gas utilities forecast nominal increases in demand over the next 5-10 years. Natural gas lost market share relative to other energy sources during the moratoria on new gas hook-ups, but now, new construction chooses gas whenever it's available.

The key regulatory issues concerning gas utilities are:
1) Evaluation of state-wide LCP;
2) Pre-approval of supply contracts;
3) Transportation customers switching fees; and,
4) By-pass fees.

The PUC is expected to conduct evaluations of the utilities' LCP/IRP plans in an oversight capacity. There is a staff of three (F.T.E.) working on gas LCP/IRP, and no independent research is planned by staff.

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INDIANA

Gas Utilities Serving State (gas-only or combination)

1)	Indiana Gas Company	(gas only)
2)	Citizens Gas & Coke	(gas only)
3)	Northern Indiana Public Service	(gas only)
4)	Ohio Valley Gas Corporation	(gas only)
5)	Indiana Utilities Corporation	(gas only)
6)	Midwest Natural Gas	(gas only)
7)	Northern Indiana Fuel & Light	(gas only)
8)	Kokomo Gas & Fuel	(gas only)
9)	Lawrenceburg Gas	(gas only)
10)	Southern Indiana Gas & Electric	(combination - gas & electric)

I. Status of state PUC least-cost regulation and practices for gas utilities

The Indiana Commission has not actively considered least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. Efforts within the Commission have concentrated on regulations regarding least-cost purchasing.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Demand-side management (DSM) programs for natural gas utilities have not been mandated by the Commission. Some of the gas utilities offer energy audits to their residential/multifamily customers for a fee. Interruptible rates are offered to commercial/industrial customers by some gas utilities. There is no formal policy or rules which may encourage fuel substitution by customers.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The Commission does not require gas utilities to implement DSM programs; therefore, no economic tests to measure DSM program cost-effectiveness are performed.

Neither the Indiana Commission, nor the gas utilities have developed a methodology to estimate the avoided costs of new gas supplies, or long-run marginal cost estimates.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Specific guidelines have not been outlined for prudence reviews of gas purchasing. Indiana State Code No. 8-1-2-42(G)(3) requires least-cost/best-cost purchasing by gas utilities to the extent that the Commission must find that the utilities have made every reasonable effort to ensure a long-term supply at the lowest price which is reasonably possible. The Commission reviews natural gas purchasing practices on a case-by-case basis, semi-quarterly or annually as necessary. If a discrepancy arises, administrative law judges (ALJ) determine if the utilities have adhered

sufficiently to the Indiana code. The Commission does not require gas utilities to file gas supply plans in advance of purchases.

V. Future PUC activities and key regulatory issues

The Commission is not aware if the gas utilities forecast any increases in gas demand during the next 5-10 years or any major capacity additions to the existing gas transportation system.

Take-or-pay issues are pending before the Commission. In regard to natural gas regulations, there appears to be no other key regulatory issues facing the Commission at this time. The Commission has no planned activities concerning LCP/IRP for natural gas in the near future.

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IOWA

Gas Utilities Serving State (gas-only or combination)

1) Interstate Power Company	(combination - gas & electric)
2) Iowa-Illinois Gas & Electric	(combination - gas & electric)
3) Iowa Southern Utilities Company	(combination - gas & electric)
4) Iowa Electric Light & Power	(combination - gas & electric)
5) Peoples Natural Gas/Utilicorp	(gas only in Iowa)
6) Midwest Gas	(gas division of combination)
7) United Cities Gas	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

The Iowa Utilities Board is implementing rules which require utilities to conduct energy efficiency programs. With the support of the governor's environmental initiative behind the Board and state funding for an energy efficiency study, a working group composed of Board staff, staff of utilities, members of the Consumer Advocate Division of the Department of Justice and staff from the Department of Natural Resources, representatives of the construction and building industries, and members of the academic community, developed a legislative proposal to promote the efficient use of energy. The Iowa General Assembly adopted a comprehensive set of recommendations, and required the state's gas utilities to devote 1.5% of their revenues to energy efficiency.[20]

The goal promulgated by the legislature states that Iowa seeks to use energy resources more efficiently (especially non-renewable energy resources) to enhance economic growth, reduce negative environmental impacts, and decrease the state's dependence on energy resources purchased outside the state. Implementing these goals will entail development of programs to promote energy efficiency and conservation in industrial and residential applications. Specific guidelines and requirements for the implementation of energy efficiency programs have been proposed by the Board in Dockets No. RMU-90-27 & 30 issued August 31, 1990 and October 24, 1990, respectively. Both dockets apply equally to rate-regulated gas and electric utilities. RMU-90-27 proposes rules for these utilities to file comprehensive plans detailing proposed energy efficiency programs. RMU-90-30 proposes rules for cost recovery.

As outlined in RMU-90-27 energy efficiency programs must be filed with the Board and include the following:

- a forecast of future energy capacity needs compared with existing supplies;
- an assessment of the future capacity availability and cost of these supplies;
- identify and assess the potential and cost of demand-side options; benefit/cost comparisons; a description of implementation procedures for selected programs, including budget requirements, monitoring and evaluation procedures.

More specifically the Board's proposed rule making regarding DSM program criteria includes the following:

[20] W. H. Smith, Jr. Natural Gas. "State Regulation: LDCs Can Implement Energy-Efficiency Programs." November 1990, p.27.

- a description of the option (i.e., energy-using facilities, equipment, or customer behavior which the option is proposed to change);
- a description of the option's target market;
- an assessment of major market barriers; attraction for customers; marketing strategies;
- resources and support services available to customers;
- an analysis of the saturation rate;
- an assessment of the technical potential the option has to reduce peak energy demand;
- an estimate of the anticipated number of participants for the next five years;
- an estimate of implementation costs for each of the next five years, which includes:
  - planning and design costs;
  - administrative costs;
  - advertising and promotional costs;
  - equipment costs and installation costs; and,
  - miscellaneous costs.
- an estimation of net energy savings, including: take-back effects, free riders, elasticity studies; performance degradation, and length of customer participation.

Combination utilities may file combined energy efficiency plans as long as the plan specifies which programs are attributed to the electric operation, gas operation, or both. Energy efficiency plans must benefit all customers, and at a minimum the Board requires that all plans include hot water heater wrap, commercial lighting, tree planting, low income directed programs, and a program to encourage the purchase of energy efficient equipment.

After a utility files a plan which meets the Board's requirements, it is docketed as a contested case. Intervenors may then propose the plan be approved, modified, or rejected. The Board requires these parties to include in their filing:

- an analysis of why the plan should be rejected; or
- a statement of proposed modifications, and why these modifications are appropriate.

The utility may respond with a submission accepting or rejecting the proposed modifications with an analysis of their decision. The contested case proceeding is scheduled to be completed with the result of an established plan within a six month time frame. Modifications after implementation and Board approval are filed in a similar fashion as the procedures stated above. The first DSM plan should be filed by July 1991.

II. Type and extent of natural gas DSM programs (including fuel substitution)

DSM programs that are presently being implemented evolved from earlier utility conservation programs. All gas utilities offer energy audits (continued from RCS audits) with the exception of United Cities which was exempted because they have only a small number of residential customers. People's Natural Gas, as a contractor for the State, offered a weatherization program to residential customers. Some gas utilities in the past and on a pilot basis offered financial incentives for high efficiency equipment. Those programs are not currently in operation.

In the commercial sector, all gas utilities offer interruptible rates. In addition to these programs, an Iowa Energy Center will be established to research energy efficiency and conservation and to support educational and demonstration programs. One-tenth of one percent of the total gross operating expenses of each electric and gas utility per year is designated to fund the Center.

Most DSM programs are pilot programs. Through Docket RMU-90-27, the Commission has established guidelines for the implementation of full-scale programs in a gas utilities' conservation plan filing. These guidelines are as follows:

- Monitoring and evaluation criteria:
  - Time frame - program duration period and 2 years after;
  - Monitor progress and any adjustments;
  - Describe: customer participation; energy efficiency measures installed; actual costs and performance of energy efficiency measures.
  - Data collection: interviews, data processing forms; inspections; engineering and statistical information; and metering.
  - Cost-effectiveness and economic evaluation: free-ridership; customer persistence; and take-back.
  - Evaluation of non-program effects: weather and economic activity.
  - Assure statistical confidenee and reliability.

The proposed rules outlined in RMU-90-30 include a reward/penalty option for the entire plan.

> The Board proposes to grant a reward to utilities which achieve an overall plan benefit/cost ratio which is greater than 1.25. In addition to achieving the overall plan benefit/cost ratio greater than 1.25, in order to receive a reward, the utility must have expended more than 75 percent of the spending level approved by the Board. A utility which achieves an overall benefit/cost ratio of less than 1.0 will be penalized. A penalty also will be imposed upon a utility which has expended less than 75 percent of the spending level approved by the Board.[21]

The benefit/cost ratio will be based on a societal test, adapted from the California Standard Practice Manual, 1987.[22]

The gas utility must also prove to the Board that the expenditures for energy efficiency programs were reasonable and cost-effective. DSM program costs are recovered in an energy efficiency cost recovery filing which is a separate filing from a general rate case.

The Board has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution by customers.

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[21] Docket No. RMU-90-30, p.6.

[22] The calculation used in the Societal Test compares the present value of the benefits to the present value of the cost over the useful life of an energy efficiency option from a societal perspective. The present value is calculated using an average of the ten year and thirty year Treasury Bond rates as the discount rate Benefits are the sum of the present values of utility avoided cost including the effects of externalities. Costs are the sum of the present values of utility program costs, excluding incentives, plus participant costs and any increased utility supply costs for each year of the useful life of the option or program.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Screening methods for DSM programs are discussed in RMU-90-27. Screening criteria which must be used in a utility's energy efficiency plan include: cost-effectiveness; energy conservation potential; required lead time; life-time of option; and free ridership.

All economic tests described in the California Standard Practice Manual are available to the utilities. The Board requires the Total Resource Cost Test and the Societal Test.

In the absence of a fully quantifiable methodology to estimate environmental externalities the Iowa Board has stipulated that a 7.5% externality credit for natural gas DSM and a 10% credit for electric utilities DSM be factored into the avoided cost calculations. The value of the benefits of DSM programs will be based on avoided gas cost.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Board conducts annual purchasing reviews for all gas utilities. Gas purchases may also be reviewed in rate cases if appropriate. Current annual forecasts are included in a utility's supply filing, and the Board does not require the utilities to seek pre-contract approval. There have been no least-cost or best-cost purchasing rules adopted. However, both the Board and the utilities recognize the reliability feature in a best-cost scenario. Least-cost is determined case-by-case, based on precedent and the reliability of supply.

Under the proposed rule, DSM programs will be reviewed in separate proceedings from a general rate case to ensure that expenditures and related costs of DSM programs are associated solely with the energy efficiency plan.

V. Future PUC activities and key regulatory issues

There are projected minor overall increases of gas demand throughout Iowa. Pipeline additions are being brought on line to offer diversity in pipeline suppliers.

The key regulatory policies facing gas utilities include:

1) Proposed energy efficiency rules; and
2) Manufactured gas plant site clean-up expenses.

The Board staff is planning to review 15 energy efficiency plans per year (8 electric, and 7 gas). Two staff members direct staff working on gas LCP/IRP and other issues. No independent research is planned, however some additional work may be proposed as a result of the two LCP/IRP dockets.

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KANSAS

Gas Utilities Serving State (gas-only or combination)

1)	Arkansas Louisiana	(gas only)
2)	Greeley Gas	(gas only)
3)	KN Energy	(gas only)
4)	Peoples Natural Gas	(gas only)
5)	Kansas Public Service/Utilicorp United	(gas only)
6)	Union Gas System/United Cities	(gas only)
7)	KPL Gas Service	(combination - gas & electric)
8)	Midwest Energy	(combination - gas & electric)

I. Status of state PUC least-cost regulation and practices for gas utilities

The Kansas Corporation Commission is not actively considering least-cost planning (LCP)/integrated resource planning (IRP) for natural gas, but has begun to examine LCP/IRP for electric utilities.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The only Commission required conservation program is a residential energy audit program (Docket No. 120755). All gas utilities must notify new customers every two years regarding the availability of energy audits. In the commercial sector, interruptible sales and transportation agreements are made between gas utilities and some large customers.

By state statute [KSA 66-117(D)] the Commission encourages public utilities to invest in conservation. A gas utilities fixed rate of return is adjusted 1/2 to 2% to allow cost recovery for specific conservation measures. Programs are evaluated on a case-by-case basis during the course of a rate case. However, the utilities have seldom expressed interest in this statute. The Commission is thinking about opening a least-cost planning docket, or at least bringing this statute to the gas utilities attention.

There is no formal policy or rules regarding DSM programs that may encourage fuel substitution.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The gas utilities are not required to use any specific economic tests to measure DSM program cost effectiveness.

A KPL Gas Service filing after January 1991 (probably in February or March 1991) will include marginal cost estimates. No avoided cost methodology for new gas supplies has been developed, however, the Commission is getting ready to examine that issue.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Purchase gas adjustment reviews are conducted during a rate case proceeding for all natural gas utilities. There are no specific criteria, rules, or guidelines that are used during a review. However, the Commission does examine whether the supply was acquired at the least-cost, and is the most reliable source of supply. Gas utilities are not required to file supply plans in advance of purchases. Supply plans are reviewed during a rate case, but the Commission neither approves or denies supply contracts.

V. Future PUC activities and key regulatory issues

Key regulatory issues facing gas utilities include:
1) Switch to marginal cost based pricing versus fully allocated embedded costs;
2) Take-or-pay issues;
3) Incentive regulation in regard to purchasing practices;
4) FERC regulation and bypass issues;
5) Flexible pricing for different customer classes; and,
6) Unbundling of gas rates.

The Commission believes that gas utilities should be doing LCP since the incentive is already in place [KSA 66-117(D)], and the utilities are under a legal commitment to do so.

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KENTUCKY

Gas Utilities Serving State (gas-only or combination)

1)	Columbia Gas of Kentucky	(gas only)
2)	Louisville Gas & Electric	(combination - gas & electric)
3)	Union Light Heat & Power	(combination - gas & electric)
4)	Western Kentucky Gas Company	(gas only)
5)	Delta Natural Gas	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Kentucky does not require least-cost planning (LCP)/integrated resource planning (IRP) for natural gas utilities. The Commission has just started developing LCP/IRP for electric utilities, and gas LCP/IRP may follow.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Some gas utilities offer energy audits and informational programs to their residential customers. Weatherization assistance is offered through other community based organizations.

The Commission has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution. However, for rate making purposes the Commission has stated that gas and electric utilities may not be reimbursed for advertising expenses which promote fuel switching.

Gas utilities have not intervened or opposed an electric utility DSM program that offers rebates or financial incentives for high efficiency equipment that potentially competes with gas-fired equipment. As conservation and DSM become more important issues, this may occur.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No required economic test or analysis method has been proposed to evaluate cost-effectiveness of gas utility DSM programs.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Gas purchasing practices are reviewed in PGA filings of natural gas utilities. Detailed analysis of gas purchases are presented. The staff examines each contract and purchase. Hearings may be held to determine whether costs may be recovered by the gas utilities. PGAs are reviewed as filed on a case-by-case basis and determined by case precedent.

There is no formal policy for PGA reviews, however, in a PGA proceeding gas purchases would be examined to ensure that the gas supply was purchased at the least-cost which also guaranteed the most reasonable supply.

The Commission does not require gas utilities to file gas supply plans in advance of purchases. However, the large LDCs include expected gas costs in PGAs which occur in advance of purchases.

Large LDCs have by and large taken some supplies from spot/ short-term markets basically for industrial and interruptible load. Some spot gas is assigned to residential customers, but firm supplies are maintained for this load.

V. Future PUC activities and key regulatory issues

The key regulatory issues facing gas utilities include:

1) Transportation policies;
2) Bypass policies; and
3) Cost-of-service issues.

The Commission staff has been reviewing natural gas LCP/IRP in other states, but no formal gas LCP/IRP policies are proposed at this time.

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LOUISIANA

Gas Utilities Serving State (gas-only or combination)

1)	Gulf States Utilities	(combination - gas & electric)
2)	Arkansas Louisiana Gas/ARKLA	(gas only)
3)	Translouisiana	(gas only)
4)	Louisiana Gas Service Co.	(gas only)
5)	Dixie Service	(gas only)
6)	Entex/ARKLA	(gas only)
7)	Norco Gas & Fuel	(gas only)

* Mr. Edwards stated that there are a total of 42 natural gas companies in Louisiana, many of which are small.

I. Status of state PUC least-cost regulation and practices for gas utilities

The state of Louisiana does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. LCP/IRP has not been actively considered by the Staff or the Commission due to the fact that Louisiana has an adequate supply and is a gas producing state.

II. Type and extent of natural gas DSM programs in effect, including fuel substitution

Demand side management (DSM) programs pertaining to natural gas have not been developed in Louisiana. None of the gas utilities perform energy audits or offer any other type of conservation activities for residential customers. On March 12, 1974 a general Commission order prohibited promotional practices for electric and natural gas utilities. The Commission has no authority over industrial sales and is not aware of any DSM or conservation programs offered to these customers.

The Louisiana Commission has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution by customers.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

There are no natural gas DSM programs in Louisiana, therefore, no economic tests to evaluate the program cost effectiveness of these programs is performed, nor are there any Commission requirements to do so.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Louisiana does not conduct prudence reviews of natural gas distributors. The state has not adopted any form of least-cost or best-cost purchasing rules. Gas utilities are not required to file gas supply plans to the Commission in advance of purchases.

In discussing the recent trends of the relative mix of long-term, short-term and spot supplies for Louisiana, the following comments were made. United Gas Pipeline supplies the majority of the gas supply to the gas distribution companies. There is little opportunity to buy from other suppliers. Louisiana Gas Service is presently putting in pipeline in order to purchase from ARKLA. Translouisiana purchases some natural gas from the spot market for state office cooling, but the majority of their purchases still comes from United Gas. Gulf States Utility (combination-gas & electric) does buy inexpensive gas on the spot market and stores this gas for electric generation.

V. Future PUC activities and key regulatory issues

Gas utilities are not required to submit any load forecast plans, therefore, the Commission cannot comment on the possibility of any major capacity additions to the existing gas transportation system.

The Commission sees no activity in regard to integrated resource planning for natural gas utilities.

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MAINE

Gas Utilities Serving State (gas-only or combination)

1) Northern Utilities (gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

The state of Maine does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. The Commission is not actively considering LCP/IRP for natural gas utilities at the present time, and believes that Northern Utilities provides the lowest reliable price for gas. Cost adjustment hearings verify this twice a year.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The Maine Public Advocate's office encouraged two conservation programs for residential and multifamily customers which the Commission subsequently adopted. These programs are: 1) hot water wraps; and 2) slow-flow shower head aerators. Although no formal Commission ruling exists, Northern Utilities encourages its customers to install high efficiency natural gas boilers/furnaces. The Commission allows Northern Utilities to encourage natural gas customers who are already on line to switch from electricity to natural gas, a cash incentive is offered. Northern does not perform energy audits nor do they offer weatherization or envelope improvements.

In the commercial/industrial sector, Northern Utilities runs a promotional program to encourage the use of natural gas hot water equipment. Northern does offer interruptible rates. In an effort to levelize summer and winter natural gas load, the Commission is examining gas cooling. Presently, there is only one commercial gas cooling customer in the state of Maine.

Any programs that Northern presently offers are open to all their customers. Northern Utilities has provided hot water wraps to 4,000 of its 11,000 residential gas customers (of which 80-90% have gas water heaters).

A Commission fine levied on Northern Utilities supplied the initial $50,000 for the hot water wrap program. Any remaining costs incurred by the utility are recovered through rates.

There is no formal policy or rules regarding DSM programs which encourage fuel substitution, and the Commission has not required electric utilities to encourage gas use for any particular end-uses. The Commission relies on the gas utilities efforts to ensure efficient gas residential heating and hot water heating. The gas utilities have not intervened or opposed any electric utility DSM programs that offer rebates or financial incentives for high efficiency equipment that potentially competes with the gas fired equipment.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The Maine Commission does not require its natural gas utility to measure DSM program cost effectiveness. Northern Utility does perform a cost-benefit analysis and its annual filing requires that Northern report energy savings. However, the Commission emphasizes how effectively the market for conservation has been saturated (i.e., how many hot water wraps have been installed

versus the number of gas hot water heaters), rather than calculated savings. The Maine Commission and Northern Utilities have not developed a methodology to estimate avoided costs of new gas supplies.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Maine Commission conducts two cost adjustment hearings per year (summer & winter). Prudence reviews may be conducted if a take-or-pay issue comes into question during a cost adjustment hearing. There are no specific criteria, rules, or guidelines that are used in prudence reviews of gas purchasing. The Commission has not adopted any form of least-cost or best-cost purchasing rules. Northern files a five year supply forecast and is not required to file a gas supply plan in advance of gas purchases.

Northern receives most of its gas from Granite State Transmission, Inc. (running from Tennesee to Haverall, MA and Portland, ME), their interstate transmission company. Northern is backing off the higher priced firm gas from Granite and filling in their supply with lower priced spot gas.

V. Future PUC activities and key regulatory issues

According to Mr. DiProfio, Northern is forecasting an increase in natural gas use due to the sudden jump in oil prices. Northern anticipates customers switching over from oil heating to natural gas heating. A proposed new pipeline (originating in Canada) will run to Portland and Portsmouth to handle the additional gas demand.

The key regulatory issues facing gas utilities in Maine include:
1) open access and transportation rates; and
2) demand-side management programs.

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MARYLAND

Gas Utilities Serving State (gas-only or combination)

1) Baltimore Gas & Electric	(combination - gas & electric)
2) Maryland Natural Gas/Washington Gas	(gas only)
3) Citizens Division/Chesapeake Utilities	(gas only)
4) Cambridge Division/Chesapeake Utilities	(gas only)
5) Columbia Gas of Maryland	(gas only)
6) Frederick Gas/Washington Gas Light	(gas only)
7) Elkton Gas/Pennsylvania & Southern Gas	(gas only)
8) South Penn Gas/Emmitsburg District	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Maryland does not require formal least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. However, the Maryland General Assembly presently is considering legislation that will require gas and electric utilities to implement energy efficiency and conservation programs that the Commission deems cost-effective and adopt ratemaking policies that provide appropriate financial incentives.[23] The legislation will help stimulate IRP activity at the major gas LDCs.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The Maryland Commission does not require the natural gas utilities to implement any demand side management (DSM) programs. All gas utilities will perform an energy audit for residential/multifamily customers; however, there is a fee for these audits. Baltimore Gas & Electric (BG&E) allows its customers to charge gas equipment to their gas bills. BG&E provides this service interest free for the first three months. Some of the natural gas utilities provide interruptible rates for their commercial/industrial customers. Additionally, the Commission recently approved a BG&E filing that would encourage commercial customers to substitute natural gas air conditioning for electric air conditioning.

The Commission has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution by its customers, nor does the Commission require electric utilities to encourage gas use for any particular end-uses.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Due to the fact that Maryland does not require gas utilities to implement any DSM programs, no economic tests are employed to measure DSM program cost effectiveness. Neither the Commission nor the gas utilities have developed a methodology to estimate the avoided costs of new gas supplies, but alternatives are identified and evaluated in hearings and when evaluating annual gas supply plans.

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[23] Maryland House of Delegates, House Bill No. 520, February 1, 1991.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Commission reviews LDC's purchasing practices to assure the appropriate optimization of cost and reliability factors. The Maryland Commission conducts a thorough prudence review of all gas utilities every six months. There are no specific criteria, rules or guidelines that are used in prudence reviews of gas purchasing regarding least-cost or best-cost purchasing rules. The major gas utilities file Commission required gas supply plans annually, but not in advance of gas purchases. Commission staff noted a greater amount of spot market purchases by gas utilities.

V. Future PUC activities and key regulatory issues

No major capacity additions to the existing gas transportation system is anticipated by the Commission or the gas utilities, but both parties do expect a greater distribution of natural gas. Key regulatory issues within the Commission will focus on a broader range of gas supply matters.

Following the work of NARUC regarding natural gas integrated resource planing, the Commission foresees more active involvement in this area.

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MASSACHUSETTS

Gas Utilities Serving State (gas only or combination)

1) Bay State Gas Co.	(gas only)
2) Commonwealth Gas Co.	(gas only, subsidiary of combination)
3) Berkshire Gas Co.	(gas only)
4) Boston Gas Co.	(gas only)
5) Colonial Gas Co.	(gas only)
6) Essex County Gas Co.	(gas only)
7) Fall River Gas Co.	(gas only)
8) Fitchburg Gas & Electric Co.	(combination - gas & electric)
9) Blackstone Gas	(gas only - municipal)
10) North Attleboro Gas	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning processes at natural gas utilities are being developed as companies file rate cases with the Massachusetts DPU. The DPU is not planning a state wide rule at this time. Two regulatory entities, the DPU and The Energy Facilities and Siting Council, are involved in least-cost planning in Massachusetts. The Energy Facilities Siting Council has responsibility for biannual reviews of the long term demand forecast and supply plans submitted by each gas and electric utility. The three gas utilities with the largest sales, Bay State, Commonwealth, and Boston Gas, are subject to the most rigorous review.

The DPU has responsibility for approving the DSM programs described in the conservation plan submitted by each utility. Conservation policy is part of the rate case review process. The DPU approaches LCP on an ad hoc basis during rate cases. The Boston Gas Co. has submitted a plan, parts of which have already been approved, which include a budget of up to $60 million over the next five years to be used for conservation programs. The Berkshire Gas Co. and Colonial Gas Co. have also begun initial efforts in implementing conservation programs, which the DPU would like to expand into full scale programs by the 1991-92 heating season.

There is no prescribed methodology for developing DSM options. Each utility has a different procedure. An initial list of DSM program options was prepared by the Massachusetts Natural Gas Council, a trade group of regulated natural gas utilities, along with MASS SAVE, and the Massachusetts Audubon Society. In general, the DPU recommends that gas utilities follow this sequence of steps in considering DSM options:

1. Data collection of end-use information on dwellings and equipment, and available conservation measures;

2. Calculation of the avoided cost of new gas supplies - There are regulations developed for electric QF which were adapted for natural gas. Costs vary by measure and by season. The long-term avoided cost estimates can be evaluated for a specific measure;

3. Identification of energy savings and associated costs of individual measures for consistency with the cost effectiveness test;

4. Development of a comprehensive list of potential measures - including a) evaluation of interactive effects, b) evaluation of administrative costs, c) development of program delivery mechanism and, d) review of the reliability factor - an assessment of equipment conservation achievement, usually a discount factor applied to the manufacturers' estimate; and,

5. Final assessment of program cost-effectiveness.

The goal of the process is to develop an exhaustive list of all cost effective DSM programs.

II. Type and scope of natural gas DSM programs (including fuel substitution)

DSM programs are currently developed by gas utilities as a consequence of DPU and Siting Council orders resulting from a rate case or biannual review. For residential customers, all gas utilities have an energy audit program implemented through MASS SAVE. Some of the gas utilities maintain DSM programs which include weatherization, envelope improvements, and financial incentives for high efficiency equipment.

For the commercial and industrial customer classes, some gas utilities offer weatherization, envelope improvements, and gas cooling rebates. All offer interruptible rates as well as a load management rate - for a minimum number of days of service and payment of the alternate fuel cost. Boston Gas Co. is working on a conservation plan for the commercial and industrial markets. The DPU expects them to submit the plan in early 1991.

The DSM programs planned as part of the development of a least-cost plan will be implemented on a full scale basis. The DPU has rejected the pilot program concept, explaining that there is adequate data to support full scale programs beginning with a preliminary phase of program development.

The DPU offers financial incentives to encourage conservation on a case-by-case basis. For example, in the case of Boston Gas, the DPU linked conservation targets and incentives. If the company achieves the full amount of "the exemplary" conservation estimate, they are awarded a .5% premium return on equity. The stream of benefits begin once the company achieves 25% of the estimated conservation savings, when incentive payments accrue to the utility. Additionally, the DPU has tried to eliminate disincentives to conservation, by allowing companies to recover a return on the margin of sales lost to conservation. Concurrent, real-time cost recovery is made for DSM program costs through the cost of gas adjustment. This is a semi-annual filing which does not usually entail hearings.

Fuel substitution policies are a topic of the current docket number 90-261-A of the Massachusetts Electric Co. In this case, the electric company has proposed a number of conservation measures which are expected to be challenged by Boston Gas Co. as being less cost-effective than electric to gas fuel switching. The list of intervenors in this case is a long one - including most electric and gas utilities operating in Massachusetts, consultants, rate-payer groups, public interest groups, and others. The DPU is expecting this to become a test case for fuel substitution in Massachusetts.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Gas utilities are encouraged by the DPU to perform the Ratepayers Impact Measure Test, as well as the societal test. The societal test includes: 1) the cost of the DSM program, including the company and participant costs; and 2) the company's avoided cost plus estimates of any avoided costs attributed to environmental externalities. Gas companies are required to evaluate a number of specific issues in screening DSM options, such as: cost-effectiveness; energy conservation potential; required lead time; lifetime of options; free ridership; cream skimming; diversity; reliability; and, type of load displacement.

Avoided costs and long run marginal costs are filed by each gas utility during rate cases. In general, utilities use an avoided gas cost to value the benefits of DSM programs.

IV. Relationship between prudence reviews of gas utility purchasing practices and integrated resource planning

Prudence reviews of distributor gas purchasing practices for short term (less than one year) or spot supplies occur during the semi-annual Cost of Gas Adjustment Reviews. Massachusetts General Law chapter 164, section 94A gives the DPU additional authority to review and approve contracts of longer than one year before they become effective. These are known as "94A" investigations, and to date, only three have occurred.

Both the Siting Council and the DPU have a general "least-cost" or"best cost" rule to assure that the least-cost supplies have been selected and appropriate benefits accrue to the ratepayer. Additionally, if a company is shopping for gas supplies of longer than one year, they must demonstrate to the DPU why such a purchase is cost effective compared to other supply or demand options such as conservation.

Gas utilities have subscribed for substantial increases in long-term supplies to service expanding markets such as cogeneration and, increased electricity generation. Gas sales from the spot market are also increasing for interruptible and supplemental supplies.

V. Future PUC activity and key regulatory issues

The (former) Massachusetts Energy Office in 1988 forecast annual natural gas demand increases of 5.2% annually through the mid-1990's.

The key regulatory issues facing gas utilities at the DPU include:
1) Developing integrated resource management plans;
2) Competitive ratemaking considerations; and,
3) Improved coordination between the DPU and other energy-related regulatory agencies.

The key regulatory issues facing gas utilities at the Siting Council are:
1. Developing integrated resource management plans;
2. Improved demand forecasting to respond to a growing and dynamic market;
3. Development of demand driven, rather than supply constrained forecasting.

The DPU is expected to conduct additional studies in the area of fuel substitution. Industry lines between gas and electricity may blur if fuel substitution becomes a viable issue in the LCP plans of both.

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MICHIGAN

Gas Utilities Serving State (gas-only or combination)

1)	Consumers Power Company	(combination - gas & electric)
2)	Southeastern Michigan Gas	(gas only)
3)	Michigan Consolidated Gas	(gas only)
4)	Michigan Gas Utilities Company	(gas only)
5)	Michigan Gas Company	(gas only)
6)	Peninsular Gas Company	(gas only)
7)	Northern States Power Company	(combination - gas & electric)
8)	Wisconsin Public Service Corp.	(combination - gas & electric)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/ integrated resource planning (IRP) for Michigan gas utilities is under consideration by the Commission. The Commission decided that a planning initiative for electric utilities would be more effective and then to continue with gas utilities.

Conservation efforts of gas and electric utilities are outlined by the Michigan Public Service Commission in Case No. U-8528 (June 28, 1988). Each utility[24] which has a Commission approved Michigan Residential Conservation Service (MRCS) program files a report to be examined within the context of a collaborative review process.[25] The report must contain:

1) a description of the utility's existing conservation programs;
2) costs and benefits of the programs for the past 12 months;
3) proposed changes of programs if any;
4) a three year plan for the implementation of existing and new energy conservation programs, including a target for demand reduction, projected budget, staffing levels, and a description of program activities;
5) projected cost-benefit analysis; and,
6) projected annual budget.

The report is filed on a biennial basis and subject to review and approval by Staff.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Gas utility conservation programs have evolved from earlier utility conservation programs and through a collaborative working group. Residential/ multifamily customers may request an energy audit from all Michigan gas utilities. Some gas utilities have expanded their programs to include weatherization assistance (insulation and infiltration measures) for low-income customers, financial incentives for high efficiency equipment, and heating system retrofits. In the

[24] These are the gas utilities for which the Commission regulates rates. There are three other gas utilities in Michigan where rates are approved by local franchises.

[25] Consisting of the utility, MPSC staff, other government agencies, and representatives of various customers, sectors, and interest groups.

commercial/industrial sector some gas utilities offer weatherization programs and incentives to replace existing equipment with high-efficiency equipment.

Michigan Consolidated is believed to have the most aggressive conservation programs. Most utility programs are audit driven. Other programs are implemented at the pilot level. The Commission is trying to persuade gas utilities to allocate more funds for direct investment in energy conservation programs.

Specifically identified conservation expenses to the gas utilities are recovered through a specific surcharge to the rates (known as the RCS surcharge).

There are promotional practices guidelines, but there is no formal policy regarding fuel substitution. The collaborative process has utilities reviewing each others conservation plans. They have developed a procedure for notifying the competing energy utility of their opportunity to present an alternative proposal whenever fuel switching is recommended to a customer.[26] The Staff and the Michigan Department of Social Service have been discussing the feasibility of converting electric water heating to gas for some low income customers.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The Utility Cost test, the Societal test (including avoided cost estimates and appropriate externalities), and the Participant test are used by Staff to evaluate each gas utility DSM program submitted to the Commission. The utilities have also used the Non-participant test, but this is not considered by Staff to be an appropriate test of cost-effectiveness.

In the context of Case No. U-8528 there is no clear indication of the method gas utilities use to value the benefits of DSM programs. Conservation programs are implemented due to regulatory requirement and for community service. The rate used to measure the benefits of DSM programs depends on the test used.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

In 1982, Legislative Act 304 replaced the automatic purchased gas adjustment clauses with a system designed to require the Commission to evaluate decisions underlining the acquisition plans of both gas and electric utilities for reasonableness and prudence. When evaluating a gas cost recovery plan the Commission is required to consider the volume, cost, and reliability of the major alternative gas supplies available to the utility; the cost of alternative fuels available to some or all of the utility's customers; the availability of gas in storage; the ability of the utility to reduce or eliminate any sales to out-of-state customers; whether the utility has taken all appropriate legal and regulatory actions to minimize the cost of purchased gas; and other relevant factors. The utilities file a five year demand and supply forecast which identifies sources of supply, projected costs, and

[26] Established subsequent to Michigan PSC, Case No. U-8528 by collaborative working work. In the matter of the proceeding, on the Commission's own motion, to investigate, review and evaluate the Michigan Residential Conservation Services Programs and Zero-Interest Loans Programs operated by Michigan gas and electric utilities. June 28, 1988.

costs of alternate fuels.[27] Gas supply plans must be filed three months before the annual period before the utility can begin charging its customers. There is also a gas cost reconciliation proceeding conducted after the annual period is over to reconcile the LDC's reasonable and prudently incurred gas costs with the actual gas cost revenues it receives.

In an Order of 1988 for Michigan Consolidated Gas, the Commission stated that even though it may be appropriate to pay a premium for a reliable gas supply (which may entail more costly long-term contracts), the goal of supply is to provide the least-cost service which is consistent with price, reliability and security.[28]

In regard to the trends of purchasing spot gas supply or entering long-term or short-term contracts, each utility acts independently in deciding what the best acquisition strategy is for the company. Utilities have significantly diversified their supply portfolios.

V. Future PUC activities and key regulatory issues

The Commission has encouraged utilities to diversify their gas supply portfolio and to reduce contract requirements to meet the lower demand for sales gas. Over the past two decades, the industrial sector has decreased its demand for natural gas and the average annual residential gas usage has decreased. This has added to the gas supply surplus. Approximately one third of the gas consumed in Michigan is end user direct purchased gas transported by pipeline companies and LDCs.

Key regulatory issues facing the gas utilities are:

1) Continuing the sales market for commodity customers and ensuing a reasonable cost and a sufficient and reliable gas supply;

2) Addressing any adverse effects of lifting the utilities obligation to serve certain transportation customers especially during the tight gas supply market; and

3) Incentive regulation for target efficiency goal achievement.

The Strategic Planning Division of the Michigan PSC would like to investigate gas IRP further; however, electric IRP has occupied the staff time and resources.

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[27] S. M. Fetter, Commissioner, Michigan Public Service Commission, "The Natural Gas Role in Integrated Energy Resource Planning, " at the National Association of Regulatory Utility Commissioners, Annual Convention and Regulatory Symposium, Orlando, Florida, November 12-15, 1990.

[28] Ibid.

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MINNESOTA

Gas Utilities Serving State (gas-only or combination)

1)	Minnegasco, Inc.	(gas only)
2)	Interstate Power Company	(combination - gas & electric)
3)	Midwest Gas/Iowa Public Service	(gas only)
4)	Northern States Power	(combination - gas & electric)
5)	Northern Minnesota Utilities	(gas only)
6)	Great Plains Natural Gas	(gas only)
7)	Western Gas	(gas only)
8)	Peoples Natural Gas/Utilicorp	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Natural gas least-cost planning (LCP)/ integrated resource planning (IRP) has not been actively considered. Unlike electric utility LCP/IRP, there has been no environmental imperative to implement LCP/IRP for natural gas. A surplus supply of natural gas has not induced the state to develop conservation targets.

II. Type and extent of natural gas DSM programs (including fuel substitution)

All DSM programs which are being implemented have evolved from earlier utility conservation programs. The Commissioner of the Department of Public Service has specified procedures to be followed by public utilities and/or interested parties in submitting, analyzing, and selecting proposals for "conservation improvement programs and renewable resources pilot programs." [29]

A submission must be described in detail, including:
- project objectives;
- cost effectiveness estimates of the project to the utility, participants, and all customers;
- anticipated percentage of low-income and renters participating;
- budget provisions, ratemaking treatment, and cost-recovery method;
- effect on peak and average consumption;
- computations of avoided or reduced costs; and,
- community energy organization involvement if applicable.

A separate status report must include:
- total number of customers (indicating the total number of low-income, renters, and other);
- total amount spent on project (total and average per participant); and
- any additional information the Commissioner deems necessary.

The Commissioner conducts a completeness review of the filing to determine if all necessary information has been included in the plan. Comments are solicited from all interested parties. The

[29] Conservation Improvement Rules, Chapter 7690, §0100-1500, March 14, 1990.

Commissioner makes recommendations based on the comments it receives; the utility may incorporate the Commission's comments; and the plan is either accepted, accepted with modification, or not-approved.

All gas utilities offer energy audits to residential customers. Some utilities offer weatherization assistance (insulation and infiltration); financial incentives for high efficiency equipment; heating system retrofits; and fuel substitution programs. Interruptible rates are available to all commercial/industrial gas customers. Some gas utilities offer high-efficiency equipment replacement incentives, and weatherization assistance (insulation and infiltration). Minnegasco and Northern States Power are considered to have the most active DSM programs. The larger utilities' programs are mostly full scale. The other utilities have a mix of full scale and pilot programs.

The Conservation Improvement Program outlines cost recovery methods for DSM programs. Cost recovery is provided for in a utility's rates. A small regulatory lag may occur only if a utility over spends its budget, however a utility is assured of recovering all Commission approved funds.

No formal policy or rules regarding DSM programs that may encourage fuel substitution by customers have been adopted.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Gas utilities perform the utility revenue requirements test, the ratepayers impact measure test, and the participant test to measure DSM program cost effectiveness.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Quarterly reports on third party gas (spot market) are filed by all gas utilities. Annual end of year summaries are also submitted. There are no specific criteria or rules that are used in reviews of gas purchases, but some general guidelines are given in the rules on annual filings.

Roughly, fifty percent of gas purchases are spot market purchases.

V. Future PUC activities and key regulatory issues

Gas demand for the Twin Cities is estimated to increase by 4-5% per year for the next five years.

The key regulatory issue facing gas utilities is FERC versus state regulation.

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MISSISSIPPI

Gas Utilities Serving State (gas-only or combination)

1) Mississippi Valley Gas Company (gas only)
2) Entex/ARKLA (gas only)
3) Union Gas Company (gas only)
4) Mississippi Gas Cooperation (gas only)
5) North Mississippi Natural Gas (gas only)
6) Willmul Gas & Oil (combination - gas & oil)
7) Walthall Natural Gas (gas - servicing only one town)
8) Vicksburg Water & Gas (unregulated, servicing one city)

I. Status of state PUC least-cost regulation and practices for gas utilities

Internal staff discussion has taken place in regard to least-cost planning (LCP)/integrated resource planning (IRP), but LCP/IRP is not actively considered at this time. The issue would more than likely be brought up during a major rate case which has not occurred since 1985.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Mississippi Valley Gas Company and Entex perform energy audits for residential/multifamily customers, and also offer weatherization assistance and envelope improvements. These programs are pilot programs.

The utilities and the Commission have investigated opportunities of offering weatherization and envelope measures in the commercial/industrial sector, but no action has resulted. High efficiency equipment installation is encouraged, but there are no financial incentives. Commercial/industrial customers serviced by Mississippi Valley and Entex may receive interruptible rates.

Mississippi offers no financial incentives to gas utilities to encourage conservation. No formal policy or rules regarding DSM programs that may encourage fuel substitution by customers has been adopted.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No Commission regulations require economic tests to evaluate gas utility DSM program cost effectiveness. Avoided cost methodology and marginal costs estimates have not been addressed by the Commission nor the gas utilities.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Prudence reviews are conducted every five years for electric utilities only. There are no specific criteria, rules, or guidelines proposed for prudence reviews of gas utilities.

Mississippi gas utilitics have been trying to access the spot market, but some utilities are tied to 10-20 year contracts.

V. Future PUC activities and key regulatory issues

The key regulatory issue facing gas utilities is the by-pass problem. LCP/IRP regulation is not planned in the near future.

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MISSOURI

Gas Utilities Serving State (gas-only or combination)

1) Missouri Public Service	(combination - gas & electric)
2) St. Joseph Light & Power	(combination - gas territory outside electric territory)
3) United Cities Gas Company	(gas only)
4) Associated Natural gas	(gas only)
5) Union Electric	(combination - owns 3 small gas utilities)
6) KPL Gas Service	(gas only)
7) Laclede Gas Company	(gas only)
8) Missouri Natural Gas Company	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

At the Commission internal staff discussion has taken place in regard to least-cost planning (LCP)/integrated resource planning (IRP) for natural gas, but electric LCP has been of greater concern. Some staff members have commented that electric and gas IRP should be brought along in as much a parallel matter as possible.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Gas utilities no longer offer RCS type audits for residential/multifamily customers. Some utilities have voluntary weatherization and envelope improvement programs. Interruptible rates are available to commercial/industrial customers who qualify and request these rates. A formal policy regarding conservation or DSM programs that may encourage fuel substitution has not been adopted. Utilities must obtain a variance from the Promotional Practices Rule in order to offer rebates or other financial incentives for the purchase of high efficiency electric or gas appliances.

Gas-electric competition has been a major stumbling block to DSM programs. Union Electric (UE) carried out an experimental DSM program in the summer of 1989 which offered rebates for the purchase of high efficiency (SEER $\geq$ 10) central air conditioners and heat pumps. Even though the program was temporary and experimental in nature, was limited to a geographic area where UE was the primary gas supplier, and was focused mainly on air conditioner purchases, UE's application for a variance from the Commission's Promotional Practices Rule was opposed by other gas companies. They objected on the grounds that the program was a thinly veiled attempt to gain space heating market share. The Commission did approve the temporary variance, and UE completed the study, but concluded that due to the large proportion of "free riders" (approximately 60%) the rebate program was not cost-effective.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No economic tests are performed to evaluate gas utility DSM program cost-effectiveness.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Commission conducts prudence reviews on an annual basis of all ten investor owned gas utilities. There are no statutory requirements. Take-or-pay problems have been an area of concern. Gas utilities are not required to supply plans in advance of purchases. Least-cost/best-cost rules are not in place, however, the Commission is examining this issue.

V. Future PUC activities and key regulatory issues

The Commission expects an inter-state pipeline construction project to begin within the next 12 to 18 months. There are two potentially competing proposal is in the south-central part of the state. Additional pipeline deliverability to the St. Louis area is also planned. Interest has been exhibited by gas utilities to service areas where they do not presently service.

Key regulatory issues faced by gas utilities concern:

1) Prudence issues regarding contracting for new supplies;
2) Access to spot market, transportation issues, bypass policies; gas utility's obligation to serve;
3) Jurisdictional issues with FERC (i.e, inter-state bypass of gas sales customers); and,
4) Jurisdictional issues with Department of Transportation (safety authority and responsibility questions).

A task force has been established to investigate strategic resource planning for electric utilities, but gas IRP remains at least 2 years away.

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MONTANA

Gas Utilities Serving State (gas-only or combination)

1) Montana Power	(combination - gas & electric)
2) Montana Dakota Utilities	(combination - gas & electric)
3) Great Falls	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Montana does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities, but the Commission has recently opened a docket on this issue, and LCP/IRP is under active consideration. The Conservation and LCP Advisory Committee (consisting of public advocacy groups, and including members of the Northwest Power Planning Council) petitioned the Commission on August 13, 1990 in regard to certain actions of Montana Power Company. Following this petition on October 1, 1990 a Notice of Inquiry was sent out by the Commission regarding PSC consideration of LCP and competitive resource acquisition. The Commission believes potential energy efficiencies exist which the gas utilities have not addressed.

II. Type and extent of natural gas DSM programs in effect, including fuel substitution

The Montana Commission does not require the natural gas utilities to implement any DSM programs. Any current DSM programs are run at the initiative of the gas utilities. Montana Power provides energy audits for its residential/multifamily customers upon request. The utility also provides weatherization assistance and envelope improvements free of charge to low-income customers. All other residential/multifamily customers may apply for 0% loans. Montana Power does have a program for gas heating system retrofits and a financial incentive program for high-efficiency boilers/furnaces. Montana Power did offer cash rebates to its customers to switch from electric hot water heaters (serviced by Pacific Power & Light) to gas water heaters. Montana Power limited the program to areas where its company offered gas service only. This program was only implemented in one service area, and has been discontinued.

In the commercial sector, Montana Power and Montana Dakota Utilities both have provisions in their rate structures that allows them to lower their rates in order to keep customers from switching to alternative fuels. Montana Power also offers interruptible rates. Montana Power purchases some of its energy supply from cogeneration plants.

Programs presently being implemented in Montana are a mixture of full scale and pilot programs.

Montana allows gas utilities to recover conservation program costs. Tax credits are given to the utility to cover the costs of providing 0% interest loans. There is a state statute which gives the Commission the authority to allow the gas utilities a higher return on equity (up-to 2% on any retrofit program), but this has not been requested by any gas utilities. Low-income conservation program costs are rate based.

The Commission has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution. This is one of the issues in the current LCP docket.

The Commission has not required electric utilities to encourage gas use for any particular end-uses.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The Montana Commission does not require the natural gas utilities to perform any economic tests to measure DSM program costs. This is one of the issues in the LCP docket.

The natural gas utilities are working on a methodology to estimate avoided costs of new gas supplies.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Montana Commission does not perform prudence reviews on a regular basis. If a discrepancy does arise, there is a general statute that gives the Commission authority to conduct a prudence review. There are no specific guidelines or rules concerning prudence reviews, but the statute does call for short-term cost minimization. Montana has not adopted any form of least-cost or best-cost purchasing rules. The Montana Commission does not require gas utilities to file gas supply plans in advance of purchases.

Natural gas contractual terms tend to be shorter. The average length of contracts is 3-5 years with the average contract price renegotiated annually.

V. Future PUC activities and key regulatory issues

The gas utilities have forecasted increases in gas demand during the next 5-10 years and major capacity additions to the existing gas transportation system. Montana Power is attempting to become a pipeline carrier in addition to being a distribution company. This will increase the capabilities of the North/South pipeline.

The future regulatory issues facing gas utilities in Montana include:
1) disaggregation of Montana Power's vertically integrated system;
2) continually providing less expensive natural gas and reliable service; and,
3) the LCP docket.

It is premature to make any judgements or conclusions regarding the LCP docket. The Commission is contemplating: whether the gas system should be included in LCP planning; should the LCP concentrate solely on electric utilities; or, should the docket include both electric and gas simultaneously. The only staff presently working on natural gas LCP would be in the context of the pending LCP docket.

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NEBRASKA

Gas Utilities Serving State (gas-only or combination)

1.	Northwestern Public Service	(gas only)
2.	KN Energy, Inc.	(gas only)
3.	Metropolitan Utilities District of Omaha	(gas only)
4.	MINNEGASCO	(gas only)
5.	Peoples Natural Gas	(gas only)
6.	Municipal Gas Operated	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

The Nebraska PSC does not regulate the state's natural gas suppliers: therefore, Nebraska does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. The natural gas utilities are regulated by local municipalities.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The only DSM programs which would exist in Nebraska are those that are performed voluntarily by a gas utility or municipality, but no DSM programs have been mandated by the state.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Not Applicable.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Not Applicable.

V. Future PUC activities and key regulatory issues

Not Applicable.

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NEVADA

Gas Utilities Serving State (gas-only or combination)

1) Southwest Gas Corporation (gas only)
(composed of two Nevada divisions - Southern Nevada & Northern Nevada)

2) Sierra Pacific Power Company (combination - gas & electric)
(WestPac is the gas division)

3) CP National Gas Company (gas & telephone)

I. Status of state PUC least-cost regulation and practices for gas utilities

Nevada has a least-cost plan (LCP)/ integrated resource plan (IRP) in practice for Southwest Gas and Sierra Pacific. CP National Gas Company has been granted exemption from LCP filing requirements because of its relatively small size. Least-cost planning requirements developed as a result of electric LCP/IRP requirements, and a 1987 legislative initiative authorizing the PSC development of a subsequent PSC order. Nevada Administrative Code (NAC) 704.953-973 issued on April 18, 1990 outlines the plans for acquisition and provision of natural gas. The Code 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 first LCP was filed by the Southern Division of Southwest Gas Corporation on July 1, 1990. Gas utilities serving northern Nevada are required to file a LCP in January 1992.

The LCP regulation requires a ten year forecast beginning with a three year plan of action. NAC 704.9655 outlines program requirements "for conservation and load management: required assessments and comparisons; contents; implementation." The plan must include:

1) an assessment of base conservation: its effects of conservation and load management induced by higher prices, the continuation of existing programs; its effects by end-use when feasible; and, the impact of conservation on forecasted base growth;

2) a list of measures and programs that the utility determines to be technically feasible, ranked according to their level of saving energy, reducing demand, or both;

3) results of program cost-benefit analysis;

4) a description of customer classes and type of use; a schedule of proposed programs listed according to expected savings and reduction of peak demand; and, preliminary cost and benefit assessment including market penetration estimates;

5) a description of implementation procedures; and,

6) a detailed description of the methodology used to determine and compare the benefits and costs of DSM programs.

The percentage of utility gas sales subject to LCP/IRP requirements is 99%.

The Commission rejected a DSM program proposed by Southwest Gas for southern Nevada. The Commission has asked them 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.[30]

II. Type and extent of natural gas DSM programs (including fuel substitution)

DSM programs that are operating now in Nevada evolved from earlier utility conservation programs or through conservation programs of a combined utility. After 1992 when all gas LCPs have been filed, the DSM programs will be Commission required programs. In the residential sector, all gas utilities offer energy audits, weatherization assistance (insulation and infiltration measures), and financial incentives for high efficiency equipment. Fuel substitution programs and water heater wraps are offered by Sierra Pacific Power (Westpac).

All gas utilities offer interruptible rates to their industrial dual fuel, transportation curtailment priority customers.[31] Some utilities have implemented programs to encourage industrial customers to replace existing equipment with high efficiency equipment. Gas cooling incentives are being examined by one gas utility as a possible DSM program.

Sierra Pacific has a mix of full scale and pilot DSM programs. Consequently, the gas DSM programs are associated with electric DSM programs. The Commission staff believes that Sierra Pacific has more advanced gas DSM programs. Southwest Gas' DSM programs are in the formative stages. Cost recovery of DSM programs are deferred until a gas utility's next rate case.

The PSC has not required electric utilities to encourage gas use for a particular end use. The Staff considers natural gas to have preference over electricity for most direct heating applications.

Southwest Gas intervened in Nevada Power Company's LCP filing in 1986 and 1988 (Docket Nos. 86-702 and 88-701) regarding Nevada Power's program to offer incentives for high-efficiency heat pumps. In so far as these incentives are not eligible for cost recovery, the Commission has decided not to interpose themselves in this case.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The Total Resource Cost Test will be used to evaluate the cost-effectiveness of DSM programs by the utilities.

The policy for required screening criteria for DSM options is evolving as gas LCPs are filed. DSM options are ultimately evaluated according to cost-effectiveness. Current screening criteria that precede benefit-cost analysis include market potential, reliability and duration, load shape effects, customer acceptance, and potential for free-ridership.

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

[31] PSC General Order No. 18.

The PSC and gas utilities are developing a methodology to estimate the avoided costs of new gas supplies. Avoided capacity costs and avoided energy are reviewed separately. Avoided capacity costs are evaluated according to three criteria: 1) avoided cost of facilities; 2) gas inventory charges; and 3) pipeline contract capacity costs.[32] Marginal avoided energy costs are evaluated according to two components: 1) variable cost (e.g., fuel cost); and, 2) gas inventory charge which is a negative component when evaluated in this capacity. Gas utilities will use this approach in assessing the value of DSM benefits. Long-run marginal cost estimates have been developed by the gas utilities. The Staff has requested that a pipeline contract capacity cost be included in the LRMC estimates.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Purchased gas adjustment reviews are held at 6-18 month intervals for all gas utilities. The Nevada PSC gas LCP regulation requires that an annual gas supply report be filed by each utility.[33] An LCP/IRP review is a separate activity from a purchase gas adjustment review.

Most gas supplies are tied to less than one year term contract. Transportation and open access has shifted the burden of supply planning to local distribution companies.

V. Future PUC activities and key regulatory issues

Southwest Gas' Southern Nevada Division forecasts an increase of 7% annual residential customer growth rate from 1990-94 and 5% from 1995-1999. Residential customers will reach 218,000 in 1999 from a total of 132,000 in 1990. Gas sales are anticipated to jump from 314,250,503 therms in 1990 to 615,926,044 therms in 1999. This includes transportation and firm sales. This increase can be largely attributed to the increased use of natural gas for electric generation. Southwest Gas has pipeline additions under construction.

Key regulatory issues facing gas utilities include:

1) Growth in demand;
2) FERC activity (all gas comes into Nevada through El Paso or Northwest Pipeline system);
3) A further refinement of benefit-cost analyses to include environmental externalities;
4) Mechanism to remove ratemaking disincentives for DSM investments; and,
5) Use of declining block rates for residential customers.

All necessary tools are in place to review gas LCP plans as they are filed. The Staff will make revisions and recommendations to the Commission on all future LCP plans. There is presently from one to six FTE staff members working on natural gas LCP depending on the level of activity. It is expected to average one to two FTE over time.

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[32] Technical Appendix to Southwest Gas 1990 Southern Nevada Resource Plan, July 1990.

[33] NAC 704.9705.

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NEW HAMPSHIRE

Gas Utilities Serving State (gas-only or combination)

1) Energy North Natural Gas (gas only)
2) Northern Utilities (gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Natural gas least-cost planning (LCP)/integrated resource planning (IRP) discussions have been held by the Commissioners and staff of the New Hampshire PUC, but there is no formal docket. The state has not developed any energy conservation goals for natural gas utilities.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Any DSM programs in operation in New Hampshire are done voluntarily by the gas utilities. Residential/multifamily customers may request energy audits and information from the gas utilities. Docket DF-90-176 opened in October 1990 raises issue with Energy North's advertising of "free hot-water heaters." Plumbing contractors registered the initial complaint with the Commission arguing that the gas utilities are using unfair market practices. November 13, 1990 was the first day that the Commission sent auditors to Energy North. Results of the investigation are pending. Designed to promote gas sales and not demand side management, this program illustrates the strong competition between the gas and electric utilities for market share.

The Commission requires new customers to pay a capital contribution if the expected non-gas revenues do not recover costs over a four year period. The gas utilities are lobbying the Commission to reduce the up-front cost. In the commercial/industrial sector interruptible rates are offered in the summer months.

No formal policy or rules regarding DSM programs that may encourage fuel substitution by customers has been adopted by the Commission. The electric utilities have not been required to encourage gas use for particular end-uses.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No Commission required economic tests are used by gas utilities to measure DSM program cost effectiveness.

In the last 2-3 years the Commission has been evaluating a marginal cost study for pricing in general rate cases. The study was completed in 1989. The methodology will be used in each utility's next rate case.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Commission holds cost of gas adjustment hearings every six months for both gas utilities. The mix of supply over the next six months is evaluated. No specific criteria, rules, or guidelines are used. A comparison is drawn from one company to the other in order to assess the prudency of the purchases. The Commission also relies on their past evaluation experience.

Each gas utility is required to file supply contracts with the Commission, but no contract pre-approval is necessary. If the Commission during the course of a cost adjustment hearing finds that the utility over-or under-recovered during the preceding summer/winter period, the utility has to reconcile this in the subsequent summer/winter period.

Over the last few years the gas utilities have made a dramatic shift to spot purchases for summer demand.

V. Future PUC activities and key regulatory issues

Over the past few years rapid economic growth has necessitated an increase in pipeline capacity and additions to the existing gas transportation system. Energy North is currently participating in the Iroquois project. Northern Utilities will also begin purchasing supply from the Iroquois Pipeline via the Granite State Transmission pipeline (expected completion 1995/1996). Bay State is the parent company of Granite State Gas Transmission and Northern Utilities.

Key regulatory issues facing gas utilities include:
1) Transportation procedures to the distribution system,
2) Least-cost planning and demand side management issues, and
3) Supply issues, such as: capacity brokering on the pipeline, and gas inventory charges.

The New Hampshire Commission staff has been following LCP/IRP in other states.

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NEW JERSEY

Gas Utilities Serving State (gas only or combination)

1) Elizabethtown Gas Co.	(gas only)
2) South Jersey Gas Co.	(gas only)
3) New Jersey Natural Gas Co.	(gas only)
4) Public Service Electric & Gas Co.	(combination - gas & electric)

I. Status of state PUC least-cost regulation and practices for gas utilities

New Jersey has no direct regulation covering natural gas LCP/IRP, however, the Draft New Jersey Energy Master Plan[34] contains guidelines on "Least-Cost Planning Strategies for LDCs."[35]

"The costs of building and financing new gas supply pipelines and distribution and transmission systems are ultimately borne by the utilities customers. These costs can be lowered by reducing demand through conservation measures. Demand-side management and supply-side planning must therefore aim to reduce the LDC's revenue requirements by selecting the least expensive gas purchase plans and reducing the need for capital expenditure."[36] "Current New Jersey LDC strategies need to more fully incorporate conservation into the planning process... LDCs must employ a planning model that integrates supply-side and demand-side options."[37]

The final NJEMP is expected in early 1991.

In November 1990, the BPU proposed regulations concerning the establishment of incentives for electric and gas utility participation in demand side management activities. "The proposed rules provide for the electric and gas utilities in the state to file, biennially, a Demand Side Management Resource Plan (Plan) for review and approval by the Board."[38] The first plan for each utility is due in 1991. Each utility's plan is expected to be different.

II. Type and scope of natural gas DSM programs (including fuel substitution)

DSM program options in the context of an integrated resource plan are under development at New Jersey's natural gas utilities. The BPU staff expects that utilities will prepare estimates of

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[34]Draft 1990 New Jersey Energy Master Plan (NJEMP), October 1990, was prepared by the NJEMP Committee pursuant to P.L. 1987 c365, that establishes an Energy Master Plan Committee responsible for preparation, adoption, and revision of master plans regarding the production, distribution, and conservation of energy. This group includes the President of the Board of Public Utilities, the Commissioners of Community Affairs, Environmental Protection, Health, Human Services and Transportation, and the State Treasurer. The Final NJEMP is expected in early 1991.

[35]Ibid. p. 29.

[36]Ibid. p.30.

[37]Ibid. p.32.

[38]State of New Jersey Board of Public Utilities, Conservation Incentives Rulemaking Docket No. EX 90040304, Demand Side Management Resource Plan, Proposed New Rules, November 15, 1990, p. 7.

the conservation impact, including the technical and market potential, of DSM programs proposed in the Plan to be filed in 1991. A criteria issue will be the valuation of avoided cost. Utilities do not believe that conservation programs will affect peak demand, and that as a company, they can only have an impact on commodity costs.

Within the proposed regulations, energy conservation targets are included in the conservation plans, however, utilities are not required to achieve them. " Within the Plan the utilities are required to propose an overall savings target for the Plan, and a series of "Performance-Based DSM Programs". These programs will provide each utility with the opportunity to earn returns on investments in energy efficiency measures based on the actual performance of the programs. Performance will be evaluated by comparing the costs associated with each program to the avoided costs savings to the utility. Along with the program descriptions, the utility will be required to file a program implementation plan, a performance measurement and verification plan for each performance-based program, an avoided cost study, and a proposed cost recovery mechanism to permit the timely recovery of program expenses through rates."[39]

Most of the DSM programs currently in effect were first instituted in 1982. Programs implemented by gas utilities in the residential and multifamily customer class include: energy audits under the Home Energy Saving Program (HESP); low-income weatherization and envelope improvements; financial incentives for high efficiency boilers, furnaces, and water heaters; and, heating system retrofits.

Commercial and industrial DSM programs currently in effect include a few utilities with a gas cooling rate, and interruptible rates in addition to energy audits conducted in the Commercial and Apartment Conservation Services (CACS) program.

The proposed regulations include a section on financial incentives to gas utilities to encourage conservation. "Specifically, the framework for utility incentives provided for in the proposed regulations is as follows. The utility will be allowed the opportunity to earn a foundation level of return on investments in Performance-Based Programs. In addition to the foundation level of return the utility can earn incentives based upon a shared savings of a portion of the program's net benefits. Net benefits are defined as the net present value of avoided cost savings less the net present value of program costs. The definition of new benefits which are subject to shared savings can be expanded to include incidental savings of other fuels (for example heating oil) to the extent the utility can adequately demonstrate such additional savings."[40]

The proposed regulation also include negative incentives. "In order to introduce a degree of risk sharing and allocation commensurate with the opportunity for earning incentives, the proposed rules provide for negative incentives to be deducted from the foundation level of return to the extent that the program results in negative net benefits."[41]

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[39]Ibid. pp.7-8.

[40]Ibid. p.8.

[41]Ibid., p.9.

Conservation expenses are currently recovered as a pass through in rates, with no regulatory lag. Proposed regulation include plans for an annual adjustment of a deferred account to take place during the utility's fuel adjustment hearing.

The BPU has not addressed fuel substitution as a feature within DSM programs. Currently, fuel substitution programs are generally not allowed when they are likely to have a load building effect. The BPU has not required electric utilities to encourage gas use for particular end-uses, however, Jersey Central Power & Light Co. has encouraged electric heating customers to switch to natural gas. To date, gas utilities have not intervened or opposed any electric utility DSM programs that offer rebates or financial incentives for high efficiency equipment that potentially competes with gas-fired equipment.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Various economic tests to measure DSM program cost effectiveness were included in a report prepared for the New Jersey Conservation Analysis Team Project (NJCAT).[42] This was a collaborative effort which included seven New Jersey utilities, the BPU, the NJ Department of the Public Advocate, and the NJ Department of Commerce, Division of Energy. The gas utilities participating were Elizabethtown Gas Co; New Jersey Natural Gas Co; Public Service Electric & Gas Co.; and South Jersey Gas Co.[43] The contractor prepared aggregate results of the benefit-cost analyses using the Total Resource Cost Test. "This test includes all benefits and costs to ratepayers and the sponsoring utility, but excludes benefits and costs to other utilities, government bodies, and the rest of society. The main report also presents results for three other benefit-cost tests -- the Participant Test, the Ratepayer Impact Test, and the Utility Cost Test."[44]

The BPU's proposed regulations include plans for a performance evaluation of each DSM program which compares program costs with avoided costs. (See Section II above.) "The avoided cost studies utilized in developing the incentives must be consistent with studies used to evaluate other utility resource acquisitions. It is recognized there has been less experience to date with calculation of avoided costs for natural gas utilities in the State than for electric utilities. The gas savings valuation methodologies employed in the August 1990 New Jersey Conservation Analysis Team (NJCAT) Report represent a substantial effort toward development of avoided cost studies for gas and should provide guidance to the gas utilities and the Board in preparing and reviewing the DSM Plans."[45]

DSM screening criteria are not currently required, although the proposed regulations include some mention of screening criteria beyond the list of specific conservation programs which the utilities are required to undertake. These are designated as "Core Programs", and may be

[42]For a detailed discussion of benefit-cost tests evaluated for the NJCAT, see The New Jersey Conservation Analysis Project: Final Contractor's Report To The NJCAT, Prepared for: The New Jersey Conservation Analysis Team. Prepared by: RCG/Hagler Bailly, Inc, contact: Mr. Dan Violette, published August 14, 1990.

[43]New Jersey Conservation Analysis Project: Contractor's Report to the NJCAT; Executive Summary, prepared by RCG/Hagler Bailly, Mr. Dan Violette, August 14, 1990, p. E-1.

[44]Ibid., p. E-1.

[45]Op.Cit., Conservation Incentives Rulemaking, pp. 7-8.

considered in the incentive-based programs if they can be demonstrated to be cost-effective, and that energy savings can be adequately measured.[46] Achievement of 90% of projected savings are required for cost recovery.

The BPU's proposed regulations include a requirement for an avoided cost calculation for comparison with the "Performance-based" DSM programs. The NJCAT Report discuss several approaches including a twenty year long-range dispatch model; a Weighted Average Cost Approach, other marginal approaches, the System Marginal Cost Approach; and, recommends the Targeted Marginal Approach. This approach "is a compromise between the complexity of a fully automated dispatch model and the simplicity of the ... [other marginal cost]...approaches." "Simply stated, the portion of conservation savings which had been served by the base load gas supplies is valued at the margin of that group of base load supplies actually utilized each month. The portion of conservation savings which had been served by peaking supplies is valued at the margin of the group of peaking supplies actually utilized each month. The remaining conservation savings, that which is due to temperature sensitive load other than the peaking portion, is valued at the marginal cost of the group of supplies which may be called upon to serve it: i.e. spot gas, base supplies of storage, depending upon the month examined and the actual supply portfolio utilized."[47]

IV. Relationship between prudence reviews of gas utility purchasing practices and integrated resource planning

The BPU conducts a prudence review of all distributor gas purchasing practices annually in fuel cost proceedings. There are no specific criteria, rules, or guidelines used in prudence reviews, although affiliate purchases may receive more scrutiny. BPU staff believes that the value of the prudence review is in encouraging more aggressive negotiating for new supplies on the part of the distributor companies. The proposed regulations, if adopted, will ensure that conservation policy is intertwined with any review of new long-term supplies.

Recent trends in the relative mix of long-term, short-term and spot supplies for New Jersey's gas utilities indicate that all have backed away from using the pipeline as the sole supplier. There are more long-term contracts with market based pricing.

V. Future PUC activity and key regulatory issues

Gas utilities forecast substantial increases - 20% in gas demand during the next 5-10 years due to the popularity of gas-fired cogeneration, and gas-fired electricity generation. The BPU supports additional transportation to meet this projection.

The key regulatory issues facing gas utilities in New Jersey are:

1. Conservation bidding, as included in the proposed regulations;
2. Integrated resource planning program management;

[46] Ibid., p.11.

[47] Op.Cit. NJCAT Final Contractor's Report, pp. 7-4,7-5.

3. Prudence reviews;
4. Innovative tariff design; and,
5. Impact of flexible pricing on capacity brokering.

The BPU is expected to conduct at least two activities in the area of integrated resource planning for gas utilities: final determination of the proposed regulations; and, detailed review of the conservation plans submitted by each utility.

There is currently one full time staff person assigned to LCP/IRP in the gas division.

Independent research planned by staff includes an investigation into LCP/IRP activities in other states; and, a standard methodology for estimating avoided cost.

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NEW MEXICO

Gas Utilities Serving State (gas-only or combination)

1) Gas Company of New Mexico	(gas only)
2) Hobbs Gas Company	(gas only)
3) Jal Gas Company	(gas only)
4) Raton Natural Gas	(gas only)
5) Zia Natural Gas	(gas only)
6) Las Cruces Gas System	(gas/non-regulated)
7) Los Alamos County	(gas/non-regulated)
8) Rio Grande Natural Gas	(gas/non-regulated)

I. Status of state PUC least-cost regulation and practices for gas utilities

There has been internal Staff discussion regarding least-cost planning (LCP)/integrated resource planning (IRP) for natural gas.

II. Type and extent of natural gas DSM programs (including fuel substitution)

For residential/multifamily customers, energy audits, weatherization assistance, and envelope improvement measures are offered by all regulated gas utilities; however, these programs are not Commission mandated. Commercial/industrial customers may request interruptible rates from any gas utility. There are no incentives for cogeneration projects, but some limited cogeneration is taking place.

No formal policy or rules regarding DSM programs that may encourage fuel substitution is in effect in New Mexico.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Only limited, voluntary conservation programs function in New Mexico; therefore, no economic tests to evaluate DSM program cost effectiveness are required or performed.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Prudence reviews are conducted on an as needed basis. There are no specific criteria, rules, or guidelines that are used in prudence reviews of gas purchases. The Commission does not require gas utilities to file supply plans in advance of purchases. No least-cost or best-cost criteria has been applied to gas purchases.

The Commission does not track any trends in the relative mix of long-term, short-term and spot supply contracts of natural gas utilities.

V. Future PUC activities and key regulatory issues

There are no key regulatory issues involving gas utilities at this time. The Commission does expect increased activity in reference to LCP/IRP, but no time frame has been acknowledged.

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NEW YORK

Gas Utilities Serving State (gas only or combination)

1) Brooklyn Union Gas	(gas only)
2) Central Hudson Gas & Electric Co.	(combination - gas and electric)
3) Consolidated Edison Co.	(combination - gas and electric)
4) National Fuel Gas Distribution Co.	(gas only)
5) New York State Electric & Gas Co.	(combination - gas and electric)
6) Niagara Mohawk	(combination - gas and electric)
7) Rochester Gas & Electric Co.	(combination - gas and electric)
8) Long Island Lighting Co.	(combination - gas and electric)
9) Orange & Rockland Utilities	(combination - gas and electric)
10) Syracuse Suburban	(gas only - commercial customers only)
11) St. Lawrence Gas Co.	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

The New York PSC does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. All NY utilities currently submit demand forecasts to the NY State Energy Office.[45] The PSC reviews a supply (procurement) plan for all utilities. Efficiency measures may be included.

Consideration of LCP for natural gas is being conducted as part of the State Energy Planning Process by the State Energy Office, PSC, and Department of Environmental Conservation. There are preliminary plans for a study focusing on broad policy issues. Pilot programs focusing on high efficiency equipment replacement are under consideration for 1991-92 as part of the State Energy Planning Process.

II. Type and scope of natural gas DSM programs (including fuel substitution)

Gas efficiency programs are currently developed by gas utilities at the suggestion of PSC staff or have evolved from earlier conservation programs such as New York's Home Insulation Energy Conservation Act (HIECA). HIECA replaced the federal RCS energy audit program. Under HIECA utilities are required to file an annual HIECA plan, to include energy audits and weatherization. All utilities provide audits for residential and multifamily customers. Some utilities have also begun pilot programs for weatherization, envelope improvements, financial incentives for high efficiency equipment, and heating system retrofits. All gas utilities have fuel substitution programs in place, as well as heating surveys and equipment sizing programs.

All gas utilities have fuel substitution programs in place for commercial and industrial customers. Some utilities also have high efficiency equipment replacement programs; gas cooling rebates; interruptible rates; industrial heat recovery; and energy audits.

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[45] 1989 New York State Energy Plan, September 1989, New York State Energy Office.

National Fuel Gas Distribution Co. and Brooklyn Union Gas Co. are reported to have the most active efficiency programs for gas utilities in New York. Most efficiency programs are in the pilot program stage of development across the state; other programs are characterized as being in the very initial stage of development.

New York does not offer financial incentives to gas utility shareholders to encourage conservation, although the incentives are available for electric utilities. Currently, efficiency program costs are included in rates, and new expenses are deferred until the next rate case. A few utilities receive concurrent cost recovery which is reconciled annually. This is achieved on a case-by-case basis during rate cases.

The PSC has not adopted any formal policy or rules regarding gas efficiency programs that may encourage fuel substitution by customers. Electric utilities are allowed, but not required to encourage gas use as a substitute for electricity. Combination companies are most likely to participate in fuel substitution programs focusing on commercial cooking. National Fuel Gas Distribution Co. intervened[49] in a proceeding to oppose financial incentives for electric thermal storage equipment by New York State Electric and Gas. New York State Electric & Gas Co. subsequently withdrew its rebate for electric thermal storage equipment.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Gas utilities are not required by the Commission to assess gas efficiency pilot program cost effectiveness. Gas utilities are not required to use certain criteria in screening efficiency options, and have not developed or proposed criteria to the PSC.

Development of a methodology to estimate the avoided costs of new gas supplies will be the major focus of a forthcoming study by the New York State Energy Research and Development Authority. This ia a dominant issue in a current proceeding [50] involving all nine major utilities. It is a generic proceeding concerning low-income weatherization. Difficulties in evaluating the cost-effectiveness of energy efficiency programs in this docket have led to questions on calculating avoided costs.

Gas utilities use a variety of methods - wholesale rate, retail rate , and avoided gas cost - to value the benefits of gas efficiency programs. No one cost-benefit test is required, and the value of conservation can change depending on the method used in each test.

IV. Relationship between prudence reviews of gas utility purchasing practices and integrated resource planning

Distributor gas purchasing practices are reviewed in rate cases, and in periodic meetings - such as the monthly purchased gas adjustment (PGA) filings. The PSC has not adopted "least-cost" purchasing rules. Gas utilities are not required to file gas supply plans in advance of purchases.

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[49]New York PUC Case No. 28223, August 1990.

[50]New York State Docket No. 89M124.

Recent trends in the relative mix of contracts indicate that all firm gas requirements are backed up by long-term contracts, and that companies are also active in the spot market to maintain incremental supplies.

V. Future PUC activity and key regulatory issues

Gas utilities in New York forecast major capacity additions to the existing gas transportation system, such as the Iroquois Pipeline. This is expected to increase by 15% to 20% the volume of gas available in New York. Additionally, other pipelines such as, Empire and Falcon Seaboard, and cogeneration projects are associated with new pipeline projects. These are proposed to increase summer gas use in order to maintain the gas flow in the pipeline. Before approving these projects, the PSC staff raised the question of whether or not conservation might displace the need for new pipeline capacity, and determined that it could not.

The PSC staff is expected to conduct the following activities in the area of integrated resource planning for gas utilities:

1) Consideration of gas least-cost planning - including how to evaluate benefits and costs, market opportunities for conservation, determining gas avoided costs, and working with the utilities to develop energy efficiency programs; and,

2) Pipeline project issues.

There is currently one staff person assigned to gas LCP/IRP.

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NORTH CAROLINA

Gas Utilities Serving State (gas-only or combination)

1) North Carolina Natural Gas	(gas only)
2) Pennsylvania & Southern Gas	(gas only)
3) Piedmont Natural Gas	(gas only)
4) Public Service Company of North Carolina	(gas only)
5) Greenville Utilities	(municipal - not Commission regulated)
6) City of Rocky Mountain	(municipal - not Commission regulated)
7) City of Wilson	(municipal - not Commission regulated)
8) City of Monroe	(municipal - not Commission regulated)

I. Status of state PUC least-cost regulation and practices for gas utilities

North Carolina does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. There has been internal staff discussion on this topic, but staff concerns have been directed at evaluating supply requirements.

II. Type and extent of natural gas DSM programs (including fuel substitution)

There are no Commission regulations requiring gas utilities to implement DSM programs. All gas utilities voluntarily perform energy audits, offer weatherization assistance, and provide envelope improvements for the residential and multifamily sector.

In the commercial/industrial sector some gas utilities offer gas cooling rebates. There is no Commission mandate, but some gas waste heat recovery projects are underway. All gas utilities offer interruptible rates.

Gas utility costs for providing conservation programs are reviewed during a general rate case. The Commission may or may not grant cost recovery at this time.

The Commission has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution. In the industrial sector, the Commission encourages alternate fuels when curtailing loads becomes necessary.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No economic tests are used by gas utilities to measure DSM program cost effectiveness nor does the Commission require any tests to be performed. Avoided cost methodology and marginal cost estimates have not been developed by the Commission or the gas utilities.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Commission conducts reviews of gas purchases on a contract-by-contract basis for all gas utilities. Gas purchasing contracts do not need Commission pre-approval. No specific criteria, rules, or guidelines have been adopted for these reviews. The Commission encourages a least-cost/best-cost gas supply through its use of "Rider-D." Rider-D is a provision which allows savings the gas utilities incur through purchasing gas below original estimated prices to be returned to all ratepayers.

North Carolina gas utilities have maintained a fairly balanced mix of long-term, short-term, and spot supplies.

V. Future PUC activities and key regulatory issues

Transcontinental is expanding its capacity through the southern expansion project to North Carolina. The Commission is also encouraging additional pipelines to be constructed in the state.

Key regulatory issues facing gas utilities include:
1) Development of prudence standards and review procedures for supply purchases;
2) Encouragement of additional pipeline activity.

Incremental and gradual LCP/IRP activities are expected in the future.

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NORTH DAKOTA

Gas Utilities Serving State (gas-only or combination)

1)	Great Plains Natural Gas Company	(gas only)
2)	Montana Dakota Utilities Company	(combination - gas & electric)
3)	Northern States Power Company	(combination - gas & electric)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/integrated resource planning (IRP) is not required for natural gas utilities at this time. The Commission is presently working on electric LCP/IRP.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The Commission does not require gas utilities to implement any conservation or demand-side management programs. All three gas utilities offer interruptible rates to their commercial customers.

No formal policy or rules regarding DSM programs that may encourage fuel substitution by customers have been adopted.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

There are no demand-side management programs in North Dakota, therefore, no economic tests or analysis methods are used by gas utilities to measure DSM program cost effectiveness.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Commission conducts reviews of gas purchases during the course of a rate case on a case-by-case basis, although no formalized rules or guidelines have been established. Gas utilities are not required to file supply plans in advance of purchases.

V. Future PUC activities and key regulatory issues

Northern States Power is forecasting an increase in future gas demand. Great Plains Natural Gas believes its demand will remain steady while Montana-Dakota Utilities believes that its natural gas demand will decrease.

The key regulatory issue facing gas utilities is cost of service. Due to pipelines opening up for transmission service, the local distribution companies now have the option of purchasing from new suppliers.

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OHIO

Gas Utilities Serving State (gas-only or combination)

1)	Cincinnati Gas & Electric	(combination - gas & electric)
2)	Dayton Power & Light	(combination - gas & electric)
3)	East Ohio, West Ohio & River Gas Companies (all under 1 holding company)	(gas only)
4)	Columbia Gas of Ohio	(gas only)
6)	Pike Natural Gas Company & Eastern Natural Gas Company (both under the same holding company)	(gas only)
7)	Ohio Gas Company	(gas only)
8)	Suburban Fuel Gas	(gas only)
9)	National Gas & Oil Corporation	(combination - gas & oil)
10)	Murphy Gas Inc.	(gas only)
11)	Northeast Ohio Natural Gas Corp.	(gas only)
12)	Northern Industrial Energy Development, Inc.	(gas only)
13)	Ohio Cumberland Gas Co.	(gas only)
14)	Piedmont Gas Co.	(gas only)
15)	Waterville Gas & Oil Co.	(combination - gas & oil)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/ integrated resource planning (IRP) for natural gas utilities is under consideration by the Ohio Commission. The Commissioners and the staff agreed that the electric LCP/IRP process should be implemented first, with natural gas LCP to follow. Commission staff and the gas utility staff have informally discussed LCP/IRP.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The only Commission requirement regarding DSM or conservation programs provides that the gas utilities make energy audits available to their residential/multifamily customers. The gas utilities are allowed to recover the cost of energy audits through their rates. No DSM or conservation programs are required to be performed for the commercial sector.

The Commission has not adopted a formal policy encouraging fuel substitution. Fuel substitution is considered a market share competition practice which is best handled by utilities to keep risks with the companies and not the ratepayers.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Until DSM programs have been implemented, the Commission will not require economic tests or analysis methods. When DSM programs are developed, the Commission has indicated that it favors average/embedded pricing to value the benefits of DSM programs.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The financial/accounting reviews for the major companies are conducted annually to assure that the gas cost recovery calculations have been correct and properly applied to customer bills. The management/performance audits review the prudence of the gas purchases and related practices and are conducted biennially. Although the Commission has not formally adopted rules to govern these reviews, there is a guideline for assessing performance and that is that each company must demonstrate that its purchases were made at the least cost consistent with acquiring reliable supply.

Gas utilities have been switching from spot supplies to longer term contracts with producers.

V Future PUC activities and key regulatory issues

No pipeline additions are planned for the next 5-10 years. Industrial gas use is projected to remain at current levels, and residential/commercial demand may increase slightly.

The key regulatory issues facing gas utilities include:
1) Gas transportation pricing; and
2) Pricing alternative services.

There are presently two staff members working on gas LCP/IRP.

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OKLAHOMA

Gas Utilities Serving State (gas-only or combination)

1).	Arkansas Louisiana Gas Company/ARKLA	(gas only)
2).	Oklahoma Natural Gas Company	(gas only)
3).	Southern Union Gas Company	(gas only)
4).	KPL Gas Service	(gas only)
5).	LeAnn Gas Company	(gas only)
6).	Lone Star Gas Company	(gas only)
7).	Arkansas Oklahoma Gas Company	(gas only)
8).	Northeast Oklahoma Public Facilities	(gas only - unregulated)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/integrated resource planning (IRP) has not been actively considered for natural gas utilities. Natural gas prices have been low and reliable service is maintained.

II. Type and extent of natural gas DSM programs (including fuel substitution)

DSM programs are not required, however, all gas utilities offer energy audits to their residential/multifamily customers. Some operate weatherization assistance and envelope improvement programs. Gas utilities advertise the merits of gas heating, but offer no financial incentives. All gas utilities provide interruptible rates to commercial/industrial customers.

A state statute allows the Commission to examine conservation costs incurred by a utility during a rate case proceeding. The Commission may or may not allow the costs to be recovered through rates. Promotional and advertising costs may not be recovered.

There is no formal policy or rule regarding DSM programs that may encourage fuel substitution by customers. Several years ago gas utilities intervened in an electric utility program that offered a financial incentive for high efficiency heat pumps.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No economic tests are performed by the utilities or required by the Commission to evaluate gas utility DSM program cost effectiveness.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Commission holds authority to conduct prudence reviews, but these reviews are not required on a regular basis. The state has not adopted specific criteria, rules, or guidelines that would be used during a review. Gas purchasing policies are subject to review on an individual case basis.

There has been a considerable growth of spot market activity over the past three years.

V. Future PUC activities and key regulatory issues

No key regulatory issues face the gas utilities at this time. LCP/IRP activity may be initiated in the next 3-5 years.

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OREGON

Gas Utilities Serving State (gas-only or combination)

1)	CP National Corporation	(part of Washington Water Power, a combination utility; pending PUC approval)
2)	Cascade Natural Gas Corporation	(gas only)
3)	Northwest Natural Gas Company	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

The Oregon PUC implemented electric and natural gas least-cost planning after a formal investigation resulting in Order No. 89-507 on April 20, 1989. Northwest Natural Gas' final LCP was submitted to the Commission on December 7, 1990. Cascade Natural Gas will submit a LCP on January 15, 1991. CP National has requested a delay of its LCP filing until the gas operations portion of the company is sold. All natural gas sold by gas utilities in Oregon is subject to least-cost planning requirements.

Initial LCP draft plans have generally focused on least-cost purchasing for supply requirements. The PUC would like utilities to thoroughly evaluate DSM options, and believes that certain features are integral to the LCP process. These features are:

1) All Resources must be evaluated on a consistent and comparable basis;

2) Uncertainty must be considered;

3) The primary goal must be least-cost to the utility and its ratepayers consistent with the long-run public interest; and,

4) The plan must be consistent with the energy policy of the state of Oregon (ORS 469.010).

The PUC has referred both gas and electric utilities to the Northwest Power Planning Council plan and the draft handbook on Least-Cost Planning published by the National Association of Regulatory Commissioners for additional recommended criteria.[51] The utilities may be penalized in rate cases if they are unable to develop an acceptable least-cost plan.

The Oregon Department of Energy and the PUC are currently working on a study of gas conservation goals. The report is due the first quarter of 1991.

II. Type and extent of natural gas DSM programs (including fuel substitution)

DSM programs that are currently being implemented have evolved from earlier utility conservation programs or are Commission required. All gas utilities offer residential energy audits,

[51] Oregon PUC Order No. 89-507, April 20, 1989.

informational programs, weatherization assistance (infiltration and insulation). Oregon statute requires low interest financing of weatherization for residential customers.[52] All gas utilities provide low income financing for the purchase of high efficiency equipment. However, the Commission considers this a promotional program, and will not allow cost recovery. Some gas utilities operate alternate fuel conversion programs. Costs for these programs are currently not recovered through rates. In the commercial sector, all gas utilities offer interruptible rates and commercial audits.

DSM program costs are expensed as they occur, and reviewed by the Commission in the next rate case. Financial incentives are not offered to gas utility shareholders to encourage conservation, however, the Commission staff may be considering incentive mechanisms in the development of LCPs.

The PUC does not have a formal policy concerning fuel substitution. The topic is currently under investigation in informal discussions. The Fuel Switching Investigation Group (FSIG) will be recommending guidelines concerning this issue. FSIG is a voluntary advisory group made up of PUC staff, the Oregon Department of Energy (ODOE), all gas and electric utilities, the Citizen's Utility Board, and consumer groups. The group was established by the PUC and ODOE staff in April 1990. The group meets periodically as progress is made on developing economic analysis of fuel substitution potential. A report is due the first quarter of 1991.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The utilities have not formalized an approach in developing economic tests to measure DSM program cost effectiveness. The Commission has not ordered that specific economic tests be used, but that all resources must be evaluated on a consistent basis.

Utilities have been required to file avoided costs of new gas supplies for several years.[53] The LCP Order requires long-run demand forecasts which will be used to refine the avoided cost calculation.[54] Gas utilities file avoided costs every year. Long-run incremental costs of capacity and supply are currently developed by customer class and are considered in rate cases.

The gas utilities are using the avoided cost of supply-side resources to evaluate the costs and benefits of DSM resources to the utility and its core customers.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Prudence reviews are conducted for all gas utilities on an annual basis or if gas costs are

[52] ORS 469.631-720.

[53] Docket No. UM21, Order No. 84-720, September 12, 1984.

[54] Order No. 89-507.

changed by more than 10%.[55] No specific criteria, rules or guidelines have been adopted for prudence reviews of gas purchases. Gas supply plans are filed with the Commission during a PGA review.

There is no connection between the PGA process and the review of the LCP process. The Staff expects a better connection in the future as DSM programs are developed.

Recently, utilities have tended to favor relatively short term natural gas contracts as opposed to long-term contracts or spot supplies.

V. Future PUC activities and key regulatory issues

Gas utilities are forecasting an increase in gas demand of 2-4% per year over the next five years. PGT Pipeline and Northwest Pipeline plan expansions of their natural gas transportation systems over the next five years.

Key regulatory issues facing gas utilities include:
1) DSM program planning; and,
2) Fuel switching/substitution.

Presently 1.5 FTE staff members are working on gas LCP/IRP.

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[55] Implemented by the Commission as of November 1, 1989.

PENNSYLVANIA

Gas Utilities Serving State (gas-only or combination)

1) Columbia Gas of Pennsylvania (gas only)
2) Equitable Gas Company (gas only)
3) National Fuel Gas Distribution (gas only)
4) Pennsylvania Gas & Water (combination - gas & water)
5) Peoples Natural Gas (gas only)
6) T.W. Phillips Gas & Oil (combined - gas & oil)
7) UGI Corporation (combined - gas & Luzerne electric)
8) Philadelphia Electric Company (combined - gas & electric)
9) There are 19 additional small gas utilities.

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/integrated resource planning (IRP) has not been actively considered for natural gas utilities. The Commission has directed its efforts to developing an LCP for electric utilities, which is not yet completed. Natural gas LCP is about 1-2 years away.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Residential/multifamily natural gas DSM programs are required by the PUC for low-income customers. All gas utilities perform energy audits; and, provide informational materials, weatherization assistance, and envelope improvements. Gas utilities are not required to extend these programs to non-low income customers, but may do so voluntarily.

Columbia Gas and Equitable Gas, Peoples Natural Gas, and National Fuel Gas Distribution Co. have a boiler/furnace program in which the company repairs and/or replaces this equipment at an average cost of $2,000 per customer. The program was targeted to low-income customers and then extended to small-commercial non-profit groups. Columbia Gas repaired/replaced 95 boiler/furnaces last year, Equitable Gas - 110, Peoples Natural Gas - 102, and National Fuel Gas Distribution Co. - 54.

There is no formal PUC policy or rules regarding DSM programs that may encourage fuel substitution by customers. However, Pennsylvania Gas & Water, Philadelphia Electric and UGI Corporation have been engaged in programs which encourage the use of natural gas.

Pennsylvania Gas & Water (PG&W) invested $110,000 in its heating equipment rebate program. A $300 incentive was offered to non-gas heating customers to make the switch to high-efficiency gas heating (80% Annual Fuel Utilization Efficiency or greater). There were 429 participants in this program. Pennsylvania Power & Light (electric company) services 80% of the new residential construction market in PG&W's service territory. This program is an attempt to capture a larger market share for gas heating.

Philadelphia Electric Company and UGI Corporation both sponsored gas heating conversion programs. This program encourages non-gas users with access to gas lines to convert to gas and to use high efficiency gas equipment (80% AFUE or greater). Customers must use high efficiency

equipment to be eligible for the rebate. Philadelphia Electric targeted oil heating customers, invested $83,000, and converted a total of 2,301 customers. UGI Corporation targeted oil and electric customers, invested $366,000, and converted 738 customers in 1989.

In the commercial/industrial sector UGI invested $9,000 in a gas chiller program. Equitable Gas has started to examine gas cooling possibilities. The electric utilities have expressed concern in regard to gas cooling, but no formal intervention has occurred. All gas utilities offer interruptible rates to customers with dual fuel capabilities.

Most gas utility DSM programs presently in effect are full-scale. However, gas utilities have fewer programs than the electric utilities. The electric utility full-scale and pilot DSM programs tend to be newer and more innovative. The Commission allows cost recovery of gas DSM programs to be included in rates.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Pennsylvania modeled their economic test after the California Commission Standard Practice Manual. If a utility's conservation program is more than 1/10th of 1% of a utility's total revenue budget, the utility must perform cost-benefit analysis (i.e., participant, non-participant, ratepayers, and utility tests). Once the Commission decides that these tests have been satisfactorily performed, the utility may institute the program. Cost-effectiveness, energy conservation potential, required lead time, lifetime of option, free ridership, and cream skimming are all considered in the analysis and subject to qualitative standards. No avoided costs methodology or long-run marginal costs have been developed.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Major gas utilities file annual gas cost rate adjustment (Section 1307F filing) which goes through a formal hearing process with an administrative law judge of the PUC. The Commission seeks to assure that the utilities have used the most prudent practices in acquiring their gas supply. There are no specific criteria, rules, or guidelines that are used in a review. An annual conservation report must also be filed with the Commission. However, the Commission has no authority to accept or reject utility conservation programs.

The Bureau of Audits may also hold hearings and review utility purchasing practices. Audits address the following issues:

1) Who in the gas company is responsible for procuring gas supplies?
2) What incentives are in place to insure the best price of supply?
3) What are future gas supply requirements?
4) What alternatives to primary suppliers are available?
5) Are there any problems with current suppliers?
6) Is the company seeking any new suppliers?
7) What attempts have the gas utilities made to gain access to lower spot supplies?

The Bureau of Audits reviews smaller utilities annually, and the larger utilities are reviewed annually by the PUC in a formal hearing process. An example of a discrepancy that the Bureau

may raise concerns affiliated interests. Did the utility buy its gas supply from an affiliate instead of the open market and not guaranteeing the least-cost or best-cost supply.

Gas utilities file an annual report of supply and demand, but no Commission pre-contract approval is necessary.

V. Future PUC activities and key regulatory issues

The Commission views increased demand side management activity as the key regulatory issue facing gas utilities. Natural gas DSM/LCP may follow along similar lines as the electric utility LCP. One particular issue will be up-front cost recovery for DSM. The Commission has been monitoring what other states are doing and any information that the American Gas Association has available.

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RHODE ISLAND

Gas Utilities Serving State (gas-only or combination)

1) Providence Gas Company (gas only)
2) Valley Gas Company (gas only)
3) Bristol & Warren Gas (gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/integrated resource planning (IRP) is under development. All Rhode Island gas utilities file long range (5 year) plans every two years which detail projected supply options. Two purchased gas dockets (Providence Gas - No. 1673 and Valley Gas 1736), and one current rate case (Providence Gas - No. 1971) address LCP/IRP issues. An appropriate avoided gas cost methodology has been of primary concern. Providence Gas and Valley Gas have hired a consultant to examine this question. Iterative steps used in an IRP process with consideration of DSM options will be more fully determined next year, when Providence Gas and Valley Gas file for cost recovery of DSM programs. Bristol & Warren Gas will probably not be included in proceedings until later, because it is a small utility with limited staff resources.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Rhode Island Saving Energy (RISE), a non-profit agency originally established to administer the federal Residential Conservation Service for the utilities, has been instrumental in the conservation programs which are now operating. RISE funding comes from a surcharge on bills collected from gas and electric utilities (based on a percentage of sales), with low interest loans to consumers subsidized by oil overcharge funds from the Rhode Island Energy Office. All gas utilities through RISE offer to the residential and commercial sectors: free energy audits; weatherization assistance (insulation and infiltration); financial incentives for high efficiency equipment; and heating system retrofits.

All gas utilities offer interruptible rates for commercial customers. The large utilities also have air conditioning and cogeneration rates.

Gas utilities are allowed cost recovery in their rates for conservation programs offered to low-income and non-profit institutions. These programs are additional to the RISE programs.

There is no formal Commission policy or rules regarding DSM programs that may encourage fuel substitution by customers. However, the Commission favors direct use of gas over electricity in all end-uses where it is cost-effective. End-uses such as residential heating, hot water heating; and, commercial cooling, cooking, and heating have been suggested. A fuel switching task force has this issue under review, focusing on commercial cooling, and a report is pending.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Economic screening criteria to measure DSM program cost-effectiveness have not been mandated by the Commission. Once the pending dockets have been decided, screening criteria will be determined following adoption of an appropriate avoided gas cost methodology.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Gas utilities file long range plans which include existing and proposed contracts, but the legislation mandating this does not require Commission pre-approval of the plans. Purchased gas adjustment hearings are held annually with mid-course adjustments as required. In the past, each local distribution company has depended upon a single pipeline supply source, thus simplifying the factors included in a PGA. The Commission has now found it necessary to re-examine their PGA policies to address many new supply choices which were not available in the past. A consultant has been hired to assist the PUC to establish the criteria and guidelines which may be needed.

The trend for Rhode Island gas utilities has been towards an increase of purchases on the spot market as opposed to long- and short-term contracts.

V. Future PUC activities and key regulatory issues

The Iroquois pipeline originating in Canada will add to the capacity of the existing gas transportation system, as well as increased supplies from domestic sources.

Key regulatory issues facing gas utilities include:
1) improved resource planning;
2) initiation of full scale DSM; and
3) revision of gas purchasing practices.

One staff person works on electric and gas DSM in addition to other responsibilities Procedures for review and approval of DSM programs may be resolved within the next year.

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SOUTH CAROLINA

Gas Utilities Serving State (gas-only or combination)

1)	United Cities	(gas only)
2)	Peoples Natural Gas Company of South Carolina	(gas only)
3)	Piedmont Natural Gas Company, Inc.	(gas only)
4)	South Carolina Pipeline	(gas only)
5)	South Carolina Electric & Gas	(combination - gas & electric)

I. Status of state PUC least-cost regulation and practices for gas utilities

There have been internal staff discussions regarding least-cost planning (LCP)/integrated resource planning (IRP) for natural gas utilities. However, the Staff feels that gas utilities lack the capital investment that electric utilities have to implement LCP/IRP. Gas utilities purchase reliable supplies, and LCP/IRP has not been a priority. No energy conservation goals have been adopted for natural gas utilities.

II. Type and extent of natural gas DSM programs (including fuel substitution)

No natural gas DSM programs are in effect in South Carolina. Some gas utilities will perform an energy audit for residential/multifamily customers upon request. Interruptible rates are offered to commercial/industrial customers by some gas utilities. No formal policies or rules regarding DSM programs that may encourage fuel substitution by customers has been adopted by the Commission. Gas utilities advertise the merits of residential gas hot water heating, but no financial incentives are offered.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

Due to the lack of DSM programs, economic tests to evaluate gas utility DSM programs are not performed.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

All regulated gas utilities (United Cities, Peoples, Piedmont, South Carolina Pipeline, and South Carolina Electric & Gas) are subject to annual Commission review. No specific criteria, rules, or guidelines are used in prudence reviews of gas purchases. The Commission has found that gas utilities have provided reliable firm and interruptible supplies at competitive market prices. No least-cost/best-cost purchasing rules have been adopted. The South Carolina Consumer Advocate was concerned that South Carolina Pipeline was not purchasing gas at the least-cost. In hearings on October 24, 1989 (Docket #90-10-G) South Carolina Pipeline replied (and the Commission concurred) that its purchases were prudent and guaranteed a reliable supply of firm natural gas.

Since 1984 the Commission has observed a trend toward a greater number of spot purchases to supply industrial and interruptible customers. Long term contracts are arranged with suppliers to meet peak firm load.

V. Future PUC activities and key regulatory issues

The key regulatory issue facing gas utilities is the ability of natural gas utilities to compete with alternative fuels (i.e., propane, wood chips, #6 and #2 fuels) in the industrial sector.

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SOUTH DAKOTA

Gas Utilities Serving State (gas-only or combination)

1) Minnegasco (gas only)
2) Montana-Dakota Utilities Company (combination - electric & gas)
3) Northwestern Public Service (combination - electric & gas)
4) Midwest Gas (gas only, however Iowa Public Service (electric) is also a subsidiary of the same parent company.)

I. Status of state PUC least-cost regulation and practices for gas utilities

The South Dakota Commission is not considering LCP/IRP for natural gas utilities at the present time. There is adequate pipeline capacity and no perceived shortage of natural gas, therefore, LCP/IRP is not a priority.

II. Type and extent of natural gas DSM programs in effect (including fuel substitution)

The Commission does not require natural gas utilities to implement any demand-side management (DSM) programs. Some gas utilities may voluntarily offer energy audits to their residential/multifamily customers. Interruptible rates are available to commercial/industrial customers by all gas utilities.

The Commission does not have authority to offer financial incentives to gas utilities to encourage conservation. This authority would come out of the Governor's office.

A formal policy or rules regarding DSM programs that may encourage fuel substitution by customers has not been addressed by the Commission. Gas end-uses have not been promoted over any electric end-uses.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The natural gas utilities do not implement any DSM programs; therefore no Commission required economic tests are performed. The Commission, nor the gas utilities have developed a methodology to estimate the avoided costs of new gas supplies.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The South Dakota Commission does not conduct prudence reviews for natural gas utilities. The state has not adopted any form of least-cost or best-cost purchasing rules. Natural gas utilities are not required to file supply plans in advance of purchases.

There has been an increase of purchases on the spot market over the past three years.

V. Future PUC activities and key regulatory issues

The gas utilities do not forecast any increases in gas demand during the next 5-10 years or any major capacity additions to the existing gas transportation system.

At present the major regulatory issue facing gas utilities is the gas utilities intervention in an electric utility's rate adjustment policy.

The Commission sees little or no activity in LCP/IRP for natural gas utilities in the near future.

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TENNESSEE

Gas Utilities Serving State (gas-only or combination)

1)	Chattanooga Gas Company	(gas only)
2)	Nashville Gas Company	(gas only)
3)	United Cities Company	(gas only)
4)	Hardin Gas Company	(gas only)
5)	Jelico Gas Company	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/integrated resource planning (IRP) for gas utilities has not been considered. The Commission believes that it is the gas utilities responsibility to shave their peak when needed. The Commission believes that the utilities have operated responsibly and reliably.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The gas utilities do not operate any conservation or DSM programs. Firm and industrial rates and peak demand charges apply to the commercial/industrial sector.

No formal Commission policy or rules regarding DSM programs that may encourage fuel substitution by customers have been adopted.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

There are no DSM programs in effect; therefore, no economic tests are used to evaluate gas utility DSM programs.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Tennessee has just hired a consultant to investigate prudence procedures. The consultant will be examining gas utilities efforts to provide a reliable supply at a reasonable cost. The three largest gas utilities, United Cities, Nashville Gas, and Chattanooga will be subject to this review.

Least-cost/best-cost purchasing rules have not been adopted. The gas utilities are not subject to contract pre-approval.

Gas supply contracts have recently demonstrated a trend toward intermediate terms, whereas six months ago contracts were month to month.

V. Future PUC activities and key regulatory issues

Key regulatory issues facing gas utilities include:

1) New PGA rule which will guarantee cost recovery of gas purchases.
2) Prudence standards are presently being reviewed by a consultant and recommendations are forthcoming.

Least-cost planning will not be addressed by the Commission for at least two years.

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TEXAS

Gas Utilities Serving State (gas-only or combination)

Texas has approximately 300 gas utilities of which a majority are investor owned distribution and transmission companies.

I. Status of state PUC least-cost regulation and practices for gas utilities

There is no state mandate regarding least-cost planning (LCP)/integrated resource planning (IRP) for natural gas utilities, nor is LCP/IRP being considered at the present time.

II. Type and extent of natural gas DSM programs (including fuel substitution)

DSM programs for natural gas utilities are not required on a state-wide basis. Municipally run gas utilities may have conservation programs in effect for their service territory only. Upon inquiry to one of the major interstate gas utilities in Texas, Lone Star Gas, it was revealed that Lone Star does provide energy conservation information to their customers. Energy audits were stopped after federal legislation repealed mandatory RCS audits.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

There is no state statute or Railroad Commission order which requires economic tests to evaluate DSM program cost effectiveness.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Regulatory authority of gas utilities is divided among the Texas Railroad Commission and individual city councils. The Railroad Commission conducts rate reviews and quality of service reviews for distribution utility operations outside city limits for every intrastate gas utility operating in Texas. City councils have jurisdiction over utilities' operations within their city limits and municipally-owned distribution utility operations. City council decisions may be appealed to the Railroad Commission. Reviews are conducted any time a rate increase is filed. The Gas Utility Regulatory Act, Article 1446(e) outlines specific criteria and guidelines used in rate reviews. If rate increases reflected the inclusion of any conservation programs, part of the review might consider cost recovery. The Commission is not required to provide cost recovery of conservation programs. Decisions would be on an ad hoc basis. The Railroad Commission also has authority over issues concerning natural gas pipeline safety.

On a state-wide basis no form of least-cost or best-cost purchasing rules have been adopted. Gas supply plans are not required to be filed with the Commission in advance of purchases.

V. Future PUC activities and key regulatory issues

The Railroad Commission has expressed that a key regulatory issue facing gas utilities is cost of service for distribution companies.

The Texas Municipal League, which acts as a coordinating body for municipal utilities, stated that conservation and DSM issues could be of future concern due to the passing of the Clean Air Act and any subsequent legislation.

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UTAH

Gas Utilities Serving State (gas-only or combination)

1) Mountain Fuel Supply Co.

I. Status of state PUC least-cost regulation and practices for gas utilities

Utah does not require least-cost planning (LCP) or integrated resource planning (IRP) for natural gas utilities. Hearings on electric LCP/IRP started in April 1990, and the Commission explicitly excluded planning for gas LCP/IRP. Electric LCP will occupy the majority of Commission time for the next six months to a year. Progression regarding gas LCP policy is at least one year away.

II. Type and extent of natural gas DSM programs (including fuel substitution)

DSM programs are not implemented in Utah. Mountain Fuel will do energy audits upon customer request. Costs of providing these audits may be recovered in rates. Interruptible rates are offered to commercial/industrial customers.

There is no formal Commission policy regarding fuel substitution, however, the gas utilities have been allowed to expand their service territory partly in response to the impending federal Clean Air Act.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No economic tests are used or required to evaluate gas utility DSM programs.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

The Commission has not established any specific criteria, rules, or guidelines that are used in prudence reviews of gas purchasing policies. Prudence reviews are conducted in the context of rate cases for all gas utilities. Rate case reviews focus on the gas utilities purchasing and transmission policies. No least-cost or best-cost purchasing rules have been adopted, but this issue arose in a recent rate case.

Most of the gas supplied to Utah is arranged through long-term contracts. Mountain Fuel purchases its supply from its affiliated pipeline and producer.

V. Future PUC activities and key regulatory issues

A planned extension to the Southern Idaho pipeline will serve new communities in Utah which in turn will provide for the added capacity needed to service these communities.

Key regulatory issues facing gas utilities in Utah include:

1). Affiliated interest concerns regarding Mountain Fuel's wholly owned subsidiary, Questar, which is the predominant gas supplier to Utah. Mountain Fuel maintains majority control over producing, transporting, and distributing gas in Utah.
2). Gas supply dispatch and acquisition to non-Mountain Fuel affiliates.
3). Federal policy on pipeline gas purchases.

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VERMONT

Gas Utilities Serving State (gas-only or combination)

1) Vermont Gas Systems

I. Status of state PUC least-cost regulation and practices for gas utilities

The Vermont Public Service Board has a least-cost plan (LCP)/ integrated resource plan (IRP) in implementation. Docket No. 5270, issued April 16, 1990 outlines the Boards requirements for all major electric and gas utilities servicing Vermont.

Initially, a Board procedural order of April 22, 1988 opened the investigation into energy efficiency DSM and LCP measures. The procedural order addressed DSM and LCP in four phases.

Phase 1. The Board required that all utilities file baseline data on the status of: 1) existing DSM programs; 2) existing and projected supply-side resources; 3) projections of customer demand; and 4) existing utility procedures for integrated resource planning of demand and supply resources.

Phase 2. Required utilities to evaluate the potential of demand-side resources to meet future energy need. Strategies to use DSM measures to provide least-cost service would be explored by the utilities, and methodologies to quantify and evaluate resources would be determined.

Phase 3. All parties to the procedural order were requested to address the existing institutional and regulatory structure which may actually be disadvantageous to utilities efforts of implementing DSM measures and an IRP. Recommended changes were welcomed by the Board.

Phase 4. The final phase before issuing Docket No. 5270 provided an opportunity for all parties to submit rebuttal testimony and to summarize their positions. Small utilities filed a motion in June 1988 requesting exemption from full participation. This motion was granted on the terms that these utilities file limited participation plans.

Docket No. 5270 mandates that all utilities submit three filings to the Board. The first filing, a work plan for the development of comprehensive DSM programs, must be submitted within 90 days. The second filing submitted within 180 days is an implementation plan which includes incentives, budgets and targets. The third filing is a fully integrated resource plan which provides for annual summary reviews. The IRP is to be re-filed and reviewed every three years thereafter. Vermont Gas Systems has one year to submit its third filing.

Vermont Gas Systems' filings will include specific DSM measures as stated in the Docket. One targeted program is a pilot program promoting cost effective electric heat conversions to natural gas. Vermont Gas must also perform detailed analysis of the costs and savings of installing and operating high-efficiency gas appliances and heating equipment for residential and commercial customers.

The Board recommends that an incentive program to promote high-efficiency space heating should be designed cooperatively in areas where electric and gas service overlap. A form of cost-sharing may be negotiated between Vermont Gas and electric utilities where it is determined that

cost-effective conversions from electric heat have been identified. Cost-effectiveness must be defined in societal terms (refer to Wisconsin PSC's statement, "Interfuel Substitution Principles, 4/7/89 as a guideline). That is, a cost-benefit analysis should indicate the fuel that offers the least-cost combination with energy efficiency.

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. Long term financing based on minimum efficiency standards may also be provided through the gas utilities. Minimum efficiency standards are those standards which will take effect in 1992.

Another objective of the Docket is to include in Vermont Gas' IRP filing the capability to purchase saved gas through efficiency programs as an alternative to obtaining additional purchases and capacity. This would require Vermont Gas to calculate and compare the life-cycle costs of saved versus purchased gas taking into account price escalation and avoided storage costs. The IRP filing also allows Vermont Gas to attach a 15% risk and externality factor when assessing cost-effectiveness of gas efficiency improvements until an explicit methodology can be reached to estimate external costs of natural gas combustion.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Outside of future DSM programs addressed in the Docket, Vermont Gas Systems does offer energy audits and informational material to its residential customers. Interruptible rates are available to commercial customers.

Cost recovery methods of DSM programs identified in the Docket have been recommended according to three specific policies: 1) allow utilities to recover expenses associated with energy efficiency programs along similar rate making procedures used to collect costs of supply investments; 2) recognize the necessity of incorporating aggregated tests of whether a utility's demand-side measures are "used and useful"[56]; and 3) use a mechanism which closely parallels reduced earnings accrued in a supply-side Allowance for Funds Used During Construction (AFDUC). This method, commonly referred to as ACE (Account Correcting for Efficiency mechanism) allows a utility to accrue and to recover any net revenue losses that a utility can demonstrate are attributable to its DSM programs. The ACE mechanism removes a disincentive, but does not create a bonus incentive to allow the utilities to share in societal net benefits of DSM.

The Board has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution, however, a policy is pending. A motion filed by non-utility parties, represented by Vermont Public Interest Research Group, stated that Central Vermont Public Service is unwilling to pursue fuel switching even if it proves to be cost-effective for ratepayers. In an ongoing debate, Central Vermont argues that the Public Service Board has no jurisdiction to order Central Vermont to pursue cost-effective fuel-switching measures.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

[56]Docket No. 5270, State of Vermont Public Service Board, April 16, 1990, p.1-7.

Economic tests used by gas utilities to measure DSM program cost-effectiveness are based on the societal test which includes an estimate of environmental externalities. DSM screening criteria used are: cost-effectiveness; energy conservation potential; free ridership; and cream skimming. In April 1990, the board ruled that utilities should discount demand-side resource costs by 10% to reflect the "comparative risk and flexibility, advantages of such resources and that supply side resources will be increased initially by 5% to capture costs not already included in the monetized prices of supply sources."[57]

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Prudence reviews are conducted during the course of a rate case for Vermont Gas. There are no specific rules or guidelines that are used. IRP filings and reviews will be a separate activity from a general rate review.

There are no state adopted least-cost or best-cost purchasing rules. However, the Docket recommends "that the Board require Vermont utilities to begin pursuing least-cost strategies that integrate both supply and demand options."[58]

V. Future PUC activities and key regulatory issues

Vermont Gas Systems has reached peak capacity, and is expanding their gas transportation system in anticipation of an inerease in demand during the next 5-10 years.

Key regulatory issues facing Vermont Gas Systems include:

1) implementation of DSM programs moving towards a fully integrated resource plan;
2) clarification of IRP regulatory policy where electric service overlaps territories with gas service (i.e., fuel substitution policies).

There are four Board members working on LCP/IRP implementation with 1 FTE working on gas LCP/IRP.

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[57]Vermont PSB 1990, Docket No. 5270, April 16, 1990.

[58]Vermont PSB 1990, Docket No. 5270, April 16,1990, p.I-8.

VIRGINIA

Gas Utilities Serving State (gas-only or combination)

1) Commonwealth Gas Services	(gas only)
2) Northern Virginia Natural Gas	(gas only)
3) Shenandoah Gas	(gas only)
4) United Cities Gas	(gas only)
5) Virginia Natural Gas	(gas only)
6) Charlottesville Gas Division (municipal jurisdiction)	(gas only)
7) Danville Department of Utilities (municipal jurisdiction)	(combination - gas & electric)
8) Richmond Department of Public Utilities (municipal jurisdiction)	(gas only)
9) Southwestern Gas	(gas only)
10) Roanoke Natural Gas	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Least-cost planning (LCP)/integrated resource planning (IRP) has not been actively considered by the Virginia State Corporation Commission. Electric regulations have occupied the Commission staff's time.

II. Type and extent of natural gas DSM programs (including fuel substitution)

Some Virginia gas utilities voluntarily operate conservation programs which include: energy audits (residential/multifamily customers), and weatherization financing (all customers). Interruptible rates are offered to commercial/industrial customers. Conservation program costs are recovered through rates. The Commission evaluates programs on a case by case basis, no specific guidelines are used.

No formal policy or rules regarding DSM or conservation programs which would encourage fuel substitution have been adopted.

The gas utilities have intervened on the electric utilities proposed program to offer incentives for dual fuel heat pumps. One case (PUE 900009) is pending before the Commission. Some gas utilities have also expressed concerns over the electric utilities' promotion of energy saver homes (all-electric homes).

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No economic tests are used or required to evaluate gas utility conservation or DSM programs. No avoided cost methodology or marginal cost estimates have been developed.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Gas utilities file a five year plan annually which is reviewed by Staff. No specific criteria, rules, or guidelines are used in reviews of gas purchasing policies, and no formal hearings are held.

Commission Order of December 29, 1988 states that gas utilities must purchase gas supplies which ensure reliability at the best-cost possible which may or may not be the least-cost.

Quarterly purchase gas adjustment (PGA) filings are reviewed, however, there is no provision for advanced Commission approval of supply contracts.

Recent trends in the relative mix of long-term, short-term and spot supplies of natural gas indicate a reduction in spot activity and an increase in the level of long-term third party LDC purchases directly from producers.

V. Future PUC activities and key regulatory issues

Virginia has experienced significant growth in gas-fired electric generation contributing to an unprecedented load growth.

Key regulatory issues facing the Commission include:
1) New growth in gas-fired electric generation; and,
2) Pipeline construction.

Commission activity is not planned in the area of LCP/IRP for natural gas utilities.

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WASHINGTON

Gas Utilities Serving State (gas only or combination)

1) Cascade Natural Gas Corp.	(gas only, multijurisdictional)
2) Northwest Natural Gas Co.	(gas only, multijurisdictional)
3) Washington Natural Gas Co.	(gas only)
4) Washington Water Power Co.	(combination, multijurisdictional)

I. Status of state PUC least-cost regulation and practices for gas utilities

The state of Washington requires that a least-cost plan be prepared by each natural gas utility regulated by the Commission. State PUC regulations were enacted by PUC order in October 1987. Regulations stipulate that the utilities must prepare the 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." (WAC 480-90-191). The regulations include a description of the type of information to be included in the least-cost plan:

"(3) Each gas utility shall submit to the Commission on a biennial basis a least-cost plan that shall include:

(a) A range of forecasts of future gas demand in firm and interruptible markets for each customer class for one, five and twenty years using methods that examine the impact of economic forces on the consumption of gas and that address changes in the number, type, and efficiency of gas end-uses.

(b) An assessment for each customer class of the technically feasible improvements in the efficient use of gas, including load management, as well as the policies and programs needed to obtain the efficiency improvements.

(c) An analysis of each customer class of gas supply options including:

(i) A projection of spot market versus long-term purchases for both firm and interruptible markets;

(ii) An evaluation of the opportunities for using company-owned or contracted storage or production;

(iii) An analysis of prospects for company participation in a gas futures market;

(iv) An 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) The 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." (WAC 480-90-191)

One gas utility, Washington Water Power, has submitted a least-cost plan to the Commission and the other three LDCs are expected to file in 1991.

II. Type and scope of natural gas DSM programs (including fuel substitution)

DSM program options may be suggested by participants in the Technical Advisory Committee. This is a collaborative working group made up of PUC staff from all states (in the case of a multijurisdictional utility); private conservation/environmental groups; public advocate's counsel; the state energy office; the largest industrial consumers; and, utility staff. Although participants often make program suggestions, the development of any DSM program is done by the utility.

DSM programs are developed using the following steps:
1) The utility develops a range of forecasts of energy sales and peak day consumption;
2) The utility develops a menu of all possible DSM program options with program costs and schedules;
3) DSM programs are screened for cost-effectiveness;
4) An evaluation methodology is prepared for those programs which pass the cost-effectiveness screen;
5) Demand and supply options are integrated to meet sales estimates; and,
6) The price impact is determined and the whole sequence is re-iterated.

Currently, all gas utilities in Washington have some level of energy audit or information program for residential customers. Some have programs providing financial incentives for high efficiency equipment. Both are considered to be full scale programs. Weatherization assistance or envelope improvement programs are not in place. All gas utilities use interruptible rates for commercial and industrial customers, but that is the only DSM program available to them.

Fuel substitution programs are considered to be an electric DSM program when used to substitute gas for electricity. Fuel substitution as a load building measure is not considered a gas resource. The PUC does not require electric utilities to encourage gas use; and has also disallowed advertising expenses of electric utilities for discouraging gas use.

Gas utilities in Washington are not reported as having comprehensive DSM programs in effect. In the past, competitive electric rates were relatively low, effectively keeping down gas market share. Price increases for gas exacerbated this condition, making gas utilities averse to any increase in utility sponsored conservation.

DSM program costs may be recovered in rate cases. Legislation enacted in 1980 allows an incentive rate of return (ROR) rate base treatment for utility programs that improve efficiency, but no gas utility has taken advantage of this.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs:

There is no official economic test prescribed by the Commission for evaluating gas DSM programs. The principal difficulty in establishing the cost-effectiveness of DSM, as well as other resources, is in calculating avoided costs, which should include avoided commodity cost and avoided transmission costs. Pending development of a more sophisticated method, which will be the subject of future discussions with all gas utilities, the Commission staff has recommended that utilities use

a "proxy avoided cost," consisting of their weighted cost of gas (WACOG), escalated at a combination of commodity and GNP escalation rates.

Once avoided costs are established, utilities then apply an appropriate cost-effectiveness test to determine the optimal amount of DSM to include in their least-cost plans. At present, gas utilities generally are applying the "total resource cost" test to establish the cost effectiveness of DSM. This test has in the past been approved by the Commission for electric utility DSM programs.

A recent study on cost-effective gas DSM, performed by Washington State Energy Office (WSEO 1991) under contract to the Commission, is being used by all four LDCs as guidance in their DSM review.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives

The Washington PUC conducts a prudence review of gas purchasing practices in rate cases. The prudence review is linked to the least-cost plan. The utility cannot recover costs if it cannot demonstrate consistency with the least-cost plan. This happened once - to Washington Water Power. A pipeline contract expense was planned to be passed on to core customer's rates; the PUC requested evidence of this as a necessary expense in light of the least-cost plan order.

V. Future PUC activity and key regulatory issues

Washington Water Power expects a 2-4% annual increase in gas demand due to a shift from electric to gas end-uses. Other gas utilities project more modest increases due only to local economic growth.

The key regulatory issues facing gas utilities are:
1) Bypass and transportation;
2) Obligation to serve;
3) Least-Cost Planning;
4) Rate design;
5) Conservation;
6) Fuel substitution; and,
7) Environmental externalities.

The PUC and legislature will investigate the extent of bypass and transportation activity and the ability of gas utilities to serve firm customers. There are likely to be hearings or legislative action on this issue, and possibly a notice of inquiry. There are presently 1.2 FTE staff working on gas LCP.

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WEST VIRGINIA

Gas Utilities Serving State (gas-only or combination)

1). Mountaineer Gas Company	(gas only)
2). Hope Gas	(gas only)
3). Shenandoah Gas Company	(gas only)
4). Carnegie Natural Gas Company	(gas only)
5). Equitable Gas Company	(gas only)
6). West Virginia Power Gas Service	(gas only)
7). Pennzoil	(gas only)

I. Status of state PUC least-cost regulation and practices for gas utilities

Although there have been discussions between the gas utilities and the Commission regarding LCP/IRP, gas LCP/IRP is not required in West Virginia. The state is a gas and coal producing state which seeks to balance the interests of utilities, consumers and the general economy of the state.

II. Type and extent of natural gas DSM programs (including fuel substitution)

The West Virginia Commission does not require natural gas utilities to implement DSM programs. Some gas utilities provide energy audits to their residential/multifamily customers. The costs of providing these audits are recovered by the utilities through their rates. The Commission has not made a decision regarding the gas and electric utilities request to offer financial incentives for customers to purchase high efficiency equipment. All gas utilities offer interruptible rates to their commercial/industrial customers.

The Commission has not adopted a formal policy or rules regarding DSM programs that may encourage fuel substitution by customers. The Commission has not required electric utilities to encourage gas use for any particular end-uses.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

No economic tests to measure DSM program cost effectiveness are performed due to the fact that the gas utilities do not implement any DSM programs.

Neither the Commission nor the gas utilities have developed a methodology to estimate the avoided costs of new gas supplies.

IV. Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.

Although the state has not adopted any specific criteria, rules, or guidelines of purchasing policies, the Commission does conduct prudence reviews on a case-by-case basis. Since 1983 there

has been a general Commission regulation requiring the gas utilities to purchase the least-cost gas supplies that are readily available and reliable.

Gas utilities file an annual purchase gas adjustment as per Commission requirements. The gas utilities are allowed to recover the differences between their estimates for that period and the actual costs.

There had been much more activity on the spot market than in the past, but this activity has leveled off. There is a trend now to purchase natural gas locally as opposed to interstate purchases (i.e., from Louisiana and Texas). A 1983 Commission regulation encourages the purchase of Appalachian gas supply. Presently, seventy-five percent of the gas purchased is produced in West Virginia.

V. Future PUC activities and key regulatory issues

The Commission's 10 year forecast predicts a 2-3% increase in pipeline additions. The utilities concur with this forecast.

FERC regulations will guide the Commission with such regulatory issues as: inventory; storage; cost-based rates; and, transportation.

Most of the present and future research regarding IRP/LCP will focus on the electric utilities, and not the gas utilities.

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WISCONSIN

Gas Utilities Serving State (gas only or combination)

1) Wisconsin Gas Co.	(gas only)
2) Wisconsin Natural Gas Co.	(gas only)
3) Wisconsin Public Service Co.	(combination - gas & electric)
4) Wisconsin Power & Light Co.	(combination - gas & electric)
5) Madison Gas & Electric Co.	(combination - gas & electric)
6) Northern States Power Co.	(combination - gas & electric)
7) Wisconsin Southern Co.	(gas only)
8) Wisconsin Fuel & Light Co.	(gas only)
9) Superior Water, Light & Power Co.	(combination - gas & electric)

I. Status of state PUC least-cost regulation and practices for gas utilities

The state of Wisconsin does not have a specific regulation requiring least-cost planning for gas utilities, but does have a series of different regulations (e.g., avoided costs and DSM programs) which effectively give results similar to gas least-cost planning. The PSC staff is currently conducting an investigation into interfuel substitution which will introduce to gas utilities the economic tests useful in gas planning. It also expects to [illegible] an investigation of integrated resource planning for natural gas at a later date.

DSM programs are applied to all gas sales. Electric utilities in Wisconsin are required to implement a full featured LCP, and therefore, the combination utilities have a more thorough overlap in DSM program experience. Wisconsin utilities must file financial data annually; this usually precipitates a rate case. It is during a rate case that a utility proposes DSM program goals and budgets for review by the PSC.

The principal criterion for selecting DSM options is net benefits. The total technical cost test is used to rank options. End-use forecasting is used by a few gas utilities, but not all. All utilities are required to estimate the conservation impact. The technical and market potential of a DSM program is done on a short term basis. Free riders are estimated using a variety of methods. Sales forecasts are prepared on an annual basis, not according to peak. Sales forecasts are not usually based on end-use models. Utilities calculate a change in sales resulting from conservation. Conservation impacts are small within a given test year compared to total sales, plus throughput by transportation customers.

In 1977, gas utilities were required to reduce house heating consumption 25% by 1985. Wisconsin has not developed further long-term energy conservation goals for natural gas utilities, but short-term conservation goals are determined in a rate case. Goals are set according to net benefits by end-use. Avoided cost is used to value conservation. The Commission is now going through the first round of goal setting for natural gas DSM programs. Changes in the regulatory treatment of conservation goals are expected as they gain more experience in how each DSM programs works.

II. Type and scope of natural gas DSM programs (including fuel substitution)

DSM programs are currently developed by the gas utilities in Wisconsin. The utility brings plans for DSM programs to PSC staff for review. The PSC staff lets them know which areas of the plans need improvement. There is usually no major disagreement.

For the residential and multifamily customer classes, all gas utilities offer energy audits. All utilities have weatherization and envelope improvement programs for low-income customers, and some gas utilities also implement rebate programs for non-low income customers. All gas utilities have financial incentives for high efficiency equipment and fuel substitution programs. A few gas utilities also have programs which include boiler tune-ups and hot water cutouts.

For commercial and industrial gas customers, all utilities have programs which provide rebates for installation of high efficiency equipment. All utilities have implemented a fuel substitution program and interruptible rates, although there is not much interruptible load left due to transportation gas arrangements. A few gas utilities also have weatherization and envelope improvement programs, gas cooling rebates, and a program for steam traps. The gas cooling rebates are demonstration programs.

Most natural gas DSM programs are full scale, with a few pilot programs. Wisconsin Power and Light, and Wisconsin Gas are reported to have the most active DSM programs in Wisconsin, although they are said to be significantly behind the comprehensiveness of electric utilities' programs.

Costs for DSM programs are recovered through the use of an escrow account and/or rate basing. Conservation costs are estimated and those funds are put in an escrow account. The utilities draw down on this account as expenses accrue. The PSC staff states that this is more difficult for accountants to monitor than conventional accounting, but it does ensure full cost recovery of DSM program costs.

The PSC has an electric policy on fuel substitution called Interfuel Substitution Principles, but not one for gas yet. There is a current formal docket concerning fuel substitution scheduled for hearing in February 1991 that will consider the use of the same economic tests for gas promotion that are used with electric planning. Also, it will address methods of allocating costs between electric and gas utilities where fuel substitution programs occur. The PSC is now trying to evaluate promotional costs. For example, no promotion of efficient electric water heaters is permitted for cost recovery where natural gas is available. A decision in the fuel substitution docket is expected in May 1991.

The PSC has required electric utilities to encourage gas for particular end-uses, although the pressure to do so has not been intense. In cases where gas is deemed most cost-effective, electric utilities cannot use rebates for electric equipment. Gas is encouraged for multifamily heating. Use of gas for commercial cooling is part of a three year study now underway. The No Losers Test is currently used to evaluate gas promotion end-use options. The PSC is now also looking at the benefits to society of alternative options and the decision in the docket referred to above will determine whether the Total Resource Cost test will be used to evaluate gas promotion end-use options.

There has been little[59] formal intervention by gas utilities regarding electric DSM programs that offer rebates or financial incentives for high efficiency equipment that potentially competes with gas-fired equipment, but there has been plenty of grousing. Many gas utilities regard electricity as their greatest competitor.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

A variety of economic tests are used by gas utilities in Wisconsin to measure DSM program cost effectiveness. They include the Utility Revenue Requirements test; the No Loser test; the Total Resource Cost test; the Societal test; and, the Technical Cost test (the incremental cost difference between the cost of the efficient option and the cost of the standard option compared to total benefits). The Non-participant Test is not generally accepted by the PSC for evaluation of conservation programs.

Utilities are not required to use certain criteria in screening DSM options, but they are required to use a participant test to measure program cost effectiveness, and to develop an avoided cost calculation for use in net-benefits goal setting (although this is still only a back of the envelope sort of attempt at this time). Utilities would prefer to rely more heavily on the No Losers Test.

Gas utilities are not known to have developed estimates of long-run marginal costs. This topic received a lot of attention in the early 1980s, but enthusiasm has since been lost. Utilities currently use price forecasts and short run incremental costs for acquisition.

Gas utilities in Wisconsin value the benefits of DSM programs by focusing on participant benefits using a participant based cost-effectiveness test. Measurement methods vary for each utility. Some use a seasonal rate plus demand charges. At least one utility is known to use SEND OUT@, a supply planning model.

IV. Relationship between prudence reviews of gas utility purchasing practices and integrated resource planning

Every gas utility files an annual supply plan with the PSC. There is no particular prudence review at this time, although the PSC does have the regulatory authority. The current practice is for utility staff to brief the PSC staff on all areas of the supply plan. The PSC has threatened to conduct a prudence review, but has not.

The PSC has started a compliance review of audit procedures, but they have not yet adopted "least-cost" or "best-cost" purchasing rules. There is considerable interaction between utilities and PSC staff to constitute informal monitoring. Supply plans are not required to be filed in advance of purchases, but the utilities are notified that if they plan any major revision to the prior year's supply plan, they must discuss those changes with PSC staff.

[59] Wisconsin Gas was a party to the last Advance Plan docket and testified on use of gas as an air-conditioning fuel, rather than avoided CTs.

The prudence review process in Wisconsin is a separate activity from LCP/IRP. It is described to be "a club that's out there." The PSC has enforced prudence reviews on electric utilities on a limited basis, but not as yet on gas.

Since open access came to Wisconsin, many gas utilities have gotten away from buying gas from the pipeline. ANR Pipeline Co. was able to negotiate a gas inventory charge. Wisconsin expects that less gas will be sold on the spot market, and more conversion from contract demand to storage options.

V. Future PUC activity and key regulatory issues

Core gas demand is expected to rise 1-2% per year. Peak is expected to rise faster than annual load. There will also be some increase in gas demand due to 17 new gas combustion turbines to be installed by electric utilities over the next 6 years which will result in a need for capacity extensions or reinforcements. Further increases in demand could result from aggressive fuel substitution programs or PSC restrictions on building of baseload coal-fired units.

The key regulatory issues facing gas utilities are:
1) Integrated Resource Planning process requirements;
2) More rigorous regulation regarding prudence reviews of purchases;
3) Avoided cost calculations;
4) DSM planning for transportation customers;
5) By-pass; and,
6) End-use data collection.

The PSC is expected to conduct limited activities in the area of gas IRP due to staff constraints. They will probably move in the area of DSM programs and fuel substitution more quickly because that has already been done on the electric side. The Wisconsin Center for DSM Research may prepare a study on avoided cost calculations and statewide potential for DSM programs some time in the next two years. Further, the Commission has directed staff to open an investigation into IRP.

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WYOMING

Gas Utilities Serving State (gas-only or combination)

1)	KN Energy	(gas only)
2)	MGTC, Inc.	(gas only)
3)	Mountain Fuel Supply	(gas only)
4)	Northern Gas Company	(gas only)
5)	Petrolane Gas Company	(gas only)
6)	Wyoming Gas Company	(gas only)
7)	Wyoming Industrial Gas Company	(gas only)
8)	Cody Gas Company	(gas only)
9)	Frannie-Deaver Utilities	(gas only)
10)	Cheyenne Light Fuel & Power	(combination - gas & electric)
11)	Montana-Dakota	(combination - gas & electric)

I. *Status of state PUC least-cost regulation and practices for gas utilities*

There is no Commission order which requires least-cost planning (LCP)/integrated resource planning (IRP) for natural gas utilities. Legislative statute §37-3-115 provides that a utility may retain 0-10% of the savings incurred if a utility can lower its supply costs. Supply costs may be lowered through a plan which may include one or more of the following: the use of alternate sources of energy (i.e., solar); promotion of high efficiency appliances; load integration; and, finding a lower cost supply. This statute applies to both electric and gas utilities. However, it is not mandatory, and has not been actively implemented by the utilities. The statute does not take specific conservation targets into consideration.

II. Type and extent of natural gas DSM programs (including fuel substitution)

All gas utilities offer energy audits and informational programs for residential customers, however, some utilities charge a nominal fee. Low-cost weatherization programs are also made available by some gas utilities. Weatherization programs are not rate based. The utilities either charge a small fee, or recover costs through non-regulated programs. The Wyoming Department of Planning and Economic Development sponsored a rebate program to encourage consumers to purchase high efficiency equipment. Petroleum violation funds were used to fund the program. In the commercial sector, some gas utilities offer stand-by and transmission rates.

There is no formal Commission policy or rules regarding DSM programs that may encourage fuel substitution by customers.

III. Economic tests and analysis methods used to evaluate gas utility DSM programs

The Commission has not mandated that gas utilities use specified economic tests to measure DSM program cost effectiveness.

IV. *Relationship between prudence reviews of gas utility purchasing practices and IRP/LCP initiatives.*

No specific criteria, rules, or guidelines are used in prudence reviews of gas purchases, however, the Commission does review all gas purchases on a case-by-case basis. Cost of gas supply changes are examined. The gas utilities file supply contracts with the Commission, but no pre-approval is necessary.

The Commission's regulatory objectives are to ensure an efficient, safe, and lowest cost supply of natural gas to as many people as possible, and will continue this policy in the future.

Many gas supply contracts are going to be coming up for re-negotiation in the next five years. The Commission is concerned that if the gas bubble is actually disappearing, prices will increase sharply. The effect upon the consumer will have to be examined.

V. Future PUC activities and key regulatory issues

Integrated resource planning for gas utilities may be a future initiative. More efficient use of supply, transportation, and purchasing practices could all be issues addressed in an integrated resource plan. The Commission staff is not presently working on LCP/IRP. The gas utilities have begun to study LCP/IRP, and may be asked to discuss their views with the Commission.

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