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Primer on Gas Integrated Resource Planning

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PRIMER ON GAS INTEGRATED RESOURCE PLANNING

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Foreword

This primer is the culmination of a project sponsored by the Energy Conservation Committee of the National Association of Regulatory Utility Commissioners (NARUC). In 1990, the Energy Conservation Committee formed a Subcommittee on Gas Integrated Resource Planning to examine technical and policy issues relevant to integrated resource planning (IRP) for gas utilities. The purpose of this effort is to provide the same useful discussion of issues for regulators as had been achieved through two previous handbooks related to IRP for electric utilities. We gratefully acknowledge the outstanding work which has been accomplished by Chuck Goldman, Alan Comnes, John Busch and Stephen Wiel of the Lawrence Berkeley Laboratory and express our appreciation for the project funding provided by the Department of Energy (DOE) through the Assistant Secretary for Energy Efficiency and Renewable Energy.

This primer addresses utility and regulatory considerations which are relevant to the strategic planning process in the provision of natural gas utility service. Such strategic planning is key to the prudent operations of gas utilities, just as it is for electric utilities. An optimum resource selection process should not be viewed as new to either industry, but rather is already or should have been an integral part of a given company's operations. This primer is not intended to serve as a handbook, but rather as a treatise exploring considerations which are worthy of review by those willing to give the subject of IRP for natural gas fair and objective consideration. One of the very purposes of this project is to compare key similarities and differences between strategic planning processes for electric and gas utilities. While IRP for electric utilities has received more attention, that does not make it more important, particularly to the customers of gas utilities.

As background research was in progress, the Energy Policy Act of 1992 (EPACT) was passed which requires state regulatory commissions to consider whether it is appropriate to implement IRP for gas utilities. The EPACT requirements positively affect the timeliness and relevancy of this primer because it provides state commissions and their staffs with information on technical and policy issues they will face in their consideration of gas IRP.

We believe an unprecedented and successful effort has been made in the development of the primer to obtain input and comments from industry groups, consumer representatives and technical experts through the formation and active involvement of a Technical Advisory Group (see "Acknowledgements"). This document has also been reviewed extensively by individuals from the NARUC Energy Conservation and Gas Committees and their respective Staff Subcommittees. Over 40 individuals contributed their ideas during this project, and helped assure that this primer provides a fair and balanced treatment of gas IRP policy and technical issues. We sincerely thank those individuals who together have contributed hundreds of hours improving the quality and usefulness of the report.

As this primer goes to press in the fall of 1993, many Local Distribution Companies (LDCs) and their customers are experiencing significant price increases as the result of implementation of FERC Order 636 and increased demand for natural gas. Pricing trends and multiple choices for supply make state-of-the-art resource planning for natural gas critical.

We trust that you, the reader, will find this primer to be a resource of great value.

Commissioner Steve Ellenbecker
Gas IRP Subcommittee Chair

Commissioner Jo Ann Kelly
Gas Committee Liaison

Paul Newman
Lead Staffmember, Gas IRP Subcommittee

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Executive Summary

State public utility commissions (PUCs) have taken increased interest in integrated resource planning (IRP) for gas local distribution companies (LDCs). IRP involves a process used by utilities to assess a comprehensive set of supply- and demand-side options based upon consistent planning assumptions to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost. Consideration of gas IRP by state PUCs is driven by several factors:

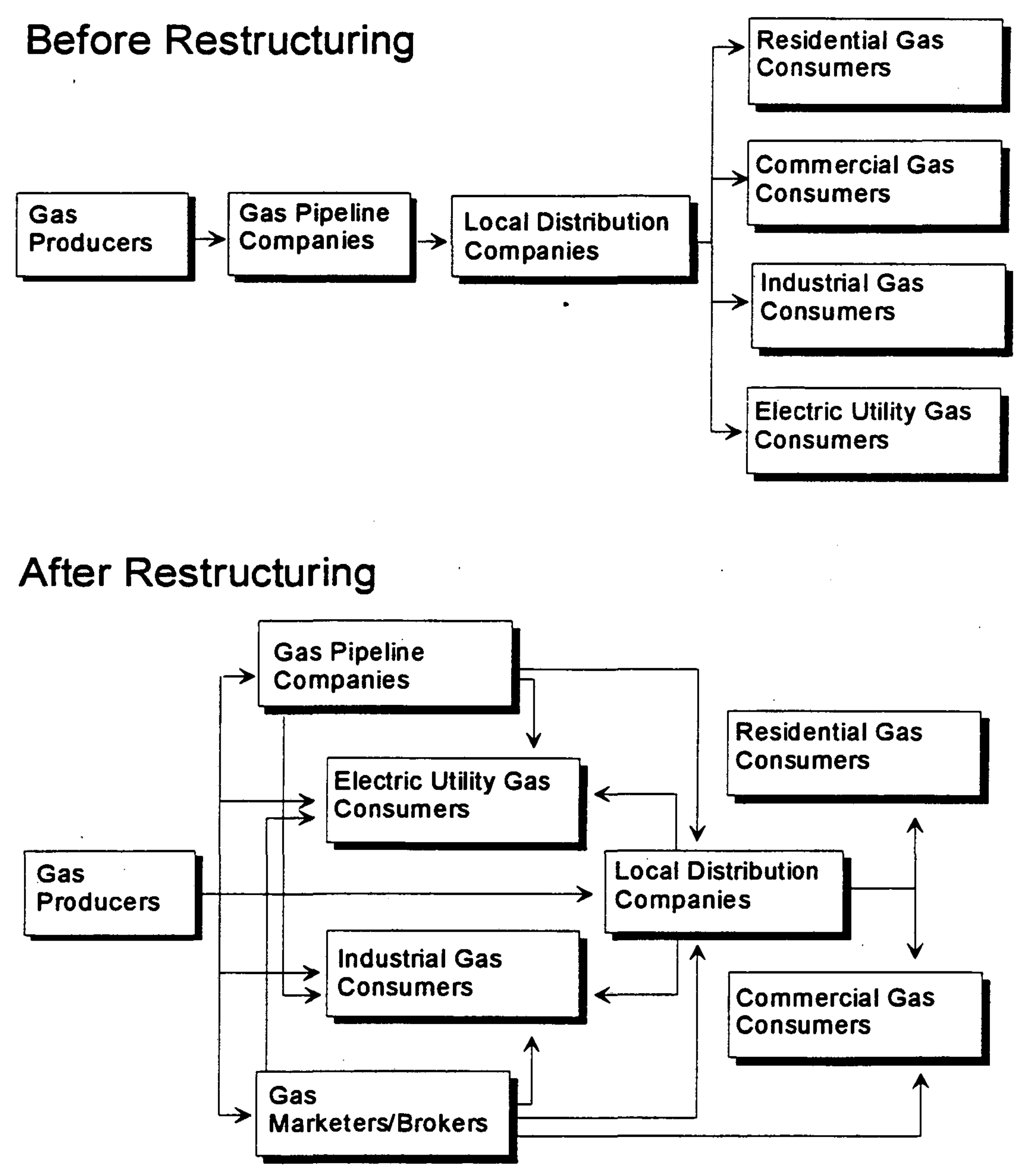
- environmental concerns and energy policies at the national and state levels that emphasize reliance on environmentally acceptable, domestic energy resources;
- internal dynamics and changes in the gas industry; and
- developments in the electric power industry (e.g., widespread use of IRP processes in that industry).

The growing energy and environmental concerns of the U.S. government are illustrated by the Energy Policy Act of 1992 (EPACT). EPACT includes provisions that encourage energy efficiency and requires state PUCs to consider use of integrated resource planning by gas LDCs.

During the past fifteen years, profound changes in the U.S. gas industry have resulted from market forces and regulatory policies (see Figure ES-1)(Arthur Andersen & Company and Cambridge Energy Research Associates 1988). Gas wellhead prices were deregulated and vibrant markets for spot gas, short-term contracts, and futures have developed, which allow producers and gas marketers to sell directly to LDCs and large-volume end users. In a series of Federal Energy Regulatory Commission (FERC) Orders (436, 500, 636), interstate pipelines were required to provide open access to end users and gas marketers/brokers, completely unbundle their merchant and transportation services, develop capacity release mechanisms, and shift to a "straight-fixed variable" rate design. The resulting industry restructuring has had a major impact on gas utilities who must now become active managers of their own gas supply portfolios, choosing among different suppliers and developing the proper mix of short- and long-term supply. LDCs are faced with deciding whether to develop their own gas supply portfolios or contract out portfolio aggregation and rebundling functions to other parties (e.g., producers, pipeline affiliates, marketers).

State regulators face the challenge of managing and responding to the competitive forces that have been unleashed by gas industry restructuring. PUCs will have to decide to what

Figure ES-1. Evolution of Gas Marketing



Source: Arthur Andersen & Company, and Cambridge Energy Research Associates 1988 extent they want to extend and replicate FERC policies and goals for pipelines in their regulation of gas LDCs. State PUCs and gas LDCs are likely to continue recent trends in which they distinguish between captive core and large volume noncore customers in terms of the services offered, the extent of regulation, and their obligation to serve. Current procedures for monitoring gas supply costs and reliability may also have to be adapted in the period after FERC Order 636. State PUCs must also consider differences between electric and gas utility industries when developing appropriate regulatory policies and expectations for gas LDCs.

Some states have adopted formal gas IRP regulations with mixed success; regulators of adopting states were influenced by the electricity industry's IRP paradigm and tried to transfer that approach to the gas industry. In some cases, PUCs were also attempting to be consistent in their treatment of regulated energy industries or wanted to facilitate statewide integrated electric and gas planning.

Table ES-1 highlights differences between the U.S. gas and electric industries in five major areas: industry structure and organization, planning practices, end-use market characteristics, avoided supply costs, and access to retail utility service. Distinctive features of gas LDCs compared to electric utilities include a lack of vertical integration, shorter planning horizons, a focus on supply procurement and distribution system expansion rather than generation capacity expansion, more intense competition in end-use markets, and lower avoided supply costs. Low avoided gas supply costs mean that it is more difficult for gas conservation programs conducted by gas utilities to pass cost-effectiveness tests.

Integrated resource planning for gas LDCs is one approach for state PUCs to consider in addressing the challenges of gas industry restructuring. An IRP regulatory process may typically involve:

- a formal integrated resource plan presented by a gas LDC in a regulatory forum that is separate from rate cases;
- explicit consideration of a wide variety of supply- and demand-side options;
- public participation in the development and/or review of the resource plan;
- review, and possibly approval, of the utility's plan by a regulatory commission.

Table ES-1. Differences Between Gas and Electric Utilities

	Electric	Gas
Industry Structure and Operation	• Vertically-integrated, except for new generation	• Separate firms handle production, Transmission & Distribution (T&D) • Prominence of storage
Planning Practices	• 10-30 yrs	• 1-10 yrs
End-Use Market Characteristics	• Electricity is an essential service • More difficult to fuel switch	• Gas service is optional • Core and noncore markets
Avoided Supply Costs	• Higher than gas when adjusted for equivalent energy services provided • Methods reasonably well developed	• Methods still evolving
Access to Retail Utility Service	• Virtually universal	• Not as widely available as electric

Potential benefits of gas IRP cited by proponents include:

- IRP provides documentation and support for the strategic planning activities of gas LDCs;

- IRP may provide for implicit or explicit risk-sharing on major supply and capacity decisions between utilities and regulators;

- IRP helps overcome market barriers and imperfections that inhibit penetration of high-efficiency end-use options, and by encouraging gas DSM, may provide new opportunities for high-efficiency gas technologies where societal benefits can be demonstrated;

- IRP facilitates public participation and input in resource planning;

- IRP helps facilitate coordinated energy and environmental planning.

Others involved in the gas industry believe that there are significant drawbacks to gas IRP regulatory processes. They conclude that significant differences between electric and gas utilities mean that the benefits captured by a formal IRP proceeding are likely to be small and will not justify the additional transaction costs of such a process. They are generally supportive of some IRP objectives (e.g., fair consideration of supply- and demand-side options, development of appropriate evaluation criteria for DSM programs), but conclude that the regulatory process associated with addressing IRP objectives should be far less complex and costly than approaches typically used for electric IRP. In critiquing the value of gas IRP regulatory processes, they raise the following issues:

- The direct and indirect costs of an additional gas IRP regulatory process can be substantial, and the benefits are uncertain and likely to be small. Critics note that gas IRP processes often involve significant amounts of utility, regulatory, and third party staff time, which could be better spent, given limited resources, on other activities. Concerns over the costs of the process are important because the potential benefits of gas IRP are inherently less than those that can be realized by an electric IRP process. Supply-side decisions for gas LDCs do not imply large, long-term irreversible cost commitments and competitive gas markets limit opportunities for a public process to further reduce gas costs.

- A gas IRP regulatory process, particularly one that implies regulatory preapproval, is incompatible with the development of a competitive gas industry.

- The gas conservation potential that can be acquired cost-effectively by an LDC is relatively small because much of the economic potential will be captured through government appliance and building standards and codes. Moreover, the potential scope for developing cost-effective energy efficiency programs is less for gas utilities than for electric utilities because gas avoided costs are lower.

Both proponents and critics of gas IRP regulatory processes agree that strategic planning is critically important for gas LDCs. To some degree, the incremental benefits of a formal IRP process will depend on the extent to which a LDC's existing strategic planning process already includes and adequately addresses IRP goals and objectives. Alternative regulatory approaches can achieve many of the goals of IRP for gas LDCs; a variety of regulatory strategies are currently being considered and tested by state PUCs.

The primary focus of this primer is on technical and analytical issues that gas LDCs and state regulators are likely to confront in attempting to achieve IRP objectives and goals. A 1991 survey conducted by the National Association of Regulatory Utility Commissioners (NARUC) found that a lack of information on various IRP-related technical and analytical issues limited consensus. This primer, prepared at the request of NARUC's Energy Conservation Committee, is intended to fill the informational gap. Because gas IRP is a relatively new phenomenon and there is less consensus on accepted practices, many topics in the primer cannot be treated in a definitive manner; instead they are treated through a discussion of alternative approaches and their implications.

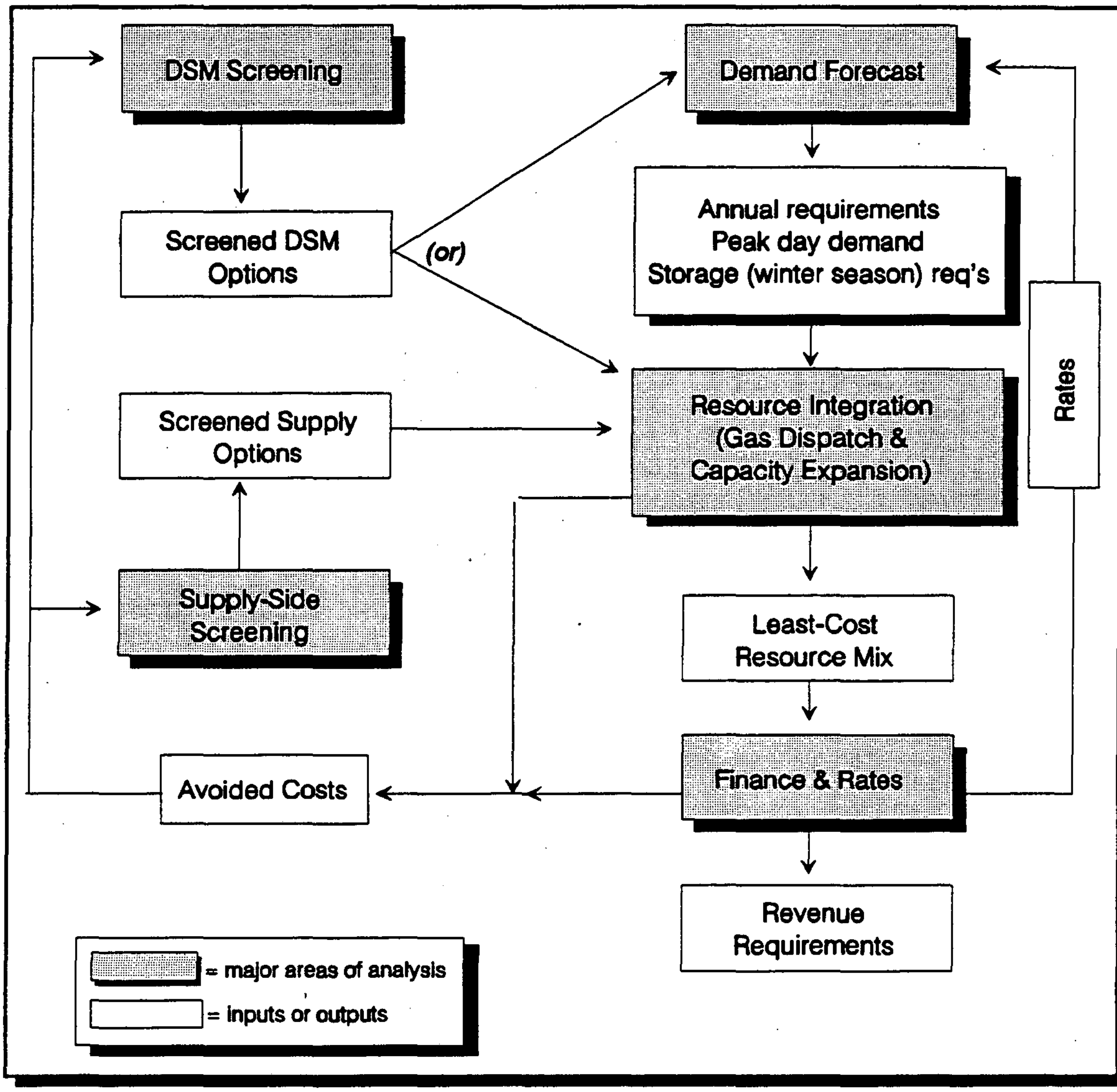
Gas IRP Methods and Models

Regardless of whether gas IRP is pursued through a formal regulatory process or set of methods that are overlaid upon existing business and regulatory practices, IRP requires the coordination of several major areas of utility resource planning: demand forecasting, supply-side resource selection, demand-side resource selection, resource integration, and financial and rate forecasting. This coordination should begin with a clear set of objectives that define the mission of the gas local distribution company. IRP objectives usually include the minimization of private or social costs as well as other objectives that address rate impacts, equity impacts, and utility financial health. A simplified representation of the analysis framework and the relationships among various areas is shown in Figure ES-2.

Demand forecasting may be conducted using econometric or end-use models, or models that combine both. Most gas utilities currently use econometric methods to forecast residential and commercial sector demand. End-use models have advantages in an IRP context because the impacts of utility DSM programs can be reflected in the load forecast more easily and because underlying assumptions and key appliance stocks and efficiencies are more understandable to nonutility parties. The complexity of demand forecasting will increase for LDCs in the post-636 era because of increases in the size and variety of customers that purchase transport-only services from gas LDCs.

During resource integration, the utility analyzes in detail supply- and demand-side options that have emerged from screening processes and selects a mix of resource options that

Figure ES-2. Analysis Framework for Gas IRP



best meets its IRP goals and objectives. An important resource integration issue is where to incorporate the effects of gas DSM programs: as a modification of customer demands or as a resource option that is selected, along with supply-side resources, in the gas dispatch and capacity expansion models (see Figure ES-2).

Uncertainty is a critical factor in gas utility resource planning. One of the major contributions of IRP has been its emphasis on analytic techniques that explicitly assess risks associated with uncertainties in key variables. These techniques include:

- sensitivity analysis—key input variables are varied over a plausible range to determine their impact on results;

- probabilistic analysis—probability distributions are assigned to key input variables, and outcomes are computed for all possible input variable combinations or by Monte Carlo techniques; and

- scenario analysis—optimal resource plans are developed for various future scenarios based on sets of internally consistent assumptions.

Commercially-available computer models exist for almost every aspect of gas IRP, including integrated models. Most gas LDCs have chosen to link inputs and outputs of individual, detailed models into an integrated process rather than relying on integrated planning models where linkages among the major analysis areas are handled automatically by the model. The advantage of the linked, detailed approach is that it allows gas LDCs to use their organization's existing model capabilities.

Gas IRP Technical and Policy Issues

This primer addresses six major technical and policy issues that utilities and state regulators are likely to confront when conducting IRP: (1) gas supply and capacity planning in an increasingly competitive industry environment, (2) methods used to estimate gas avoided costs, (3) economic analysis of DSM programs, (4) assessment of the potential for gas DSM, (5) end-use fuel substitution, and (6) financial aspects of gas DSM.

Gas LDC Supply and Capacity Planning in the Post-636 Era

Regulatory and market changes in the U.S. gas industry mean that LDCs now have a very broad array of supply and capacity options to choose among for gas supply planning; they can no longer rely on gas pipelines for supply management. The primer focuses on four general topics: (1) existing and emerging supply and capacity resource options, (2) major supply and capacity planning methods and issues, (3) approaches to PUC oversight of gas LDC procurement decisions, and (4) gas system reliability and contingency planning.

Major strategies used by LDCs to achieve gas supply planning goals include:

- relying on a portfolio of gas supplies that is diversified with respect to gas supply owner, contract term, and, if possible, supply basin and transport facility;

- managing price risks in a post-636 world by complimenting physical gas supply contracts with financial contracts (i.e., futures, options, swaps, and other types of forward contracts); and

- managing the load shape of gas purchased from the producer either by diversifying demand amongst different groups of customers, using storage or peak-shaving facilities to manage load shape, or by developing buyback provisions for certain sales customers.

The primer highlights a number of issues that arise in capacity planning, including:

- methods of screening resource options and limitations of such analysis;

- detailed capacity expansion planning methods including iterative simulations and optimization models;

- storage resources as an alternative to pipeline supply: functions of storage (i.e., daily balancing, seasonal balancing, peak-day protection, and price benefits) and maximizing efficient use of different types of storage resources;

- the build vs. buy problem for an LDC; that is, a consideration of increased reliance on third parties for various types of capacity (e.g., joint ventures for storage resources, firm capacity sold by brokers or marketers as part of bundled product); and

- incorporation of potential for retail bypass into the capacity planning process.

In addition to cost considerations, gas LDCs review the reliability implications of gas supply and capacity options. Gas LDCs develop reliability goals over the planning horizon and attempt to balance the need for reliable service and reasonable cost. Historically, gas system reliability planners have depended heavily on prescriptive rules. Gas system reliability planning will most likely evolve under IRP and in response to ongoing industry restructuring. Increased competition will be a double-edged sword for many LDCs. LDCs will determine the appropriate reliability standard for all LDC customers and, to retain load, LDCs will have to focus more on the reliability provided to all customers, including customers formerly satisfied with interruptible service. However, the possibility of building additional facilities to provide reliability will be limited by price competition from alternative fuels and bypass alternatives.

IRP processes could lead to greater use of benefit-cost studies to determine LDC-specific reliability standards as well as inclusion of the potential reserve margin benefits of DSM options. In addition to reliability planning, gas LDCs can maximize the reliability of an existing system by developing contingency plans. Contingency plans include steps a utility can quickly take to acquire supply during periods of critical demand and detailed curtailment plans to minimize the negative consequences of any curtailment.

Methods for Estimating Gas Avoided Costs

In IRP, it is crucial for the utility to develop estimates of the gas system's avoidable costs associated with supply-side resources in order to evaluate the economic benefits of DSM resources. Avoided supply costs are also useful in initial screening of incremental gas supply capacity contracts or capacity projects as well as cost allocation and rate design. This primer presents four methods for calculating avoided gas costs: system marginal cost, generic proxy approach, targeted marginal approach, and average cost methods. Each method starts from a common point, which is a base case supply plan that meets the projected gas demand forecast.

- System marginal cost—avoided costs are estimated by taking the difference between the total change in system costs between the base case supply plan and a supply plan that is developed for a new demand forecast that includes the effect of the DSM program, which is divided by the size of the decrement on a volumetric basis.

- Generic proxy approach—an avoidable resource (or resources) is selected from the base case supply plan, and the costs of this resource are used as the basis for avoided costs.

- Targeted marginal approach—supply resources are segmented by the type of demands that they principally serve (e.g., base, temperature-sensitive, peaking loads), and the highest cost supply in each category is identified and its costs allocated to the corresponding demand impact.

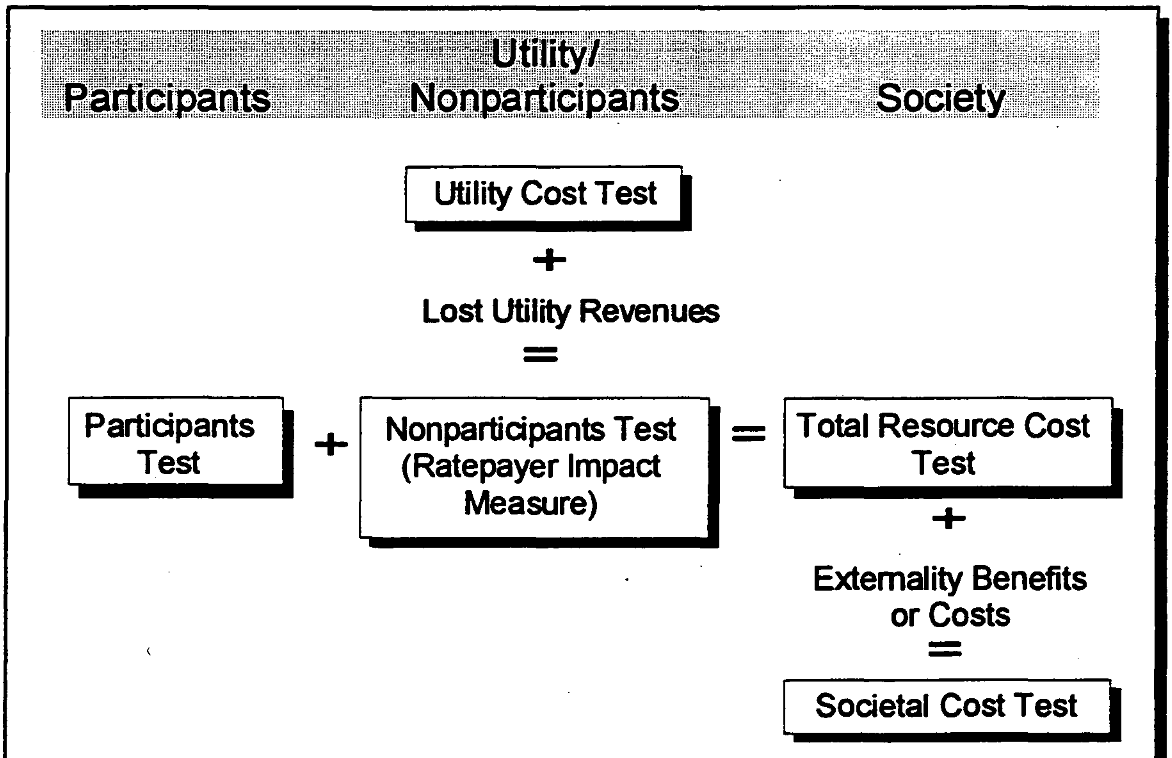
- Average cost methods—the unit cost of all supply resources is estimated based on a weighted average of their respective volumetric contribution to the total gas sendout.

Table ES-2. Issues in Estimating Gas Avoided Costs

Component	Issue
Commodity	• Uncertainty in future gas commodity costs • Impact of reduced takes on firm contracts may be constrained by minimum take or gas inventory charge (GIC) provisions
Capacity	• Short-term vs. long-term perspective • Duration of existing firm capacity contracts • Market demand and price uncertainty for existing capacity (capacity release) • Reallocation of pipeline fixed costs • Treatment of commodity-related capacity investments • Cost allocation methods for long-lived facility investments
Local Transmission & Distribution (T&D) and Customer Costs	• Frequently not avoidable by most DSM programs

Two key issues that arise in estimating gas avoided costs are accounting for the uncertainty in future gas commodity costs explicitly through sensitivity analysis and accurately assessing capacity-related costs that are actually avoidable by a DSM program (see Table ES-2).

Figure ES-3. Interrelationship of Standard DSM Benefit-Cost Tests



Source: Adapted from Washington Natural Gas (1992)

Economic Analysis of DSM Programs

The economic analysis of DSM programs or measures relies heavily on results of multiple benefit-cost tests that attempt to capture program impacts from the perspective of different affected parties (e.g., participating customers, nonparticipating ratepayers, utility, and society). Figure ES-3 provides an overview of these tests and emphasizes the relationships among them.

This primer reviews various technical issues that arise in the application of the benefit-cost tests: appropriate discount rates, period of analysis, inclusion of effects of free riders, analysis of programs that affect multiple fuels, and additional considerations for interruptible and transport-only customers. Key policy issues are also discussed: appropriate use and limitations of the benefit-cost tests in the IRP framework, implications for PUCs of establishing a primary test and the debate over usage of the Total Resource Cost (TRC) test vs. the Ratepayer Impact Measure (RIM) test, underlying assumptions of TRC vs. RIM tests regarding markets for energy efficiency and the impact of market imperfections, and alternatives to the standard benefit-cost tests.

Assessing Gas DSM Potential

Assessing the magnitude and cost of DSM resources is an important activity, in part because it provides utilities with information on one of the underlying rationales for IRP: whether or not there are significant quantities of cost-effective DSM resources that can be captured by utility DSM programs. This primer reviews results of recent gas DSM potential studies and provides technical information on individual gas equipment efficiency measures and strategies that are applicable to the residential and commercial sectors. Opportunities to improve end-use efficiency often involve multiple measures and strategies for a broad range of end uses.

In the residential sector, the economic gas savings potential ranged from 5 to 47% of total sector sales among nine LDC case studies, with a median value of 24%. In the commercial sector, the economic gas savings potential ranged from 8 to 23% of total sector sales, with a median value of 15%. In interpreting the results, it is important to understand distinctions between technical, economic, and achievable potential:

- *Technical Potential* is an estimate of possible energy savings based on the assumption that existing appliances, equipment, building shell measures, and processes are replaced with the most efficient commercially available units, regardless of cost, without any significant change in lifestyle or output.

- *Economic Potential* is an estimate of the portion of technical potential that would occur assuming that all energy-efficient options will be adopted and all existing equipment will be replaced whenever it is cost effective to do so based on a prespecified economic criteria, without regard to constraints such as market acceptance and rate impacts.

- *Achievable Potential* is an estimate of the energy savings that would occur if all cost-effective, verifiable, energy-efficient options promoted through utility DSM programs were adopted. Achievable potential excludes efficiency gains that will be achieved through normal market forces and by existing or future standards or codes.

Differences in gas efficiency potential are attributable to differences in physical stock, initial efficiency levels, heating loads, and climate severity among utilities as well as differences in study methods (comprehensiveness as indicated by measures and end uses considered) and assumptions (e.g., criteria used to establish the cost-effectiveness threshold). These results suggest that gas DSM potential is more limited than U.S. electric utilities' DSM potential; similar studies of electric utilities' DSM potential give estimates of between 25-50% of the applicable sector's sales.

This primer reviews key issues involved in designing, implementing, and evaluating gas DSM programs. Themes that are discussed include:

- the match between end-use technologies, customer segments, and program delivery mechanisms in designing DSM programs;
- strategies to minimize rate impacts in the design of DSM programs;
- opportunities for joint electric-gas DSM programs in certain market segments;
- innovative DSM program strategies (e.g., market transformation); and
- the importance of program evaluation.

End-Use Fuel Substitution

High-efficiency gas and electrical equipment can potentially substitute for one another in many applications. Fuel substitution programs can be defined as programs that substitute for energy-using equipment with a competing energy source by promoting or providing an incentive for efficiency improvements associated with the fuel conversion. These programs have been quite controversial, in part because significant tensions exist between the natural gas and electricity sectors of the U.S. economy. The two industries compete for residential and commercial space conditioning, water heating, cooking, and drying equipment markets in many parts of the U.S. The competition between electric and gas utilities has been, and continues to be, profoundly influenced by federal and state regulation. With the advent of IRP, PUCs have encouraged more active interventions in end-use markets by utilities (primarily electric utilities).

For regulators, a central issue is whether the efficient selection of fuels in certain end-use markets by consumers can be improved upon through an IRP planning process that explicitly considers fuel substitution opportunities, or whether current utility marketing practices result in a better social outcome. At a minimum, controversies over fuel substitution policies should result in PUCs reviewing their policies on promotional practices and DSM program implementation (e.g., incentive levels to customers) to ensure that existing utility DSM programs are not introducing undesirable distortions into consumers' fuel choice decisions. The gas industry has raised concerns that electric DSM programs have the effect of encouraging customers to adopt electric technologies when gas options would be more economically efficient.

Proponents of utility-funded fuel substitution programs argue that DSM programs should not be restricted to higher efficiency products using the same fuel but that utilities should identify and promote (if necessary) cost-effective fuel substitution opportunities for their customers as part of their IRP process. Opponents argue that mandatory fuel substitution would, in effect, require one utility to subsidize sales by its competitors at the expense of its remaining customers.

This primer explores the various pros and cons to utility fuel substitution programs and identifies the various policy approaches that are available to state regulators. In addition, technical opportunities for fuel substitution in the residential and commercial sector are described, including electric-to-gas options and gas-to-electric options. In evaluating fuel-switching opportunities, utilities should consider the relative site- and source-energy efficiency of technologies using each fuel, the load shape impacts on each utility, relative gas and electric avoided costs, price volatility and uncertainty of the respective fuels, and environmental impacts and tradeoffs. Arguments that have been raised by proponents and opponents in the fuel substitution debate are reviewed, and case studies of the experiences of eight state PUCs are presented in order to describe alternative regulatory approaches (Vermont, California, Georgia, Wisconsin, Oregon, Maryland, Colorado, and New York). The primer also discusses several policy and programmatic issues that state regulators are likely to confront if they choose to address fuel substitution policies explicitly: economic and other evaluation criteria, cost allocation and responsibility, customer equity issues, and treatment of unregulated fuels.

Financial Aspects of Gas DSM

Significant disincentives may exist under traditional rate regulation that dampen utility enthusiasm for energy efficiency opportunities. These disincentives include failure to recover DSM program costs, negative financial impact on gas utility earnings because of reduced sales, and loss of financial opportunities because the utility may forego more profitable supply-side investments. The primer discusses various strategies that address the financial impacts of gas DSM on utility earnings:

- DSM program cost recovery including timing issues (e.g., general rate cases versus frequent proceedings or deferred accounts) and expensing versus ratebasing;

- net lost revenue adjustment mechanisms, which allow the utility to recover margin lost from customers due to specific DSM programs;

- revenue decoupling mechanisms, which make utilities financially indifferent to short-term changes in sales and essentially guarantee that utilities will recover their authorized nonfuel revenues regardless of sales fluctuations; and

- various types of positive financial incentives for utility shareholders: an incentive rate-of-return, a bounty paid based on specific accomplishments, or shared savings in which the utility keeps a fraction (5-30%) of the net resource value provided by the DSM program.

Various methods to allocate DSM program costs are also examined because many gas consumers are price-sensitive, and competitive impacts can affect LDC profitability.

Conclusion

Although this primer is not intended to resolve major regulatory policy issues, it should contribute to the discussion and development of planning methods that have broad acceptance among regulators and gas utilities.

Chapter 1

Introduction

Consensus is growing among federal and state policymakers that natural gas will play a more prominent role in the U.S. energy future. Natural gas is an abundant domestic resource; it can be produced and delivered at prices that appear to be competitive with alternatives whose environmental impacts are often less favorable. Estimates of the recoverable gas resource base continue to increase as a result of technological innovations and production experience. A recent study by the National Petroleum Council (1992) estimated that about 600 trillion cubic feet (Tcf) of gas is recoverable at wellhead prices of $2.50/MMBtu ($1990) or less with advanced technology (see Table 1-1).[1] This represents about 30 years' worth of consumption at current levels. Moreover, the existing transmission and storage system (280,000 miles of gas transmission pipeline and about 8 Tcf of storage capacity) is more than adequate to meet existing firm requirements on an annual and peak-day basis and is sufficient to allow for growth in gas demand in certain regions (see Figure 1-1). The markets for gas are quite diverse: residential customers use gas equipment to provide energy services such as space and water heating, cooking, and drying with gas bills of $500-1000/year; large industrial users or gas-fired power plants consume gas worth tens of millions of dollars per year. The gas industry faces stiff competition in many of these markets from electricity and unregulated, alternative fuels. Thus, the potential for natural gas hinges in part on industry and federal and state regulators helping to ensure that gas is used *efficiently* and that barriers to its efficient use are removed (National Petroleum Council 1992).

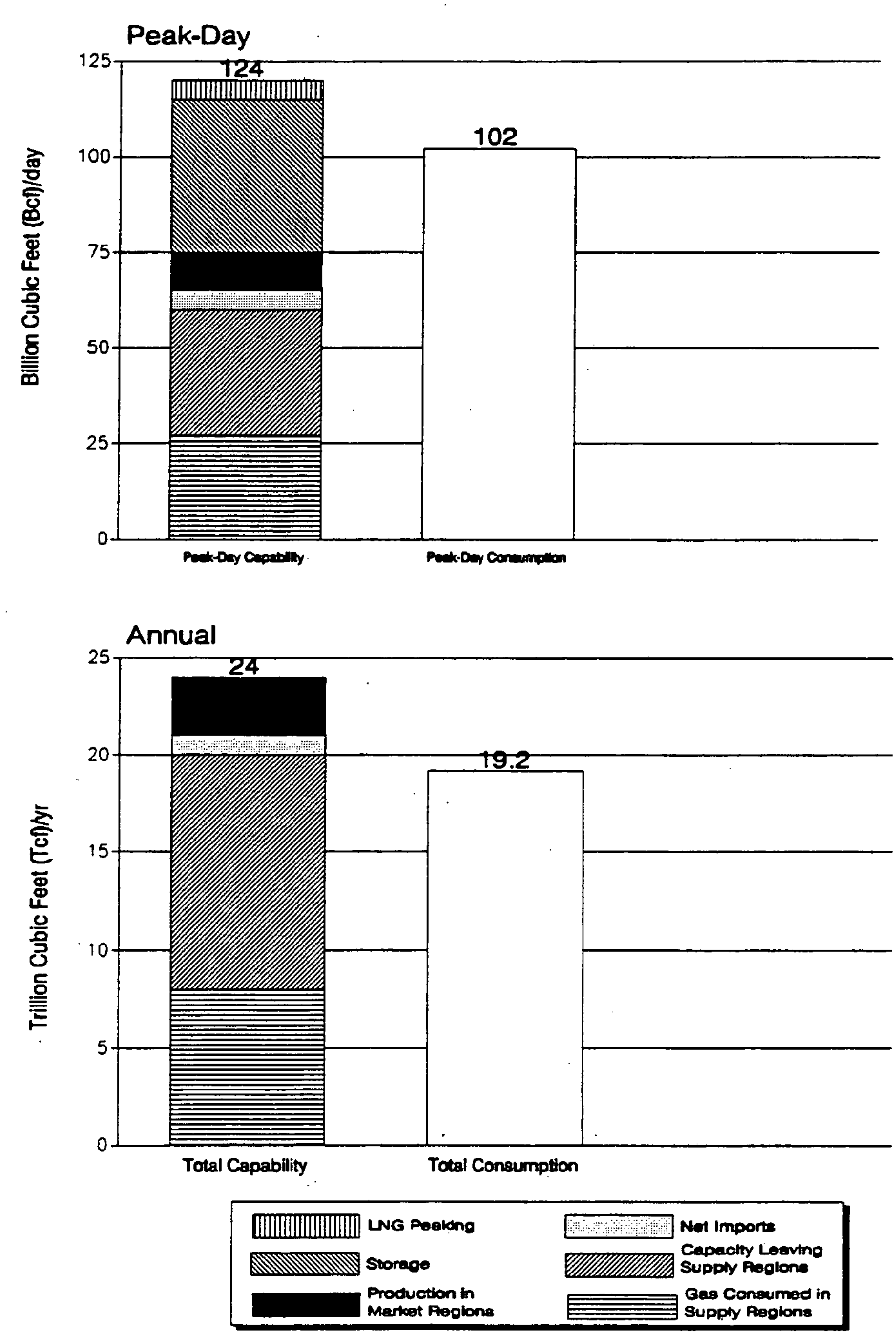
Table 1-1. Recoverable Resource Base for the Lower-48 States

	Recoverable Resource Base Trillion Cubic Feet (Tcf)	
Price ($1990)	1990 Technology	2010 Technology
Unspecified	1,065	1,295
$3.50/MMBTU	600	825
$2.50/MMBTU	400	600

Source: National Petroleum Council 1992

[1] In 1992, annual U.S. gas usage was 19.8 trillion cubic feet (Tcf) and the estimated average wellhead price was $1.84 per thousand cubic feet. One important caution: the National Petroleum Council (NPC) study also concluded that a 19 Tcf gas supply level could be maintained until 2010 if average wellhead prices were $2.50 per million Btu (MMBtu) ($1990), but would decrease to about 10-11 Tcf if wellhead prices only averaged $1.50/MMBtu ($1990). This implies that gas commodity prices would have to increase at 1.8%/year in real terms, compared to estimated 1992 wellhead prices.

Figure 1-1. U.S. Gas Transmission and Storage System: Peak-Day and Annual Capability (1991)



Source: National Petroleum Council 1992

The Energy Policy Act of 1992 (EPACT) includes various provisions that encourage energy efficiency and also promote reliance on competitive forces. EPACT amends the Public Utility Regulatory Policies Act (PURPA) of 1978 by adding two new standards for consideration by state PUCs: (1) use of integrated resource planning by gas local distribution companies (LDCs) and (2) encouragement of investments in energy efficiency and load-shifting measures by ensuring that these investments are at least as profitable (taking into account the income lost from reduced sales under such programs) as prudent supply-side investments. Each state commission is required to provide public notice, conduct a hearing on the appropriateness of these new standards, and make a determination about whether or not to adopt each standard by October 23, 1994.[2]

Developments in gas wellhead markets and changes in regulatory policy at the Federal Energy Regulatory Commission (FERC) have also created new challenges and opportunities for gas LDCs and their state regulators. State regulators, who oversee a distribution segment that still has features of a natural monopoly, have to respond to and manage the competitive forces that have resulted from gas industry restructuring. Increased reliance on market forces does not necessarily mean that state regulation is outmoded but rather that flexibility and forward-looking planning processes become increasingly important as the number and type of utility supply choices increase.

A number of state public utility commissions (PUCs) have taken an interest in integrated resource planning (IRP) for gas utilities. IRP involves a process used by utilities to assess a comprehensive set of supply- and demand-side options based upon consistent planning assumptions in order to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost.[3] Gas IRP is in its formative stages, and a variety of regulatory approaches are being considered and tested by state PUCs. However, a survey of regulatory staff conducted for the National Association of Utility Commissioners (NARUC) revealed that limited information and lack of consensus on various IRP-related technical and policy issues has hindered progress (Goldman and Hopkins 1991). NARUC concluded that additional analysis of selected issues would be useful, particularly if it drew on the initial experiences of PUCs and gas utilities that have implemented gas IRP.

[2] A more detailed discussion of relevant EPACT provisions for state PUCs can be found in NRRI (1993).

[3] For those readers who want additional information on issues associated with developing IRP for electric utilities, refer to Krause and Eto (1988), Hirst et al. (1991), and Hirst (1992b).

1.1 Overview of the Gas IRP Primer

NARUC asked Lawrence Berkeley Laboratory (LBL) to develop a primer on gas integrated resource planning. Our primary focus is on technical and analytical issues that gas LDCs and state regulators are likely to confront in attempting to achieve IRP goals and objectives. The intent of this primer is to introduce commissioners and regulatory and gas LDC staff to the full scope of IRP-related topics by highlighting major issues, synthesizing available information, and identifying additional sources for those who want more information. Because gas IRP is a relatively new phenomenon and there is a range of ideas about practices and policies, many issues in this primer are presented through discussions of alternative approaches and their implications. Many issues such as fuel substitution and financial aspects of gas demand-side management (DSM) are quite controversial from a policy standpoint.

Chapters 2-9 of this primer discuss the following topics:

- Chapter 2 reviews recent developments in the gas industry and their implications for gas LDCs and state regulators. The chapter also examines similarities and differences between the electric and gas utility industries in order to provide a context for understanding the challenges involved in creatively adapting IRP to the conditions faced by gas utilities. Principal goals and objectives of IRP are identified and the benefits and potential drawbacks of gas IRP regulatory processes are discussed.

- Chapter 3 describes the major analytic steps in developing a gas integrated resource plan and provides an overview of current IRP models and modeling tools.

- Chapter 4 reviews gas supply and capacity planning and focuses on issues that assume increased importance for LDCs in an IRP context (e.g., reliability planning criteria) and/or increased prominence in the post-636 era.

- Chapter 5 describes various methods used by gas utilities to estimate gas avoided costs and analyzes the strengths and weaknesses of alternative approaches. The technical nuances and key uncertainties presented in this chapter related to estimating gas avoided costs are designed to help regulatory and utility staff in their assessments of the potential economic benefits of various types of gas DSM programs.

- Chapter 6 discusses the various economic perspectives from which gas DSM resources can be evaluated and examines issues that arise in the application of benefit-cost tests for gas LDCs.

- Chapter 7 examines the technical opportunities of selected gas efficiency and fuel substitution options and strategies and discusses how utilities can package these measures to acquire DSM resources. The goals of this chapter are to convey the relative magnitudes and economics of the technical opportunities for the efficient use of gas as well as insights gained from the experiences of leading gas and electric utilities on effective ways to market and implement DSM options.

- Chapter 8 reviews policy issues involved with end-use fuel substitution and discusses various regulatory approaches.

- Chapter 9 discusses financial aspects of gas DSM programs, including program cost recovery and allocation methods; mechanisms such as decoupling or lost revenue adjustments, which can be used to overcome disincentives to utility DSM investments; and various bonus or incentive mechanisms.

Chapter 2

Gas Resource Planning: Need for IRP

2.1 Overview

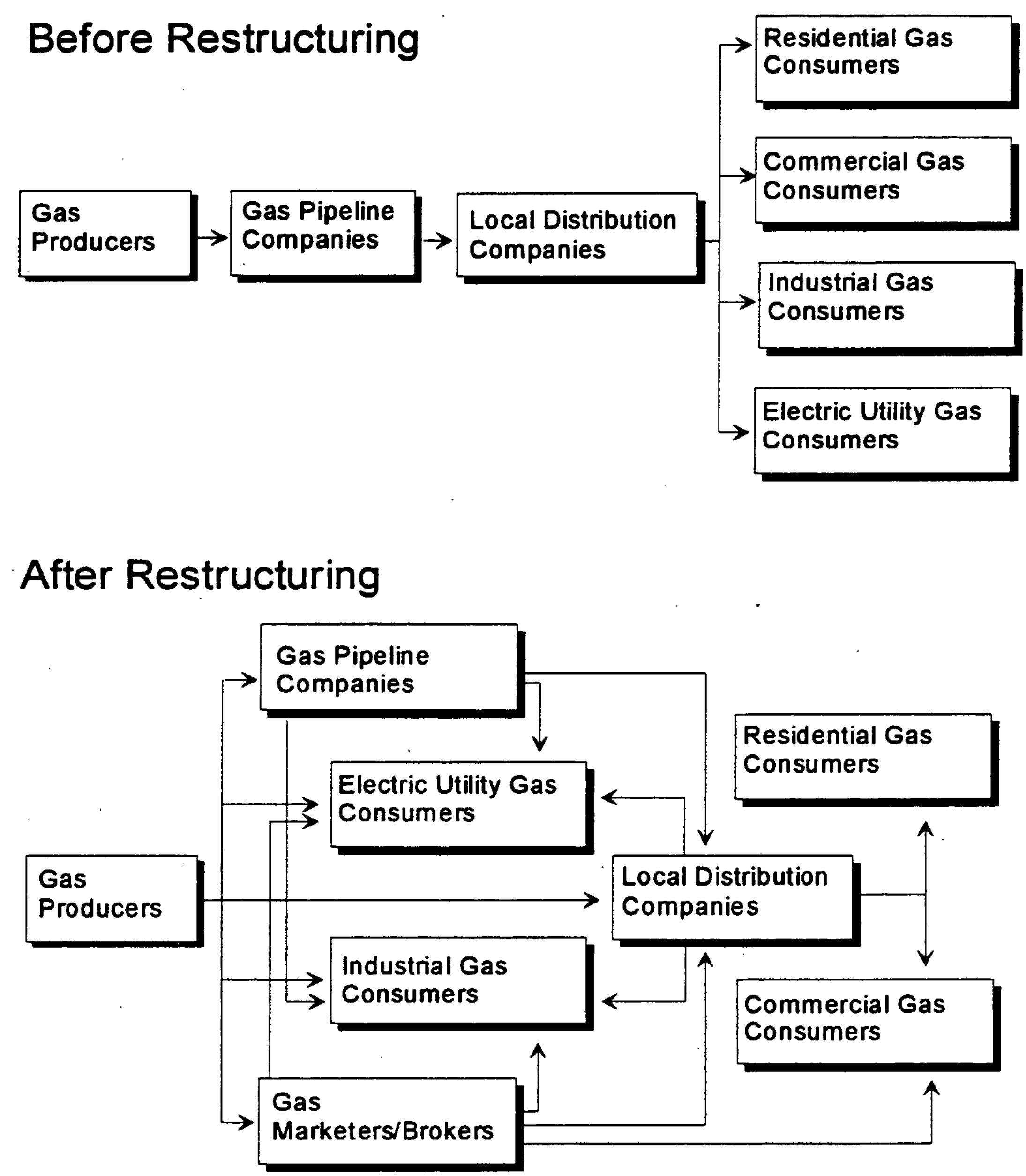
This chapter reviews the impact of structural changes in the U.S. natural gas industry on resource planning activities of local distribution companies (LDCs), summarizes recent policy initiatives at the Federal Energy Regulatory Commission (FERC), and discusses their implications for LDCs and state regulators. We examine similarities and differences between the electric and gas utility industries in order to identify areas where gas integrated resource planning (IRP) processes may have to be tailored to the conditions faced by gas LDCs. We articulate the goals and objectives of integrated resource planning and highlight the potential benefits and drawbacks of gas IRP regulatory processes based on the views of those that support and oppose gas IRP as well as the initial experiences of several states. A primary objective of this chapter is to provide a context for the remaining chapters' in-depth discussion of technical and analytical issues that arise in gas resource planning.

2.2 Gas Industry Restructuring

During the past 15 years, the gas industry has been transformed; regulated pipelines used to resell wellhead price-controlled supplies of natural gas, but now gas supply prices are determined by the market and interstate pipelines mainly transport gas that is owned by third parties. The changes resulted from the dynamic interplay between evolving market forces and actions of the Federal Energy Regulatory Commission (Harunuzzaman et al. 1991). Gas price deregulation, open access, and comprehensive unbundling are the cornerstone of federal policy initiatives that are designed to substitute market forces for more direct forms of regulation where market power is diffuse and to focus on efficient regulation where market power is concentrated (O'Neill et al. 1992).

Decontrol of wellhead prices began with the passage of the Natural Gas Policy Act of 1978 and was completed in 1993. Buyers who wanted to shop around effectively needed flexible access to long-distance and local transportation alternatives so that gas delivery could be arranged from decontrolled upstream supply options. This need led to the separation of transport service from commodity sales. The unbundling of pipeline transportation by FERC began in earnest with Special Marketing Programs and has evolved in successive FERC Orders (i.e., 436, 500, and 636) in response to legal decisions and concerns raised by various parties (see Appendix A for a summary of FERC Orders and related legal decisions). Although the transition to a more competitive

Figure 2-1. Evolution of Gas Marketing



Source: Arthur Andersen & Company, and Cambridge Energy Research Associates 1988 industry has been difficult and painful for industry participants (e.g., take-or-pay problems), these regulatory reforms have contributed significantly to lower gas costs and innovative and expanded gas service choices (Makholm 1993). Industry restructuring has resulted in significant changes in gas marketing with the entry of gas marketers/brokers and producers selling gas directly to end users via spot markets and various contractual arrangements (see Figure 2-1). By 1991, nearly 80% of all gas was sold under transportation arrangements rather than as bundled pipeline sales.

2.2.1 FERC Order 636

Order 636 is the latest gas industry restructuring effort by the FERC; it focused on several broad issues (see Table 2-1): pipeline gas merchant services; access to available transportation and storage capacity; transportation terms, conditions, and services; and ratemaking issues (see Gaske 1993 for an excellent summary of FERC 636 and its implications). Interstate gas pipelines have traditionally combined merchant and transportation functions in linking upstream gas producers with downstream markets. This bundling of services resulted in part from the conditions associated with licensing and financing pipeline construction.[1] However, various parties (e.g., producers and marketers) made convincing arguments that pipeline gas often received priority transportation service and that third parties could not, under the existing arrangements, compete on an equal basis with pipeline merchant services. Order 636 required pipelines to completely unbundle merchant and transportation services, which meant that a pipeline company's firm sales customers were converted into firm transportation customers and are now responsible for making their own gas purchases. In effect, the firm sales service agreement served as a contractual backstop for LDCs and other pipeline customers in the event of a shortfall in supplies. With the elimination of the traditional bundled sales service, all gas must be aggregated, managed, and transported separately. This is likely to lead to a situation in which the responsibility for assuring supply reliability will be dispersed among multiple entities (LDCs, interstate pipelines, and gas merchants) (CERA 1992).

Order 636 also includes a capacity release mechanism, which allows a holder of pipeline capacity to sell or assign unused capacity through a transaction controlled by the pipeline. Parties that place the highest value on firm capacity will have an opportunity to obtain that capacity through a bidding process. Pipelines are also required to offer a "no-

[1] Both regulators and lenders wanted assurances that pipelines would have sufficient supplies and demand so that gas throughput was adequate to assure that major capital investments were economic. Long-term gas contracts with suppliers and long-term sales contracts with LDCs were the means to provide these assurances.

Table 2-1. Major Provisions of Order 636

Element	Description
Unbundling of pipeline services	• Effectively mandates that interstate pipelines separate the buying and selling of gas from the transport of gas • Pipelines are also required to provide customers with open access to storage and offer these services separately from all other services
"Open access"	• Pipeline companies must provide "open access" transportation that is equal in quality for all gas supplies, whether purchased from the pipeline or not
"No-notice" service	• Pipelines currently offering bundled city-gate firm sales service must provide a quick response, backup transportation service for the benefit of competing shippers (i.e., advance notice by the shipper is not required)
Capacity release	• Authorizes a reallocation mechanism so that firm shippers can release unwanted capacity to those wanting it by holding an auction, with results turned over to the pipeline to be posted on an electronic bulletin board
Rate design	• Requires a "straight-fixed variable" rate design (see Figure 2-2), unless other agreements are negotiated with the customers • Pipelines are required to use various ratemaking techniques to mitigate "significant" changes in revenue responsibility to any customer class • Pipeline companies must phase in rate increases over a four-year period if revenue responsibility changes exceed 10% for any customer class
Transition costs	• Pipelines are given the opportunity to recover 100% of "transition costs" created by new rules (e.g., stranded investment costs)

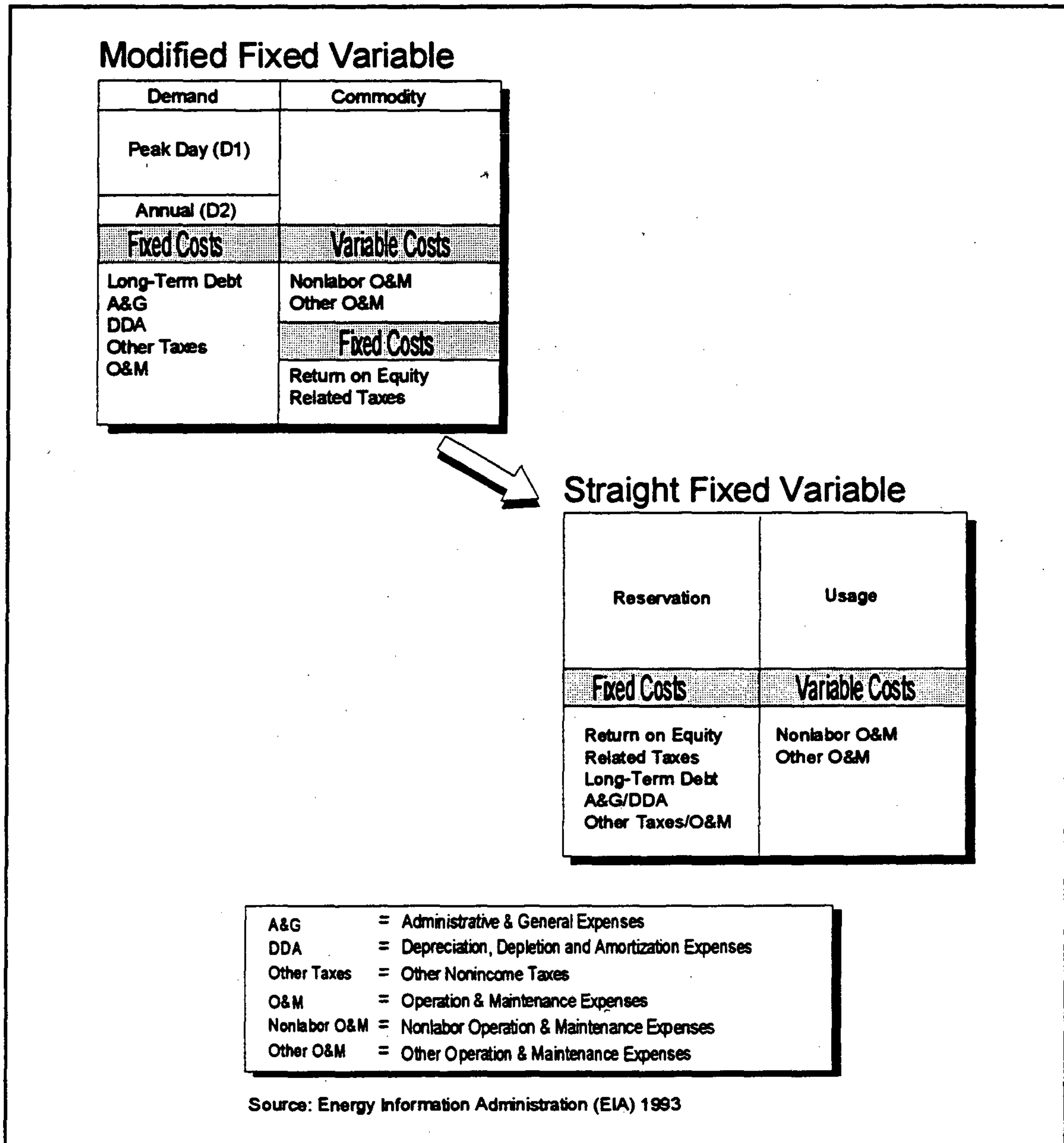
Sources: EIA 1993c, Cambridge Energy Research Associates 1992

notice" service, which is FERC's attempt to assure maximum reliability in a deregulated market.[2]

In terms of ratemaking issues, Order 636 also requires that all fixed costs associated with pipeline transportation service be recovered in a capacity reservation fee rather than the current modified fixed variable system, which allocates certain fixed costs to the

[2] "No-notice" service is technically categorized as firm transportation service but essentially includes a provision of gas supply under emergency circumstances to meet firm peak loads.

Figure 2-2. Pipeline Rate Design Changes



volumetric charge (see Figure 2-2).[3] Prior to Order 636, FERC maintained that it was important for pipelines to be "at risk" for recovery of a portion of their fixed costs in

[3] The reservation fee is charged to pipeline transportation customers on a monthly basis to reserve daily capacity, based on their requirements during peak periods.

order to provide a cost minimization incentive, which resulted in the Modified Fixed Variable rate design. FERC's reasons for switching to a "straight-fixed variable" (SFV) rate design include: having pipelines compete on costs they can control (i.e., variable costs), promoting competition at the wellhead, facilitating creation of a national gas market, and creating a level playing field between U.S. and Canadian producers. The cost impacts of the shift to SFV rate design are likely to vary widely for individual customers depending on their load factor. A recent study conducted by the Energy Information Administration (EIA 1993c) concluded that:

> ...absent other changes in the ratemaking process (e.g., mitigation strategies), the cost shift associated with moving from modified fixed variable to straight-fixed variable may be very large for low load factor customers, i.e., local distribution companies with residential and small commercial customers that have temperature-sensitive loads.[4]

Compared to modified fixed variable rates that prevailed before 1990, increases in transportation rates with SFV ranged between 40-60% for customers of a "composite" pipeline that had a 35% load factor (EIA 1993c). A longer term effect of the shift to SFV should be increased investment in gas storage or other peaking facilities. FERC's new rate design may also lead to seasonal trades (via the release program) of capacity between on-peak and off-peak customers. Any rate design represents a balance between efficiency and equity objectives. Thus, it is likely that FERC's current approach to rate design will continue to evolve as regulatory policy objectives and market realities change.

2.3 Implications of Gas Industry Restructuring

Industry restructuring has significant implications for gas LDCs and state regulators because of profound changes in the business environment of LDCs.

2.3.1 Implications for LDCs

In the past, pipelines and LDCs operated their systems together on the principle of city-gate service that bundled commodity with transportation services. An interstate pipelines' sales service insured adequate supply and capacity were available to deliver promised quantities of gas in a timely fashion, and distribution of gas was a main role of LDCs. In the post-636 era, these two industry segments must operate their systems

[4] EIA developed a composite pipeline based on six large interstate pipeline companies serving the East Coast.

together under different principles. Securing natural gas and the capacity to deliver it has become the principle mission of LDCs. With complete unbundling, LDCs have become active managers of their own gas supply portfolios, choosing among different suppliers and developing the proper mix of short- and long-term contracts. LDCs now face an expanded array of options for securing gas supplies and transportation as well as increased competition from alternative fuels and "bypass" of the LDC by its customers that can connect directly to an interstate pipeline.

In the post-636 era, the most basic strategic choice that an LDC must decide is whether to:

- develop its own gas supply portfolio, which will involve aggregating, seasonally shaping, and firming through direct purchases at upstream market centers; and bundle these supplies with firm transmission and storage rights, or

- contract out portfolio aggregation and rebundling functions to other parties (e.g., producers, pipeline affiliates, or independent marketers) that offer a firm, seasonally shaped supply at the utility's city gate (Tussing 1993).

These alternatives represent the extremes of possible approaches, and in practice many intermediate paths will most likely evolve. Regardless of the approach that LDCs take to managing their increased supply responsibilities in the post-636 era, they face an increased possibility that their actions will be reviewed by state regulators.[5] Thus, an LDC's strategic choices will be strongly influenced by state PUC preferences, especially the rules and guidelines adopted to monitor gas costs and service reliability.

The move to SFV rates and the resulting higher reservation fees for peak-day capacity will also encourage LDCs to closely examine and rationalize their capacity holdings and look for alternative and more inexpensive ways to obtain the same level of service. Various peak-shaving DSM alternatives are likely to be more attractive under SFV rate design.

[5] FERC does not plan to approve the price of commodity gas sold by pipelines restructured by Order 636. Thus, more responsibility is placed at the state level for oversight of reliability.

2.3.2 Implications for PUCs

Historically, in regulating gas LDCs, many state PUCs have focused on safety, reliability, and prices offered for natural gas services. However, the new supply management responsibilities of gas LDCs may create a need for broadened regulatory oversight of the way LDCs purchase gas supply. Current procedures typically used to monitor gas supply costs and reliability (e.g., purchased gas adjustments, prudence reviews, least-cost purchasing requirements, and occasional management audits) may have to be adapted to respond to the changes in industry structure and gas supply markets.

PUCs will also have to decide the extent to which they want to extend FERC policies and goals for pipelines to the regulation of gas LDCs. This will involve decisions about the degree to which LDCs and intrastate pipeline services should be unbundled, the benefits of and need for franchise protection for LDC services to certain market segments, and alternatives to traditional service obligations (National Petroleum Council 1992). At a minimum, state commissions and gas LDCs will continue trends which distinguish among services offered, extent of regulation, and implied obligation to serve among captive core customers vs. large-volume, noncore customers. PUCs have a continuing responsibility, however, to insure that core customers, with limited market power, are provided reliable service at reasonable rates and that deregulated activities are conducted at arm's length from a utility's regulated business in order to minimize opportunities for cross-subsidization and self-dealing. Regulation of the gas distribution sector will be required as long as uncontestable "natural monopoly" conditions exist.[6]

[6] "Natural monopoly" arises in an unregulated market when a single firm dominates the market by virtue of economies of large scale (size) or wide scope (across functions or products), which give that firm a cost advantage over any combination of multiple, smaller firms. For a gas LDC, "natural monopoly" conditions exist if its system is capable of carrying incremental volumes to or from a given point at a substantially lower expense than any "stand-alone" or "bypass" facility. Even where monopoly conditions exist, firms can exert market power only if the market is "uncontestable," which means that new entrants can't credibly threaten to enter on an efficient scale (Jaffe and Kalt 1993).

Table 2-2. Differences Between Gas and Electric Utility Industries

	Electric	Gas
Industry Structure and Organization	• Vertically-integrated, except for new generation	• Separate firms handle production, Transmission & Distribution (T&D) • Prominence of storage
Planning Practices and Resources	• 10-30 yrs	• 1-10 yrs • Less information on DSM savings and costs
End-Use Market Characteristics	• Electricity is an essential service • More difficult to fuel switch	• Gas service is optional • Core and noncore markets
Avoided Supply Costs	• Higher then gas when adjusted for equivalent energy services provided • Methods reasonably well developed	• Methods still evolving
Access to Retail Utility Service	• Virtually universal	• Need for review of line extension policies and tariffs

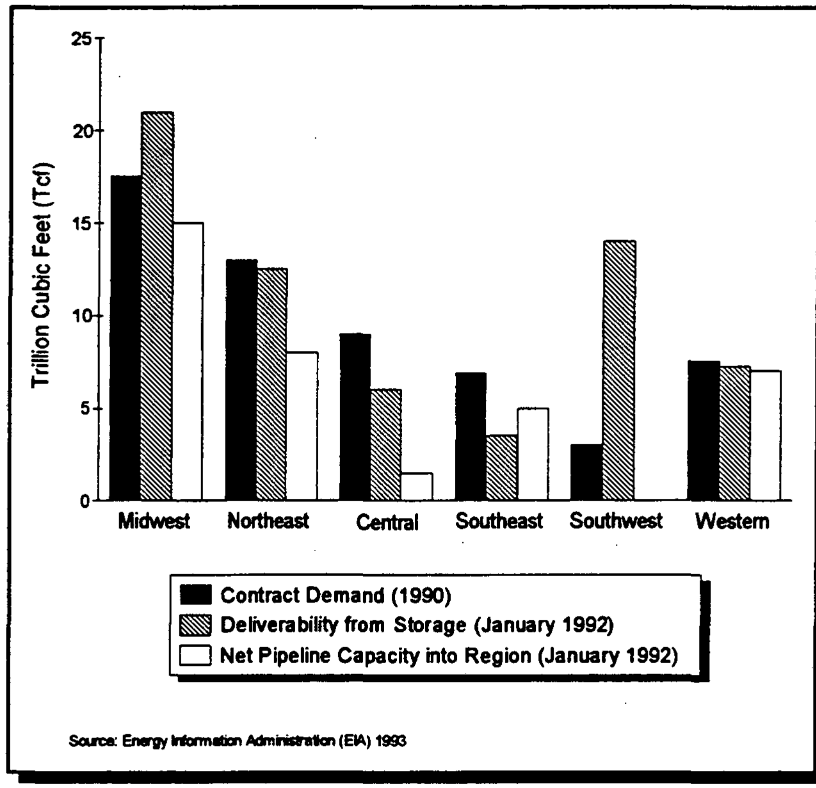
2.4 Similarities and Differences Between Gas and Electric Utility Industries

Similarities and differences between the gas and electric utility industries must also be considered by state PUCs in developing regulatory policies and expectations for gas utilities. Table 2-2 highlights differences in five major areas: industry structure and operation, planning practices and resources, end-use market characteristics, avoided supply costs, and access to retail utility service.

2.4.1 Industry Structure and Operational Characteristics

The most pronounced structural difference between the two industries is that the electric industry is highly integrated vertically. Vertical integration allows electric utilities a greater opportunity to provide a bundled good and increased pricing flexibility compared to a local gas distribution company. Gas is typically produced, transported, and distributed by three unaffiliated companies while most electric power is still generated, transmitted, and distributed by a single entity (O'Neill et al. 1992). The emergence of independent power producers and the provisions of the Energy Policy Act (e.g., creation of Exempt Wholesale Generators, transmission access) will lessen this distinction between the two industries in the future. The electric industry is likely to remain integrated for the near-term, although market forces and federal legislation and regulation of the wholesale electricity market pose increasing challenges to the vertically integrated electric utility.

Figure 2-3. Contract Demand, Peak-Day Storage Deliverability and Pipeline Capacity by Region



Each industry has three major segments: production/generation, transmission, and distribution. Transmission and distribution (T&D) systems in both industries are characterized by substantial economies of scale and of coordination. In the distribution segment, the economies are so great that it is almost always considered a natural monopoly. The availability and use of storage differ significantly between the two industries. Storage plays a much more prominent role in the natural gas industry, often providing an attractive alternative to pipeline capacity (see Figure 2-3). Gas can be stored rather easily in both gaseous and liquid states as line pack, in underground caverns, in depleted oil and gas reservoirs, and in liquified natural gas (LNG) plants. In the U.S., gas storage meets about 30% of U.S. peak-day demands while storage is too expensive for general use by an electric utility (EIA 1993c). For IRP, widespread availability of gas storage on a daily and seasonal basis has important impacts on the analysis of gas system marginal costs.

Differences in the degree of integration of the transmission and distribution networks of utilities in the two industries also affect reliability planning. Although gas systems are interconnected through pipeline systems, LDCs are often not extensively interconnected with other LDCs and thus each tends to plan for its own reliability. Electric utilities are interconnected with other systems through a grid and utilize this extensive transmission and distribution network to meet their loads in cases of emergencies. Reliability planning is typically done on a regional basis as individual electric utilities pool their requirements.

There is also a substantial mismatch between the time constants that govern operation of electric power systems and gas pipeline delivery system. These differences derive from the fundamental fact that electricity moves at almost the speed of light while gas is pumped through pipelines at about 15-20 miles per hour. The combination of shorter time to react to changing conditions, lack of storage, and constraints on system flow controls has meant that historically the electric grid was more automated and closely monitored (O'Neill et al. 1992). Because of the concern over public health, safety, and economic consequences of system gas service being interrupted during severe cold weather, gas operators have historically placed the highest priority on system reliability for residential and commercial customers who do not have short-term alternatives. Planned gas outages are possible in many gas systems for some individual large customers because these customers typically have ready access to substitute fuels, and gas utilities have a long tradition of using interruptible contracts to alleviate peak-period demands (Samsa and Hederman 1992).

Regional differences in resource endowments are important in both industries but are particularly striking in the gas industry as exemplified by distinctions between producing and consuming states. Most natural gas is produced in just five states and most gas transactions include long-haul interstate transmission.[7] In contrast, most electric generation is sited relatively closer to load centers, and most of the electric grid was originally built to connect major markets for better reliability and short-term coordination trades (O'Neill et al. 1992).

[7] The major producing states are Texas, Louisiana, Oklahoma, New Mexico, and Kansas.

2.4.2 Planning Practices and Resources

The focus of electric utility investment decisions and regulatory oversight has been on large capital projects to build new generation or transmission facilities. Historically, electric utility planners are accustomed to long-range planning for 10 to 30 year period because of the long lead times required to construct baseload power plants and the time horizon over which alternative resource options must be compared. In contrast, for most gas LDCs, fuel supply procurement and distribution system expansion rather than facility planning has been the major focus (Lerner and Piessens 1992; Samsa and Hederman 1992).

Gas supply planners must now evaluate an expanding array of supply options, and this trend is likely to accelerate in the post-636 era. However, the scale, capital requirements, and lead times for decisions on new gas facilities are often quite different than those involved in electric resource planning. For gas utilities whose major capital expenditures are related to local transmission and distribution investments, the share of bulk transmission and storage investments is small relative to investments in generation capacity and transmission in the electric industry. Lead times are short (one to three years) for these gas system investments. In today's gas supply market, three to five years is considered long term for a gas utility resource planner. Moreover, contracts of varying lengths expire at different times, so fuel supply procurement takes place almost continuously. Contracts and/or investments for capacity (e.g., acquisition of pipeline capacity, storage, and/or peaking service capacity) often entail longer time frames (e.g., 10 years). In contrast to the electric industry, among the resources being evaluated by a gas utility in an IRP plan, gas efficiency programs may require the longest lead and resource development time.[8]

At the present time, many gas LDCs have less detailed information than electric utilities do about the characteristics and performance of customers' equipment, appliance saturations, and end-use consumption. LDCs also have more limited information on the actual costs and savings of DSM resources in contrast to electric utilities. These issues affect the time frame in which gas LDCs can be expected to design and implement large-scale DSM programs.

[8] Some DSM options have economic lifetimes of 10 to 20 years (e.g., high efficiency furnaces). Planning horizons may be extended to match the life cycle of DSM applications with supply-side opportunities. Because of uncertainties in future gas commodity prices, sensitivity analysis using alternate gas price escalation rates should be conducted.

2.4.3 End-Use Market Structure and Characteristics

End-use retail markets in the natural gas and electricity industries are typically segmented along similar lines (i.e., residential, commercial, and industrial users). Product differentiation is increasing in both industries and currently involves distinctions based on reliability of service (firm vs. interruptible), usage during various seasons, and time of day (for electricity).[9] There is a general consensus that demand is relatively inelastic for most residential and commercial customers while industrial customers typically have elastic demands. Residential customers in both industries have limited options for substitution in response to short-term price hikes while large industrial customers have more choices.

There are also some important differences in the characteristics of end-use retail markets of electric and gas utilities. First, electric service is a necessity for some end uses and applications, while gas service is typically optional and gas is used for its inherent thermal and chemical properties. Second, the extent of competition in gas end-use markets is more intense than in electric end-use markets because for virtually every use of natural gas, there is a competitive alternative, either in the form of direct fuel substitution or an alternative energy form.

In both the natural gas and electric utility industries, prices paid by different types of customers and cost components differ widely. For gas utilities, these differences are quite striking and are attributable principally to variations in costs of serving different customer classes as well as differences in service quality among classes (see Figure 2-4).[10] There are several important implications for gas utilities: (1) because wellhead prices account for less than 40% of the total price paid by residential and commercial customers, changes in wellhead prices have relatively less impact on end-use prices in these sectors, (2) industrial and electric utility customers are much more sensitive to changes in wellhead prices and can alter their gas demand patterns quickly because it is often relatively easy to switch to alternate fuels, and (3) avoided gas costs may often be less than retail rates because fixed costs are high for residential and customer gas customers and because local distribution and customer-related costs are typically not avoidable.

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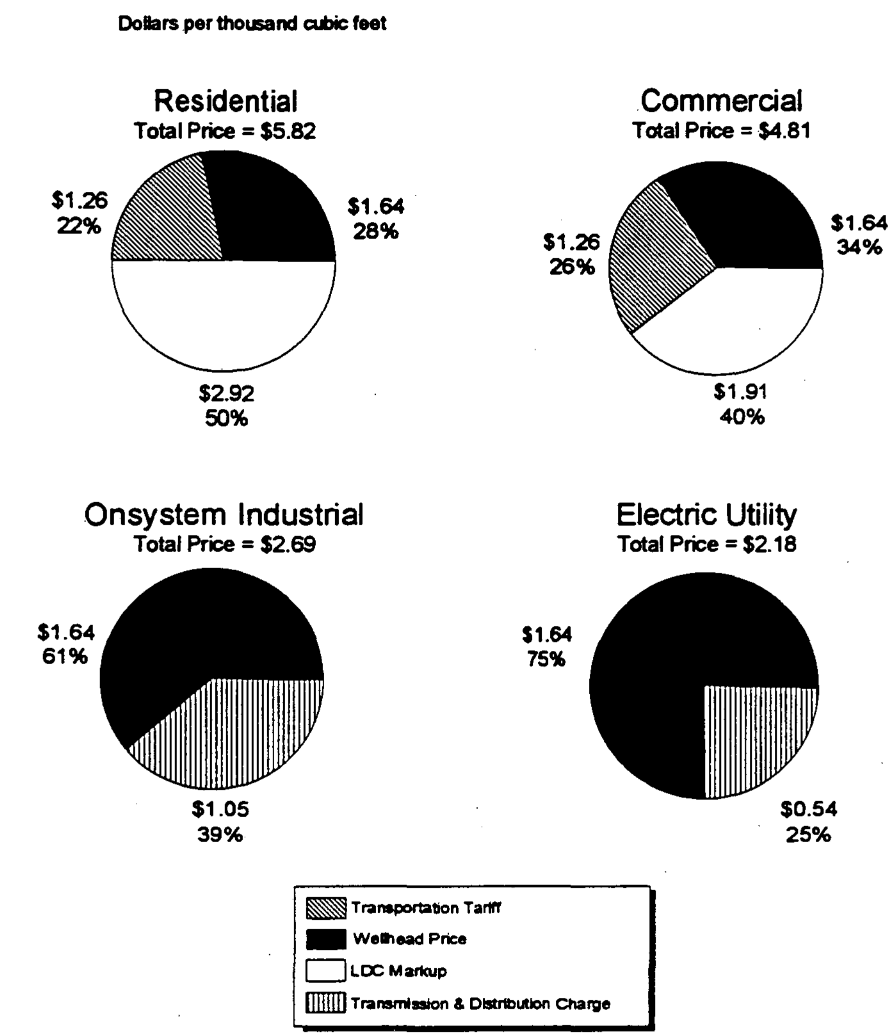
[9] Ultimately, utilities in both industries may end up providing bundled service to small customers and unbundled service for large customers with competitive alternatives.

[10] In Figure 2-4, "wellhead price" is the commodity cost of gas; "transportation tariffs" represent costs paid by the LDC to interstate pipelines from producing area to city gate; and "LDC markup" is the amount charged by the utility to cover distribution, storage, and other customer-related expenses which recover costs of providing end-user service. Note that onsystem industrial sales account for only about 33% of total gas throughput in the industrial sector; offsystem sales have become predominant (EIA 1993c).

Figure 2-4. Components of End-Use Prices by Sector (1991)



Source: Energy Information Administration (EIA) 1993

2.4.4 Avoided Costs

Avoided electricity costs often tend to be higher than gas avoided costs when adjusted for equivalent energy service provided. However, it is not that easy to directly compare avoided electric and gas costs because of differences in costing methods and conventions, end-use conversion efficiencies, and operational characteristics of electric and gas utilities (Samsa and Hederman 1992). Despite that caveat, avoided gas costs that are lower than avoided electric costs for DSM suggest that: (1) it will be relatively more difficult for gas energy efficiency programs to pass cost-effectiveness tests compared to electric DSM programs, and (2) all else being equal, net DSM program benefits might be smaller (Lerner and Piessens 1992).

2.4.5 Access to Retail Utility Service

Electric utility retail service is more widely available in the U.S. than gas service. The gas industry's access to some end-use markets is hampered somewhat because gas service is not universally available. In addition, some PUCs do not have uniform line extension policies for electric and gas retail service. Several PUCs are in the midst of reviewing their policies and tariffs for gas line extensions and are examining such questions as comparability of treatment among electric and gas utilities and the extent to which growth is in the interests of existing gas ratepayers.[11]

2.5 Alternative Regulatory Approaches

Many PUCs and gas LDCs are rethinking the role of state regulation in light of the massive structural changes occurring in the gas industry (see Public Service Commission of Wisconsin (PSCW), 1993). In this section, we describe briefly a range of generic approaches as background to a more detailed discussion of the potential benefits and drawbacks of integrated resource planning regulatory processes. Table 2-3 summarizes alternative regulatory approaches and highlights the regulatory forums and elements which would be involved in overseeing the various activities of gas LDCs (e.g., gas supply oversight, treatment of capacity and facility investments, and role of DSM).

Option A represents the status quo in the majority of states. Regulatory processes include periodic rate cases in which rates are set, purchased gas adjustment (PGA) proceedings for review and recovery of gas supply costs, and certificate of public convenience and necessity (CPCN) proceedings to approve any gas LDC's application for major facility investments. PUCs rely primarily on retrospective, after-the-fact prudence reviews of gas LDC purchase decisions although several state PUCs require utilities to file gas supply plans in advance of purchases.[12] DSM options, to the extent

[11] Some PUCs use a "net benefits to existing ratepayer" test to determine whether line extensions and other growth strategies should be allowed. This test demonstrates whether the gas utility could provide the same level of energy service to existing ratepayers at the same or lower cost while adopting the growth strategy.

[12] A 1991 NARUC survey (Goldman and Hokpins 1991) found that 39 states conduct prudence reviews of gas purchases, of which 15 states review purchases annually or on a contract by contract basis. Six PUCs (Alabama, California, Massachusetts, Nevada, Oregon, and Rhode Island) also require gas LDCs to file gas

Table 2-3. Alternative Regulatory Approaches

Approaches	Elements
Option A (Status Quo)	• Rate case • PGA proceedings or gas supply plan review • CPCN for large ratebased facilities
Option B (Long-Range DSM Planning)	• Rate case and PGA • CPCN • Long-range DSM plan
Option C (IRP Rules)	• Rate case • PGA (decisional prudence only) • Utility develops IRP plan; PUC review • Review of supply portfolio mix
Option D (IRP Rules/PUC Approval)	• Rate case • PGA (decisional prudence only) • PUC approves IRP plan • PUC approves supply portfolio mix
Option E (Incentive Regulation)	• Eliminate PGA, retain PGA partially with true-up, or use benchmark indices • Initial rate case, then long lag
Option F (Partial Deregulation)	• No mandate for LDC DSM • Retail gas merchant industry competes with or supplants the LDC's merchant function • Eliminate PGA and PUC review for noncore customers • Rate regulation of transportation rates for LDCs continues

they are considered at all, are typically evaluated as part of a gas LDC's rate case.

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supply plans in advance of purchases.

There is significant disagreement about the degree to which the status quo regulatory approach is appropriate in light of gas industry restructuring. Critics argue that traditional regulatory review processes may be too cumbersome, tend to create regulatory risk without necessarily protecting ratepayer interests, and create incentives for utilities to minimize short-run costs rather than looking at long-run cost minimization, rate stability, and reliability (Heintz 1993; Jensen 1993).

In order to encourage LDCs to consider demand-side options more systematically as strategies, a number of PUCs have required their gas LDCs to file long-range DSM or conservation plans.[13] These plans typically include short-term DSM program implementation activities as well (Option B). One rationale for this approach is that PUCs want to encourage gas LDCs to adopt some basic objectives of integrated resource planning. These goals include consideration of both supply- and demand-side options, and establishing criteria for evaluating the economics of gas DSM options. This approach attempts to develop some of the "building blocks" of IRP without requiring gas LDCs to file formal integrated resource plans, which would involve detailed analysis of existing and proposed supply-side options. In several cases, PUCs that require long-range DSM plans are also considering major changes in regulatory oversight of LDC gas purchasing, but are using separate regulatory forums from those used for DSM.

Several PUCs have established rules requiring gas LDCs to file integrated resource plans in addition to meeting requirements of existing regulatory proceedings. IRP requirements and procedures vary significantly among states, and regulatory treatment of a utility's filed plan is a critical difference. Some PUCs review, but do not approve, a utility's IRP plan; we call this approach Option C. The review process typically involves hearings or workshops intended to solicit comments from interested parties and regulatory staff on key elements of the utility's plan (e.g., the utility's supply and capacity portfolio, the mix of supply- and demand-side resources). The PUC might then comment on the utility's plan, offering suggestions for modification, but would not approve the utility's IRP plan.

As an alternative procedure, a PUC could formally approve an integrated resource plan for a gas LDC after public hearings, which might result in modifications to the utility's original plan (Option D). Under Option D, the PUC's review of gas supply planning issues might include preapproval of an LDCs supply portfolio mix. For example, Jaffe and Kalt (1993) have suggested that gas utilities propose preferred portfolio strategies for gas procurement as part of an IRP process. Based on the evidence presented by the utility and the PUC's policy goals, the commission would determine and, in effect, preapprove the general composition of the utility's acquisition portfolio (i.e., the relative

[13] A gas DSM plan would include all load shape objectives while a conservation plan would be limited to strategic conservation and possibly peak clipping load shape objectives.

mix of long-term and short-term contracts). Utilities would then use competitive bidding processes to acquire resources in their portfolio categories. The effectiveness of these efforts would be subject to regulatory review, but purchasing practices consistent with the approved portfolio would be presumed reasonable (Jaffe and Kalt 1993). Like Option C, Option D would include audits of purchase practices and monitoring of results as well as approval of exceptions to plans. In both Options C and D, LDCs and regulators share varying degrees of responsibility for the consequences of major resource decisions. Compared to other approaches, a PUC-approved plan (Option D) minimizes the risks of cost recovery and the likelihood of a prudence review for the LDC but requires a high level of proactive regulatory involvement (see Section 4.2.4 for a more detailed discussion).

Various incentive regulation approaches (Option E) have also been proposed (see Harunuzzaman et al. 1991 for general overview). In many cases, incentive regulation can complement traditional regulation (Option A) and other regulatory strategies (e.g., long-range DSM planning and the IRP regulatory process). Most proposals focus on an LDC's variable gas costs and involve either elimination or partial retention of the purchased gas adjustment (PGA) or cost-indexing approaches (see Section 4.3.4 for a more detailed discussion). For example, Hatcher and Tussing (1992) argue that linkage to a prespecified market index, in conjunction with incentive regulation that shares any cost savings among ratepayers and shareholders, will provide an effective basis for monitoring and oversight of gas costs. To encourage long-term contracts, Fessler (1993) suggests that these contracts adopt pricing mechanisms that follow the market (rather than try to outguess it) and that utilities should have the burden of proving that cost premiums over and above spot indexing are justified by benefits to core ratepayers.

Another general approach includes various partial deregulation proposals that significantly relax regulatory oversight in favor of reliance on market forces (Option F) (Harunuzzaman et al. 1991). The underlying goal is that market forces would establish rates, services (including demand-side services), and the degree of reliability desired by customers. The scope and extent of deregulation could vary just as with incentive regulation. PUCs would be required to establish new policies and rules to facilitate deregulation of certain markets (e.g., unbundling of LDC services, performance standards) and reduce the degree of regulatory oversight. Proponents advocate comprehensive unbundling and open access to transportation on local systems, leading to the emergence of a retail gas merchant industry that would compete with or supplant the LDC's merchant function. This strategy would involve deregulation of gas supply for all noncore customers and certain core customers. For this strategy, gas LDCs and PUCs may have to reallocate transportation costs associated with serving various customer classes, particularly facilities used jointly by core and noncore customers. While most customers would still rely on the LDC for transportation services, most noncore customers would procure gas independently or from third parties. Ultimately, some proponents of this approach envision that core customers may choose supply service from competitors to the LDC (Lemon 1993).

2.6 Potential Benefits and Drawbacks of a Gas IRP Regulatory Process

As the previous section illustrates, integrated resource planning for gas LDCs is one approach that state PUCs can consider to address gas industry restructuring. For discussion purposes, it is helpful to separate the underlying objectives and goals of IRP from the question of what regulatory processes would be most appropriate for gas LDCs in order to achieve various objectives. This distinction is useful because many gas industry representatives and organizations maintain that an LDCs' strategic planning process can achieve many of the objectives of IRP (e.g., consideration of both supply- and demand-side options) without a commission-mandated IRP regulatory process.

The fundamental objective of IRP is to insure that utilities assess a comprehensive set of supply- and demand-side options based on consistent planning assumptions in order to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost. In defining total costs, the regulator often assumes a societal perspective, which means that utilities are asked to consider environmental and other social costs of providing energy services in some fashion. This notion of the role of gas utilities as providers of energy services, and not simply gas therms, is an integral part of the move towards IRP (Ontario Energy Board 1991). Uncertainties and risks associated with different external factors and resource portfolios should be considered by the gas LDC as part of this comprehensive assessment of resource options.

As previously described in regulatory Options C and D, an IRP regulatory process will typically involve:

- a formal IRP plan presented by the gas LDC in a separate regulatory forum (i.e., not a rate case);
- explicit consideration of a wide variety of supply- and demand-side options;
- public participation in the development and/or review of the resource plan;
- review, and possibly approval, of the utility's plan by a regulatory commission.

Key factors to consider in assessing the value of a formal IRP process are:

- the adequacy of the existing regulatory system, given gas industry restructuring and specified regulatory policy objectives;

- the extent to which an LDC's existing strategic planning process already includes and adequately addresses IRP goals and objectives;

- determination of the potential benefits and costs of an IRP process in comparison to current and other proposed regulatory approaches; and

- the extent to which the incremental transaction costs associated with an IRP process are either not necessary or that similar costs would not be incurred with other regulatory strategies.

A handful of states have adopted gas IRP regulations and 10 to 15 gas LDCs have filed their initial integrated resource plans under these rules. Anecdotal evidence suggests that results have been mixed. For example, in Washington, gas LDCs are preparing the second generation of IRP plans, and the gas IRP process seems to have produced significant benefits for ratepayers as well as utilities (see Exhibit 2-1) (WWP 1993). In contrast, after completion of one statewide gas integrated resource plan and commission approval of the first integrated resource plans filed by individual LDCs, the Illinois Commerce Commission (ICC) concluded that gas IRP was an unnecessary cost burden on ratepayers, without the potential to provide net benefits. The Illinois legislature has repealed its IRP regulations for gas LDCs (see Exhibit 2-2) (ICC 1993). The IRP regulatory requirements adopted in Illinois are atypical in that they required a two-stage planning process (i.e., statewide plan and individual utility plans). This approach may be more time-consuming and resource-intensive for all parties compared to electric and gas IRP requirements adopted by other PUCs. At a minimum, these experiences suggest that IRP processes have to be tailored carefully to the conditions and capabilities of gas LDCs.

2.6.1 Potential Benefits

Potential benefits of gas IRP cited by proponents include:

▸ *IRP provides documentation and support for the strategic planning activities of gas LDCs.* An integrated resource planning process can help facilitate a systematic approach for utility managers to evaluate diverse business activities and potential investments (see Figure 2-5). Gas utilities will increasingly have to offer innovative services to diverse customer groups with varying needs. A robust integrated resource plan satisfies multi-attribute evaluation criteria (e.g., cost, reliability, competitiveness, and environmental acceptability) by performing well

Exhibit 2-1. Impact of IRP and FERC Order 636 at Washington Water Power

Washington Water Power (WWP), a combined gas and electric utility, has filed two IRP plans under regulations issued by the Washington Utilities & Transportation Commission (WUTC). WWP has about 102,000 residential gas customers and more than 12,000 commercial sector accounts with firm sales of about 150 million therms annually.

WWP's IRP process has produced some tangible benefits: reduced costs to utility ratepayers, improved analytic methods to value resource options, and increased resources devoted to long-term resource planning, which has helped the utility respond quickly to post-636 implementation issues. WWP's experience also highlights the iterative and ongoing nature of IRP. Many of the benefits of the IRP process have become more apparent in WWP's second IRP plan as action plan items have been implemented. For example,

- In its 1991 IRP plan, WWP added a 5% reserve margin to the peak-day forecast to allow for forecasting error and possible physical losses of supply or pipeline capacity. WWP agreed to examine this issue in more detail in its second IRP plan based on comments received by various parties. In its 1993 IRP plan, WWP concluded that its use of design-day cold weather conditions was sufficiently conservative so that the 5% reserve margin was not necessary. This means that WWP could reduce its peak-day supply by about 100-150,000 therms/day in each year over a ten-year planning period. If WWP is able to take full advantage of the capacity release provisions of FERC Order 636 to market the excess firm transportation capacity, the company could save about $15 to 25 million from reduced peak-day requirements.

- WWP has implemented several DSM programs (residential weatherization, high-efficiency appliance rebates, low-flow showerheads, and commercial/industrial incentives), which appear to be cost-effective from the utility's perspective. In aggregate, these programs are expected to produce peak demand savings representing about 8% of incremental growth in peak demand over a ten-year planning period at levelized cost of about $0.50/therm.

- As part of its electric IRP plan, WWP is implementing fuel substitution programs that pay financial incentives to eligible customers who convert from electric to gas space and water heating. Based on a successful pilot program, the company believes that these programs are effective ways to reduce average utility bills of its ratepayers.

- WWP used a targeted marginal cost method to determine supply costs avoided by DSM measures in its 1993 IRP plan. WWP believes that this method is a more appropriate methodology compared to the simple weighted average cost of gas method used in its initial 1991 IRP plan.

- WWP utilized a commercially available gas planning optimization model to prepare its 1993 IRP plan. The model was particularly useful in helping the company determine how long it should pursue capacity releases of firm transportation.

Sources: WWP 1993; WWP 1991

Exhibit 2-2. Illinois' Experience with Gas Integrated Resource Planning

In Illinois, the Public Utility Act of 1987 mandated that the Department of Energy and Natural Resources (DENR) prepare a statewide gas least-cost plan and that the Illinois Commerce Commission (ICC) establish administrative rules that implemented these legislative requirements for individual gas utilities. After adopting one statewide gas plan and approving initial plans for individual gas utilities, the ICC concluded that gas least-cost planning (LCP) should be discontinued. In June 1993, the Illinois Legislature agreed with this recommendation and amended the Public Utility Act to discontinue its gas LCP regulations.

The Illinois Commerce Commission (ICC) concluded that gas least-cost planning is an unnecessary cost burden on ratepayers, without potential to provide net benefits because:

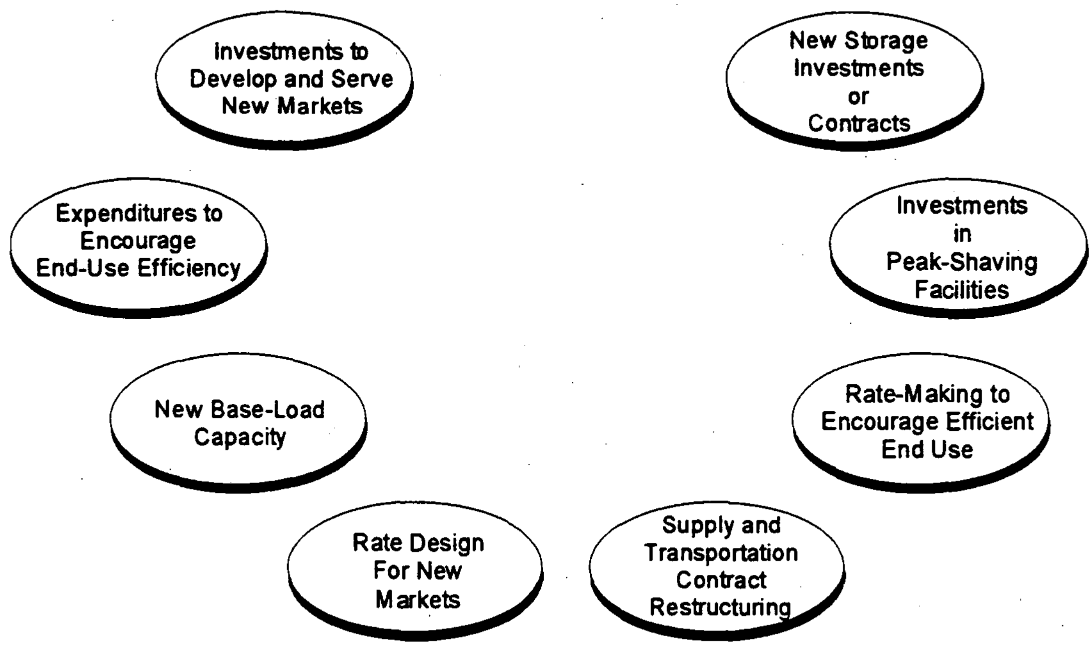
- Review of ongoing gas purchases can be accomplished more expeditiously through annual purchased gas cost reconciliation proceedings. The purchased gas adjustment reconciliation is a more direct way to influence the behavior of gas LDCs and encourage them to do forward-looking planning because they are at risk for long-term planning decisions.
- Review of capital projects and operations can best be accomplished through focused certificate or rate case proceedings.
- Most of an LDCs' costs (i.e., gas commodity costs) are constrained by the existence of a highly competitive natural gas supply market. The Commission's scarce resources are better spent pursuing electric least cost planning given the greater potential for cost reductions for electric utilities.

Sources: ICC 1993, Jensen 1993

for most criteria for a range of alternative future scenarios (EMA 1992). After completing a strategic planning process, the utility is in a much better position to explain its decision-making and resource procurement process, whether or not it is required to do so by a regulatory commission. One indicator of success would be the extent to which IRP becomes the planning process for the company's core business rather than simply a response to regulatory requirements (Bauer and Eto 1992).

▸ *IRP provides for sharing of risks of major supply management and capacity decisions between utilities and regulators.* In return for increased input into the resource planning process, regulators, on behalf of ratepayers, and other participating stakeholders implicitly accept increased responsibility for resource

Figure 2-5. IRP Framework Helps Utilities Evaluate Business Activities and Potential Investments



Source: Energy Management Associates (EMA) 1992

planning decisions (Hirst 1988b). Decisions made as part of commission-reviewed and approved processes typically are given the presumption of prudence at a minimum (Bradford 1992).

Gas LDCs may face reduced regulatory risk if they obtain pre-approval on the composition of supply acquisition portfolios, agreement on the need for a major new capital investment (e.g., storage facility), or regulatory support to use various risk management strategies to manage uncertainties in supply costs. Hedging strategies are assuming increased importance in both electric and gas resource planning as flexibility and robustness of alternative resource portfolios are evaluated under various future scenarios (Bauer and Eto 1992).

▸ *IRP helps overcome market barriers and imperfections that inhibit penetration of high-efficiency end-use options.* Gas LDCs can play an important role in accelerating the acceptance of high-efficiency gas equipment and technologies, which must overcome a variety of barriers in various market segments, such as information gaps, higher initial costs, lack of capital, and the problem of "split incentives" (see section 6.4.3) (see Krause and Eto 1988). In an IRP context, high-efficiency gas conservation and load management options can be regarded as potential "supply substitutes" and evaluated for their ability to affect the utility's supply requirements. Gas DSM may also help LDCs provide an increasing array of valued services for different market segments and create new opportunities and markets for high-efficiency gas equipment where societal benefits can be demonstrated.

▸ *IRP facilitates public participation and input in resource planning.* Many electric utilities have found that input from interested parties and stakeholders is useful, particularly in areas beyond the utility's traditional fields of expertise (Hirst et al. 1992). The form and extent of public participation vary significantly among utilities and include such activities as policy advisory groups, workshops on technical aspects of a plan, collaborative processes involving key stakeholders to develop a set of DSM programs, and solicitation of formal comments from outside parties to PUCs as part of the commissions' review processes (Raab and Schweitzer 1992).[14]

▸ *IRP helps facilitate coordinated energy and environmental planning.* Development of IRP in the utility sector has led to an increased recognition of the potential benefits of coordinated energy and environmental planning among state agencies responsible for these functions. A number of states use IRP-type processes to develop long-range energy plans for all sectors (e.g., buildings, industry, and transportation). These efforts often include an overall resource assessment, articulation of state goals in energy-related planning areas, and policy direction on balancing economic and environmental goals.

State-level energy planning often provides policy direction or input on a key issue that affects a utility's integrated resource plan. Examples include state policies on environmental externalities, siting of new facilities, and development of alternate fuel vehicles in the transportation sector (Bradford 1992). As a relatively clean-burning fossil fuel, natural gas may play an enhanced role in meeting future energy service needs to the extent that the energy and environmental implications of resource alternatives become an integral feature of state-level and utility planning processes.

[14] As competitive pressures increase, utilities are likely to request confidential status for ever-increasing portions of their IRP filings and supporting materials, which will complicate efforts to encourage public involvement and present regulators with difficult choices.

2.6.2 Potential Drawbacks

Critics of gas IRP regulatory processes emphasize the inherent limitations and regulatory costs of this approach (Kretschmer 1993). They argue that the significant differences between electric and gas utilities mean that the benefits to be captured by a formal IRP proceeding are likely to be small and will not justify the additional transaction costs of such a process. In critiquing the value of gas IRP regulatory processes, they raise the following issues:[15]

- *The direct and indirect costs of an additional gas IRP regulatory process can be substantial, and the benefits are uncertain and likely to be small.* Some policymakers argue that gas IRP processes involve significant amounts of utility, regulatory, and third party staff time, which could be better spent, given limited resources, on other activities (Kretschmer 1993).[16] Cost concerns are seen as critical because the potential benefits of gas IRP are inherently less than those that can be realized by an electric IRP process. Many gas industry groups maintain that supply-side decisions for gas LDCs do not imply large, long-term irreversible cost commitments and that competitive gas markets limit opportunities for a public process to further reduce gas costs.

- *A gas IRP regulatory process, particularly one that implies regulatory preapproval, is incompatible with the development of a competitive gas industry.* Given the realities of a rapidly evolving competitive supply environment, PUCs that review and approve utility integrated resource plans are very unlikely to be able to complete this process in a timely fashion. Moreover, if PUCs approve an LDC's integrated resource plan, the risks associated with long-range planning decisions are unnecessarily being shifted to ratepayers or regulators. This conflicts with policy goals intended to make utilities function as they would in competitive markets. Finally, in a competitive environment, the public nature of an IRP process is not necessarily a benefit because the gas LDCs bargaining power is reduced because potential suppliers have the opportunity to obtain information on the LDCs' supply plan and options.

- *The gas conservation potential that can be acquired cost-effectively by an LDC is relatively small because much of the economic potential will be captured through government appliance and building standards and codes.* The achievable DSM potential for a gas LDC is also more limited because gas avoided costs are

[15] See Jensen (1993) for a discussion of the pros and cons of gas IRP regulatory processes.

[16] One participant in the Illinois IRP process estimated that the direct costs of the gas LCP process was about $3 million for the seven gas LDCs (Jensen 1993).

lower than those for electricity. This means that, all else being equal, it is more difficult for gas utility programs to pass cost-effectiveness analysis from the economic perspective of the utility and society (Jensen 1993).

2.7 Summary

This chapter has highlighted the magnitude and nature of changes occurring in the U.S. gas industry and their potential implications for gas LDCs and state regulators. There is broad agreement among participants in the gas industry that strategic planning is critical for LDCs in the new business environment. For those regulators considering gas integrated resource planning, a major challenge is to adapt IRP processes to the conditions and circumstances of the gas industry. Flexible approaches are desirable for several reasons. First, the market forces unleashed by and uncertainties associated with gas industry restructuring mean that regulatory approaches must be compatible with emerging competitive realities. Second, the typical gas LDC may have fewer staff resources than the typical investor-owned electric utility, which also argues for more streamlined regulatory processes. Finally, in thinking about gas IRP, it is important to remember that fundamentally IRP is not an end in itself but a process designed to improve resource decisionmaking.

Chapter 3

Gas Integrated Resource Planning: Methods and Models

3.1 Overview

Regardless of whether gas integrated resource planning (IRP) is pursued as a separate regulatory process or a set of methods that are overlaid upon existing business and regulatory practices, IRP requires the coordination of several areas of utility resource planning. This coordination should begin with a clear set of objectives that define the mission of the gas local distribution company (LDC) as an energy services company. The LDC sets out to meet these objectives by conducting business and resource planning in five major areas: demand forecasting, supply-side resource selection, demand-side resource selection, resource integration, and financial and rate forecasting. This chapter provides an overview of the major areas in IRP, discusses how the areas should be coordinated, and focuses on three topics that are not covered elsewhere in this primer: demand forecasting, resource integration, and the treatment of uncertainty. An overview of computer models that are used to facilitate IRP goals and objectives is also included.

3.2 The Gas IRP Analysis Framework

A schematic representation of the IRP analysis framework is shown in Figure 3-1. The framework is not intended to be all-inclusive; instead, it highlights some of the key planning areas and their relationships to each other. IRP processes usually begin with a demand forecast; based on this forecast, the utility develops an initial or base-case resource plan which usually includes only traditional supply-side resources and excludes demand-side options. The base-case plan and variations on it are used to develop initial estimates of avoided costs. These avoided costs are used to screen alternative demand- and supply-side resources. Based on the results of screening alternative resources, alternative plans are developed that best achieve a certain objective, like the minimization of total cost (i.e., the "least cost" objective). Exhibit 3-1 summarizes the particular approach taken by one LDC, The Peoples Gas Light and Coke Co., and provides a concrete example of the major steps taken to develop an integrated resource plan.

A gas integrated resource plan must specify a planning horizon. In the electric industry, planning horizons of 20 years are common. Because of shorter lead times necessary to construct natural gas supply facilities and the greater uncertainty associated with gas

Figure 3-1. Analysis Framework for Gas IRP

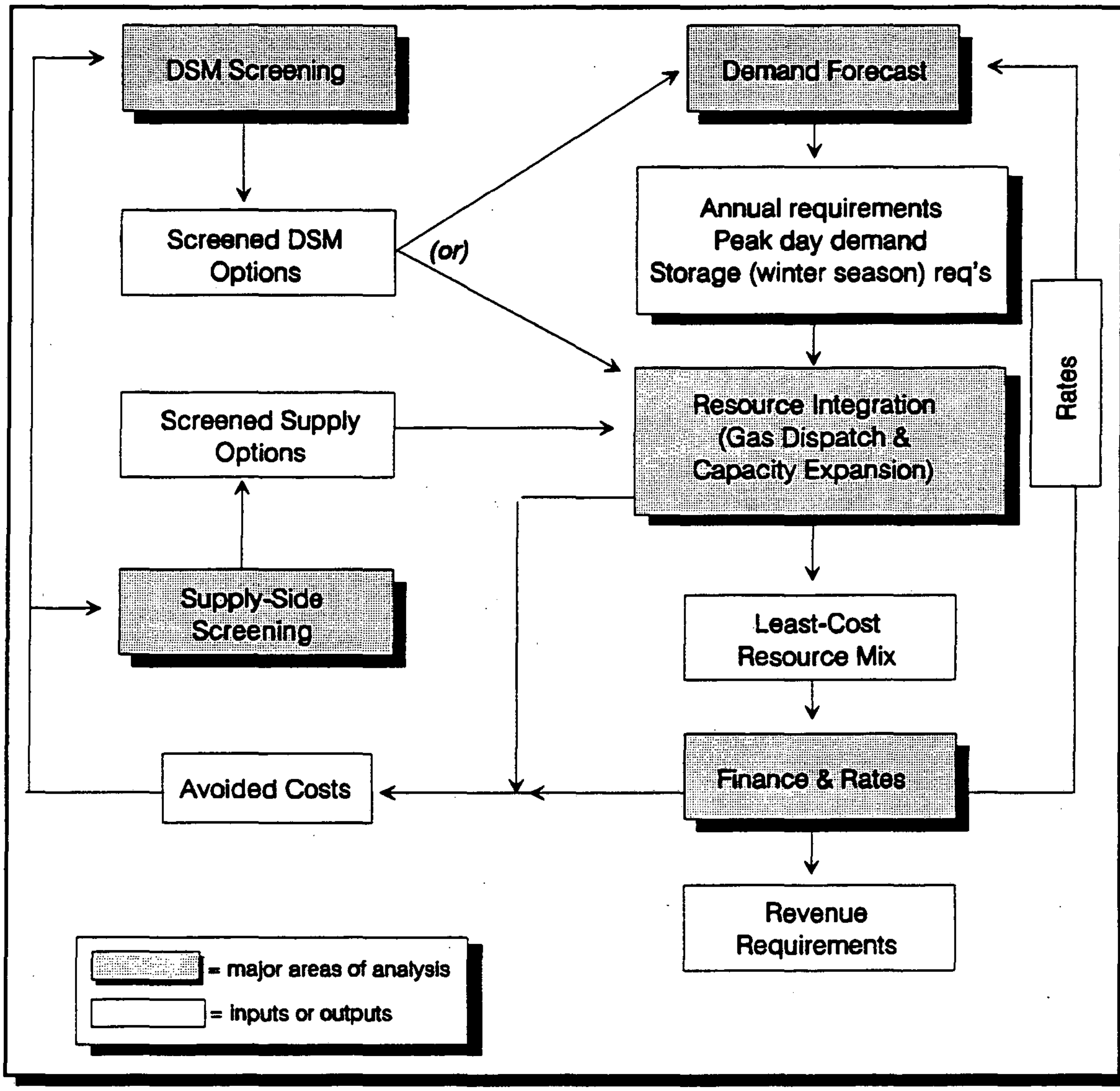


Exhibit 3-1. Major Steps in the Peoples Gas IRP Plan

The Peoples Gas Light and Coke Co. (Peoples Gas) prepared an integrated resource plan to comply with Illinois Commerce Commission rules (Peoples Gas 1991). The plan had four cornerstones: demand forecasting, supply-side management, demand-side management, and integration (see Figure 3-2). The plan was developed using a series of linked, detailed models rather than a single, integrated planning model.

Demand Forecasting

Peoples Gas forecasted demand of firm customers by combining the results of a short- and a long-term econometric model. The short-term model was designed to provide the best fit of recent historical data and could, therefore, be expected to produce more accurate forecasts in the short run. The two models were combined via weights: the short-term model was given greater weight in earlier years and the long-term model greater weight in later years. Peoples Gas forecasted the demand of larger, nonfirm customers on a customer-specific basis.

The peak-day demand forecast was estimated econometrically using recent daily sendout data and the assumption that the peak day would occur on a January weekday with ambient temperatures of -15 degrees Fahrenheit.

The company estimated demands consistent with five general scenarios: (1) a base case, (2) a high economic growth case, (3) a low economic growth case, (4) base-case economic growth combined with new demands from strong environmental regulations, and (5) a "price shock" scenario.

Demand-Side Management

Peoples Gas used a DSM screening program to assess many DSM measures and programs; measures and programs were identified that passed the Societal Cost test, Participant test, and Utility Cost test. Programs that passed the screening stage also had to be consistent with Peoples Gas's "overall DSM objectives."

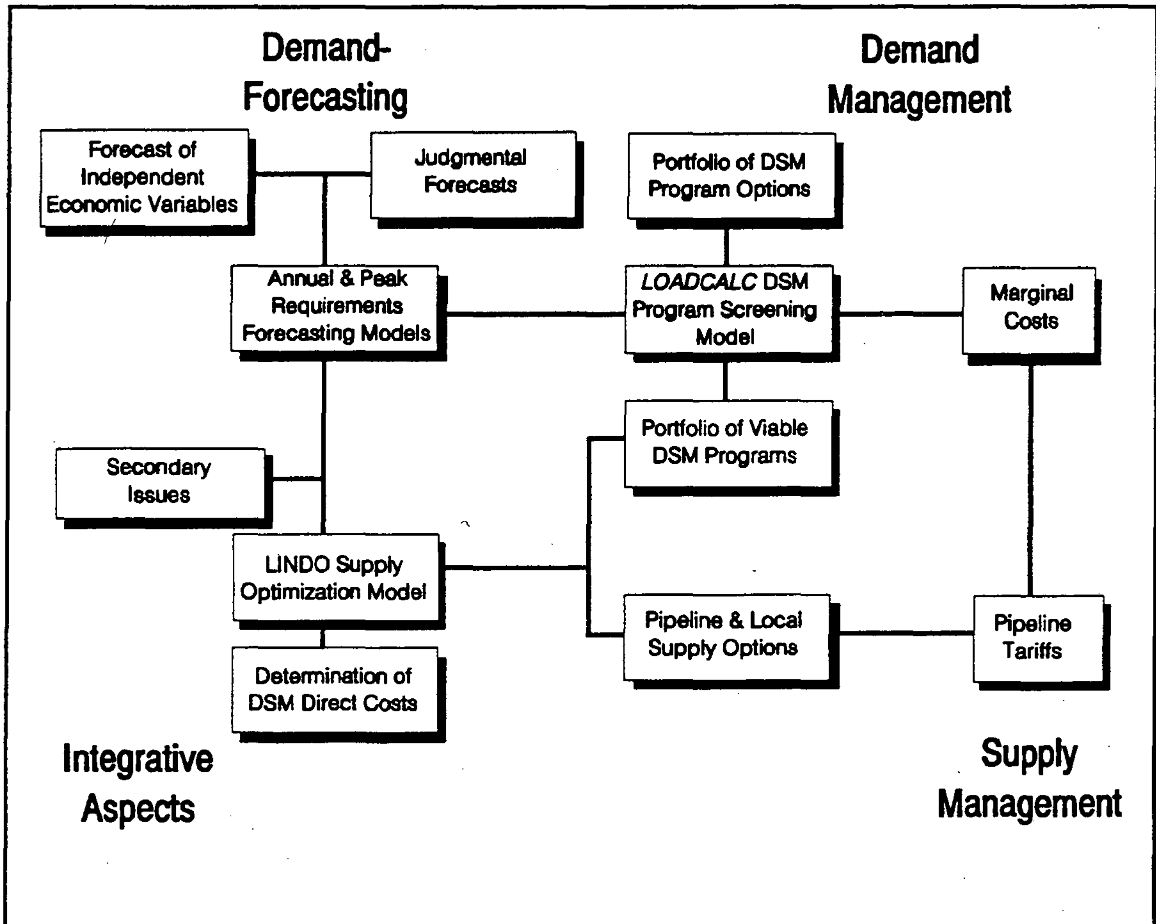
Supply-Side Management

Supply-Side management involved the enumeration of all practical supply-side options including new forms of contracting on existing pipelines as well as new capacity options.

Integrative Aspects

Peoples Gas's integrated resource plan was determined using its Daily and Monthly Optimization Models. These models are built upon LINDO, a commercial linear programming computer program. The models ensure that the system has sufficient gas supply and capacity available to meet the following design requirements: annual, January peak day, extreme Fall, and extreme Spring. The LINDO program picks the most economic supply- and demand-side options. Two types of least-cost plans were developed: a supply-only plan and a combined supply- and demand-side plan. The supply-only plan is used as a baseline for comparing energy and cost impacts and is used to develop the avoided costs for screening DSM programs. In addition to the least-cost criterion, some "secondary" attributes, such as rate impacts or the existence of possible implementation barriers, were considered in the final selection of DSM programs.

Figure 3-2. Peoples Gas IRP Process



Source: Peoples Gas Light and Coke Company 1991

demand forecasts, gas LDC planning horizons are typically shorter; three- to ten-years appears common.[1]

[1] To the extent that an IRP evaluates longer-lived resources, such as DSM measures, it may be necessary to extend the planning horizon to a point where the full costs and benefits of each resource option can be measured.

3.3 Defining IRP Objectives

It is essential that LDCs and PUCs define the mission of the LDC as an energy services company. This is done by adopting a set of IRP goals and objectives (Energy Management Associates (EMA) 1992). Achieving the proper balance between multiple objectives is a key challenge in IRP. For many PUCs, the overall goal of IRP is to develop a plan that reliably meets customer energy service needs at the lowest possible cost. Table 3-1 lists other major IRP objectives that are considered important by two major stakeholders: PUCs and gas LDCs. From these objectives, one can develop quantitative indicators for measuring how well a particular plan achieves its objectives. There is some overlap of the objectives that are important to PUCs and LDCs but not complete congruence. The degree of overlap between a PUC and an LDC strongly

Table 3-1. The Range of Objectives in Gas IRP

Major Stakeholder	Objectives	Key Indicators
PUC	Minimize source energy requirements	Total energy consumed
	Minimize total social costs	Societal Cost test, quantities of pollutants released
	Minimize total customer costs	Total Resource Cost test
	Share benefits equitably	Rate or bill impacts by customer class
	Minimize customer bills	Utility Cost test
	Minimize rates	Nonparticipants test
	Maintain reliability	Expected curtailments, reserve margins
	Maximize planning flexibility	Lead time of selected resources, dollar magnitude of long-term commitments
	Maintain market share	Market share, relative size of marketing budget
Utility	Maximize shareholder value	Stock price, return on equity

depends on the LDC's existing regulatory framework. For example, an LDC that has reasonable assurance of recovering prudently incurred DSM program costs and lost revenues is more likely to accept minimizing total costs as an objective than an LDC that does not have such an assurance.

3.4 Gas Demand Forecasting

The starting point of any gas integrated resource plan is the demand forecast, which estimates the future natural gas energy service needs of an LDC's customers. With the predicted demand, assessments of new supply- or demand-side resources can be made. For IRP purposes, the most common LDC demand forecasts are annual and design peak-day demands for each year of the planning horizon. If a gas utility has or is considering seasonal storage resources, then a forecast of peak season requirements is also needed. In addition to demand forecasts used in IRP proceedings, LDCs forecast demand for shorter-term purposes: day-to-day operations, supply portfolio planning, and revenue forecasting.

3.4.1 Econometric and End-Use Demand Forecasting Methods

There are two general types of forecasting methods: econometric and end-use. Econometric models typically rely on historical data sampled over time (*time series* data) or across customers (*cross sectional* data) to develop statistical relationships between demand and one or more explanatory variables. Econometric models may also be estimated using explanatory variables that are based on past values or moving averages of demand variable.[2] A statistical "best fit" of coefficients are found which relate demand to its explanatory variables (Pindyck and Rubenfeld 1981). The coefficients, along with additional data on the model's explanatory variables, may then be used to forecast demand. Table 3-2 shows a range of explanatory data that can be employed in econometric models for residential customers. A single econometric equation can be used to estimate total sales (Level 1), two equations can be used to estimate number of customers and use per customer (Level 2), or multiple equations can be used to estimate the number of customers in particular residential subclasses and use per customer in each of these subclasses (Level 3).

[2] Econometric models of this type are known as autoregressive (AR) and moving average (MA) models. These models may be combined to form ARMA or integrated ARMA (ARIMA) models (see Pindyck and Rubenfeld 1981). ARIMA models have proven to be very useful in forecasting peak-day demand.

Econometric models are attractive because of their power to correlate historical demand data with the historical explanatory data. Econometric models cannot, however, forecast relationships that are not somehow embodied in the historical data. The demand impacts of new, utility-funded DSM programs, which are undertaken to encourage customers to

Table 3-2. Levels of Load Forecast Disaggregation for Residential Customers

End Use——————————————————————>

<——————————————————Econometric

Level 1	Level 2	Level 3	Level 4	Level 5
Residential sales	No. of customers	• No. of space heating single family (SF) homes • No. of nonspace heating SF homes • No. of multi-family building with gas space heat • No. of nonspace-heat multi-family homes	• No. of water heaters • No. of furnaces • No. of air conditioners • No. of boilers • No. of ranges • No. of dryers	Same as level 4, except appliance turnover is explicitly modeled *e.g.* • No. of existing water heaters • No. of new (high efficiency) water heaters . . .
	Use per customer	• Use per SF home, space heat • Use per SF home, nonspace-heat • Use per multi-family building, space heat • Use per multi-family building, nonspace-heat	• Use per water heater • Use per furnace • Use per air conditioner • Use per boiler • Use per range • Use per dryer	• Use per existing water heater • Use per new water heater . . .

Source: Adapted from presentation by Jim Lamb (WAPA 1993) adopt greater levels of energy efficiency than would be expected from customer responses to rates alone, represents an event that cannot be forecasted econometrically, at least not with data sampled from a utility's own service territory.

End-use models attempt to model explicitly, with varying degrees of sophistication, the stock and energy intensity of existing gas-consuming buildings and appliances (see Table 3-2). Level 3 can be considered a quasi-end-use model because an explicit representation of space heat and nonspace-heat loads is made. True end-use models begin at Level 4 where stocks of appliances are explicitly modeled. Level 5 illustrates a further expansion of the end-use framework: appliance stocks and turnover rates are forecasted to model the change in appliance efficiencies over time.

End-use models have advantages in an IRP context because they allow the impacts of utility DSM programs to be readily reflected in the load forecast and because they make underlying assumptions about the usage and efficiency of building and appliance stocks transparent and understandable. End-use models also have disadvantages. First, end-use models require extensive data that is not readily available to most LDCs. Utilities must either conduct surveys to collect the data or borrow it from similar utilities that have conducted such surveys. Second, the lack of time series data on all explanatory variables makes end-use models difficult to verify although this should be less of an issue with continued end-use data collection.

While the collection of end-use data may be seen as a significant model development cost, end-use surveys have value beyond demand forecasting applications. For example, Washington Gas Light used the results of end-use surveys it initially conducted for the development of demand forecasting models for other purposes including the estimation of price elasticities of demand, DSM program design, and DSM program evaluation (see Table 3-3). To collect these data, the utility has spent roughly $500,000 since 1987 (Washington Gas Light Co. 1992).

In some states, end-use models are already being used for natural gas resource planning. For example, in California, the California Energy Commission and investor-owned gas LDCs rely on end-use models for long-term demand forecasts. Also, several combination utilities have transferred their end-use modeling capabilities from their electric departments to their gas departments. Econometric models are likely to remain common, however, because of the short planning horizons in the natural gas industry and the extensive data requirements of end-use models. Even if econometric models remain common, however, some end-use modeling will be necessary in IRP processes to estimate the impacts of utility-sponsored DSM.

Table 3-3. Selected End-Use Data Collection Activities of Washington Gas Light (District of Columbia Division)

Name of Survey or Study	Purpose/ Type of Data Collected	Approx Sample Size	Uses of Survey
Load Research Advisory Group (LRAG) Residential Survey (1987 and 1990 follow-up)	Gather data on household characteristics which could affect energy consumption, including appliance saturations and behavioral characteristics. Follow up survey allowed for tracking of sample households over time.	1,500	• demand forecasting (including elasticity study) • program design
LRAG Commercial Building Survey	Assess the level of energy efficiency in commercial buildings.	2,000	• demand forecasting (including elasticity study) • program design
1990 Boiler/Furnace Replacement Survey	Estimate the annual turnover of boilers and furnaces and the percentage of the total market that participated in the utility's DSM programs.	600	• program design (estimate market potential) • program evaluation
ENSCAN Metering Project	Collect daily load data. Subset of ENSCAN sample is a part of the LRAG sample, so inferences on appliance use are possible.	700	• program evaluation • demand forecasting (especially peak-day models)
Socio-Economic Survey	Collect race and income data on participants to determine whether programs are reaching a broad range of customers.	331	• program design • program evaluation
Hidden Savers Survey	Investigate why certain program participants increase rather than decrease consumption. Look for changes in participant characteristics that could explain the increase including number of appliances, building structure behavior, and household size.	303	• program design • program evaluation

Source: Washington Gas Light 1992

3.4.2 Weather Normalization Procedures

A significant fraction of residential and small commercial demand is typically weather sensitive. For historical data to be useful for short- or long-term demand forecasting, this weather sensitivity must be characterized and controlled for. Average or normal temperature conditions are usually chosen for forecasting revenues and average utilization of contracts and facilities. For planning total contract capacity and the size of facilities, LDCs also want estimates of extreme peak day, peak season, or cold-year demands.

The simplest way to conduct weather normalization is to create an index that is directly proportional to heating loads, such as the *heating degree day* (HDD) (American Gas Association 1987b). The HDD for a particular day is equal to a predefined base temperature minus the day's average temperature.[3] The base temperature is set at a point where there are no heating loads. Traditionally HDDs have been recorded using a base temperature of 65 degrees F. Lower base temperatures at 60 or 55 degrees F are, however, becoming more common as the housing stock in the U.S. is becoming more efficient and people are lowering thermostat settings. If econometric models are used, then historical data are used to find the relationship between HDD and demand per customer. If an end-use model is used, a simple linear relationship is assumed for all heating end uses. Forecasted demand is then computed using a forecast of HDDs. For average conditions, some historical average HDD is used. Extreme-day or extreme-annual HDDs are used to compute design peak-day and cold-year demands, respectively.

Additional sophistication can be added to the weather normalization process. Daily demand forecasting models require a recognition of the time lag caused by the thermal capacitance of building shells; such a lag may be incorporated into models using lagged demand or temperature data. Other weather data such as wind speed and solar insolation can also improve the accuracy of models.

3.4.3 Peak-Day Models

LDCs also develop models to forecast peak-day loads in average or extreme weather conditions, in part because many facilities, especially those located near load center, are sized to meet peak-day loads. Most peak-day models are determined econometrically. Historical winter season daily demands are used to determine a relationship between demand per customer and HDD or temperature. The estimated equation will often include

[3] Similar to the HDD's ability to predict heating loads, *cooling degree days* (CDDs) are a temperature index that can be used to predict cooling loads. CDDs may become important for gas demand forecasting if the penetration of gas-powered cooling systems increases in the future.

time-lagged temperature data patterns and wind speed. This estimated relationship is then used to determine daily demand for the situation of interest (e.g., the peak-day temperature that will satisfy the utility's reliability criteria).

There are several approaches used by LDCs to define the design peak day. Ideally, the design peak-day standard should be based on a benefit-cost study that sets marginal value of service equal to marginal cost (see Chapter 4). In practice, however, most LDCs determine their design peak-day requirements by choosing a reliability standard and estimating demand at that standard. Because of the strong temperature dependence of peak-day loads for most LDCs, reliability standards are characterized by a design temperature or HDD. Some LDCs base their design temperature on the coldest day or coldest cluster of days ever recorded in their service territories. For many utilities, weather records are available for periods longer than 60 years. Other LDCs use the 90th- or 95th-percentile cold temperature using all data recorded in their service territories. A more sophisticated approach to determining the design temperature for a service territory is to fit recorded cold-year temperatures to a mathematical distribution. The utility chooses a mathematical distribution that appears to best describe the true variation in temperature. The design day is set at the coldest temperature seen at the 90th, 95th, or 99th percentile of the *fitted* distribution. Using fitted distributions to compute the design peak day uses more information than just the data on the most extreme days; however, the results depend heavily on the type of distribution chosen by the forecaster.

Several utilities are beginning to combine econometric and end-use techniques in their peak-day forecast models. For IRP processes, the impact of appliance efficiencies on peak-day loads must be considered if the capacity-related benefits of DSM are to be realized. Analysts have attempted to incorporate appliance efficiencies into peak-day models which is an important step in making demand forecasting more consistent with IRP (Atlanta Gas Light Company 1992; Carillo 1992).

3.4.4 Demand Forecasting in an Unbundled World

Interruptible Demand

Interruptible demand is often an important component of an LDC's demand mix. While estimates of firm demand are needed to estimate the LDC's need for capacity, estimates of interruptible demand are needed for estimating revenues, rates, and profitability. Previously, interruptible demand was categorized by a system of priorities that closely matched customer class definitions. For example, it was commonplace for all electric generation boiler load to receive equal priority and that priority was usually lower than the priority given to industrial process load. In recent years, ample natural gas supplies at the wellhead combined with more stringent air quality regulations in certain parts of the country have made gas more desirable for interruptible customers; this change has resulted in demand for firm or quasi-firm service from all customer classes. Thus, it is likely that all classes except for residential and small commercial will have firm and interruptible subclasses in the future. The implication for demand forecasting is that distinctions between firm and interruptible loads must be made for additional customer classes and that such distinctions can add to the complexity of the demand forecasting process.

Transport-Only Demand

When customer-owned transport began to appear in the 1980s, it was often considered to be a subset of industrial interruptible demand because of the price sensitive nature of transportation customers and the unavailability of truly firm transport-only service from pipelines. Despite the quality limitations of retail transportation, the service has been a huge success and now transport-only customers account for much of the total throughput of many LDCs. In a post-636 world, the size and variety of customers that purchase transport-only services from gas LDCs will increase. The result of growing demand for transport-only service is that yet another dimension must be added to the demand forecasting process. Many LDCs will now need to forecast sales separately from throughput for every customer class in which transportation is offered. LDCs will develop commodity portfolios only for their sales customers and will still need to plan to acquire on-system capacity for their total firm throughput, which includes firm sales and firm transport-only loads.[4] Upstream of the LDC, it is an open question whether LDCs will be responsible for acquiring capacity for their transport-only customers. The LDC or PUC may require transport-only customers to acquire their own capacity.

3.5 Development of Alternative Integrated Resource Plans and Resource Integration

3.5.1 Developing a Base-Case Supply Plan and Initial Avoided Cost Estimates

Once the relevant demand forecasts are prepared, the next step of an IRP process is to develop a base-case plan. The base-case plan usually relies on traditional supply-side resources and typically excludes proposed DSM programs and new or emerging supply-side resource options. Avoided cost estimates, crucial for screening new resources evaluated in alternative plans, are first calculated using the base case. To estimate these costs, base-case demands are perturbed by some increment and the difference between

[4] Utility sales are equal to total throughput minus transport-only throughput.

the base case and the perturbed base case is used to calculate an initial estimate of avoided costs. Avoided costs are an important intermediate product of IRP processes because they link the various planning models used in IRP. If IRP could be conducted using only one model to evaluate all possible demand- and supply-side resources simultaneously, avoided cost estimates would not be necessary. Such a level of integration is usually impossible, so avoided costs become important for screening alternative resources. Avoided costs are a function of a plan's resource mix, so re-estimation of avoided costs may be necessary as alternative plans begin to differ considerably from the base-case plan. Methods for estimating avoided costs are discussed in detail in Chapter 5.

Once a base-case plan is prepared and initial estimates of avoided costs are available, alternative plans are developed that test one or more proposed utility actions. Possible alternative plans could include a DSM program, a new rate design, or an alternative supply-side plan. Although some PUCs may be reluctant to consider LDC marketing (non-DSM) programs, LDCs can certainly use IRP processes internally to evaluate such programs.

3.5.2 DSM Program Options

Utility-sponsored DSM programs are undertaken to modify customer demands and achieve an IRP objective. The modification of demands may be characterized in terms of load-shape objectives and include: conservation (a reduction of demand in all hours), load building, seasonal load reductions, "valley" filling, peak clipping, and peak-load shifting (see Chapter 7). Proposals for innovative pricing and improved rate designs can also be considered DSM in an IRP context because they are also undertaken to modify customer demands (Stutz et al. 1993). For example, PUCs and LDCs could consider alternative plans that promote marginal-cost-based rates that price natural gas services in proportion to current or future costs. Service characteristics that significantly affect marginal costs and which should be considered when adopting marginal-cost-based rates include: the time of year in which service is taken, the reliability provided, and the pressure level/volume capability at which service is provided.

3.5.3 Alternative Supply-Side Options

Because of the ongoing industry restructuring, new supply-side resource options are becoming feasible and, yet, may not be a part of the base-case plan. LDCs are increasingly responsible for developing their gas supply portfolios. In response to changes in pipeline transportation rate design as well as the advent of capacity release programs, LDCs will reconsider their pipeline holdings and pay increased attention to storage and other capacity options. The IRP process is well suited for the evaluation of alternative supply plans. LDC supply and capacity options and planning methods are discussed in detail in Chapter 4.

3.5.4 Resource Screening

Because detailed evaluation of any resource can be complex, LDCs typically employ screening analyses for both potential demand- and supply-side resources. As already discussed, avoided costs are a key variable in these analyses. DSM screening is often facilitated by use of dedicated computer models (see Section 3.8). Supply-side screening usually involves looking at information on system load shapes and the fixed and variable costs of supply-side options (see Section 4.3.3 for additional discussion). During the screening phase, it is a good idea to retain resources that are marginally cost-effective to allow further consideration in the more detailed resource integration stage.

3.5.5 Resource Integration

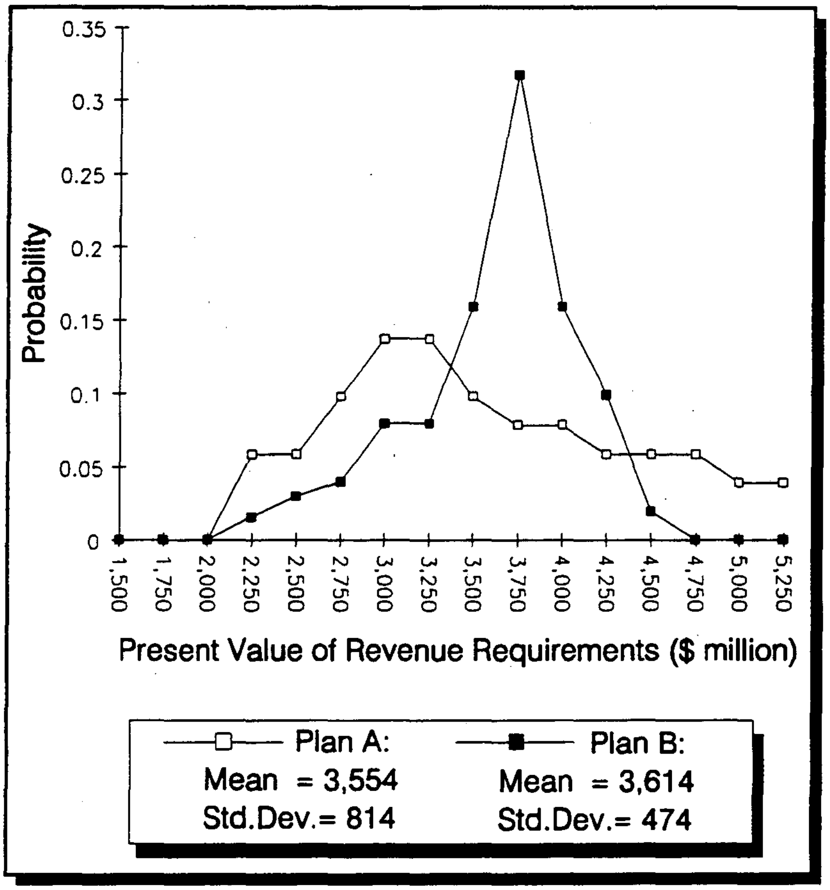
The goal of resource integration is to find the mix of resource options that best meets IRP objectives. Resource integration is facilitated by the use of gas dispatch and capacity expansion models. These models compute total system cost and help insure that energy service needs have been met adequately.

An important resource integration issue is where to incorporate the effects of a DSM program: as a modification of customer demands or as a resource option that is selected, along with supply-side resources, in the gas dispatch and capacity expansion models. It is common to incorporate DSM programs as a modification of demand. The reasons appears to be simplicity and the fact that many supply-side models are not well equipped to incorporate DSM programs as a resource. Studies that have looked at this issue in electric IRP have found representing DSM programs as a demand modifier can introduce inaccuracies that bias the IRP plan (Stone & Webster 1989; Hill 1991). Bias can be introduced because DSM programs that are treated as demand modifiers are usually selected using preliminary estimates of avoided cost that may not be equal to the final estimates. Treating DSM as a resource means that it can be evaluated in a manner consistent with supply-side options and modeled more flexibly (e.g., program size and implementation dates may be varied). Treating DSM programs as a modification of demand is acceptable, however, so long as careful attention is paid to changes in avoided costs, and alternative program sizes and implementation dates are considered.

3.6 Treatment of Uncertainty

Uncertainty is a critical factor in gas utility resource planning. Whenever a plan considers resource options that require irreversible decisions, are capital intensive, or require long-term financial commitments, the potential benefit of such options is clouded by uncertainty. The importance of considering uncertainty is illustrated in Figure 3-3. The figure shows distributions of total cost for two alternative resource plans, A and B. Plan A has a lower expected value than B, but Plan A has a larger standard deviation. As a result, there is a greater risk that plan A will, in fact, be more costly than Plan B. An LDC or PUC considering these two plans should give serious consideration to Plan B because it reduces risk. Key variables that contribute to uncertainty in resource planning include: demand fluctuations, gas commodity prices, prices of alternative fuels, level of economic activity, environmental and economic laws and regulations, weather, decisions of competing firms, the cost and availability of resources, and DSM program market penetration rates.

Figure 3-3. The Importance of Accounting for Uncertainty in Resource Plan Selection



Uncertainty can be characterized in several ways. If a particular variable is uncertain but has been measured over time, one can characterize uncertainty by estimating its *mean* and *variance*.[5] A plan's ability to respond to uncertainty may be characterized both qualitatively and quantitatively. Qualitatively, plans are often described in terms of their *flexibility* or *robustness*. A flexible plan allows for changes to be made in midcourse. Robust plans are optimal over a wide range of possible outcomes. It is also possible to use quantitative methods to assess a plan's ability to respond to uncertainty. Four general methods for analyzing uncertainty in an IRP context are: (1) sensitivity, (2) probabilistic, (3) scenario and worst-case, and (4) multi-attribute. (Hirst and Schweitzer 1988; Hirst 1992a)

3.6.1 Sensitivity Analysis

Of the general methods for addressing uncertainty, the easiest is sensitivity analysis, in which a preferred plan is developed using a deterministic set of inputs; key inputs are varied over a plausible range to assess their impact on key output variables. If key results change significantly, alternative plans should be considered.

3.6.2 Probabilistic Analysis

With probabilistic analysis, key variables are given probability distributions as well as mean values. Key outputs are computed using not just expected values of input variables but also combinations of inputs taken from other points on their probability distributions. Outcomes are computed by either enumerating all possible configurations of inputs and computing outcomes for each configuration or by setting a fixed number of runs where values for each input are sampled in accordance with their probability of occurrence. The latter method is known as a *Monte Carlo* analysis. For either method, all random variables need to be characterized by their degree of dependence on or independence from each other.

Probabilistic analysis is illustrated in the reliability plan developed at San Diego Gas & Electric Co.; it is highlighted in Exhibit 4-1.

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[5] A mean is the simple average of a sample or population. Variance is a measure of how a variable will move around its mean and is equal to the average of the square of each data point minus the mean of the data. A *standard deviation*, which is equal to the square root of the variance is another common measure of uncertainty. A bandwidth that is set at a variable's mean plus or minus its standard deviation will encompass 68% of a sample or population's variation. Two standard deviations will encompass 95% of the variation. A related term is *risk*: the probability or chance that a certain positive or negative outcome will occur.

3.6.3 Scenario and Worst-Case Analysis

In scenario analysis, sets of internally-consistent input assumptions are developed before a plan is constructed. Scenarios could describe such futures as "most likely," "high commodity price, low economic activity" or "high demand caused by environmental regulations." Plans are developed separately for each scenario. This method of addressing uncertainty is useful because it may find a course of action that is not least cost under the "most likely" scenario but is the most appropriate course of action in a large number of scenarios.

Scenario analysis may be considered an intuitive form of probabilistic analysis. Although probabilistic analysis is theoretically attractive, it may be too difficult to articulate the nature of each random variable and the variables' relationships to each other. For example, weather is uncertain but, because of historical records, can have its uncertainty characterized precisely. On the other hand, the demand for natural gas powered vehicles is also uncertain but has no historical precedent, so any distribution assigned to a demand variable would require considerable judgement. Rather than force numeric distributions on each source of uncertainty, scenario analysis only requires a handful of internally consistent scenarios. Optimal plans are then developed for each scenario. The challenge in scenario analysis is to maximize the use of available data and intuition to develop a representative set of scenarios.

A variation on scenario analysis is something called "worst-case" analysis. In this analysis, the utility plans for one extreme scenario but ends up facing a totally different scenario. Such an analysis gives an estimate of the cost of being "wrong" and shows the benefits of flexible plans.

3.6.4 Multi-Attribute Analysis

Rather than develop input scenarios, it is also possible to develop sets of attributes, objectives, or criteria. A set of plans are then rated according to their ability to meet major objectives (such as those listed in Table 3-1) or specific plans are developed that best meet specific objectives. For each objective, the plan may be subject to sensitivity analysis or probabilistic analysis. Plans that are best for a wide range of objectives are given favor in this type of approach. For example, Washington Gas Light rated several plans against eight attributes and each plan was given a total score based on its ranking for each attribute (see Table 3-4) (Washington Gas Light Co. 1992).

A multi-attribute analysis often addresses uncertainty implicitly because the attributes selected can be indicators of a plan's riskiness. For example, an attribute that measures the share of long-term contracts in the gas supply portfolio indicates a concern over the

Table 3-4. Ranking Alternative Plans Against Attributes: Washington Gas Light Co.

Attribute	10% of DCPSC's DSM Goal	100% of DCPSC's DSM Goal	125% of DCPSC's DSM Goal	DSM Pilot Programs Only
Meet Design Day & Sales Req.	9	2	1	8
DSM Programs	9	2	1	8
Commission Goals	2	9	10	3
Least Cost	6	1	2	9
Free Riders	9	2	1	8
Rate Impact	9	2	1	7
Environmental Impact	2	9	10	3
Good Will	1	5	2	8
TOTAL	**47**	**32**	**28**	**54**

Note: DCPSC = District of Columbia PSC
Source: Adapted from Washington Gas Light (1992)

price volatility or reliability of short-term supplies. The more risk-related attributes are included in the analysis and are given weight, the more likely it is that the ultimate plan selected will be able to respond to uncertainty.

3.7 Public Participation and Action Plans

Development of an integrated resource plan involves more than just technical analyses. As described by Hirst (1992b), a comprehensive IRP regulatory process should include meaningful public participation and action plans. These components are described further below.

3.7.1 Public Participation

Most PUCs have well developed rules for allowing public participation in commission proceedings. In an IRP proceeding, public participation can be enhanced through the creation of a technical advisory group. For participation to be meaningful, several things must occur. First, participation in the plan should begin at an early, preapplication stage so that any contributions of the participants have a chance of being incorporated into the filed plan. Second, the advisory group should include members from a wide range of interests. Relevant parties include consumer representatives, PUC staff, environmental groups, gas pipelines and suppliers, and representatives of the DSM and building trades. Third, although expertise on gas issues should not be a prerequisite, the utility should strive to include members who are either knowledgeable about some of the subject areas or who can commit the time to make a meaningful contribution. Fourth, advisory group members should be given a real opportunity to make a contribution to the plan. This is not to say that the utility has to agree to everything that the members of the advisory group want, but the utility should, where there is consensus, strive to incorporate into the plan contributions made by advisory group members and, in areas where there is disagreement, respond to questions or criticisms raised about the plan.

Some PUCs have taken the advisory group concept a step further and promote *collaborative processes* that represent an intense form of public participation on one or more aspects of an integrated resource plan (e.g., DSM program development). Collaborative processes usually involve frequent meetings and detailed review of issues with the goal of trying to build a consensus on as many issues as possible. In some cases, consensus processes are better able than traditional, litigated proceedings to reach agreement on certain challenging issues or focus areas of disagreement for later resolution by the PUC (Raab and Schweitzer 1992).

A major challenge for PUCs that wish to see successful public participation in gas IRP proceedings will be how to respond to LDC requests for confidentiality on the price and availability of certain resource options. Gas LDCs are likely to either resist submitting or request confidentiality on certain information because they believe such information could harm them competitively. It is possible to establish a procedure for reviewing requests for confidentiality and, if necessary, make certain aspects of the IRP filing subject to protective orders. Unfortunately, such procedures and orders may have the effect of limiting or increasing the cost of public participation.

3.7.2 Action Plans

"Least cost planning" transforms into "least cost doing" by means of the action plan, which describes a set of near-term activities designed to achieve integrated resource plan goals. Action plans usually describe the near-term goals and activities for the utility's DSM programs (including measurement and evaluation), supply acquisition activities, utility projects to improve the quality of the next plan (model development, data collection), and continued public participation.

3.8 Overview of IRP Models

Computer models facilitate several of the major areas of IRP: demand forecasting, DSM screening, the estimation of gas system supply and capacity costs, and financial and rate modeling. Table 3-5 characterizes the major types of computer models available. Models used in electric utility planning have a long history and have had extensive technical review, including scrutiny during the course of litigated PUC proceedings. In contrast, planning models for gas LDCs are relatively new and have not been scrutinized to the same degree.

Models can be important tools in IRP and provide valuable insights; however, if data are poor or assumptions questionable, model results will not be very useful. In reviewing IRP plans, PUC staff should pay particular attention to underlying assumptions and quality of input data.

3.8.1 Demand Forecasting Models

Demand forecasting models may be categorized as either econometric or end-use (see Section 3.4). Many generic econometric computer packages are available. End-use demand forecasting models are more specific to the energy utility industry than econometric models are. End-use modeling for gas LDCs is still in a developmental stage and some LDCs have adapted end-use models originally developed for electric utilities.

Table 3-5. Classification of Gas IRP Methods and Models

Type of Model or Method		Primary Purpose & Results	Examples of Commercially-Available Models (& Vendors)
I.A.	Demand Forecasting: Econometric	•Forecast: -firm & interruptible annual gas demand -firm peak-day demand -other peak periods, such as cold-year winter	• Utilities usually build upon one of the many standard econometric packages
I.A.	Demand Forecasting: End Use	•Are most useful for estimating annual requirements of firm customers •Can explicitly model the impacts of DSM programs	•COMMEND (EPRI) has been adapted to the natural gas industry by Wa. Gas Light
II.	DSM Screening	•Track end-use data •Estimate DSM program savings •Compute benefit-cost tests •Model market diffusion processes	•LOADCALC (Applied Energy Group) •COMPASS (SRC) •DSM Planner (BCI, Inc.) •ECO (Tellus Institute)
III.A.	System Supply and Capacity Costs: Gas System Simulation	•Produce pressures & flows at various points in the LDC's system •Assess the feasibility & cost of alternative expansion plans in detail	•GASSS & GASUS (Stoner Assoc.)
III.B.	System Supply and Capacity Costs: Gas Dispatch	•Determine the optimal use of existing gas supply facilities & contracts •Compute average costs, marginal costs •Estimate curtailments	•GDC (Planmetrics) •Sendout (Energy Management Associates) •GasPlan (Tellus Institute) •ROGM (Raab Economic Consulting)
III.C.	System Supply and Capacity Costs: Capacity Expansion	•Compute optimal choice of supply- (& possibly demand-) side resources over a multi-year time frame •Produce least-cost supply plan & long-run avoided costs	•Contract Analyzer (Planmetrics) •Sendout (Energy Management Associates) •GasPlan (Tellus Institute) •ROGM (Raab Economic Consulting)
IV.	Financial and Rates	•Compute: -revenue requirements, rates -financial statements -key financial indicators	•PROSCREEN II (Energy Management Associates)
V.	Integrated	•Provide modules that cover the following areas: -dispatch -capacity expansion -DSM program screening -demand forecasting -marginal costs -financial and rates	•UPlan-G (Lotus Consulting Group) •Sendout (Energy Management Associates) •Energy 2020 (Illinois Dept. of Energy and Natural Resources)

Source: LBL and GRI data

3.8.2 DSM Screening Models

DSM screening models are useful for developing a portfolio of DSM programs. For evaluating DSM programs, data are needed on end-use characteristics, stocks of appliances, and the cost and performance of DSM measures. Commercially-available DSM screening models often include default values for some of these inputs and typically calculate the standard economic tests for DSM programs (see Chapter 6). Some DSM screening models include market diffusion models, which can be useful for estimating the market penetration of DSM technologies.

3.8.3 System Supply and Capacity Cost Models

Gas System Simulation

Gas system simulation programs (Table 3-5, item III.A) actually model the flows and pressures of a gas transmission and distribution network based on detailed representations of the gas system's pipes, compressors, storage reservoirs, and valves. These models take a detailed description of a gas pipeline, storage, and distribution facilities and solve for pressures and flows using algorithms that model the behavior of natural gas in a network system. To simplify the complex problem these models are designed to solve, the models typically simulate the gas utility system using only daily or hourly demands for limited periods of time at design conditions. Network simulation models have not been introduced into IRP proceedings, but they are essential in determining the cost of supply-side capacity expansion options. For an accurate estimate of the capacity of a pipeline or storage resource option, the option must first be modeled using a gas system simulation model.

Gas Dispatch or Sequencing Models

Gas dispatching or sequencing is the process of scheduling and taking gas on a short-term basis. Dispatching is done on an hourly and daily basis by the gas control group of every gas LDC. Complex data acquisition and control systems as well as transaction data bases are used by many LDCs to track gas flows and dispatch resources in real time and to make short-term forecasts. Such systems and models are not discussed further here. IRP processes will, however, use simplified models of the gas dispatching process for medium- and long-term planning purposes. Dispatch models may be used to make detailed forecasts of an LDC's contract mix and purchased gas budget one month to two years into the future. For longer-term planning, dispatch models are used to estimate the impacts of facility additions on purchased gas costs. The gas dispatching problem can be solved in a variety of ways including spreadsheets, utility simulation, and linear programming techniques (Hornby 1991; Washington Gas Light Co. 1992). The general goal of the model is to find a least-cost dispatch of gas supply resources subject to firm demand constraints, interruptible demand price constraints, capacity constraints, storage limitations, and contractual constraints (particularly minimum take obligations). While many LDCs rely on models developed in-house, a sample of commercially-available models is shown in Table 3-5.

Gas dispatch models used for planning purposes must model the highly variable loads that are common to LDCs. One simple way to do this is to "splice" loads for the design peak-day onto an annual load profile. With this hybrid demand profile, the model can compute a least-cost dispatch for the expected year and make sure that adequate supply and capacity are available on the peak day. Demand variability is also addressed by performing multiple dispatch model runs for each year under different weather scenarios.

Capacity Expansion Models

As the time horizon grows to periods greater than one year, the LDC faces the problem of optimizing the mix of contracts and facilities as well as the problem of economic dispatch. Capacity expansion models are designed to address this problem. Two general approaches to solving the capacity expansion problem are iterative simulation and full optimization. In the iterative approach, a utility articulates a set of facilities and then computes total costs over a multi-year period. In conjunction with this method, gas dispatch models may be used to compute purchased gas costs. Alternative plans are developed and simulated until an optimal one is found according to the LDC's planning objectives. Some trial and error is involved in selecting plans for simulation. LDCs commonly use the iterative approach and implement the approach using in-house models. In the full optimization approach, the planning model automatically selects and sizes facilities and computes total cost. The models find the optimal expansion plan using automated iterative simulations, linear programming, or other optimization algorithms. Most commercially-available capacity expansion models can run as optimization models. Capacity expansion planning methods are discussed in more detail in Section 4.3.

3.8.4 Financial and Rate Models

Financial models typically compute income statements, balance sheets, and cash flow statements for each year of the plan. This information is useful for estimating impacts on an LDC's cost of capital and shareholder impacts. Many LDCs have financial models already developed in-house. Although financial models are needed for short-term operational purposes, financial models used for medium- or long-term planning are usually simpler than those used for operations.

Rate models take the cost data estimated by gas dispatch and capacity expansion models and use these data to compute class average rates and, possibly, specific tariffs for each year of an IRP plan. This information is useful for determining an integrated resource plan's economic impact on a particular customer class. If an LDC's gas demand forecasting model responds to changes in rates, rate models are also necessary to update the demand forecast. Most rate models are developed by utilities in-house.

3.8.5 Integrated Models

LDCs and PUCs must make an important decision before embarking on an IRP analysis: whether to use linked, detailed models or to use an integrated model. Electric utilities faced the same choice when developing IRP models for their industry (Eto 1990). With the first approach, utilities link into an integrated process the inputs and outputs of individual, detailed models for each step of the integrated resource plan. In the second approach, utilities use integrated planning models that incorporate elements necessary for a comprehensive analysis of DSM and supply-side options, and major linkages among the major areas of analysis are handled automatically by the program. Commercially-available integrated models for gas utilities have been developed by Lotus Consulting Group and Energy Management Associates. Despite the availability of integrated planning models, most gas utilities have used linked, detailed models. The advantage of the linked, detailed approach is that utilities can maximize use of their existing model capabilities already developed and maintained in various company departments. Linking models from different departments in an IRP proceeding can also provide an incentive for departments to increase communications among themselves. Further, the linked, detailed approach can lead to maximum consistency between IRP modeling results and the results of modeling efforts conducted by the LDC internally or in other regulatory proceedings. The advantage of integrated models is that, once set up and calibrated, they are simpler to use, especially when many alternative plans are to be tested. Integrated models may also be better suited for use in contested IRP proceedings where parties other than the LDC want to independently prepare LDC resource plans.

3.9 Summary

Gas IRP takes a set of multiple objectives for meeting customer energy service needs of a gas utility and creates a plan to best meet those objectives. The major areas of analysis in IRP are demand forecasting, DSM resource selection, supply-side resource selection, resource integration, and financial and rate forecasting. The planning horizons of gas integrated resource plans are typically shorter than those for electric integrated resource plans. Ten years is a common time horizon for gas integrated resource plans. Overall, the informational and coordination requirements of gas IRP are large, but IRP provides a way to improve the quality of resource planning decisions.

Demand forecasting may be done using econometric or end-use methods. Econometric methods are more common, but end-use methods are gaining acceptance by gas utilities. Even if econometric models are used, some sort of end-use modeling is necessary to incorporate the impacts of utility-funded DSM in the demand forecast. Demand forecasting will grow more complicated as the range of services offered by gas utilities increases.

Gas IRP includes enhanced public participation and action plans to insure successful implementation. Some utilities and PUCs have found collaborative processes to be useful in improving the design of DSM programs, and, in some cases, these processes can result in reduced transaction costs compared to more traditional regulatory processes that involve litigation. Action plans provide a concrete set of actions for the near term that are consistent with the long-term plan.

Commercially-available computer models exist for almost every aspect of gas IRP, including integrated models. Most utilities have chosen to rely on linked, detailed models because this approach maximizes the use of an LDC's existing modeling resources.

Ideally, DSM should be treated as a resource option in the supply planning process rather than as a modification to the demand forecasts. DSM resources may also be modeled as demand modifiers if careful attention is given to changes in avoided costs caused by changes in the IRP plan and if alternative program sizes and implementation dates are considered.

A good way to address uncertainty is to carefully select a set of internally consistent scenarios for which alternate IRP plans are developed or to evaluate alternative IRP plans against a set of key attributes. The best plan may not be the lowest cost plan for any single scenario or attribute. Instead, the most robust plan is likely to perform well over a wide range of scenarios or to meet multiple engineering, economic, customer service, and public policy objectives.

Chapter 4

Supply and Capacity Planning for Gas Utilities

4.1 Overview

This chapter discusses resource planning methods of gas local distribution companies (LDCs) with an emphasis on supply-side alternatives. The supply-side planning environment for LDCs is rapidly changing as more resource options are available, and LDCs can no longer rely on gas pipelines for supply management. The ramifications of gas industry restructuring are not yet fully understood and more changes are likely. Analysts and industry participants have issued reports and papers that focus on supply and capacity planning problems for LDCs, but none are comprehensive in light of the rapid change in the industry (NARUC Staff Gas Subcommittee 1990; Hatcher and Tussing 1992; U.S. Department of Energy (DOE) and the National Association of Regulatory Utility Commissioners (NARUC) 1993). This chapter discusses gas supply and capacity planning with an emphasis on four topics: (1) existing and emerging supply and capacity resource options, (2) major supply and capacity planning methods and issues, (3) public utility commission (PUC) oversight of gas LDC procurement decisions, and (4) reliability and contingency planning.

4.2 Planning for Gas Supply Portfolios

4.2.1 Overview

With the ongoing gas industry restructuring, the scope of gas LDC procurement activities has been reduced now that large end users have taken increased responsibility for procuring their own gas supplies. Gas LDCs still procure supplies for firm, usually "core," sales customers and many interruptible sales customers. Gas LDCs also procure gas as a standby or balancing service for transport-only customers who intermittently fail to deliver their own gas. LDCs can procure gas from an expanding set of supply options. In this section, the major types of gas supply contracts are discussed and terms and concepts are introduced for regulatory staff who are involved in reviewing and evaluating an LDC's supply plan. Alternative regulatory frameworks to review LDC procurement decisions are also discussed because a PUC's review process can significantly influence a gas LDC's procurement practices.

4.2.2 Gas Supply Options

A diverse set of gas supply options has existed for several years at the wellhead, and, in a post-636 environment, LDCs will be expected to look beyond interstate pipelines for sources of firm supply. Because of concern about the future price and availability of spot gas supplies, LDCs will also be re-evaluating the "short" side of their gas portfolios. Table 4-1 briefly describes the major types of gas supplies by contract type. Gas supply contracts are either physical gas contracts or financial gas contracts. Physical contracts include pipeline sales service, long-term firm contracts, gas reserve purchases, monthly or multi-month firm contracts, spot contracts, and customer buybacks. Financial gas contracts are relatively new in the gas industry and include contracts that are primarily designed to mitigate price risks rather than provide physical gas supplies. Financial gas contracts include forward, futures, options, and swap contracts. The remainder of this section examines key issues that arise for LDCs when assessing these supply options.

Basic Contract Terms: Spot Contracts

Any gas supply contract needs to specify the quantity of gas sold, term of the sale, point of delivery, and price. Because of the short, nonfirm nature of spot contracts, their terms may be considered the lowest common denominator of all gas contracts. Spot contracts specify an average daily quantity of gas as well as a maximum daily quantity (MDQ) of gas. MDQs are usually higher than the anticipated average demand to allow for daily variations in demand. Usually one party will act as a shipper and be responsible for scheduling gas delivery on the interstate pipeline and paying any transportation charges. Spot contracts allow either party to terminate the contract without penalty. Sometimes prices are renegotiated midmonth to prevent either the buyer or seller from terminating the contract.

Characterizing Long-Term Contracts

Long-term contracts are not synonymous with firm contracts, but reliability provisions are commonly included in longer-term gas contracts. Longer-term contracts are entered into for at least four reasons: (1) to improve supply reliability, (2) to improve price stability, (3) to improve revenue stability, and (4) to reduce transaction costs. In addition to the basic provisions included in spot contracts, longer-term contracts include provisions regarding supplier reliability, volume or take flexibility, and price determination. Supplier reliability is very important to buyers and buyers often attempt to eliminate unreliable suppliers by requiring potential suppliers to go through a prequalification process. Buyers ask the following basic questions when assessing supplier reliability: (1) does the supplier control the physical resource? (2) does the supplier

Table 4-1. Overview of Gas Supply Options

Option	Description/Features
Spot	Contracts to sell gas that allow either party to terminate without penalty. Term is usually on a calendar month basis. Spot markets are now evolving into daily markets where significant trading (and price variation) occurs all month long.
Long-term Firm	Gas supply contracts with terms longer than one year. A long-term firm contract usually provides greater reliability than a similar sized spot contract and includes procedures for dispute resolution. In return for accepting performance-penalty terms, the supplier usually requires the buyer to make volume commitments in the form of gas inventory charges, take-or-pay charges, reservation charges, or other minimum-take provisions. Prices may be fixed, indexed to inflation, indexed to spot gas prices, or indexed to alternative fuel prices.
Monthly or Multi-Month Firm	Contracts for firm supply on a short-term (less than one year) basis. They are usually entered into to supply swing- and heating-season loads. They are considered more reliable than spot supply and can provide a higher degree of price certainty than spot.
Pipeline Sales Service	As a result of FERC Order 636 pipeline sales gas (merchant function) are deregulated and unbundled from associated pipeline transportation and storage services. Merchant services provided by a pipeline or its affiliates may not be bundled with any regulated pipeline services and must compete with unaffiliated marketers that also sell gas through the pipeline.
Purchase of Reserves	A contract that purchases a quantity of proven or developed gas reserves. The reserves may require additional development before they can be delivered to the customers. The reserve purchase contract may be in the form of a joint venture among a set of parties.
Forward Contracts, Futures, Options, and Swaps	A forward contract is a contract to buy a quantity of natural gas at a specific location on a prespecified future date. Futures contracts are a type of forward contract that is publicly traded on the New York Mercantile Exchange (NYMEX). An options contract is the purchase of the right (but not the obligation) to buy a quantity of gas supply for a prespecified period at a prespecified future price. Swap contracts allow the exchange of gas contract terms between two parties without necessarily a trade of physical assets.
Customer Buyback	Utilities can make advance arrangements via contracts or tariffs to buy gas supply or gas capacity from certain firm customers to meet the needs of other firm customers during periods of high demand. A variation of customer buyback is known as a "BTU" contract where an alternative-fuel-capable customer agrees to be curtailed at the utility's discretion. The customer is reimbursed for the difference between the delivered price of gas and alternative fuel available to the customer.

control necessary transportation rights? (3) does the supplier have adequate "back office" resources (personnel and information and control systems) to respond to changing conditions such as last-minute nomination changes? and (4) what is the financial strength and reputation of the supplier? These reliability concerns are reflected in long-term supply contracts via penalty provisions, warranties, or early termination provisions if the seller fails to deliver. Although most firm contracts will have some sort of *force majeure* clause that will excuse the seller from performing because of unexpected events that are beyond the seller's control, the firmest contracts will have very narrow *force majeure* terms. With penalty or early termination provisions, buyers are financially compensated in the event a supplier does not perform. Under warranty provisions in firm contracts, suppliers warrant performance under the contract with their entire resource base—essentially waiving supplier *force majeure* terms.

Most firm contracts provide for revenue stability, which is valuable from the seller's perspective, by placing incentives in the contract to keep load factors high via a fixed payment obligation, a minimum-take provision, or a *gas inventory charge* (GIC).[1] Although these specific clauses vary in their mechanics, all discourage the buyer from deviating from the nominal volume terms of the contract. Because load factors are low for many LDCs, volume flexibility is an essential element of firm contracts but is likely to come at a price because of the seller's desire for revenue stability.

Some firm contracts, especially those of less than one year's duration, simply specify a fixed price. Longer-term firm contracts are likely to have more complex pricing formulae. Many firm contracts are indexed to spot prices but with significant embellishments. First, the contract may specify a premium or a discount from spot prices. Second, spot prices may be part of a formula that dampens fluctuations in the contract price relative to spot prices or combines a spot index price with other indices, such as alternative fuel prices or inflation indices. Besides initial price determination rules, long-term contracts often include conditions under which price can be renegotiated and any indices readjusted.

The Future Role of Pipeline Supply Services

Pipelines were the traditional source of gas supply for many LDCs. With the Federal Energy Regulatory Commission's (FERC's) Order 380, LDCs were no longer required to meet pipeline minimum bill obligations and began to take advantage of low-cost supplies that became available in the spot market. This trend accelerated with the passage of FERC Orders 436 and 500 et al., which encouraged the availability of nondiscriminatory transportation services. Despite the availability of transport-only services, many LDCs still relied on pipeline supplies to meet their firm customers' needs

[1] Take or pay charges are another way to insure volume/revenue stability although this term is no longer commonly used in new gas supply contracts. GICs were originally FERC-regulated supply inventory rates for gas held by interstate pipelines. It appears that the term GIC is being carried over into deregulated gas supply contracts at least in some instances.

during peak seasons. FERC Order 636 deregulated the gas sales operations of the regulated pipeline companies. As a result, pipelines have (1) negotiated gas supply contracts with their customers on a deregulated and unbundled basis, (2) sold or assigned gas supplies to an affiliated LDC or marketing company, (3) bought out or otherwise terminated gas supply contracts with producers, or (4) sold or assigned gas supply contracts to independent marketers. Any gas sales subsequently made to customers via options (1) and (2) are subject to the FERC's existing rules regarding standards and conduct and reporting requirements between pipeline operating divisions and their gas marketing division or affiliate under FERC Order 497 (Federal Energy Regulatory Commission (FERC) 1988). To facilitate the transition to an unbundled pipeline industry, the FERC will allow four different kinds of prudently incurred costs to be considered *transition costs* and to be recovered by the pipeline through its transportation rates: (1) unrecovered PGA balances, (2) gas supply "realignment" costs, (3) stranded investments, and (4) new facility costs necessary for implementing the rule.[2] In the post-636 environment, supplies from the affiliated marketing arms of pipelines will not be very different from supplies available in the competitive marketplace. Pipelines are required to offer supply service at deregulated rates before selling gas supplies to other parties. Some LDCs are choosing to buy gas from the pipeline while other LDCs have ceased sales transactions with their pipelines and are now negotiating with producers or marketers for firm gas supplies.

Although the pipeline merchant function is deregulated and diminishing, pipelines will still offer a limited supply service in the form of *balancing* services. First, pipelines are required to provide no-notice transportation service to customers who took bundled city-gate services as of May 18, 1992. This service is technically a transportation service, but because it allows a pipeline customer to transport gas from the pipeline without advance notice, pipelines providing the service will have to have gas supplies on hand until the customer replaces the taken gas with its own. Second, some pipelines will offer balancing tariffs, which allow customers to pay for the right to be out of balance by a certain amount every month. Third, pipelines have imbalance tariffs and scheduling penalties to charge customers a premium price for gas consumed on an unscheduled basis and reimburse customers (usually at a discount) for gas supplied on an unscheduled basis.

[2] It is FERC policy to allow pipelines to recover 90% of prudently incurred transition costs via firm transportation reservation rate surcharges and 10% via interruptible rates. Gas supply realignment costs were an important issue addressed in FERC Orders 500 and 528 (FERC 1987 and 1990) . The FERC's allocation of these realignment costs, mostly take-or-pay buy-out or buy-down costs, required pipeline shareholders to absorb a portion of the transition costs. According to the FERC, the Order 500/528 allocation rules will remain in effect until pipelines are in full compliance with Order 636.

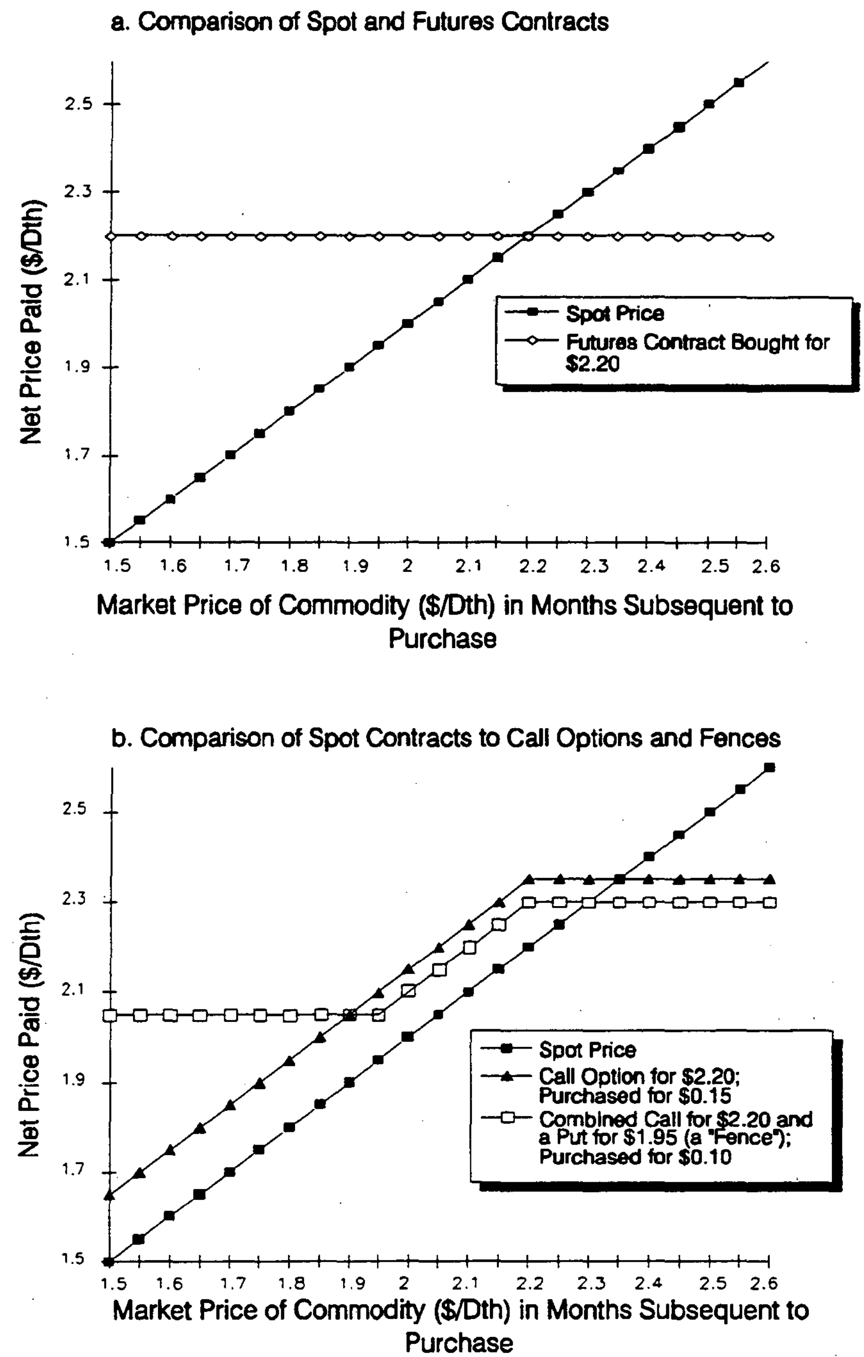
Futures and Other Types of Financial Gas Contracts

Financial gas contracts are an increasingly popular resource option to gas buyers. Most financial gas contracts are considered to be *derivative contracts*; i.e., the value of the contract is derived from prices in one or more primary commodity or financial markets. Futures and options contracts have emerged as the most well-known forms of financial gas contracting. A futures contract is a standardized type of forward contract that is publicly traded. A natural gas futures market has been open on the New York Mercantile Exchange (NYMEX) since April 1990. The market allows a party to buy or sell multiple contracts of 10,000 MMBtu each of natural gas for delivery at the Henry Hub of the Sabine Pipeline Company in Louisiana up to 18 months into the future. "Open interest," the number of outstanding contracts at a given point in time, has grown steadily since the market's inception and averaged more than 2,000 in 1992 (Energy Information Administration (EIA) 1993c; Mitchell 1993). The seller of a futures contract is obligated to provide the gas at Henry Hub at the future date but, as in other commodity futures markets, many of the contracts are sold before the future date so only a fraction of the outstanding contracts ultimately result in a physical delivery. The futures market provides two valuable functions from the perspective of gas utilities and consumers: (1) it provides a price discovery function (i.e., futures prices represent current expectations of where prices are heading) and (2) futures contracts and related options contracts allow buyers and sellers of gas to protect themselves from unfavorable price changes. By buying or selling in the futures market, one can lock in a particular price up to 18 months before delivery begins. Figure 4-1a compares unhedged prices to contracts purchased on the futures market. The futures contract at $2.20/MMBtu is represented as the horizontal line. The "45 degree" line shows the price that would be paid if a buyer bought gas in the spot market rather than buying a futures contract for delivery up to 18 months into the future. With a futures contract, the buyer would take the gas at the $2.20/MMBtu contract price regardless of subsequent spot market prices. Options contracts allow flexibility in price hedging. For example, a buyer of gas worried about price run-ups, could buy call options for purchasing gas at a prespecified "strike" price for a prespecified time period in case future prices eventually exceed the strike price. Similarly, a seller of gas, worried about price drops can buy put options contracts, which guarantee a floor price. Put and call options contracts can be combined into "fences" or "collars" that provide a price ceiling and a floor (see Figure 4-1b).

Although the futures market is a useful tool for managing gas price risks, the market has several limitations:

- Contracts are available only 18 months into the future so the NYMEX futures market does not provide a way to manage longer-term price risks.

Figure 4-1. Examples of Contracts Available on the Futures Market



Source: Adapted from Mitchell (1993)

- The market does not explicitly address risk associated with demand variability. Parties that hold futures contracts on the contracts closing date are obligated to buy or sell. In contrast, nonexchange-traded long-term firm gas contracts may have provisions that allow the buyer greater volume flexibility.

- Closing futures prices have not tracked spot prices as well as would be expected in an efficient market (Energy Information Administration (EIA) 1993c). Closing futures prices for a given month have generally been higher than spot prices for the same period. Although the difference between closing futures and spot prices may shrink, it is a potential inefficiency in the current market.[3]

- The futures market depends on speculators to make it liquid. Although they are essential to a proper functioning futures market, speculators can add volatility to the market, which can make regulators reluctant to allow LDCs to directly participate in the market.

Regulatory structures that facilitate or allow for LDC participation in the futures market are discussed in more detail in Section 4.2.4. In two cases where a specific incentive regulatory program has been proposed or adopted, LDCs have proposed to enter the gas futures market (Henken 1993; New Jersey Natural Gas Company 1993).

Other types of financial gas contracts are being written in addition to the exchange-traded futures and options contracts. Because of the desire to mitigate price risks to a greater degree than can be provided by the exchange-traded markets, LDCs and other gas buyers consider entering into nonexchange-traded (also known as *over-the-counter*) financial gas contracts. Over-the-counter gas financial contracts may be written more flexibly than exchange-traded contracts; in particular, they can be written to address risks more than 18 months into the future. An example of an over-the-counter financial gas contract is a multi-year forward options contract that allows a buyer to purchase of natural gas at a market price that is capped at the buyer's alternative fuel prices. The buyer may pay some fixed payment in return for being indemnified if the market price of natural gas rises above the alternative fuel price. Swaps may be considered as another example of an over-the-counter contract; in them, two parties essentially trade part or all of the financial obligations of their gas supply and/or capacity contracts. For example, a party holding a gas purchase contract that is tied to the spot market may trade its pricing terms with a party who holds a fixed-price contract. Usually, the risk-taking party will enter the transaction in return for a premium payment; thus the risk-taking party accepts higher price volatility but lowers its expected cost of gas.

[3] This potential bias is not reflected in the examples presented in Figure 4-1.

4.2.3 Portfolio Construction and Risk Management

There is general consensus among industry participants on the overall goals of LDC gas supply planning. An LDC chooses a mix of gas supply resources to best meet the needs of its sales customers. For firm customers, supply reliability is a paramount goal. Meeting that criterion at the lowest possible cost is important, as is cost or price stability. For nonfirm sales customers, reliability is important but secondary to price. Nonfirm customers tend to have more heterogeneous needs, so specific supply contracts that vary with respect to reliability and pricing terms are useful in meeting their needs. LDCs are responsible for acquiring gas supplies to meet all these goals.

While it is possible to articulate these goals, it is not possible to provide prescriptive rules or methods for building a supply portfolio because each LDC has a unique set of available resources and a unique set of customers with preferences regarding reliability, price, and price stability. Further, uncertainty makes trading off different supply attributes difficult; it is only possible to identify major strategies used to plan gas supply portfolios. The first major strategy employed by LDCs is to rely on a portfolio of gas supplies that is diversified with respect to gas supply owner, term of contract, and, if possible, supply basin and transport facility. The second major strategy is for the LDC to manage the load shape of its customers by aggregating customers, setting up voluntary or mandatory curtailment provisions, acquiring storage, and acquiring peak-shaving facilities. These key themes of portfolio construction and load shape management are discussed further below.

Gas Supply Diversity

For reasons already noted, contract diversity means that a gas utility's supply portfolio includes more than just pipeline sales gas and spot gas contracts. Some LDCs have articulated guidelines for determining the mix of short- and long-term contracts in their portfolio. For example, these LDCs strive to enter into enough firm gas contracts to meet peak-day conditions plus a possible reserve margin (Peoples Gas Light and Coke Company 1991; Washington Water Power Company (WWP) 1993). Although use of storage or peak-shaving equipment is used to lower the peak-day requirements, ultimately some upstream planning demand is set and contracted for. Firm contracts usually have terms long enough to cover the next winter, and many utilities consider long-term contracts because they believe these contracts improve reliability, provide price certainty, and/or reduce transaction costs. LDCs seem reluctant at this time to enter into contracts with durations longer than three to five years given uncertainty over cost recovery (see

Section 4.2.4).[4] Although LDCs are seeking a high percentage of firm contracts in their resource mix, they also strive for take flexibility to allow for periods of slack demand. Gas utilities usually strive for enough volume flexibility so that they do not incur GIC or minimum-take charges in an average- or warm-temperature year. LDCs look for additional volume flexibility so that they can take advantage of the spot market during periods of low prices. As already noted, volume flexibility usually comes at a price, so LDCs must balance cost premiums with the future potential benefits of take flexibility. For interruptible sales customers, LDCs will usually acquire shorter-term, nonfirm contracts. If an LDC had confidence that a certain block of interruptible demand would exist at all times except for times of curtailment, it may aggregate that demand with firm demands and contract for longer-term firm supplies.

Some participants in the industry have a very different philosophy than described above for determining contract mix. An emerging view is that shorter-term supplies without explicit reliability clauses, such as spot contracts, can be a part of the peak-day supply mix of the LDC, even for firm customers (Hatcher and Tussing 1992; Tussing 1993). In a competitive market, buyers should face no impediments when purchasing gas supplies, even in periods of high demand; that is, there is not a reliability risk in relying on spot contracts. There is only price risk. If the prevailing market requires premiums for the contracting of long-term firm supply relative to spot gas, some argue that those premiums may not be worth the cost (Sutherland 1993). As an example of this philosophy, the California PUC recently issued a policy statement essentially putting the burden of proof on the LDC to justify any long-term contracts that come at a price premium (California Public Utilities Commission (CPUC) 1992b).

Although there is considerable controversy over the role of long-term firm contracts in LDC supply portfolios, the controversy does not appear to be over whether long-term contracts have a place in a LDC's supply portfolio. Long-term contracts save on transaction costs, and as long-standing buyer-supplier relationships are common in other industries, it is reasonable to think such relationships will re-form in the natural gas industry. The one controversial issue appears to be whether long-term contracts will be sold at a premium or a discount over spot gas. It is commonly understood that long-term contracts provide reliability and price stability to the buyer. Long-term contracts also provide revenue stability to the seller, and such revenue stability can allow for greater leveraging of supply assets and higher equity profits to the producer. Thus, all other things being equal, gas producers may be willing to provide a discount for a long-term contract with high minimum-take or GIC provisions. The ultimate premium or discount

[4] Owners of nonutility electric generation projects appear to be the biggest buyers of long-term contracts. Contracts with durations of 15 years or more have been signed, often as a way to facilitate the project's financing.

for long-term contracts will be best determined in a competitive marketplace. From a policy perspective, it is more appropriate for PUCs to allow market forces to determine ultimate price relationships rather than to accept assertions that term premiums are positive, negative, or zero.

LDCs also consider diversifying with respect to factors other than contract term. Diversity with respect to geography is important because it tends to improve reliability. Well freeze-ups or hurricanes in one area may not affect another area. Geographical diversity also improves the LDC's competitive position: the LDC is not captive to suppliers from a particular region. Even if geographical diversity cannot be achieved because of unavailability or expense of facilities that connect to alternative supply basins, diversity in ownership is also valuable; it means the LDC is not captive to any one producer or pipeline and reduces the risks associated with a particular supplier having financial problems. Diversity can be sought both at the time of solicitation and from the time that delivery of gas is taken. One of the advantages of competitive bidding is that the LDC can consider offers from a large number of potential suppliers (see Section 4.2.4).

Managing the Producer Load Shape

Average load factors for gas LDCs are low. In 1991, residential load factors were 45%. The load factor for all sectors (residential, commercial, industrial, electric utilities) was 67% (Energy Information Administration (EIA) 1993b). In addition, temperature-sensitive loads of firm customers vary greatly from winter to winter, making load factors for planning purposes even lower. Contracting for a low-load-factor load in isolation requires acquisition of wellhead and pipeline capacity that will be poorly utilized. In general, a gas buyer can get better price terms by buying at a high load factor.

LDCs can do several things to improve their buying power with producers despite the fact that many of the end uses or customer classes served by LDCs have low load factors. First, LDCs can diversify demand among different groups of customers before seeking gas supplies: the loads of low-load-factor customers may be combined with interruptible customers or customers that have counter-cyclical loads. For example, firm heating loads can be combined with interruptible loads or with electric generation loads. LDCs can perform this aggregation function or groups of customers can band together before entering into supply contracts. Also, smaller LDCs can benefit by teaming up with other LDCs on the same pipeline to reduce transactions costs and, possibly, improve load factors. Of course, when two different types of customer groups are combined, cost and risk allocation issues need to be considered. For example, if an LDC combines residential and commercial loads with industrial loads, and subsequently must pay a GIC or minimum-take charge because of reduced industrial load due to bypass, there is an unforeseen cost that must be absorbed by either the remaining sales customers, LDC shareholders, or, possibly, the industrial customer who left the system.

Second, the LDC can use storage or peak-shaving facilities. Such facilities are discussed in more detail in Section 4.3.

Third, PUCs and LDCs can develop customer buyback arrangements. Many states already have mandatory curtailment provisions, and the terms *firm* and *interruptible* generally separate the highest priority customers from lower priority customers. In fact, however, customer value of service exists over a wide range and many PUCs are moving to voluntary curtailment provisions. Customers who are interruptible by default are given the option to buy firm or near-firm service if they wish. One way to improve the range of services offered and to improve LDC load shapes is to have LDCs enter into contracts with customers with firm or near-firm rights but be allowed to curtail them in certain periods of high demand. These contract may specify compensation to the customer in return for curtailment. The gas utility improves its load shape as a result, and no party is involuntarily curtailed.

4.2.4 Regulatory Oversight of LDC Supply Portfolios

As the range of gas supply options increases for gas utilities, PUCs may need to re-evaluate their regulatory framework for the review of gas supply portfolios. Because gas supply purchases account for such a large proportion of an LDC's average rate, PUCs have a particular interest in reviewing a utility's gas supply planning and purchase practices. Four general regulatory approaches for reviewing gas supply portfolios are discussed although none are mutually exclusive: (1) reasonableness reviews, (2) portfolio preapproval, (3) incentive mechanisms, and (4) deregulation. Table 4-2 also provides a description of the approaches with respect to key policy attributes.

Reasonableness or Prudence Reviews

Almost every PUC in the U.S. has allowed LDCs to set up a fuel offset or purchased gas adjustment (PGA) account to improve, compared to traditional rate cases, the LDC's ability to recover gas supply costs (Burns et al. 1991). PGAs allow for more frequent revisions of rates to adjust for changes in gas supply costs. Most PGAs allow for "truing up" of forecast and actual costs, which substantially reduces LDCs' risk for recovery of supply costs. In response to this risk shift, many PUCs conduct audits or hold hearings to review the reasonableness of utilities' purchases. If utilities are found to be unreasonable, some portion of the cost of the purchases may be disallowed recovery in rates. The reasonableness review approach has the advantage of allowing PUCs to review

Table 4-2. Approaches for Review of LDC Gas Supply Purchases

Regulatory Approach	Is PUC Oversight Proactive or Reactive?	Ability of Approach to Adapt to Changing Market Conditions:
Reasonableness Review	• Reactive	• Low, unless PUC commits to a high level of staff resources
Preapproval	• Proactive	• Medium (preapproval of specific contracts) • High (preapproval of contract mix only)
Incentive Regulation	• Proactive	• High, until conditions change so much that index is no longer fair
Deregulation	• Oversight is relinquished until PUC decides to re-regulate	• High

utility decisions before ratepayers pay the full bill. Reasonableness reviews reduce an important asymmetry of information that exists between a utility and its regulator. The regulator can never hope to have all the information that the utility has on an ongoing basis. In an *ex post* environment, however, the PUC has enough time to get all the facts it needs to review the reasonableness of a gas utility's supply portfolio. Reasonableness reviews, although generally unpopular, have been effective in catching or preventing large errors made by LDC managers. As PUCs have improved their audit and analysis capabilities, reasonableness reviews have become more comprehensive and have been cited as causing inappropriately risk-averse behavior on the part of LDCs. Some analysts have argued that LDCs, in an environment of intense prudence reviews, begin to purchase gas not to meet the overriding goals of reliability, cost, and cost stability, but rather purchase gas in ways defensible in a reasonableness review (Pocino 1993). Although PUCs can continue to use reasonableness reviews in a post-636 world, the job of reviewing reasonableness will become more complex as the range of utility options increases. LDCs and producer interests are likely to claim that reasonableness reviews in a post-636 world impede LDCs from making the best gas purchases. However, regulators will be reluctant to remove after-the-fact reasonableness reviews because their regulated utilities that have heretofore been protected and many will not have a proven record of operating in competitive gas markets.

An alternative to the reasonableness review approach that is somewhat more forward looking but does not require express preapproval by PUCs is the use of informal meetings between LDCs and regulators to discuss gas procurement decisions in advance. Such processes allow the LDC, the PUC, and PUC staff to exchange information and to understand each party's thoughts and considerations. In such a process, the PUC still retains its rights to conduct reasonableness reviews at a later date. PUCs in California, Illinois, Ohio, and New York have used this approach in the past and, for some states and in some cases, it has helped eliminate contentious reasonableness review proceedings.

Preapproval and Competitive Bidding

An alternative or supplement to reasonableness reviews is the use of regulatory preapproval. Any LDC can consider preapproval as a regulatory approach but PUCs that expect to adopt specific LDC integrated resource plans (see Section 2.5) must decide whether and how far the preapproval of the plan extends into the gas procurement area. In the preapproval approach, an LDC files a procurement plan and, possibly, a set of specific contracts for preapproval. The procurement plan, specific contracts, or both are subjected to hearings and are ultimately approved, approved with modifications, or denied by the PUC. With preapproval, utilities are not subject to the same degree of regulatory risk as is the case with the reasonableness review approach. If the PUC has a preapproval process, then the LDC is held responsible only for the way it executes the plan or the way it responds to new situations not foreseen in the plan. If the utility has preapproval for specific contracts, then it is at risk only for review of the management of those contracts. Utilities can also be at risk if they intentionally misrepresent their supply alternatives in the preapproval process.

Although competitive bidding is not an approach to regulatory review, it can be particularly helpful in facilitating a preapproval process. The use of competitive bidding by an LDC can reduce the PUC's regulatory review dilemma because bidding relies on competition, rather than utility management actions, to find the best possible price for each type of gas supply contract. Bidding, in conjunction with preapproved market shares for short- and long-term contracts, has been proposed by Jaffe and Kalt (1993) as a workable approach to preapproval. Public bidding for spot gas is common, but public bidding for long-term contracts (as envisioned by Jaffe and Kalt) is less common. Even if it were used more frequently by LDCs, bidding would not be simple because many of the desirable attributes of a long-term contract, such as bidder reputation or supply reliability, need to be evaluated along with the bidder's price. Moreover, LDCs may request confidentiality for many of the contract terms, including price terms, which further complicates the process of regulatory preapproval.

Incentive Regulation

Incentive regulation attempts to harmonize the least-cost goals of the ratepayer and the profit motives of the LDC. Incentive regulation often does this by increasing the financial incentive for the utility to reduce its costs, usually by decoupling prices from costs via an external cost index. Because of the financial incentives it offers the utility, incentive regulation usually eliminates the need for retrospective reviews of utility gas purchasing decisions. Sustained or increased oversight of the LDC's service reliability is usually necessary by the PUC to make sure an LDC does not improve financial performance by degrading quality.

There are several ways that incentives can be used as a substitute for traditional regulation of gas LDC procurement decisions. First, PGAs could be eliminated and the gas commodity portion of rates would be set in rate cases. This form of intentional regulatory lag would give utilities an incentive to minimize gas purchase costs between rate cases. Second, PGA mechanisms could be retained, but "true-ups" would occur only for a fixed portion of the utility's purchased gas costs. Thus, the utility would have a financial interest in any changes in purchased gas costs relative to those set in rates. Such a mechanism, in which the utility was at risk for 20% of deviations in the PGA account, has been used in Oregon (Burns et al. 1991). Third, incentives based on indices could be used as benchmarks for setting rates. If a utility's costs are lower than a chosen index, it can keep a portion of the savings. Conversely, if purchased gas costs are higher, ratepayers are at risk for only a portion of the shortfall (Harunuzzaman et al. 1991). Such a mechanism has been proposed by economists for some time and has recently been adopted by the California PUC for San Diego Gas and Electric Co. (California Public Utilities Commission (CPUC) 1993). The challenge with indexed-based incentive mechanisms is in developing the benchmark formula. The majority of publicly-available gas prices are for spot transactions and many LDCs would balk at being held to a spot-only price standard when they are trying to achieve a high degree of reliability. However, there are ways to address this problem. For example, it is possible to set the index as a *function* of spot prices rather than exactly equal to spot prices. It is also possible to use the gas costs of similarly situated utilities in the index formula.

Deregulation of Gas Procurement

Another approach to regulatory oversight of LDC procurement activities is to rely on competition via deregulation. Deregulation reduces the need for regulatory oversight of LDC's gas purchases as fewer customers rely on the LDC for procurement services. For customers who purchase gas from the LDC but have the *option* of transporting their own gas, it may make little sense to have a PGA or to review the LDC's procurement decisions. Instead, the gas utility could be given the option to quickly change prices with no PUC approval. The gas utility would have the discipline of the marketplace to keep its prices low and service reliability high.

It is generally acknowledged that there are limits to how far customer-owned transportation will extend. Thus, there are limits on how far deregulation of LDC procurement activities can go before the risk of LDC's abusing their monopoly power becomes large. Recent evidence indicates, however, that transport-only service may be feasible for more customers than was once believed. The term core customers was first coined to identify customers who want vertically integrated services from the LDC. The definition of core customers has required revisions in recent years as many smaller industrial and larger commercial customers have become transport-only customers via aggregation programs. Even smaller customers, such as schools, churches, and fast food restaurants have participated in self-procurement programs in California and in Toronto, Canada (Lemon 1993). If such aggregation programs become sustainable, PUCs may have reason to further diminish their regulatory oversight of LDC procurement practices.

4.3 Planning for the Expansion of Capacity

4.3.1 Overview

This section focuses on the capacity expansion process, which, in this discussion, is defined as the process of choosing facilities that deliver gas from the wellhead or pipeline intake to the LDC's local transmission and distribution (LT&D) system. LT&D planning, while an important part of an LDC's overall planning, is not discussed because of space constraints in this chapter. Most facilities considered in the capacity planning process are expensive and long-lived; thus, attention to resource planning is warranted. This section describes the major capacity options and discusses simple and complex planning methods. Issues that are highlighted include: methods of screening resource options, consideration of storage resources as an alternative to pipeline supply, treatment of bypass in capacity planning, and the "build-versus-buy" problem.

Table 4-3. Overview of Gas Capacity Options

Option	Description/Features
Pipeline Firm Transportation	Firm transportation service is now sold on an unbundled basis. Firm transportation may be acquired when a sales customer converts contract demand quantities to firm transportation capacity, through the reservation of existing or new capacity held by the pipeline, or through short- or long-term release contracts.
Pipeline "No Notice" Service	For pipeline customers who took bundled city-gate service as of May 18, 1992, pipelines will be required to provide "no-notice" service as part of tariffs in compliance with FERC Order 636. No-notice service is technically a transportation service—customers can take gas at their delivery point in excess of their scheduled quantity without advance notice up to the MDQ in their service agreement with the pipeline. Customers are ultimately responsible for arranging the gas supply.
Pipeline Interruptible Transportation	Interruptible transportation does not provide any firm capacity.
Storage	Storage is used to balance the system on a daily basis, provide peak-season capacity, and provide capacity on an extreme peak day. Because of volume constraints, storage is not appropriate as a year-round source of capacity. Availability of underground storage is limited to certain geographical areas.
Propane-Air	Propane-air systems are smaller systems built near load centers used primarily to meet peak loads. Propane air systems are primarily limited to areas where underground storage is unavailable.
Liquified Natural Gas (LNG)	LNG provides a similar function to storage in areas that do not have natural storage resources. LNG facilities built in conjunction with marine terminals can use imported LNG supplies.
Customer Buyback	LDCs can make or facilitate arrangements via prearranged contracts or tariffs to buy gas and/or gas capacity rights from certain firm customers to meet the needs of other firm customers during periods of critical demand.

4.3.2 Options for Providing Gas Deliverability

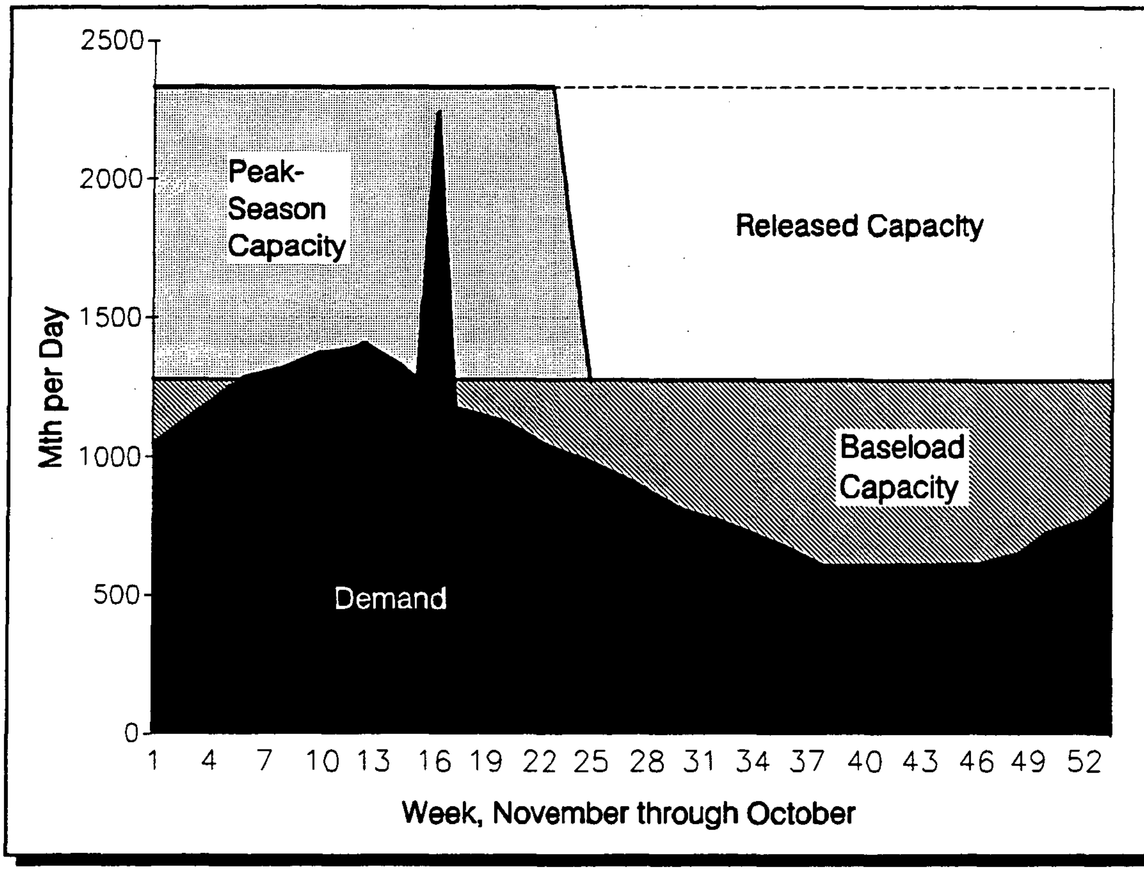
Gas LDCs can provide in several ways for capacity within their service territories (see Table 4-3). Interstate pipeline capacity and storage capacity are the two most common sources of capacity, and propane-air and liquified natural gas (LNG) systems have also provided capacity in certain areas. LDCs that have supply resources in their state also rely on intrastate pipeline capacity.

New Ways to Contract for Capacity: Capacity Release and Buyback Programs

Although the physical means of providing capacity has not changed much in recent years, the ways that LDCs can contract for the capacity have changed. A vivid example of a new way of contracting for capacity is the option of acquiring it on a secondary market through the capacity release program allowed for in FERC Order 636. All pipelines are required to set up a capacity release system so that firm customers (releasing shippers) may sell (release) their capacity rights in a secondary market. The program supersedes earlier attempts at creating secondary markets via brokering and buy-sell programs. Unlike these earlier programs, all secondary transactions are controlled by the interstate pipeline and are subject to FERC oversight. A firm capacity holder may release its capacity for any term up to the term of its service agreement with its pipeline. The releasing shipper may come to the pipeline with a prearranged deal or may publicly solicit bids via the pipeline's electronic bulletin board. There is considerable flexibility in how the release contract may be written so long as the terms of the release are nondiscriminatory; i.e., other prospective shippers have a fair opportunity to bid on the same release contract. Release contracts will go to the highest bidder subject to the FERC-approved maximum pipeline rate for firm service. Also, prospective shippers in prearranged contracts have the right of first refusal to match any competing, higher bids. The releasing shipper is still liable for the full reservation charge and any reservation surcharges associated with its release contract should the buying shipper fail to pay on its release contract. Thus, the creditworthiness of any prospective shipper is an important factor from the point of view of the releasing shipper. As a result, many pipelines are attempting to establish requirements for determining the creditworthiness of prospective shippers.

From the perspective of resource planning, the advent of a secondary market for firm transportation capacity allows for planning flexibility. LDC planners can now assign a value to an existing capacity resource rather than simply treat it as a sunk cost for the life of the service agreement associated with the resource. Planners can make forecasts of the market price of the release capacity and consider alternative capacity options, such as storage, that may be more economical than holding onto existing pipeline capacity. Given the move to straight-fixed variable (SFV) pipeline rate design, such options are being seriously considered by LDCs. Figure 4-2 provides an example of how one LDC, Washington Water Power Co., expects to release its firm capacity on a seasonal basis. The biggest difficulty in considering capacity release as a resource option is that it may be very difficult to forecast the price of released capacity. As long as it is likely that

Figure 4-2. Potential Releasable Capacity in a Year: Washington Water Power Co.



there is some value to the pipeline capacity in a release market, however, LDCs should evaluate the need for the capacity and consider whether there are options cheaper than pipeline capacity that provide the equivalent amount of capacity.

Another contractual option for the acquisition of capacity is customer buyback contracts. Under buyback programs, LDCs facilitate arrangements in which certain firm customers acquire the right to buy back capacity and supply from other firm customers during times of peak demand. Buyback programs have been developed in California where the investor-owned LDCs will, under extreme conditions, divert sales gas and transportation gas (and the capacity that goes along with it) from firm noncore customers to firm core customers (California Public Utilities Commission (CPUC) 1991; California Public Utilities Commission (CPUC) 1992c).

4.3.3 Methods for Screening Resource Options

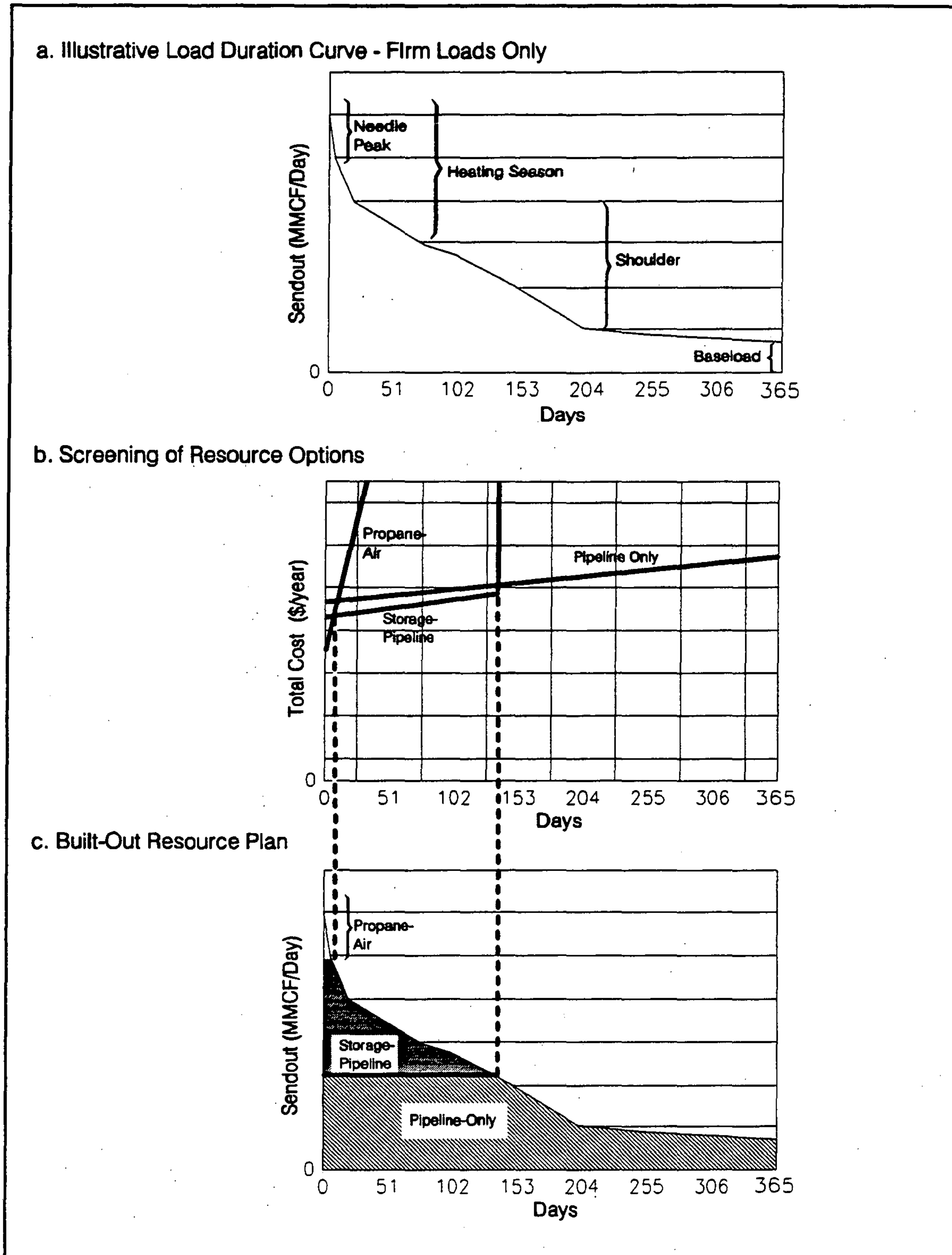
Gas utility supply resources have fixed- and variable-cost components. The optimal mix of resources is often found by trading off the fixed charges against the variable costs. The optimal resource for a particular customer or set of customers depends on load factor or degree of utilization. Many LDCs will either formally or informally conduct a screening analysis of supply-side resources using supply-side cost data and an LDC *load duration curve* (see Figure 4-3 for an example).

A load duration curve for the firm loads of a hypothetical LDC is shown in Figure 4-3a. Daily loads (or sendout) are sorted from highest to lowest along the X-axis. Certain loads are constant year-round and are referred to as base load. There is also a peak or needle peak that represents the highest demand conditions. For a gas utility with temperature-sensitive loads, the needle peak is based on design peak-day conditions rather than expected (average) peak-day conditions. Winter season and shoulder loads reflect temperature-sensitive loads; other variations in loads that appear in the shoulder area are caused by weekday-weekend demand fluctuations.

It is possible to make an initial assessment of the optimal mix of resources using screening curves for various resources such as propane-air; storage reservoirs with associated injection, withdrawal, and pipeline capacity; and pipeline-only capacity (Stoll et al. 1989) (see Figure 4-3b).[5] Using cost data normalized to one unit of capacity ($/MMcf) and estimates of associated commodity costs, Figure 4-3b shows the total annual cost of operating one unit of capacity of the different resource options at different load factors. The annual fixed charge is indicated for each resource at the point where its line crosses the Y axis. Where the curves of two resources cross on Figure 4-3b gives an indication of the optimal size and load factor for a particular resource. Because storage resources need to be filled, a particular storage-pipeline combination has a maximum load factor above which it cannot be used. Thus, the screening line for the storage-pipeline option has a cost "kink" at its maximum capacity factor. In this stylized example, the propane-air plant is not optimal to run more than nine days per year. The storage-pipeline resource is cheaper to run than a pipeline-only resource but only up to the point of its maximum capacity, approximately 85 days per year. For the remainder of the year, it is optimal to use pipeline-only resources. Figure 4-3c shows the dispatch of firm loads based on the screening curve analysis.

[5] Although not shown in the example, an existing resource may be screened against other alternatives by setting the Y-axis intercept at the resale value of the resource. For example, the resale value of existing pipeline capacity may be set at its estimated release price. Care must be taken to make sure the optimal size determined by the screening curve mix is feasible for the existing resource.

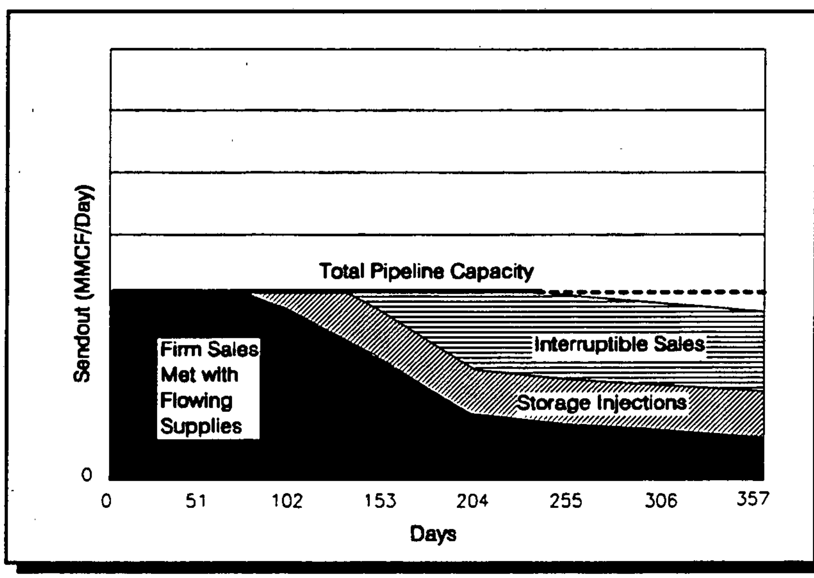
Figure 4-3. Screening Curve Analysis for 3 Hypothetical Resource Options



For an LDC, the built-out load duration curve shown in Figure 4-3c shows how demands of firm customers are supplied on the LDC's system. Another useful representation of the LDC's load duration curve is the one seen by its gas suppliers. Such a load duration does not include loads met by propane-air and incorporates the levelizing effects of storage resources. Figure 4-4 shows the producer load duration curve that corresponds to the example presented in Figure 4-3. At this point it is possible to ascertain the level of service that can be provided to interruptible sales customers. For the stylized example presented, Figure 4-4 indicates a high degree of curtailment to interruptible customers. Many LDCs may chose to acquire additional capacity to serve interruptible customers.[6] If they do so, however, the cost of such additional resources will need to be recovered from interruptible customers because the screening curve analysis provides only an estimate of the least-cost way of meeting firm customer needs.

The stylized screening analysis presented in Figure 4-3 and Figure 4-4 was intentionally designed to consider a limited set of resources. Table 4-4 shows a somewhat broader set of resources and indicates the portion of the load duration curve for which they are most likely to be appropriate.

Figure 4-4. "Upstream" or "Producer" Load Duration Curve



4.3.4 Detailed Methods and Issues in Expansion Planning

Screening analyses are useful because they highlight the fixed-variable cost tradeoffs that are at the heart of many resource planning decisions. Moreover, by estimating an optimal set of resources for firm customers, the analysis provides an estimate of the default level of reliability for interruptible customers. To make the analysis relatively simple,

[6] With the advent of unbundled pipeline services, interruptible customers could also improve their level of reliability by acquiring upstream capacity resources on their own.

Table 4-4. Typical Screening of Gas System Capacity Options

Option	Relative Fixed Costs	Appropriateness for the Following Load Types: Base	Shoulder	Heating	Peak
1. Pipeline Firm Transportation	H	Y	Y	Maybe	Maybe
2. Pipeline No-Notice Firm Transportation	L	N	N	N	Yes
3. Pipeline Interruptible	L	Maybe	Maybe	Maybe	No
4a. Pipeline Storage	M	N	N	Y	Maybe
4b. Building Storage	M	N	N	Maybe	Y
5. Propane-Air	L	N	N	N	Y
6. LNG Plant	M	N	N	N	Y
7. Customer Buyback	L	N	N	N	Y

Notes: L, M, & H represent low, medium, and high, respectively.
Source: Adapted from Newman and Kaul (1992)

however, certain complexities are suppressed in the screening curve methodology:

- Transport-only demand is an important component of many LDCs' throughput. Even though transport customers can be incorporated into a screening curve analysis, the LDC does not control the commodity supplies chosen by the transport-only customer and it may have little control over the upstream capacity that is contracted for by the transport-only customers. Thus, an LDC's planning for transport-only customers will be predominantly limited to forecasting transport-only customer choices and estimating the cost implications of these choices on the LDC's system.

- The load duration curve suppresses significant year-to-year variation in loads that are common on LDC systems. In any particular year, the capacity utilization of a particular resource may be much higher or lower than the levels shown in the screening curve method. Similarly, the level of service that can be provided to interruptible customers can show significant year-to-year variation.

- Load duration curves suppress the chronological variation in loads. Such variation may be important because the costs of some supplies vary by season and some resources can only change or sustain their output up to a limit. For example, storage resources may be able to run at peak capacity only for a matter of days before inventory levels fall, causing pressures and withdrawal capacity to drop.

- Optimal quantities of resources estimated by the screening analysis may be infeasible. Many resources come in fixed sizes and these constraints need to be considered.

- Differing reliability of resources needs to be considered.

- Screening analyses typically do not explicitly address uncertainties associated with cost and availability. A complete analysis would attempt to quantify risks and uncertainties in addition to quantifying expected costs.

More comprehensive and detailed methods are required to handle these additional complexities. LDCs typically perform more detailed analyses using one of two general modeling techniques: (1) iterative simulations and (2) optimization models.

Iterative Simulations

In the iterative simulation approach, the LDC uses rules of thumb or carefully chosen assumptions to decide which resource to acquire next. Using an initial set of assumptions an initial resource plan is simulated for a multi-year period. Although a computer simulation model for annual dispatch may be used, the planner rather than the model articulates the LDC's capacity configuration. For many LDCs, the initial plan is built out using existing capacity resources and incremental pipeline capacity. From the initial case, alternatives to the resource plan are tested. For example, a storage project may be tested and compared to incremental pipeline capacity. As another example, an LDC may consider releasing or relinquishing capacity and letting transport-only customers acquire capacity on their own. Alternative plans are simulated until a balance is achieved among particular indicators such as: total present value cost, curtailments, and the quantity of fixed-cost obligations entered into. Although this method may seem ad hoc or imprecise, it has advantages. For many LDCs, total growth in demand is not large, and many existing resources are effectively sunk costs. Thus, the number of resource option combinations for meeting demand in the future is relatively small and can be articulated without the aid of a detailed computer model. In addition, there may be considerable uncertainty associated with many of the cost estimates, so the possible benefit of fine tuning relative shares of the resource options may be small compared to the associated uncertainty of the resource plan's total cost.

Methods Using Optimization Models

Optimization models are detailed computer models that attempt to compute a least-cost resource plan considering the costs of resources, customer demand, reliability criteria, and other relevant constraints. The goal of the process is the same as for the iterative simulations method except that a computer model is used to estimate the LDC's capacity configuration rather than having the capacity configuration set iteratively by the planner. Optimization models may use simulation (internal to the model), linear programming, or other optimization techniques to find a resource plan (solution) that best meets the objective function. The objective function is usually specified as the total present value cost of a resource plan subject to a reliability constraint (see Section 3.8 for a list of commercially available optimization models).

4.3.5 Issues in Gas Capacity Planning

In this section, several of the most important resource planning issues for LDCs are discussed to provide insights into why more sophisticated LDC planning methods are often needed and why actual plans are often revised frequently.

Storage

LDCs that, in a pre-636 world, received storage as part of bundled pipeline sales service will now have to buy it on an unbundled basis along with pipeline capacity and gas supply.[7] Thus, LDCs and direct consumers of the gas pipeline system must now reconsider the purpose of existing storage and consider investments in new types of storage. Storage has four general functions for LDCs:

- Daily balancing: LDCs move gas in and out of storage on an hourly and daily basis to compensate for regular imbalances in supply and demand.

- Seasonal balancing: LDCs increase load factors and minimize upstream pipeline capacity requirements by acquiring storage to meet significant

[7] Pipelines will still retain some storage facilities to provide day-to-day balancing of pipeline transportation services.

portions of peak-season loads. Having storage is usually more economic than relying on pipeline capacity alone.

- Peak-day protection: During the months most likely to include an extreme peak day, storage withdrawal capability is kept at a maximum. Providing this capability usually requires a certain amount of extra inventory on hand to keep field pressures high. Once the possibility of a peak day has diminished, the gas inventory may be used for other purposes.

- Economic benefits: Storage resources can be used for economic benefits in supply markets. Inexpensive gas supplies generally available in off-peak periods can be stored and used in times of higher prices. Further, firm gas contracts can cost less if they can include high take provisions that are facilitated by storage facilities.

Different types of storage systems have different strengths and weaknesses in terms of being able to provide the four general functions described above (see Table 4-5) (Duann et al. 1990). Underground depleted reservoirs and storage from aquifers are generally the cheapest types of reservoirs to develop. Gas in and out of these reservoirs flows slowly, so if high deliverability is desired, many withdrawal wells must be developed or a large inventory of gas must be kept in the reservoir. Salt domes are more expensive to develop than these other two options but offer fast withdrawal capability, which makes them well suited for peaking, daily balancing and shorter-term cycling. Pipeline line pack is a byproduct of the pipeline system. Its inventory size is limited but is often an important resource for daily balancing. LNG systems provide another storage option; they are expensive but are not geographically limited like underground reservoirs. Thus, they may be a viable storage resource where other options are unavailable.

No definitive conclusions may be drawn when comparing the types of storage resources to storage functions because the cost and availability of storage varies by region, and every LDC's load shape is different. The concept of "layering" storage, where LDCs use more than one kind of storage resource to meet different storage functions, makes sense for many LDCs (Bickle 1993). For example, demand variations that require frequent storage cycling may be best levelized using storage provided in salt domes while steady winter season demand can be best supplied by depleted oil and gas reservoirs. An LDC also will need to consider the location of the storage resource. Storage close to an LDC's loads provides extra reliability benefits and decreases the cost of pipeline capacity. Storage located close to production fields or near major pipeline interconnections is more likely to exist already, or, if new, is likely to be developed by multiple sponsors. Therefore, storage in these locations is likely to be more flexible and/or come at a lower cost. Although not near LDC load centers, storage near production areas or market centers can provide many functions, including the economic optimization of supply

Table 4-5. Types of Storage Resources by Type of Reservoir Facility

Type of Storage	Features
Depleted Oil & Gas Reservoirs	Inexpensive to develop reservoir, limited to certain geographic areas. Reservoir of permeable rock requires many wells or a large inventory to provide deliverability
Underground Aquifers	Same as above; may be available in areas where depleted reservoirs are not. Viability of aquifers as gas reservoirs requires extensive testing.
Mined underground reservoirs (including salt domes)	Compared to alternatives above, more expensive to develop. Usually provides a high degree of cycling capability.
Pipeline line pack	Amount of available line pack generally limited; depends on pipeline configuration.
LNG	Can be built in a wide range of areas and, if built with a marine terminal, can take supplies from overseas. More costly to develop, higher running costs, safety considerations.

Source: Duann et al. (1990)

contracts, provided that sufficient downstream capacity is contracted for by the LDC.[8]

Scope of the Resource Plan

With the option of releasing or relinquishing capacity, LDCs have gained flexibility in the way they contract for pipeline capacity. Such flexibility, however, raises issues of scope for the planner. For many LDCs, the most likely buyers of released pipeline capacity will be large customers of the LDC. Even if large customers of the LDC do not bypass the LDC's system within its service territory, they may choose to contract for their upstream capacity rights independent of the LDC. Although LDCs, PUCs, and customers should certainly evaluate the potential benefits of such capacity transfers, these

[8] A market center is an area where many interstate pipelines meet that allows gas purchasers to choose among multiple suppliers.

transfers may have little impact on the total cost of gas facilities in an LDC service territory because these transfers represents a cost shift rather than a reduction in total facility costs.

Similarly, scope issues arise when an LDC considers terminating, or reducing the size of a service agreement with a pipeline. If there is no market for the unloaded capacity, it will end up as a stranded investment and may not represent a cost savings from a regional or societal perspective even though it may be pursued by the LDC to lower its costs. Further, under FERC cost-of-service ratemaking, LDCs that unload capacity that becomes stranded may face higher future rates when the pipeline attempts to recover its stranded costs from remaining customers (including the LDC) in a future rate case.

Ownership of Capacity: Buy versus Build

Most of the resources that provide deliverability are long lived. LDCs make long-term cost commitments when they (1) build long-lived facilities that have little resale value or (2) enter into a long-term agreement to purchase a resource from an independent provider. Resources provided by independent suppliers with few long-term commitments may not be "least-cost" in a static analysis but may be valuable from a risk management perspective because they do not obligate the LDC to purchase the resource if conditions change. For resources built near load center, there may be no alternatives to having the LDC construct the resource or commit to it on a long-term basis. Pipeline and storage resource options, however, will be more fungible. Existing pipeline capacity may be released or relinquished; new or existing pipeline capacity may be purchased as part of a bundled product from a producer or marketer; and storage resources constructed near production fields or market centers may be built as joint ventures and sold in small portions for limited terms. Prices for use of these facilities will be set more often by the marketplace than by the regulator. LDCs need to weigh the flexibility of going to rented resources against cost and reliability considerations.

Incorporating Potential Bypass into the Resource Planning Process

Sensitivity to potential bypass is an important consideration in utility resource planning. In the past, bypass was limited to large customers who could burn alternative fuels. This bypass option still exists but is becoming limited in certain parts of the country because of more stringent air quality regulations. Direct connections between customers and interstate pipelines are another form of bypass. FERC Order 636 and other FERC decisions have increased bypass pressures for many LDCs. FERC's adoption of SFV rate design, which effectively lowers rates to customers with high load factors, may make bypass attractive to these customers to the extent the changes to SFV are not reflected in the LDC's transportation rates.[9] FERC Order 636 also allows for the pass-through of transition costs to LDCs and their customers. Via bypass, industrial customers may be able to avoid paying some of the Order 636-related transition costs that they will pay if they stay on the LDC's system.[10] As customers bypass the LDC's system, there is the potential for stranded investment on the LDC system. Depending on how it is allocated, stranded investment can raise the rates of remaining customers and can induce further LDC bypass.

Bypass considerations do not fundamentally alter the planning process. However, bypass increases uncertainty with respect to sales, throughput, and cost recovery. LDCs should consider the impacts of higher-than-expected bypass before entering into any new, long-term resource commitments. Also, the rate impacts of any resource plan on rate-sensitive classes has to be carefully considered.

4.4 Reliability and Contingency Planning

4.4.1 Overview and Conceptual Framework

As is readily apparent in the preceding sections, the reliability of gas supply and capacity options is an important quality to the LDC or customer. The reliability that is ultimately provided to a customer depends on multiple supply- and demand-side considerations; because of this, IRP for gas LDCs should explicitly include a *reliability planning* component. A major purpose of reliability planning is to strike a balance between reliable service and reasonable cost. Because demand, supply cost, and supply availability are uncertain, it is difficult to balance reliability and cost objectives. For a typical gas system, it is relatively inexpensive to meet average gas demands. However, for firm customers who depend on supplies in cold weather when demand is high, such a system would be unsatisfactory. At the other extreme, it is possible to build gas systems to meet all foreseeable demands; such a system would be reliable but expensive. For example,

[9] Many LDCs will allow industrial customers to contract directly with the upstream pipeline for transportation services, thus allowing the benefits of SFV to flow to the customer.

[10] If a customer bypasses an LDC and reserves firm transportation service from the interstate pipeline that serves the LDC, it will be required to pay a transition cost surcharge on its reservation charge just like the LDC. Bypass customers may be able to pay lower transition costs, however, if (1) the LDC, through its cost allocation process, allocates more transition costs to the bypass customer than it would pay by directly contracting with the pipeline, (2) the bypass customer purchases only interruptible transportation service which receives a lower transition cost allocation under the FERC's rules, or (3) the bypass customer buys released capacity at a discount or transportation service with a different pipeline that has no, or lower, transition costs.

a 7% reserve margin on pipeline capacity can add 1% to the average rates of a typical LDC.[11]

Contingency planning is the process of setting up plans or rules that respond to events that can cause curtailments. Whereas reliability planning focuses on determining the appropriate quantities of long-term resources to provide adequate services, contingency plans focus on short-term actions that can mitigate a curtailment in response to an uncommon or unforeseen event. Contingency planning may be seen as a way to maximize the reliability of a system given a fixed set of supply and capacity resources, especially for firm customers.

Reliability is a relatively precise concept: it is the probability that demand will exceed supply in a given period (Kahn 1988). Probabilistic methods are necessary to compute reliability because both demand and supply exhibit random variation. The term Loss of Load Probability (LOLP) has been developed for measuring the reliability of electric systems and the term Loss of Load Risk (LOLR) has been used to quantify reliability of gas systems (Hiebert et al. 1992). Typically, reliability for gas systems is described in terms of actual or expected *curtailments*, which are the therms demanded but not served in a given period. Reliability can be measured historically or estimated for a future period. If it is measured historically, several years of data should be used because events in one year may not be representative of a system's true reliability.

An important component of reliability planning is establishing an appropriate reliability target or set of targets. All utility systems have a point at which adding additional facilities costs more than they are worth in providing reliability. In gas utility reliability planning, targets may be set based on standard industry practice or by performing a benefit-cost study that tries to find the optimal level of reliability.

A comparison of reliability planning in the gas and electric utility industries helps to illustrate the reliability problem faced by gas system planners. LOLP, or the associated criterion called expected unserved energy (EUE), is regularly computed by electric utility planners. Uncertainty in demand and supply can be characterized relatively precisely in that industry. There are reasonably good standards for identifying appropriate reliability targets and ongoing research on value of service is improving the accuracy of reliability targets. In comparison, the quantitative computation of reliability, especially forecasted reliability, for gas systems is difficult. Demand is much more random for gas systems than for electric systems. Gas supply resources also have random availabilities, but the distribution of those availabilities is not well understood. Actual physical failures of gas

[11] The example assumes an LDC with a 50% load factor, an average retail rate of $0.505/therm, and an avoidable pipeline reservation charge of $120 per year per Dth/day.

Table 4-6. Supply-Side Risks

I. Physical

- Wellhead or storage withdrawal:
  - -blowout
  - -freeze up
  - -damage caused by hurricane, tornado, or flood
  - -ground water intrusion

- LNG
  - -explosion
  - -condenser equipment failure
  - -electrical power failure

- Transmission, Distribution, or Storage Injection
  - -explosion
  - -accidental puncture of pipe
  - -vandalism

II. Contractual

- Producer/marketer nonperformance because of bankruptcy or other financial problems
- Buyer/seller price disputes that lead to nonperformance
- Gas supply and/or capacity diversion to another customer because of ill-defined interstate transportation rights
- Uncompensated diversion of storage gas by an adjacent well
- Gas supply diversion to another customer who is willing to pay more

production, transportation, storage, and distribution components appear small when compared to failure rates of thermal electric generation units. The lack of vertical integration, however, makes it difficult to characterize supply uncertainty precisely. Data on supply-side outages are not disseminated as widely in the gas industry as in the electric industry and, because gas LDCs do not directly control upstream gas supply and delivery facilities, there is an added contractual risk that resources will become unavailable even though the risk of physical failure is small (see Table 4-6). In addition, outage probabilities for electric utilities are usually computed assuming independence; in contrast, many of the risks faced by natural gas systems are correlated to weather and are, thus, dependent rather than independent. Finally, although both electric and gas customers value service over a wide range, gas systems are often faced with two groups of customers with very different reliability needs: residential and small commercial customers who cannot tolerate a loss of service, especially in cold climates, and large commercial, industrial, and electric generation customers who are often willing to accept curtailments of significant duration in return for competitive prices.

4.4.2 Reliability Planning in Practice

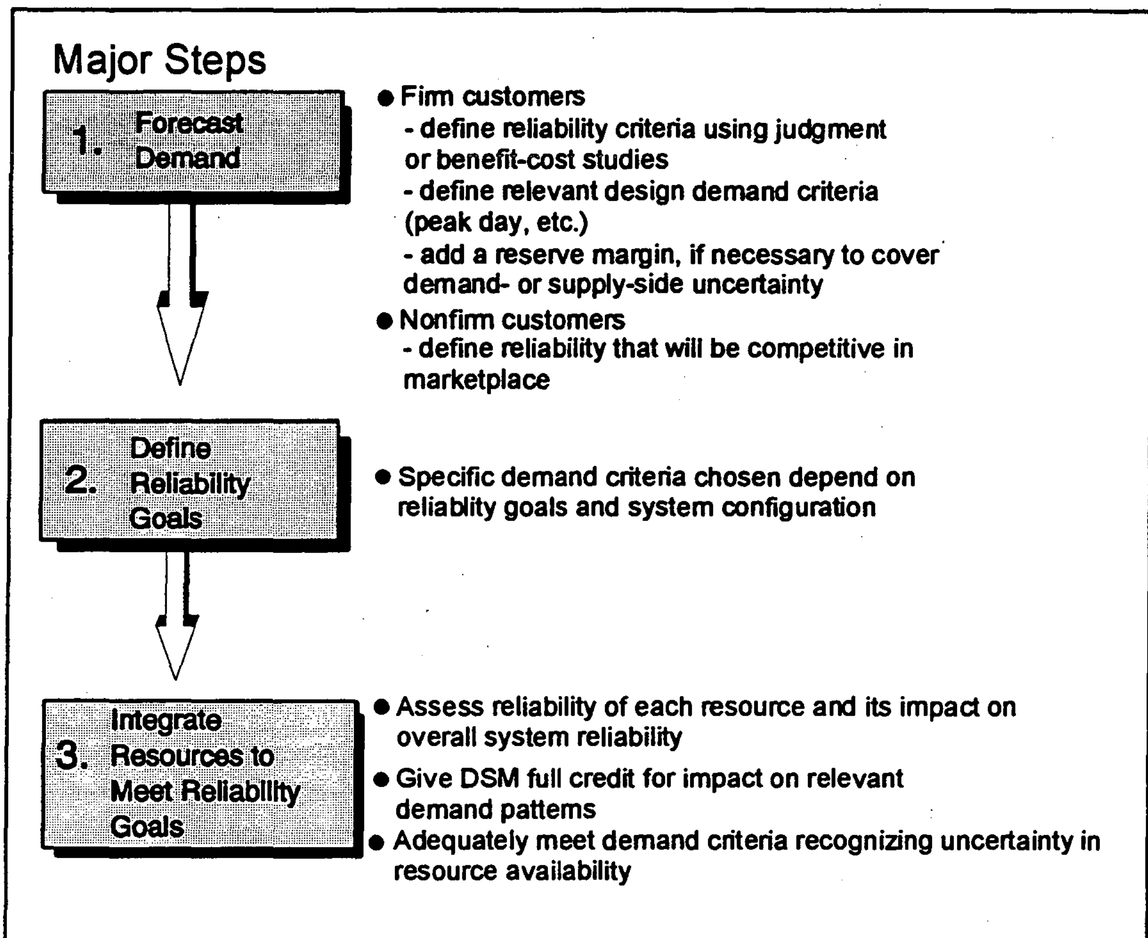
Although the conceptual framework for assessing reliability is similar in the electric and gas industries, gas system reliability planning has historically been based more on prescriptive rules than on detailed study. When gas LDCs define a peak day for firm demand, they typically incorporate extreme weather conditions for their service territories.[12] Sometimes an additional *reserve margin* is included to account for uncertainty in the peak-day demand estimate and uncertainty in supply. Reserve margins are often expressed as percentages of the design peak-day demand.[13] The design day criteria and any reserve margin are usually determined conservatively and typically involve judgment. In practice LDCs—especially LDCs in cold climates—set the design day high enough to meet the demands of essential-needs customers under *any* foreseeable weather conditions. With the peak-day target set for each year of the resource plan, LDCs assess the reliability of each supply and capacity resource. Often this assessment is qualitative rather than quantitative. The relative reliabilities of spot- and long-term supplies has become a major issue as a result of such reliability assessments (see Section 4.2). In the traditional reliability planning process, the reliability provided to interruptible customers is not explicitly determined. Instead, they are served at the "default" reliability that is available after firm loads have been planned for.

Gas system reliability planning will likely evolve under IRP and in response to ongoing gas industry restructuring. A three-step process for incorporating reliability into gas IRP processes is shown in Figure 4-5. Increased competition will require additional focus on the appropriate reliability standard for all LDC customers (see step one). Competition will be a double-edged sword for many LDCs. To retain load, they will need to focus more on the reliability provided to customers with competitive alternatives including customers previously considered interruptible. Building of expensive facilities to provide reliability will, however, be limited by price competition from alternative fuels and bypass alternatives. Greater use of benefit-cost studies to determine LDC-specific reliability standards is likely to become more common (see Exhibit 4-1). In the absence

[12] For many gas LDCs, reliability targets other than peak day are important. For example, systems with large storage resources may define reliability targets in terms of cold-year demands or cold-year, winter-season demands as well as peak-day demands.

[13] The term *reserve margin* is defined differently in the electric and gas industries. In the electric utility industry, reserve margin is a percentage of the expected annual peak-hour demand. In the natural gas industry, design-day peak demand is used in the denominator.

Figure 4-5. Incorporating Reliability into the Gas IRP Process



Source: Adapted from Jensen (1992)

of detailed benefit-cost studies, LDC should use judgment to determine an appropriate reliability standard and attempt to meet it by evaluating the reliability of each resource option and its impact on overall LDC system reliability (see steps two and three). As can also be seen from the third step of Figure 4-5, demand-side management (DSM) resources can modify peak-day demands, and the avoided costs used to evaluate DSM resources should include the full value that DSM resources provide on a peak day, including any reserve margin benefit. Like supply-side resources, DSM resources have uncertain availabilities, and this uncertainty should be incorporated into the reliability planning process.

Although the advent of IRP and other changes in the industry indicates that LDCs need sophisticated reliability assessments, few deviations from standard utility practice can be

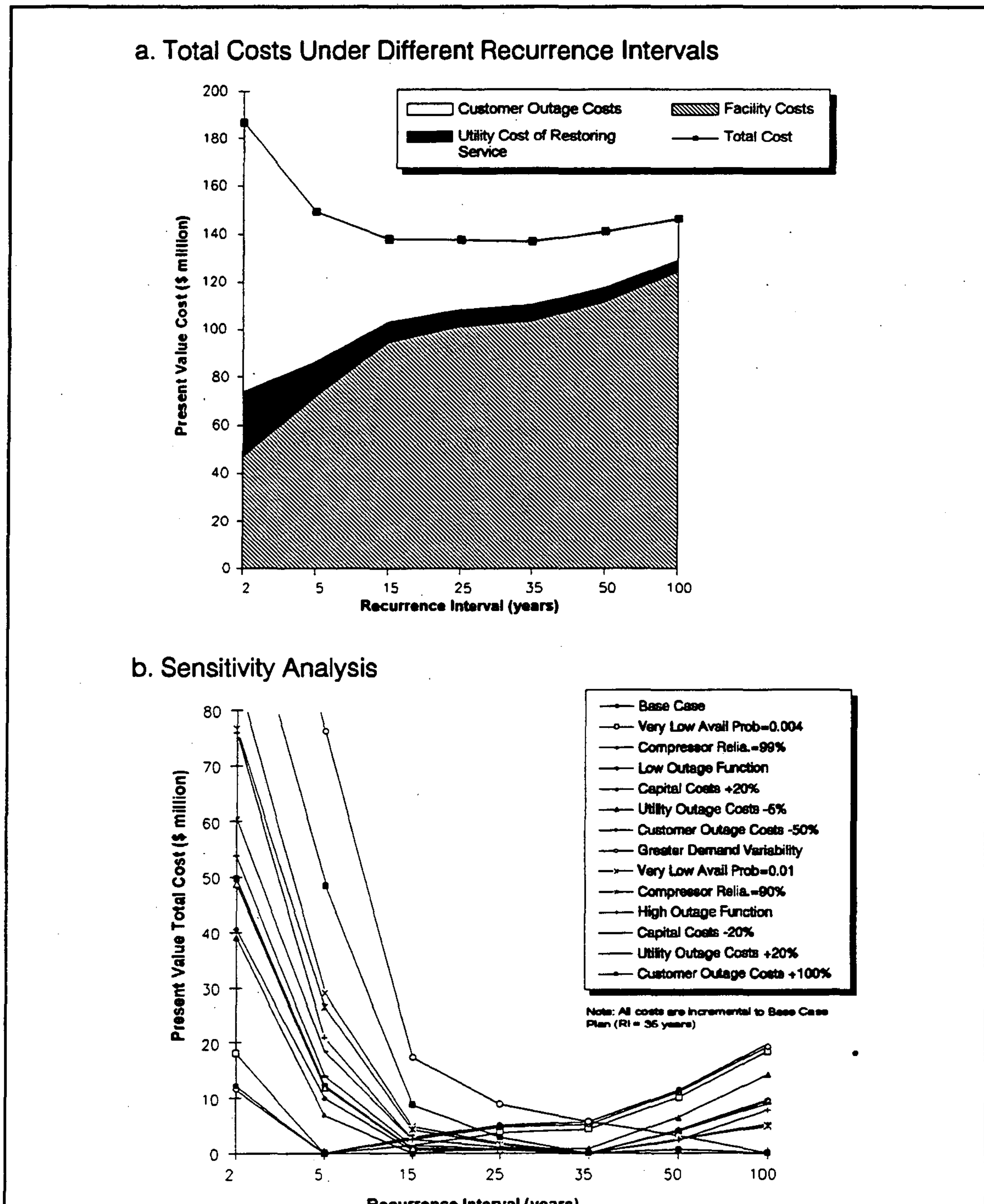
Exhibit 4-1. Use of Benefit-Cost Studies in Assessing Reliability Targets

In 1987, gas system planners at San Diego Gas and Electric Co. (SDG&E) conducted a benefit-cost study to determine its gas system reliability target (Penny and Smith 1987). SDG&E computed the cost of building systems that provide different levels of reliability. Reliability was assessed in terms of a *recurrence interval* (RI) which is the average number of years between curtailments. At each level of reliability three kinds of costs were assessed: (1) the relatively certain cost of constructing facilities, (2) the expected cost of having the utility restore service after curtailments (e.g., relighting pilot lights), and (3) the customers' costs of experiencing a curtailment. An optimal level of reliability is one that minimizes these three costs. The study considered uncertainty on both the demand and supply side when computing total costs at a given RI. Figure 4-6a shows the results of SDG&E's study. Optimal reliability is found at an RI somewhere between 15 and 35 years. SDG&E recommended a 35-year RI because the risk of outcomes with very high outage costs was much less than with a 15-year RI. The 35-year RI recommended in the study was eventually used in the resource planning studies filed as part of the California PUC's long-run marginal cost proceeding (California Public Utilities Commission (CPUC), 1992a).

The SDG&E study is a good example of incorporating uncertainty and risk management into the resource planning process. Its base-case study is an example of probabilistic analysis using a Monte Carlo approach. SDG&E acknowledged that many of the assumptions treated deterministically in the base-case study were uncertain. To address this, SDG&E ran 13 sensitivity cases in which key inputs were varied. New total cost curves were computed for each case and compared to the base case. The results of the sensitivity cases are shown in Figure 4-6b. Under the assumption that the set of sensitivity cases is fairly representative of all possible contingencies and that each case has a similar probability of occurrence, it is possible to look at the trough in Figure 4-6b (RI = approximately 35 years) as being the most *robust* RI with respect to uncertainty.

cited. The recurrence interval study conducted by SDG&E is a good example of a benefit-cost study (see Exhibit 4-1). A modest extension of the reserve margin concept, known as the Deliverability Assurance Ratio (DAR), was developed by the Illinois Department of Energy and Natural Resources for its review of gas IRP plans filed by Illinois LDCs (Hemphill 1989; Jensen 1992). Computations of LOLR have been made in the literature but have not been filed in any regulatory proceedings by an LDC (Hiebert et al. 1992). During 1993, the Indiana Utility Regulatory Commission directed Indiana Gas Co. to re-evaluate its method for setting reserve margins. This study may provide insights into improved reliability planning methods.

Figure 4-6. Using Benefit-Cost Studies to Determine Reliability Planning Targets: SDG&E



Source: Perry and Smith 1987

4.4.3 Contingency Planning

Gas LDCs can enhance reliability and the value of service provided to its customers by preparing to quickly respond to contingencies that threaten service. Contingency plans can include procedures that (1) maximize the use of alternative fuels and alternative suppliers, (2) improve operational flexibility to minimize the impact of both upstream and downstream capacity constraints, (3) can initiate a curtailment and determine the order in which customers are curtailed, and (4), in the case of a severe curtailment, prioritize human-needs loads in specific geographic areas so that every person has access to a heated building. Contingency planning is already conducted in some form by most LDCs but the changing industry structure and unbundling trends require that the plans be re-evaluated periodically. For example, the growth of LDC transport-only service, including firm transport-only service, has required some PUCs to modify curtailment policies to include the conditions in which transport-only customers are curtailed and the price to be paid for any diverted supplies (California Public Utilities Commission (CPUC) 1991; Virginia State Corporation Commission 1991). The elimination of the pipeline supply function as a result of FERC Order 636 is making interstate gas supply operations more decentralized and is another reason to re-evaluate contingency plans. While some LDCs are doing this for their service territories, there has been an industry-wide attempt to improve contingency planning at the regional level. The Natural Gas Council has created five North American reliability planning regions: West, Southeast, Northeast, Midsouth, and Midwest (Natural Gas Council (NGC) 1993). Within each region, phone lists are being distributed so that individual utilities and customers know who to call when supply-demand balances reach critical conditions. The NGC is also encouraging members to enter into mutual assistance agreements that provide explicit procedures on how participating parties can exchange supplies and capacity in times of critical supply or demand.

4.5 Summary

Gas resource planning begins with an evaluation of the LDCs reliability objectives and an analysis of what resources are necessary to meet them. LDCs ultimately strive to provide gas supply and transportation services that are of value to their customers. This requires balancing reliability, cost, and price stability attributes of all resource options. Supply and capacity are closely related concepts for the LDC. For the purposes of near-term resource planning, however, portfolios of supply contracts are usually developed independent of the gas capacity planning process. For supply portfolio planning, the biggest issue facing LDCs is determining the relative shares of different types of contracts for their portfolios, including contracts of varying terms. The competitive marketplace for gas supply may ultimately sort out some of these contract share debates.

LDC procurement activities are also likely to be significantly affected by the state PUC's regulatory approach to reviewing LDC procurement decisions.

With regard to capacity planning, LDCs will consider releasing existing capacity as well as acquiring new capacity to better meet reliability targets, to lower capacity costs, or to lower gas supply costs. For many LDCs, storage options will be increasingly attractive as an alternative to pipeline capacity. A simple screening analysis may be conducted to trade off the fixed and variable cost attributes of different resource options. More sophisticated resource planning is required to fully incorporate all the constraints that are relevant to an LDC and its customers.

Before embarking on a resource plan, PUCs and utilities should carefully consider their reliability objectives on both the demand and supply side. Current industry practice is to address reliability for firm customers by setting a conservative design peak-day target and, possibly, adding a reserve margin to that target. The reliability of individual resources to meet that target are assessed either qualitatively or quantitatively. Unless facilities are constructed specifically for interruptible customers, the reliability provided to interruptible customers is a byproduct of the firm customer reliability plan. In light of IRP and the ongoing gas industry restructuring, there will likely be an increased trend towards using benefit-cost analysis for determining appropriate reliability targets for both firm and interruptible customers. Once an LDC has acquired resources to meet its reliability targets, contingency planning can be used to maximize customer reliability. Contingency plans include procedures that maximize short-run resource availability and minimize the negative consequences of any necessary curtailments.

Chapter 5

Methods for Estimating Gas Avoided Costs

5.1 Overview

The concept of avoided cost grew out of federal legislation designed to encourage efficient production and the use of renewable fuels in the electric power industry; this legislation also sought to achieve these ends by stimulating investment of private, unregulated capital in the electric power sector. The concept has evolved to become the standard against which the benefits of electric utility demand-side management (DSM) programs are valued.

This chapter focuses on the estimation of avoided costs for gas as a means of valuing the benefits of gas-utility-sponsored DSM, including efficiency improvements, peak-shaving, and strategic load building. Given the vast differences in the characteristics of supply and demand resources and the state-of-the-art in gas planning tools, evaluating DSM on a program by program basis and optimizing both DSM and supply resources in an automated framework is currently impractical. Avoided cost methods have become the conventional means by which we approximate an overall supply-demand optimization. Avoided costs can and have been used in evaluating supply resources and in rate design, but those applications are not discussed in detail in this chapter.

Because the avoided-cost concept came from the electric power industry, it is useful to review features of the gas industry that are different from the electricity industry and of particular relevance to estimating avoided cost: (1) local distribution companies (LDCs) are not as vertically integrated as electric utility companies, so more of their costs are defined upstream through contractual agreements; (2) storage exists as a major gas resource option similar to pumped storage hydro for electric utilities except on a larger scale and for longer time intervals (i.e., seasonal instead of diurnal or weekly); (3) LDCs provide more diversity of services (e.g., end-user transportation, which would be analogous to retail wheeling in the electric power sector); (4) gas LDCs are not as capital intensive as electric utilities, so LDCs' cost structure tends to be dominated by variable costs; (5) the planning horizon for gas utilities is historically shorter than for electric utilities; and (6) there can be a higher degree of seasonality in gas costs than electricity costs. Given these differences, methods used to estimate avoided costs must be carefully adapted to the gas industry.

This chapter presents several methods that have been implemented or proposed for estimating gas avoided costs; a consensus does not yet exist within the gas industry or among regulators on appropriate methods. The next section describes the components of gas avoided costs. Various avoided-cost methods are then described in Section 5.3 with a discussion of their strengths and weaknesses. Major issues that should be considered in applying avoided costs to the valuation of gas DSM programs are also discussed.

5.2 Components of Gas Avoided Costs

Avoided costs for gas LDCs can be broken down into a number of components: commodity, deliverability from the wellhead to the city gate (capacity), local transmission and distribution (LT&D), and servicing customers. The relative shares of these components in the total avoided cost will vary by utility and over time. Generally, commodity and capacity costs will be the largest part of avoided cost for LDCs. The move to straight, fixed-variable rate design in FERC Order 636 will typically result in increased capacity costs for low-load factor LDCs than under the rate structure being replaced.

Two important timing-related issues need to be considered in developing gas avoided costs for analyzing the economics of DSM programs: (1) the cost structure of the LDC system, which is driven by demand patterns that are largely differentiated from one another by their time of occurrence, and (2) impact of a measure's lifetime on the time horizon of the analysis.

A range of demand patterns drives facility sizing and supply procurement (see Table 5-1) (Energy Management Associates (EMA) 1992). Although Table 5-1 indicates which demand patterns are associated with certain facilities, it does not say which demand pattern will be the binding one for facilities construction. The binding demand pattern depends on the specific supply and demand situation for each LDC. More than any other demand pattern, coincident design peak-day demand is usually the most important for designing facilities, such as system transmission, storage withdrawal, and peak-shaving capacity near load centers. Design winter season and average daily demand are other demand patterns commonly used by LDCs in supply planning. Establishing which demand patterns are binding for particular facilities is important because DSM-induced changes in the nonbinding demand patterns may have no impact on supply and hence no avoided cost implication. Ultimately, avoided costs need to be time-differentiated in a way that recognizes the demand patterns driving supply choices that in turn reflect the cost structure of the LDC. By the same token, assessing the economic merits of DSM programs using time differentiated avoided costs requires that the load shape impacts of DSM programs be decomposed into their impacts in the corresponding time periods (i.e., demand patterns). Otherwise, the wrong types and/or quantities of DSM resources will be deemed cost-effective and lead to suboptimal results in DSM resource acquisition.

Table 5-1.Typical Demand Patterns Associated with the Sizing of Facilities and Contracts

System Component	Non-coincident Design Peak Hour	Coincident Design Peak Hour	Coincident Design Peak Day	Design Winter Season	Late Season Cold Day	Avg. Summer	Avg. Daily Demand
Commodity-- Peak Deliverability			X	X		X	X
Commodity-- Energy							X
Peak Shaving		X	X				
Storage		X	X	X	X	X	
Pipeline Capacity		X	X	X		X	
LDC Transmission		X	X			X	
Distribution Main	X	X	X				
Services, Meters	X						

Source: Adapted from Energy Management Associates 1992

The second timing issue is the impact of a measure's lifetime on the time horizon of the analysis. Some DSM measures can produce savings for up to 20 years or more. In order to properly evaluate the benefits of DSM, estimates of avoided costs need to encompass the economic lifetime of DSM measures. This need means that many LDCs will have to develop estimates of avoided costs beyond their current supply planning horizon. The IRP process itself may extend LDC planning horizons beyond the typical three to five year timeframe, to 10 years or more. For planning horizons that are shorter than the lifetime of DSM measures, "end-effects" procedures can extend the last year's values to encompass the period of interest beyond.

The major issues associated with each of the following avoided cost components for gas are summarized in Table 5-2 and elaborated upon below.

Table 5-2. Issues in Estimating Gas Avoided Costs

Component	Issue
Commodity	• Uncertainty in future gas commodity costs • Impact of reduced takes on firm contracts may be constrained by minimum take or gas inventory charge (GIC) provisions
Capacity	• Short-term vs. long-term perspective • Duration of existing firm capacity contracts • Market demand and future price uncertainty for existing capacity (capacity release) • Reallocation of pipeline fixed costs • Treatment of commodity-related capacity investments • Cost allocation methods for long-lived facility investments
Local T&D and Customer Costs	• Not typically avoidable by most DSM programs

5.2.1 Commodity Costs

As characterized in Chapter 4 and summarized in Table 4-2, LDCs draw upon various types of gas supplies including long-term contracts, multi-month contracts, spot contracts, pipeline sales service (unbundled from pipeline transportation and storage service in the aftermath of FERC Order 636), purchases of reserves, futures and options contracts, and customer buybacks. LDCs dispatch supply resources in their portfolios to minimize cost, subject to operating constraints and reliability criteria. Avoided commodity costs are reflected in a change in the utilization of supply resources as a result of the DSM-induced change in demand.

A change in utilization of supply resources may allow for outright cancellation of prospective supply contracts or facilities and their associated costs. However, change in supply resource utilization may simply entail a reduction in gas takes from selected contracts. To the extent that firm supply contracts in the LDC's mix include take-or-pay clauses or gas inventory charges that penalize low load factor utilization, the avoidable commodity cost from reduced volumes of these contracts will be dampened. Gas dispatch models should handle such contract provisions and account for them in simulating least cost LDC system operation; for this reason dispatch models are useful tools to use in estimating avoided commodity costs.

The underlying uncertainty of future gas prices is an important concern in estimating avoided commodity costs. Uncertainty in future gas commodity costs is influenced by many factors: rate design policies, supply/demand balance, availability of supply, and competition with alternate fuels. Variations in future gas commodity costs could have a disproportionate influence on avoided costs because the commodity component often accounts for a significant fraction of an LDC's total cost of gas.[1] Uncertainty in future commodity costs assumes even greater prominence as time horizons under IRP are extended to ten years and beyond. Thus, in estimating gas avoided costs, it would be advisable to include a range of gas commodity escalation rates as part of the analysis. Approaches to treating uncertainties in commodity costs in avoided cost calculations are fundamentally no different than those described in Section 3.7 for other analytic areas of IRP.

LDCs typically offer a number of different categories of service to customers: firm sales, interruptible sales, transportation (firm, nonfirm), and standby sales. Which service categories should be included in the demand forecast upon which avoided costs are based? For the avoided commodity cost calculation, it has been suggested that in addition to the forecasted demands of firm sales, interruptible sales and transport customers on standby sales should be included because LDCs will sell gas to these customers if it is available and the customers are willing to pay the cost (Heaghney 1992). However, a significant uncertainty surrounds the possibility of customers switching the type of service they receive from the LDC. For instance, standby customers swinging between transportation and sales service can have a large impact on avoided commodity costs.

[1] The relative significance of avoided commodity cost in total avoided cost is a function of an LDC's load factor. For a low-load-factor LDC, fluctuations in commodity cost will have less of an impact on total avoided cost than they would for a high-load-factor LDC (all other things being equal).

5.2.2 Capacity Costs

DSM alters customer demand, which leads to changes in necessary facility investments and contractual agreements (without compromising reliability); avoided capacity costs derive from these changes. The types of supply resources providing delivery capacity within LDC service territories include pipeline capacity in the form of firm transportation, "no- notice" service, storage, liquified natural gas (LNG), or propane-air plants (see Table 4-3).[2] These capacity resources can be divided among committed and uncommitted resources. In the short run, most avoidable resources are uncommitted. In the long run, planned capacity facilities and/or firm capacity contract commitments could be avoided as well.

Options for Avoiding Capacity Costs

There is some controversy over how avoidable capacity costs in an LDC's portfolio really are, particularly in the short term. The answer is highly specific to the circumstances of each LDC. In general, "transition costs" that are approved under FERC Order 636 proceedings for individual pipelines are costs that cannot be avoided by subsequently implemented DSM programs (Armiak 1993). However, LDCs may have a number of other options for avoiding part of the costs associated with capacity that becomes excess as a result of DSM; these options include: (1) releasing capacity to the secondary market allowed for in FERC Order 636, (2) renegotiating capacity commitments in pipeline service agreements at the end of contract terms, (3) reducing or eliminating planned or committed stakes in new pipelines, and (4) making more interruptible sales from freed capacity.

The first option, avoiding capacity costs through releasing existing pipeline capacity held in firm transport contracts, depends to a great extent on market conditions. Previously, LDCs that reduced demand were unable to reap capacity cost savings until their existing pipeline contract expired and could be renegotiated. Now, for LDCs located near pipeline market hubs or near pipelines serving many customers, there may be an active market for released capacity. The great uncertainty in these cases is the price which will be determined in this secondary market. FERC Order 636 stipulates that releasing shippers remain liable for the full pipeline reservation charge and surcharges, so any difference between the market price of the released capacity and the pipeline charges will have to be made up by them. Thus, the avoided capacity cost through existing capacity

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[2] Customer buyback programs listed in Table 4-3 under gas capacity options are not cited here because they occupy a minor position in the overall deliverability of gas within LDCs and because of the difficulty in assigning an avoided cost to them.

release may only be a fraction of the contractual obligation. For LDCs located far from market centers or LDCs that are the dominant pipeline customer in their area, the question of released capacity market price may be moot as there may be few potential buyers. A more subtle boundary issue is whether releasing capacity means transferring it to entities outside the LDC service territory or to customers served by the LDC. If the capacity goes to LDC customers, then there is no reduction in total fixed pipeline costs being passed on to the customers of the LDC (Armiak 1993). An added wrinkle is that, in circumstances where there is a strong market for released capacity, LDCs might decide to simply renew contracts with pipelines and retain all of their existing capacity; a byproduct of this could be a reduction in the effective cost of relying on a "reserve margin" to ensure system reliability (Gaske 1993).

A second option for avoiding capacity costs is reducing or terminating capacity rights at the end of an existing pipeline contract term, or relinquishing capacity as part of the industry restructuring process brought about through FERC Order 636. Since the mid-1980's, with the gas supply "bubble" and the uncertainties associated with gas industry restructuring, terms for pipeline capacity contracting have tended to be short (although long-term contracts still dominate). Moreover, many of the long-term contracts signed in the early 1980's will be expiring in the next several years. However, similar issues of market demand for released capacity apply to capacity let go by LDCs. In a situation where relinquished or terminated capacity finds ready buyers, the full costs of the relinquished contract will be avoided. In a situation where the pipeline cannot fully subscribe its available capacity, the pipeline may try to recover its fixed costs by raising rates in order to remain whole. Thus, the problem of stranded or underutilized pipeline investment could result in lower net avoided capacity costs for some LDCs than would otherwise be the case.

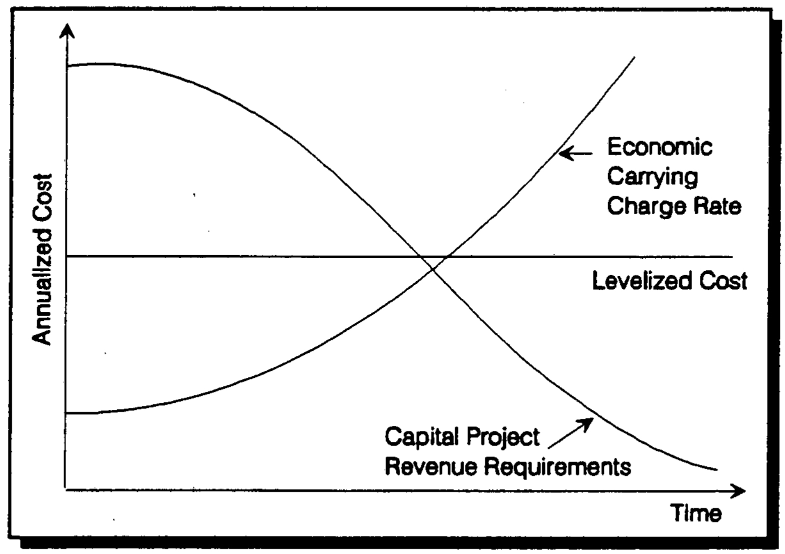
A third option for avoiding capacity costs is reducing or foregoing planned participation in pipeline "open seasons" or direct investment in new pipelines. Depending on the nature of the contract, investments in pipeline capacity rendered superfluous from one LDC's DSM program may in fact not be avoidable because of commitments to, and needs of, other parties in the project.

The last option for avoiding capacity costs is increasing interruptible sales; this is technically not a means of avoiding capacity commitments. Instead, it allows capacity costs to be redirected to taking advantage of incremental opportunities, which itself could have value to the LDC in added margins (Hornby 1991). Practically speaking, this "opportunity cost" concept may be difficult to apply because of the difficulty in ascribing a value to avoided capacity cost.

The uncertainties surrounding the market value of avoided capacity, particularly from the first two options described above, suggests that a range of avoided capacity costs should be prepared in a manner that is similar to the range of avoided commodity costs prepared from a range of gas price forecasts.

Allocation Issues

Figure 5-1. Three Methods for Allocating Capital Costs Over Time



Capacity cost is not always identical to pipeline reservation charges or fixed costs of a facility. Some resources with high fixed costs enable savings of variable costs. In the gas industry, this is commodity-related capital investment. Pipeline capacity that provides access to lower cost producer gas fields is an example of this phenomenon. One way of distinguishing between capacity and energy value in fixed costs is to assign to "capacity" the fixed costs of a resource that primarily serves capacity needs in the system to capacity and to ascribe the remaining portion to commodity. This approach is routinely employed in the electric power sector with the cost of gas combustion turbines serving as the proxy for pure capacity. The fixed costs of propane-air plants have been suggested as a proxy for capacity value for LDCs. Released pipeline capacity prices or other resources might also fill this role.

For long-lived facilities investments such as on-system storage, spreading the initial capital costs over the lifetime of the investment is necessary in order to allocate properly the capacity value of the facility over time. The economic carrying charge rate (ECCR) is useful in this regard (Kahn 1988). Figure 5-1 depicts three streams of capital costs of equivalent value in present value terms. The horizontal curve is the levelized annual cost, the falling curve is the revenue requirements stream employed in utility capital finance, and the rising curve is the ECCR increasing at the rate of inflation. Levelization, which is computationally equivalent to mortgage payments, gives equal payments over the period in nominal terms. In real terms, the value declines over time, so more of the total present value is in the early years. The revenue requirements stream represents the cost recovery process of utility investment in the regulatory arena with extreme front-loading. The ECCR method is intended to represent the behavior of capital in a competitive market operating under inflation with constant annual values in *real* terms (National Economic Research Associates Inc. (NERA) 1977). As such, the ECCR imposes no front-loading penalty and for this reason is the preferred method for allocating avoided capital costs over time.

Finally, LDCs may include only some customer service categories under their "obligation to serve," particularly from the standpoint of capacity investment decision-making. Only the demands of customer service categories that the utility chooses to serve from a capacity planning perspective would be included in any estimate of avoided capacity cost.

5.2.3 Local Transmission and Distribution Costs

Local transmission costs are associated with transporting gas from the "city gate" to the distribution main. Distribution costs are associated with transporting gas from the transmission system to customers. Together, LT&D investments are planned around local noncoincident demands rather than system coincident demands as is typical for system elements further upstream (see Table 5-1).

Scale economies are a large factor in the economics of LT&D because much of the cost of laying underground pipe is in the cost of trenching and not the pipe itself, so the incremental cost of increasing capacity (at the time of construction) can be relatively small.[3] These scale economies often dictate that LT&D expansions be designed to accommodate future growth. Costs of LT&D also have substantial geographic and density dependencies, making them less a function of demand level *per se*. Few DSM programs will result in avoided local transmission and distribution costs.

5.2.4 Customer Costs

Customer costs typically include service lines, meters, regulators, and some portion of main line extension cost. Avoided customer costs may only be relevant for DSM

[3] Additionally, piping comes in standard sizes and the impact of DSM is seldom large enough to warrant choosing pipe some standard size smaller.

programs that affect system expansion into new areas or additional customer hookups.[4] Fuel-substitution DSM programs are the most likely situation in which avoided customer costs would apply, and then only if the program resulted in new customers and not just expanded use for existing customers. These costs can be based either on engineering estimates or historical data analysis.

5.2.5 Externality Costs

The theory behind externality costs is that the market sometimes fails to incorporate all social costs in the observed prices of goods. For fuels, environmental externality costs are the most prominent. They include air and water pollutants and land impacts. These costs would ideally be based on estimates of the damage costs of the environmental impact, but reliable estimates are elusive especially for global or regional effects or effects that require putting a monetary value on human and other life forms or on aesthetic qualities. Various studies sponsored by states (e.g. New York and California) and the federal government are currently assessing damage costs of pollution. As a proxy for environmental externality costs, analysts use the costs of controlling pollutants or mitigating impacts of a project or activity as imposed by environmental regulations.[5] The choice of approach (damage cost or control cost) and the appropriate specific values to assign to each impact are areas of active and ongoing public policy debate (Consumer Energy Council of America Research Foundation (CECA/RF) 1993; ECO Northwest 1993).

A number of state PUCs have instituted or are considering rules regarding the use of environmental-externality-cost adders in integrated resource planning (Goldman and Hopkins 1991). Operationally, these adders appear as credits to more benign resources such as DSM or as additional costs to resources in the current mix or resources under consideration. These additional externality costs are reflected in estimates of avoided supply costs and are typically included in the Societal Cost test (see Chapter 6). Exhibit 5-1 describes current state regulatory activities with regard to environmental externality costs affecting gas utilities.

[4] An exception may be DSM programs targeting low-income groups where some customer-related costs are often avoidable such as uncollectible expenses and collection, termination, and reconnection costs.

[5] The control cost approach is predicated on the belief that the political process locates the intersection of the marginal benefit and cost curves when it imposes a particular standard for pollutant impact.

Exhibit 5-1 State Activities Incorporating Environmental-Externality Costs into Gas Utility Planning

Georgia	Atlanta Gas Light Co. used a composite externality cost (or value of damage or control) of $0.15/MMBtu for evaluating gas DSM programs. The calculated environmental-externality costs based on gas end-use technologies are: residential space heater -- $0.10/MMBtu residential water heater -- $0.11/MMBtu residential clothes dryer -- $0.05/MMBtu residential range -- $0.06/MMBtu commercial boiler -- $0.10/MMBtu industrial boiler -- $0.13/MMBtu
Iowa	The commission requires that natural gas least-cost planning include externalities in avoided-cost calculations. The Iowa Utilities Board proposes to add an "externality factor" to avoided cost calculations–10% for electric utilities and 7.5% for gas utilities.
Minnesota	Utilities are not required to consider externality costs when evaluating Conservation Improvement Programs (CIP). However, the commission adds an Environmental Damage Factor of $1.10/Mcf to avoided costs and lowers the discount rate from the 11.03% approved utility rate to a 5% societal rate when estimating of the cost-effectiveness of utility CIPs.
Nevada	Westpac Utilities (a subsidiary of Sierra Pacific Power Company) developed an Environmental/Societal test and used it with the four other tests described in the *California Standard Practice Manual* to evaluate each demand-side program. The test adds environmental values to other benefits and costs included in the Total Resource Cost test.
New Jersey	Gas utilities must include a commission-specified environmental externality cost in net benefits calculations, avoided costs calculations, standard offer pricing, competitive offer pricing, and the TRC test. This externality cost was estimated by Pace University to be $0.95/MMBtu (in 1991 dollars), based upon the pollution cost of gas-fired power generation. The commission stipulates that the value be adjusted annually at a rate equal to the GNP deflator index.
Vermont	The commission has adopted as *interim adjustments* a 5% adder to supply-side costs for negative externalities associated with supply sources and a 10% discount from demand-side costs for the risk-mitigating advantages of demand-side resources. This applies to both gas and electric utilities. The commission requires that the 5% adder also apply to fuel-switching programs, as it does for supply programs. However, any party is free to present evidence in compliance filings to substantiate a credit for reduction in the 5% penalty for alternative fuels.
Wisconsin	Externality regulations only apply to electric utilities. The commission requires that utilities multiply monetized greenhouse gas values by the amount of greenhouse gases a power plant will emit under a specific resource plan and apply the resulting cost to the energy-related costs of the plant for the period in which the energy is generated. The values are to be used when comparing resource options in planning, designing and implementing DSM programs. Additionally, the commission states that total technical costs plus quantified environmental externalities should be used to evaluate fuel alternatives–to determine which end uses are served at the lowest cost to society by fuels or energy sources other than electricity. The monetized values for greenhouse gases that the Commission thinks reasonable are: carbon dioxide -- $15/ton ($0.0075/lb) methane -- $150/ton ($0.075/lb) nitrous oxide -- $2,700/ton ($1.35/lb)
California	The commission requires that fuel-switching programs pass the three-prong test in which externality impacts are considered (see Chapter 8).

Source: Wang 1993

5.3 Methods for Calculating Gas Avoided Costs

Several methods for calculating gas avoided costs have been used by LDCs or proposed in the literature. The next section reviews approaches and discusses the pros and cons of each method.

The starting point for each method is a base case resource plan that satisfies a base case gas demand forecast.[6] The base case demand forecast typically includes the load impacts of committed or approved LDC DSM programs (and market- and standards-induced changes in average use) but does not include the effects of incremental DSM programs under consideration.

5.3.1 System Marginal Cost

The system marginal cost (SMC) approach calculates the change in system fixed and variable costs at the margin resulting from a change in demand. Because of the complexities of accurately determining supply-side resource responses at the margin, the use of detailed gas supply planning models is essential with SMC approaches. To the extent that gas supply planning models are being used by an LDC, a major benefit of SMC approaches is that they enable consistent treatment of avoided-cost estimation with supply planning assumptions and methods.

Three different ways of estimating avoided cost using an SMC approach are: instantaneous, increment/decrement, and differential revenue requirements methods.

[6] All avoided-cost methods are predicated on the assumption that the base case demand forecast is an accurate and reasonable representation of LDC expectations of future demand from its customers (in the absence of incremental LDC intervention) and that the base-case supply plan is the optimal plan to serve that demand based on current expectations and constraints. Any departure from this assumption will distort avoided-cost estimates.

Instantaneous Method

The instantaneous method for calculating marginal cost assumes a small perturbation to the system by DSM programs, compared to the overall size of the system. Because the load change is small—infinitesimal to be exact—no structural change to the mix of resources serving gas loads is warranted. In this approach, DSM programs facilitate a reduction in use of the most expensive resources at the margin. The instantaneous method produces what is essentially a short-run marginal cost and may only be valid for short-term valuation of gas DSM avoided cost. In principle, this method lends itself to easy time-differentiation but depends on the specific capabilities of the planning model being used. An instantaneous marginal cost is often given as a direct output of gas dispatch simulation models.

Increment/Decrement Method

The increment/decrement method (ID) is predicated on DSM program impacts being finite in size and possibly significant relative to overall demand. Load decrements apply to conservation, seasonal load reduction, or peak-clipping DSM programs whereas load increments apply to load building, valley filling, or peak load shifting DSM programs (see Figure 7-1). In the ID method, a finite, discrete block of load is added or subtracted from the demand forecast. With this new demand forecast, a second gas dispatch simulation is run and compared to the base case. Avoided costs are calculated by taking the difference in dispatch cost between the two runs (base case and ID) divided by the size of the increment or decrement on a volumetric basis.

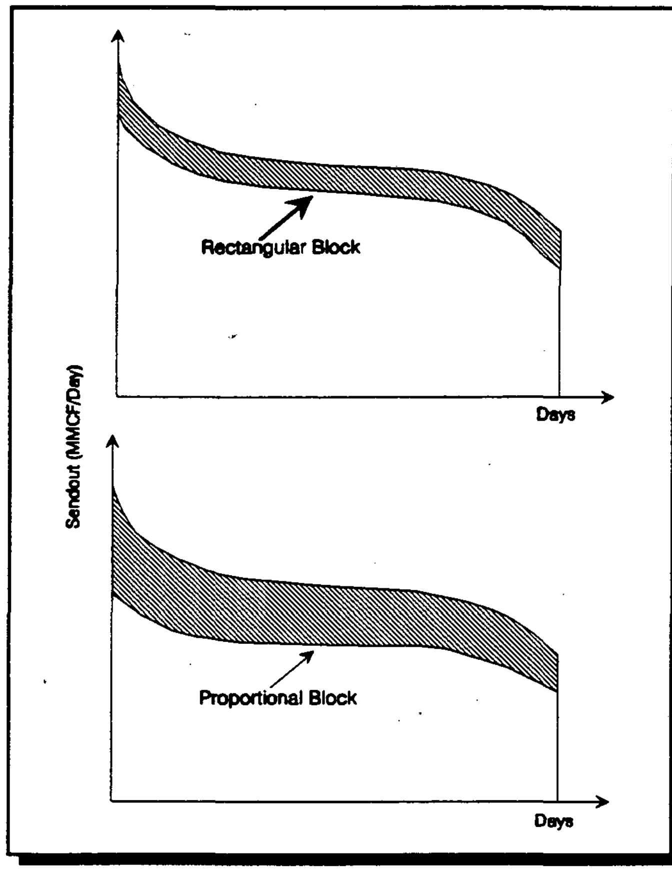
Individual DSM programs are unlikely to produce any significant impact on a utility's costs or resource mix. Thus, for the purpose of estimating avoided costs, individual DSM programs should be aggregated into resource "blocks." The size of the increment or decrement block will have an effect on the resulting estimates of avoided cost.[7] The quantity of the DSM resource that is cost-effective is dependent on the level of avoided cost. Therefore, an equilibrium must be sought where the resource block used in estimating avoided cost is the same quantity of DSM that passes screening with that avoided cost. This equilibrium is found through iteration.[8] It is imperative that the

[7] The larger the size of the decrement block, the cheaper the average cost of the supply resources displaced by it, translating into lower avoided cost. By similar logic, a larger increment block will call upon yet more expensive resources that in turn produce higher avoided cost.

[8] An initial guess of resource block size is used to estimate avoided cost, which is then used to screen DSM programs, the passing quantity of which is compared to the original resource block size. If the quantity of cost-effective DSM is smaller than the resource block, then the resource block size is reduced (or vice versa) and the

initial size of the resource block used in the ID approach be verified in order to arrive at a plausible estimate of avoided cost.

Figure 5-2. Decrement Blocks in System Marginal Cost Methods



The shape of an increment or decrement block will likewise influence the resulting avoided cost estimate. Although different programs exhibit their own characteristic load shape impacts, LDCs as a practical matter usually assume some characteristic shape (or set of shapes) in developing avoided costs. Figure 5-2 depicts two characteristic block shapes as decrements superimposed on a load duration curve. One is a "rectangular" block with the same load impact throughout the period, which would correspond to the impact one might expect from efficient hot water heating or efficient commercial cooking programs. The other is a proportional block that is a fixed percentage of the base case load shape, which would correspond to a temperature-sensitive load impact from efficient space heating programs.

If a gas dispatch model is used in performing the ID avoided cost calculation, then only system operating cost changes will be reflected in the model output. Fixed cost implications have to be accounted for exogenously. Using large increment or decrement blocks in the simulations may necessitate making modifications to the supply resource mix (either adding or removing resources, respectively). A long-term optimization model in which fixed and variable costs are simultaneously accounted for is used in the differential revenue requirements method described below.

procedure is repeated until equilibrium is reached.

Differential Revenue Requirements Method

The differential revenue requirements approach is a variant of the increment/decrement approach in which fixed and variable costs are explicitly optimized in each simulation through the use of a capacity expansion model (see Chapter 3 for typology and discussion of gas planning models). In all respects, except its integral fixed cost treatment, the revenue requirements method is the same as the increment/decrement method. In principle, this method is the most rigorous, and so it can be an arduous undertaking, requiring multiple simulations with complex models.

5.3.2 Generic Proxy Approach

In this approach, the analyst selects an avoidable resource (or set of resources) from the supply plan and uses its costs as the basis for avoided costs. The underlying concept is that a resource in the supply mix could be entirely displaced by DSM resources theoretically serves as the proxy resource. The proxy resource could be the most expensive unit or the last resource dispatched in the supply portfolio, in which case the proxy method approximates a SMC method. However, in choosing a proxy resource, it is best to seek a reasonable match between the type of load shape impact from DSM and the supply resource in the portfolio that would otherwise serve that load. For example, in evaluating a nontemperature sensitive load impact (e.g., from efficient water heating programs), the appropriate proxy resource would be the combination of contracts and other facilities designed to serve a high load factor demand.

When load-reducing DSM is placed in the resource mix, proxy resources are either cancelled outright or deferred.[9] If the DSM resource block is large enough to permit canceling the proxy resource (this depends on each LDC's unique portfolio of contracts and facilities), we can directly assign its costs to avoided cost (converted to a unit-cost volumetric basis).[10] This method's appeal is that it is relatively simple to calculate, and it is transparent; the supply-side impact is determined without running multiple gas system simulations, and its costs are tangible. The date on which the proxy resource is introduced into the supply mix can also be delayed as a result of DSM instead of

[9] This description of the proxy methodology assumes load-reducing DSM but is applicable to load-building DSM with appropriate adaptations.

[10] Because the quantity of cost-effective DSM resource is dependent on avoided cost, the reasonableness of the assumption will have to be subsequently confirmed by screening the DSM programs with the avoided-cost estimate.

cancelled altogether. Determining how long to defer the proxy resource and the value of that delay is more complicated and requires the use of a gas planning model.[11]

Table 5-3. Model Simulations Used in Proxy Deferral Method

Simulation	Demand Forecast	Supply Plan
#1	Base Case	Base Case
#2	Base + DSM Case	Base Case
#3	Base + DSM Case	Proxy Deferral Case
#4	Base Case	Proxy Deferral Case

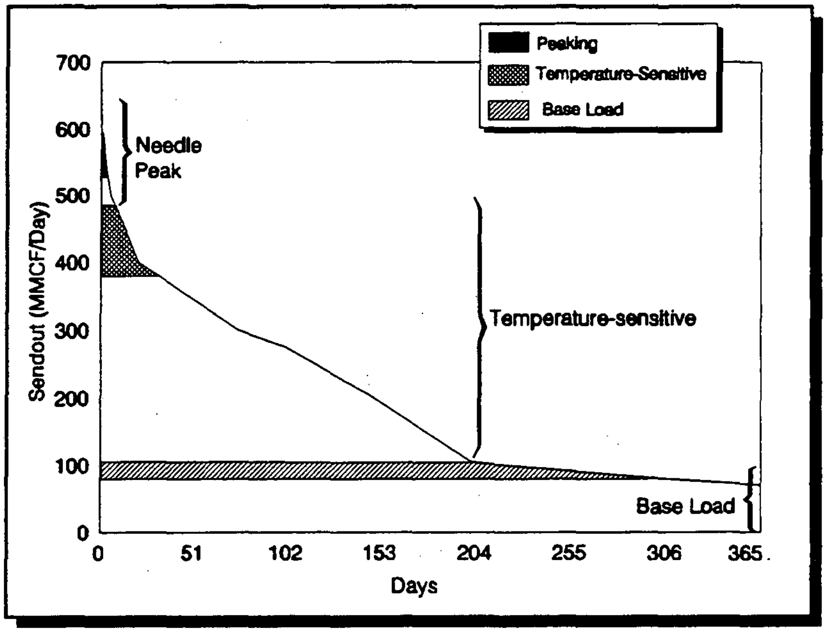
Table 5-3 shows the four gas planning model simulations usually performed in the proxy resource deferral method (Kahn 1989). As with all avoided cost methods, the proxy deferral method begins with a base-case supply plan and demand forecast (Simulation #1). The second step is to simulate the dispatch of the base-case supply plan with a decrement block of DSM in the load forecast. Simulation #2 should result in lower operating costs than in the base case because of the presence of DSM. The third step is to defer the introduction date of the proxy resource (or resources) for some period based on an initial estimate and then to run another simulation (#3) with the adjusted supply plan and the decrement load forecast. One then compares the present value (PV) of the stream of operating costs of Simulation #3 over the planning horizon with those of the Simulation #1 (i.e., the base case) with the goal of making them equivalent. If the deferral period in Simulation #3 is too short, then the PV operating costs will be lower than the base case (and vice versa). The analyst must repeat Simulation #3 with different proxy deferrals in order to arrive at this point. Once the optimal deferral is found, the last step is to simulate the dispatch of the adjusted supply plan with the base case load forecast (Simulation #4). The PV of operating costs of Simulation #4 will be higher than those for Simulation #1 because of proxy deferrals. The cost difference between Simulations #1 and #4 is the value of the deferral enabled by the DSM resource block; it is used as the basis for avoided cost. To summarize, avoided cost is the difference in PV of the stream of operating costs between the base case and proxy deferral cases (both employing the base-load forecast) divided by the load decrement (on a volumetric basis).

[11] Although this method can be applied with proxy gas resources that are physical plants, it may not be applicable for some types of contractual arrangements.

5.3.3 Targeted Marginal Cost

The targeted marginal cost (TMC) method is a composite of the proxy and system marginal cost approaches. Like the proxy method, it does not require the use of a gas dispatch simulation or long-term optimization model; instead the analyst selects the avoidable resources. Like the system marginal cost approach, TMC assigns avoided cost to the most expensive resources. The defining feature of this method is that the analyst partitions the supply resources into the types of demands they principally serve—typically base, temperature-sensitive, and peaking loads—then identifies the most costly supply in each category and allocates its costs to the corresponding demand impact (RCG/Hagler & Bailly Inc. 1991; Violette and Stern 1991). Figure 5-3 shows a hypothetical LDC load duration curve with the loads segmented into the three categories so the last resource dispatched in each category is highlighted (see shaded areas). The highlighted marginal resources targeted to specific demand patterns form the basis for avoided costs of DSM with the corresponding load-shape impacts. Costs of marginal resources are expressed on a unit cost volumetric basis in developing avoided-cost estimates.

Figure 5-3. Targeted Marginal Approach for Avoided Cost



Proponents claim that a major virtue of the TMC approach is that it explicitly accounts for cost causation (i.e., matching type of demand impact to resultant supply cost response)(RCG/Hagler & Bailly Inc. 1991; Violette and Stern 1991). Unfortunately, the causation is asserted by the analyst rather than demonstrated through the rigors of a supply planning process, so this benefit depends heavily on the skill of the analyst to accurately disaggregate and match up appropriate supply and demand elements.

5.3.4 Average Cost Methods

The principal virtue of average costing methods for estimating gas avoided costs is their simplicity. In this approach, the unit costs of all supply resources in the utility's portfolio are aggregated together, usually weighted by their respective volumetric contribution to the total sendout. This weighted average cost of gas (WACOG) customarily includes costs incurred at the city gate on an annual basis but could in theory be seasonally-differentiated and expanded to include other costs incurred by LDCs, such as LT&D costs.

These methods are based on embedded cost, which disregards many important LDC system operating characteristics. Further, use of average cost in avoided-cost estimation assumes that average cost of the current portfolio mix equals marginal cost, which will not be true for many LDCs.

5.3.5 Summary of Strengths and Weaknesses of Alternative Avoided-Cost Methods

Methods that rely on complex planning tools may offer the *potential* for greater precision, but if they are beyond what is needed for an LDC to adequately estimate avoided cost, then those methods will not be appropriate despite their general advantages. With this caveat in mind, some generalized pros and cons of the various methods for estimating avoided cost are summarized in Table 5-4.

System marginal-cost approaches offer the potential for greatest accuracy, showing both in physical and cost terms what is avoided through DSM programs. These methods require the use of a complex supply planning model, which can be costly and introduce the very real possibility of undetected error because of the formidable data requirements and "black box" quality of such models. A primary advantage is that use of SMC methods can help to ensure consistency between avoided-cost estimates and the overall planning process. Thus, SMC methods are the most harmonious with the goals and process of IRP.

Generic proxy methods are relatively transparent, and this is their main advantage; proxy resources are actual supply resources whose costs are generally known. If the DSM resource block is large enough to permit removal of the proxy resource from the mix, then a complex planning model is not needed to arrive at an avoided-cost estimate. However, if DSM only delays the introduction of the proxy resource, then a complex planning model is required to determine accurately the deferral period and the value of it. The potential weakness of both generic proxy approaches is that they rely heavily on the analyst's judgment to properly select the proxy resources. In addition, the proxy

Table 5-4. Strengths and Weaknesses of Alternative Avoided-Cost Methods

Method	Strengths	Weaknesses
System Marginal Cost	• Precise • Supply impact identified • Consistent with resource planning process	• Requires complex model
Generic Proxy	• Transparent • Model use optional • Supply impact determined (or asserted)	• Potential for proxy & DSM mismatch • Relies on judgment
Targeted Marginal	• Relatively easy • No model required	• Heavy reliance on judgment
Average Cost	• Very easy • No model required	• No relationship between DSM and supply impacts • Difficult to time-differentiate

deferral method includes the computational burden of complex planning models.

The key advantage of the targeted marginal cost approach is the relative ease of computation involved. No model is required in applying this approach; however, like all avoided-cost approaches, it requires a base-case supply plan that has been prepared presumably using a planning model. This method places heavy reliance on the analyst's judgment to break the supply mix into its constituent resource types—peaking, temperature sensitive, and base-load—and to properly choose the marginal resource within each.

Finally, the average-cost approach is the easiest method, and, like the targeted marginal approach, requires no significant modeling effort beyond developing a base-case supply plan. The disadvantage of this approach is that the computed cost based on the current portfolio of contracts may differ significantly from the costs actually avoided by DSM programs. WACOG used in avoided-cost applications tends to underestimate the value of savings during the temperature-sensitive and peak periods and to overestimate them in the off-peak period. At best, it should be considered a first-cut estimate of avoided cost.

Economic Analysis of Gas Utility DSM Programs: Benefit-Cost Tests

6.1 Overview

Demand-side management (DSM) programs are typically analyzed using a benefit-cost framework. This chapter defines the most common benefit-cost tests used, discusses their uses, and explores technical and policy issues that arise in their application. The benefit-cost tests currently used by many PUCs have their roots in a report developed by the California Energy and Public Utilities Commissions: *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs* (California Public Utilities Commission (CPUC) and California Energy Commission (CEC) 1987).[1] PUCs have also derived their benefit-cost tests from the NARUC's publication *Least-Cost Utility Planning: A Handbook for Public Utility Commissioners Volume 2* (Krause and Eto 1988).

In principle, a benefit-cost test is the same whether it is applied to electric or gas DSM programs. Issues arise in applying the tests, primarily because of differences in industry structure. A total accounting of the benefits and costs of a gas utility DSM program will involve more entities because gas local distribution companies (LDCs) are not as vertically integrated as electric utilities. Methods and levels of avoided costs also differ between the two industries (see Chapters 2 and 5). Gas LDC services are unbundled for many customers, so the fuel cost savings of a DSM measure may not entirely flow through the LDC. Further, demand for natural gas services is generally more variable than demand for electricity and, from the perspective of the LDC, demand uncertainty is even greater due to competition from non-LDC gas suppliers and bypass pipelines.

Benefit-cost tests can be used for evaluating a variety of DSM activities, including conservation, load management, fuel substitution, and load building.[2] LDCs primarily use the benefit-cost tests as screening tools; that is, they are mostly used for winnowing large numbers of DSM program options. An LDC's ultimate decision to pursue a DSM program includes other factors in addition to the standard benefit-cost tests (see Chapter 3).

[1] One of the first papers to address the benefit-cost tests for conservation programs was a paper by White (1981).

[2] To keep the terminology as simple as possible, most of the examples will assume that the DSM program is a conservation program.

This chapter is structured as follows. Definitions and discussions of the most common benefit-cost tests are provided in Section 6.2.[3] Important technical complexities to the benefit-cost tests are addressed in Section 6.3. Examples of the tests are provided for both energy efficiency and fuel substitution programs. Section 6.4 discusses policy topics including: (1) the role of benefit-cost tests in the broader integrated resource planning (IRP) process, (2) the ongoing debate over the Total Resource Cost and Ratepayer Impact Measure tests, (3) frameworks for examining DSM markets and the existence of market imperfections and (4) alternatives to the standard benefit-cost tests.

6.2 The Benefit-Cost Tests

Benefit-cost tests provide useful economic figures of merit as seen from the perspective of different affected parties. Some of the most important perspectives are those of the (1) customers participating in the utility's DSM program (participants), (2) customers who did not participate in the utility's DSM program (nonparticipants), (3) the utility, (4) all utility customers, and (5) all people in a region or society.

For each perspective, benefit-cost tests show the net economic gain or loss that results from the pursuit of a DSM program. The gain or loss is measured by tallying up the program's costs and benefits and is expressed in terms of net benefits (NB) or as a benefit-cost ratio (BCR). Programs are cost-effective if the NB is greater than zero or if the BCR is greater than 1.0. In algebraic terms,

$$NB = B - C \tag{6-1}$$

or

$$BCR = \frac{B}{C} \tag{6-2}$$

The definitions of equation symbols used in all the equations presented in this chapter are provided in Table 6-1. In general, Equations 6-1 and 6-2 can be computed using benefits or costs stated on an annualized or present-value basis. For consistency, the following discussion and examples of the tests assume that the tests are computed on a present-value basis.

[3] To keep the discussion from being weighed down by technical equations, only simplified forms of the benefit-cost test equations are presented here. Readers interested in detailed equations are referred to Krause and Eto (1988), EPRI (1991a), and RCG/Hagler Bailly Inc. (1991).

Table 6-1. Definitions of Terms (in order of appearance)

NB	=	net benefit
BCR	=	benefit-cost ratio
B	=	program benefits
C	=	program costs
p	=	participants perspective
BR	=	bill reductions from DSM program
I	=	measures paid for by utility or incentives paid to participating customers
DC	=	direct cost of DSM measures (regardless of whether paid for by the utility or participant)
np	=	nonparticipants perspective
SCS	=	supply and/or capacity cost savings
RL	=	lost revenues
UC	=	utility program administration costs including shareholder incentives but excluding incentives paid to participating customers
u	=	utility perspective
tr	=	total resource perspective
s	=	societal perspective
NB_{ext}	=	net benefit of any externality impact of DSM program

Table 6-2 summarizes relevant costs and benefits for each of the perspectives and provides an overview of the equations that will be described below. The net benefit from any one of these perspectives may be computed as the sum of all the relevant costs and benefits. Notice that two of these items—customer incentives and bill savings—are costs to nonparticipants but are benefits to participants. Figure 6-1 also provides an overview of the benefit-cost tests in a way that emphasizes the relationships among them. The figure shows that the Total Resource perspective is the sum of the Participant and Nonparticipant perspectives. The Utility perspective plus the addition of lost revenues equals the Nonparticipant perspective. Finally, the Societal perspective may be seen as the sum of the Total Resource perspective plus the net environmental benefits of the DSM program.

Table 6-2. Components of the Standard Benefit-Cost Tests

	Perspective				
Cost or Benefit Component	Participants	Non-participants	Utility	Total Resource	Society
1. Participant Commodity Cost Savings†	B			B	B
2. Utility Supply or Capacity Cost Savings‡		B	B	B	B
3. Utility Program Administration Costs*		C	C	C	C
4. Incentives Paid to Customers	B	C	C		
5. Lost Revenues/ Utility Bill Savings	B	C			
6. Direct Cost of DSM Measures§	C			C	C
7. Externality Impacts					B or C

B = Benefit

C = Cost

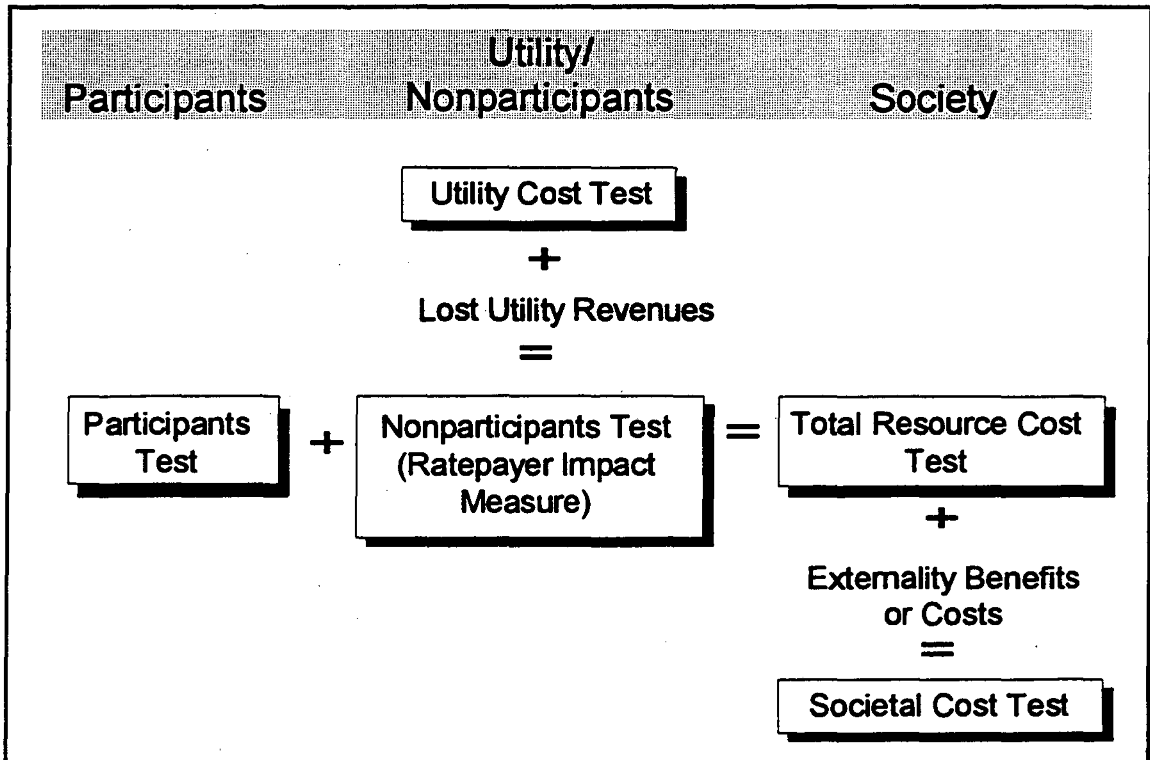
† Participant Commodity Cost Savings applies only to transport-only customers; otherwise, reduced commodity costs are reflected in the utility bill savings.

‡ Includes both avoided gas commodity and gas capacity cost savings.

* Utility Program Administration Costs includes any incentive payments made to shareholders.

§ Direct Cost of DSM measures includes all measure costs before any utility rebates.

Figure 6-1. Interrelationship of Standard DSM Benefit-Cost Tests



Source: Adapted from Washington Natural Gas (1992)

6.2.1 Participant Perspective

From the perspective of Participants, costs include the cost of the DSM measure, installation costs (including the cost of time lost by the participant during the installation), and the incremental operation and maintenance costs associated with the measure. From the participant's view, costs do *not* include the utility's program administration costs.

On the benefits side, the participant receives reduced utility bills from the DSM measure. The reduced bills are estimated using estimates of the consumption impacts of the DSM programs and the relevant LDC tariffs.[4] Bill savings may also come from the DSM measure's impact on other fuels. The customer may also receive an incentive from the

[4] As a simplification for screening purposes, bill savings are computed simply as the product of energy savings and the average or incremental rate for the customer.

utility in the form of a rebate or a subsidized loan. These payments to the participant are additional benefits. If a customer is *given* a DSM technology, such as a gas water heater wrap, the customer may never incur any out-of-pocket costs. It is standard, however, for the Participant test to include both the DSM measure cost and the utility incentive (rebate) payment and, in the case of utility "give always," the rebate simply cancels out the measure costs.

In algebraic terms, the Participant test is defined as follows:

$$NB_p = BR + I - DC \tag{6-3}$$

It is important to note that the standard formulation of the Participant test does not include the utility's supply cost savings (SCS). For sales customers of the LDC, the SCS obtained by the LDC are passed onto the participant in the form of a bill reduction (BR). Modifications to the Participant test for the case of transport-only customers is discussed in Section 6.3. It is also important to note that the standard formulation of the Participant test ignores the impact of any participant rate changes. It is, instead, convention to have the Nonparticipants test be a measure of all rate impacts. More sophisticated formulations of the Participant test can include the effects of any participant rate changes as well as the any participant energy services charges.[5]

6.2.2 Nonparticipant Perspective

Nonparticipants are utility customers who are either ineligible or chose not to participate in a utility DSM program. Their perspective is evaluated using the Nonparticipant test. Although called the Nonparticipant test, the test may be seen as measuring the rate impact on all ratepayers, even participants.[6] For this reason, the test is also known as the Ratepayer Impact Measure (RIM). The No-Losers test is yet another name for this test.

From the perspective of nonparticipants, the benefits of a DSM program consist of the supply costs savings obtained by the DSM program. Supply cost savings are computed as the product of the change in consumption and the LDC's avoided costs. Although ratemaking practices may not flow the supply cost savings immediately to the nonparticipating ratepayers, under the practice of cost of service regulation, it is reasonable to assume that utility cost reductions eventually accrue to the benefit of ratepayers.

[5] Energy service charges for DSM are discussed in Chapter 6.

[6] Because it is convention for the Participant test to not consider rate impacts caused by DSM programs, there is no double counting of rate impacts when the Participant and Nonparticipant tests are summed.

On the cost side, nonparticipants are generally charged the utility's cost of the program, including incentives and program administrative costs. Further, nonparticipants can be expected to absorb revenue requirements that the participants were relieved of when the participants' bills went down. These revenues are called *lost revenues*.

In algebraic terms, the Nonparticipant test is defined as follows:

$$NB_{np} = SCS - RL - UC - I \qquad (6\text{-}4)$$

The Nonparticipant test may be seen as an overall measure of the impact on *rates* resulting from the adoption of a DSM program. A rough estimate of the rate impact may be computed using the Nonparticipant test by taking the negative of the NB_{np}, levelizing it using an annuity factor computed using a discount rate and program life, and dividing it by after-program sales in each year. The resulting rate (in $ per therm) would be the average rate impact of the program. To compute the rate impact as a percentage rate increase, the annualized value should be divided by the total revenue requirement in each year of the program. In general, the Nonparticipant test will produce a negative net benefit, and a positive rate increase, whenever the utility's rates are above its avoided cost of serving the participating customer class.

A notable characteristic of the Nonparticipant test is that it is affected by the rates of the participant, not the nonparticipant. If rates for participating customers are above avoided costs, the Nonparticipant test will be negative. Another characteristic of the Nonparticipant test is its implicit assumption that *all* DSM program costs (program administration, incentives, and shareholder incentives) and lost revenues are passed through to ratepayers rather than shareholders. This is a reasonable assumption over a long period of time (a time greater than the LDC's typical rate case cycle). The test, however, may be an inaccurate measure of nonparticipant impacts in the short run because during that time revenue losses and, possibly, program costs may be shared between ratepayers and shareholders.[7] It is possible to develop a test that focuses specifically on the shareholder perspective but such a perspective is not a part of the standard array of benefit-cost tests.

[7] Shareholders will not share in lost revenues if the utility is allowed to make up the lost margin before the next rate case via a net loss revenue adjustment mechanism or revenue decoupling mechanism. See Chapter 9.

6.2.3 Utility Perspective

A simple test for the impact of a DSM program on a utility's revenue requirement is included in the standard array of benefit-cost tests. The Utility Cost (UC) test is defined as follows:

$$NB_u = SCS - UC - I \qquad (6\text{-}5)$$

Although called the Utility Cost test, this test does not measure impacts on a utility's management or stockholders. Instead, the Utility Cost test compares a utility's supply cost savings to the utility's cost of delivering a DSM program. As such, the Utility Cost test makes the evaluation of a DSM program similar to methods that evaluate potential gas supply options. An LDC may face a range of technologies (on both the supply and demand side) available to meet its future demands and the Utility Cost test, which focuses on revenue requirements, requires that technologies with the lowest cost to the utility be chosen.

The Utility Cost test may also be seen as a measure of the change in the average energy *bills* for all customers. Assuming the number of customers in the with- and without-DSM cases are the same, the Utility Cost test measures the net change in utility costs and this change in costs will ultimately be allocated to ratepayers. A consideration of average bill impacts can be important in a situation where a utility's avoided costs are below incremental rates. In such a situation, a cost-effective DSM program is likely to result in a negative net benefit from the Nonparticipant perspective but produce a positive net benefit from the Utility Cost perspective. This means that although average rates will rise as a result of a DSM program, average bills to all ratepayers will go down.

The Utility Cost test is similar to the Nonparticipant test except that lost revenues are not considered a cost. Lost revenues, although a cost to nonparticipants, do not add to a utility's revenue requirement.

6.2.4 Total Resource/Total Technical Perspective

The Total Resource Cost (TRC) test takes the broadest perspective on private costs and benefits in evaluating the net benefits of a DSM program.[8] As may be seen from Figure 6-1, the TRC is roughly the sum of the Participant and Nonparticipant tests. Revenue losses and customer incentives that adversely affect nonparticipants are largely cancelled out by the bill savings and incentives received by the participants. All that is left is the

[8] Private costs and benefits exclude externalities.

direct costs of the DSM measures and the benefits from the utility's avoided costs.[9] Because the TRC represents the combination of the Nonparticipant and Participants tests, it is sometimes called the All-Ratepayers Test. The TRC is defined as:

$$NB_{tr}=SCS-UC-DC \tag{6-6}$$

With the TRC test, the utility-to-customer incentive is not considered a cost. Although this incentive is a cost to the utility, it is cancelled out by the benefit received by the participating customer.

It is generally accepted that shareholder incentives are a cost to be included in the UC term of the TRC test. Shareholder incentives may be considered a management fee paid to stockholders to assure the efficient delivery of a DSM program.[10]

Like the Participants test, the TRC test should measure the costs and benefits of a DSM program across all affected fuel types. This is an important consideration for many gas DSM programs. For example, a fuel substitution program that promotes gas-powered chillers over electric chillers will actually increase the gas supply costs. The electric supply cost savings may exceed the added gas supply costs, however.

A variant of the TRC test is the Total Technical Cost (TTC) test. The TTC test is like the TRC test but does not include any program administration costs. The TTC test may be computed by using Equation 6-6 and setting the UC term to zero. The TTC test is considered useful by some states as a screening tool for the development of a portfolio of DSM measures. When the TTC test is used, program administration costs are added to the portfolio of measures at a latter stage to insure the total portfolio is cost effective using the TRC test.

[9] There are a few reasons why the sum of the net benefits from the Participant and Nonparticipant perspectives will not always sum to the TRC. First, different discount rates may be used for different perspectives. Bill savings for the Participants test may be discounted at a different rate than the revenue loss of the Nonparticipant and they will not cancel each other. Second, it is standard to include the gross energy savings (including energy savings obtained by free riders) in the Participant test but only include net savings in the Nonparticipant test.

[10] Some analysts have argued that shareholder incentives based on shared savings are not a true cost to be counted in the TRC test but are, instead, simply a transfer of a portion of the net benefits from ratepayers to shareholders.

6.2.5 Societal Perspective

The Societal test has been developed to address concerns that there are unpriced impacts, known as externalities,[11] caused by energy consumption:[12]

$$NB_s = SCS + NB_{ext} - UC - DC \tag{6-7}$$

Societal externalities are often identified as environmental externalities caused by natural gas production and consumption. The most common environmental externality considered is air pollution impacts including greenhouse gas pollutants. Whereas air quality impacts of electricity production occur primarily at the source of production, natural gas air quality impacts tend to occur at the point of consumption. Other environmental externalities, such as land or water use impacts could also be considered. Nonenvironmental externalities can also be considered and include the impact of changes natural in gas production and consumption on the local economy and on the Nation's trade deficit and reliance on foreign energy sources.

Unlike the other benefits and costs that have been identified so far, the estimation of externality values are controversial due to the inherent uncertainty of trying to assign monetary values to them. Several PUCs have included certain environmental externalities in their long-term electric resource planning process and at least 18 PUCs consider the use of externalities in their gas IRP or DSM planning processes (National Association of Regulatory Utility Commissioners (NARUC) 1992). Compared to electric resource planning, however, the development of externality values for natural gas consumption is unlikely to receive the same level of regulatory focus given that natural gas burns cleaner than other fossil fuels. One way gas combustion externalities will arise in a gas IRP context is in the examination of fuel substitution programs. Natural gas utilities in several states have developed externality values for gas combustion, along with externality values for electricity generation, to allow for a computation of the Societal test for fuel substitution programs. (See Chapter 5.)

Example calculations of the benefit-cost tests are presented in Exhibit 6-1, Table 6-3, and Figure 6-2 for a hypothetical DSM program wherein a gas LDC promotes the purchase of high efficiency residential gas furnaces.

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[11] An externality is a benefit or cost resulting from the production or consumption of goods in a market that accrues, unpriced, to a party outside that market. Inefficiencies result because, even if the market equates private costs and benefits on the margin, the externality goes unpriced and causes a level of consumption that is not optimal from a societal perspective.

[12] Some states have modified their TRC test to include the effects of externalities rather than create a new test. In this primer, the incorporation of externalities is reserved for the Societal Cost test.

Exhibit 6-1. Benefit-Cost Analysis for a Hypothetical High Efficiency Gas Furnace Program

To illustrate how benefit-cost tests are used to analyze gas DSM programs, a hypothetical program promoting high-efficiency furnaces is analyzed. The basic data and assumptions regarding the program are shown in Table 6-3. The program should be considered hypothetical, but numbers typical for gas utilities and the DSM technology were chosen. Avoided costs are estimated based on national average prices for natural gas delivered to LDCs and assumptions were made regarding the degree of seasonal variation in avoided costs and the amount of pipeline demand charges that are avoidable. Retail rates are based on national average data (American Gas Association 1992). Escalation rates are based on a recent GRI forecast (Holtberg 1993). With regard to discount rates, an 8% real discount rate is used for participants and a 6% real discount rate is used for all other perspectives. (See Section 6.3.1 for a discussion of discount rates.)

The program offers a $300 incentive to induce customers into buying a high efficiency condensing furnace. The example generally assumes that the participating customers would already be in the market for a furnace so the cost associated with the energy efficient technology is only its incremental cost over the standard technology. The analysis looks at the lifetime benefits and costs that come from one year of participating customers—400 in total. To implement the program, the utility will spend $40,000 in program administration costs, 25% of its total payout in incentives.

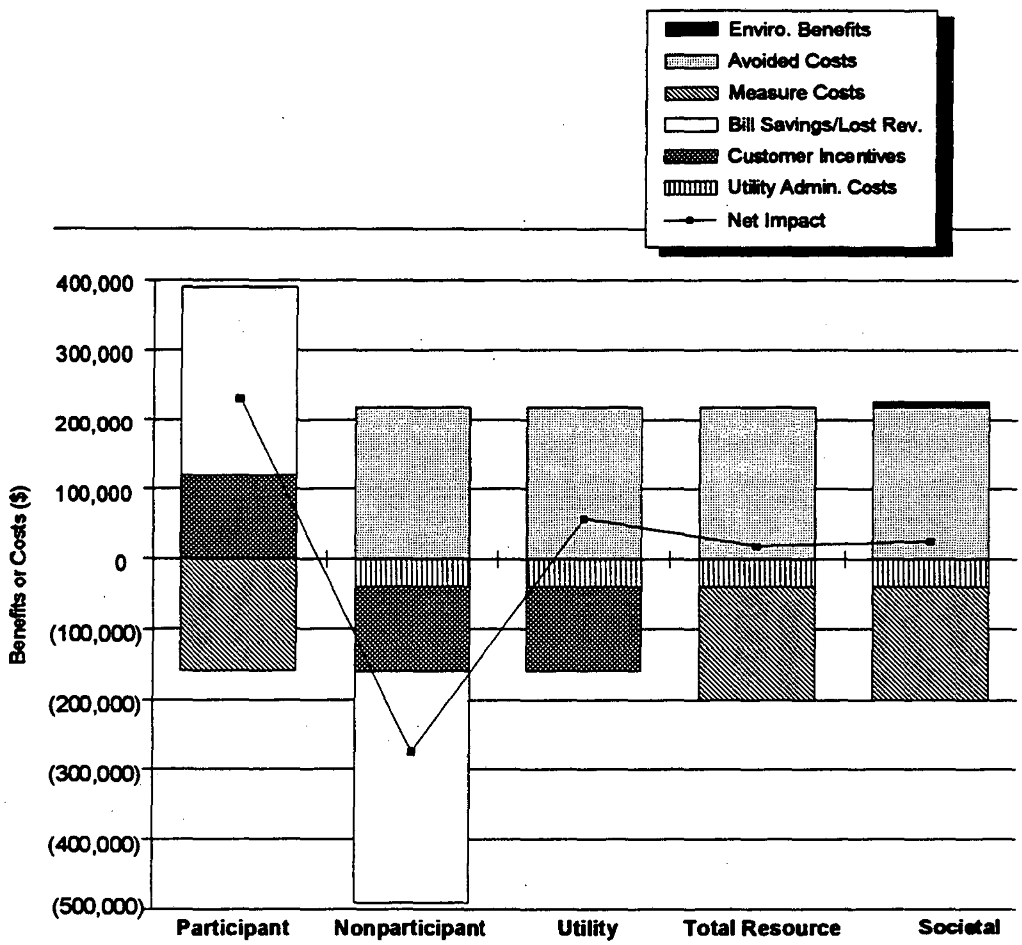
Results for the program are shown in Figure 6-2. The program is clearly a winner for participants with a net benefit of $230,000, a BCR of 1.43. For nonparticipants, the revenue loss, incentives, and program administrative costs exceed the supply cost savings and results in a loss of $274,000. The program shows positive net benefits for the Utility Cost and Total Resource Cost tests of $58,000 and $18,000, respectively. An important caveat to these net benefit figures is that it takes a considerable time, approximately 10 years, before the accrued avoided cost benefits outweigh the DSM measure costs. Thus, results would be very different if the gas avoided cost escalation rate was lower than the chosen rate of 2.5%/yr. Note also that the Participant and Nonparticipant tests do not sum to the TRC test because the bill savings seen from the Participant perspective is discounted at a different rate than the revenue loss seen from the Nonparticipant perspective.

If the reduced emissions from residential furnaces are considered, the net benefit increases by $7,000 to a total of $25,000. Reduced emissions in this example are valued at $0.015/therm, using estimates by Atlanta Gas Light in its recent IRP plan (Atlanta Gas Light Company 1992).

Table 6-3. Summary of Program Data for Residential High Efficiency Furnace Program

(1993 dollars unless otherwise noted)	
GENERAL ASSUMPTIONS	
Discount Rates (real)	
Participant	8%
All other perspectives	6%
No of participants	400
Effective life of measure (yrs)	30
PER CUSTOMER DSM PROGRAM DATA	
Gas load impacts, winter only (th/yr)	88
Incremental gas DSM measure costs	400
UTILITY COSTS	
Utility incentive, per customer	300
Utility costs, administration	40,000
AVOIDED COSTS (AC)	
Winter energy ($/th)	0.33
Real annual escalation in AC	2.50%
RATES	
Winter energy ($/th)	0.63
Real annual escalation in rates	0.70%

Figure 6-2. Benefit-Cost Tests for a Residential High Efficiency Gas Furnace Program



Costs and Benefits by Perspective (1993 Dollars)

Component	Participant	Nonparticipant	Utility	Total Resource	Societal
Customer Incentives	120.000	(120.000)	(120.000)		
Bill Savings/Lost Rev.	269.709	(332.483)			
Measure Costs	(160.000)			(160.000)	(160.000)
Avoided Costs		218.301	218.301	218.301	218.301
Utility Admin. Costs		(40.000)	(40.000)	(40.000)	(40.000)
Enviro. Benefits					7.268
Net Impact	229.709	(274.182)	58.301	18.301	25.569

Note: positive numbers are benefits. negative numbers are costs

6.3 Technical Issues in Application of Benefit-Cost Tests

6.3.1 Discount Rates

DSM measures represent investments in capital to obtain a stream of energy saving benefits over time. The trade-off between a dollar invested today and benefit realized in the future is done using discount rates (also known as the *time value of money* or the *opportunity cost of capital)*. Different discount rates are sometimes used for the different perspectives.[13] Various methods for choosing discount rates are briefly discussed in this section; see EPRI (1991a) for additional discussion.

When the DSM program is sponsored by the utility, it is common to apply the utility's cost of capital to the utility perspective. Often the utility's weighted average cost of capital (WACC) is used as a proxy for the utility's marginal cost of capital, although in theory the appropriate discount rate is one that reflects the utility's cost of incremental capital with proper adjustments (up or down) for risks associated with the DSM program.

For energy utility customers participating in the DSM program, there are two general approaches for determining the discount rate. The first is to look at the cost of funds available to consumers in real-world financial markets. Mortgage rates or credit card rates are commonly-used indicators of discount rates to small consumers. The second approach is to look at the implicit discount rates that customers apply in making decisions regarding energy services. For example, it is possible to compute discount rates based on aggregate data on purchases of efficient and inefficient appliances where customers are trading off first costs against future energy savings.

Nonparticipant discount rates may also be set by estimating the cost of funds to nonparticipating customers. A common simplification, however, is to simply set the nonparticipant's discount rate at the utility's discount rate.

For the TRC and Societal perspective, either the utility's cost of capital is used or there is an attempt made at computing a social discount rate. The utility's cost of capital is often used because it is the utility who is sponsoring the DSM program and will have to finance the DSM measures. Others advocate the use of lower discount rates for the Societal perspective. Social discount rates have been estimated by looking at discount rates on very-low-risk, long-term investments, such as 30-year Treasury Bills. Proponents of such methods argue that utility DSM programs affect a wide range of

[13] It is preferable to use the marginal opportunity cost of capital for all tests as opposed to a historical cost of capital or an average cost of capital.

people for a long period of time and that societal discount rates should be used as a matter of equity for future generations who will have to live with the effects of long-term energy resource decisions that they had no say in.

Finally, some analysts strongly reject the notion that discount rates should vary by perspective. Instead, one discount rate should be used that reflects the risk-adjusted discount rate appropriate for the DSM *program* (Alexis 1993). To estimate this discount rate, one would estimate the cost of capital if the DSM program operated as a venture separate from the utility. The variation in cash flows from the (hypothetical) stand-alone DSM program would be estimated. The cost of capital would be equal to the cost of capital of other investments available with similar variation in cash flows.

6.3.2 Free Riders and Drivers

In certain utility DSM programs, some participating customers would have installed the promoted DSM measure even if they were not provided an incentive. These types of customers are known as *free riders*. A particular participant may be free rider in one year but not in another. For example, a customer may have adopted an energy efficient technology five years out regardless of the existence of a utility program but adopted the technology immediately due to a utility program. This customer is a non-free rider for the first four years, but is a free rider from year five onwards. Similarly, a customer may be a free rider for only part of his or her savings. For example, a utility program that promotes buildings that are 30 percent more efficient than current building codes should not count the savings made by customers that would, even without a program, build in efficiency in excess of the building codes by 15 percent. In this case, a portion of the savings from free riders should be excluded.

With respect to the standard benefit-cost tests, the nonparticipant, utility, and total resource perspectives should be adjusted to incorporate savings after the effects of free riders are taken into account. This is typically done by applying a "net to gross" ratio (equal to the fraction of participants who are not free riders) to the energy savings. In the case of the Nonparticipant test, the net-to-gross ratio is also applied to the lost revenues and, for the TRC test, the net-to-gross ratio is applied to the measure costs. Utility program administration costs are usually unadjusted under the assumption of free riders. Because both the measure costs and supply cost savings of free riders are excluded, the net effect of free riders on the TRC test is typically much smaller compared to its effect on the Nonparticipant or Utility Cost tests (see Exhibit 6-2).

Free drivers are customers who modify their behavior as a result of a utility program but to a greater degree or at a lower cost than a standard participant. For example, a free driver might adopt the measure promoted by the utility but never bother to apply for the

Exhibit 6-2. The Effect of Free Riders

Figure 6-3 provides an example of the effect of free riders on the high efficiency furnace program presented in Exhibit 6-1. The example assumes that 35% of the participating customers who receive the utility's $300 incentive would have bought a high efficiency furnace anyway.

Free riders have no effect on the results for the Participants test, because it is standard to base the test on gross energy savings, which includes savings obtained by free riders. Results diverge, however, for the Nonparticipant, Utility Cost, and TRC tests. In the Nonparticipant test, only net lost revenues are included—a certain amount of revenues would have been lost anyway to the free rider participants. Similarly, the avoided costs are reduced because only the net participants really save the utility supply-side costs relative to the base case. Because avoided costs are lower than incremental rates in this example, the net benefit increases to -$234,000 from -$274,000. From the utility's perspective, costs do not change, but benefits decrease. In effect, the utility must make a business decision to pay customers for measures they would have installed anyway as a way of reaching all possible participants including those that generate real savings. The result of free riders in this example is a decrease in the Utility Cost test from $58,000 to -$18,000. For the TRC and Societal tests, supply cost savings, direct measure costs, and environmental benefits (if applicable) are both reduced and the program net benefits hover near zero.

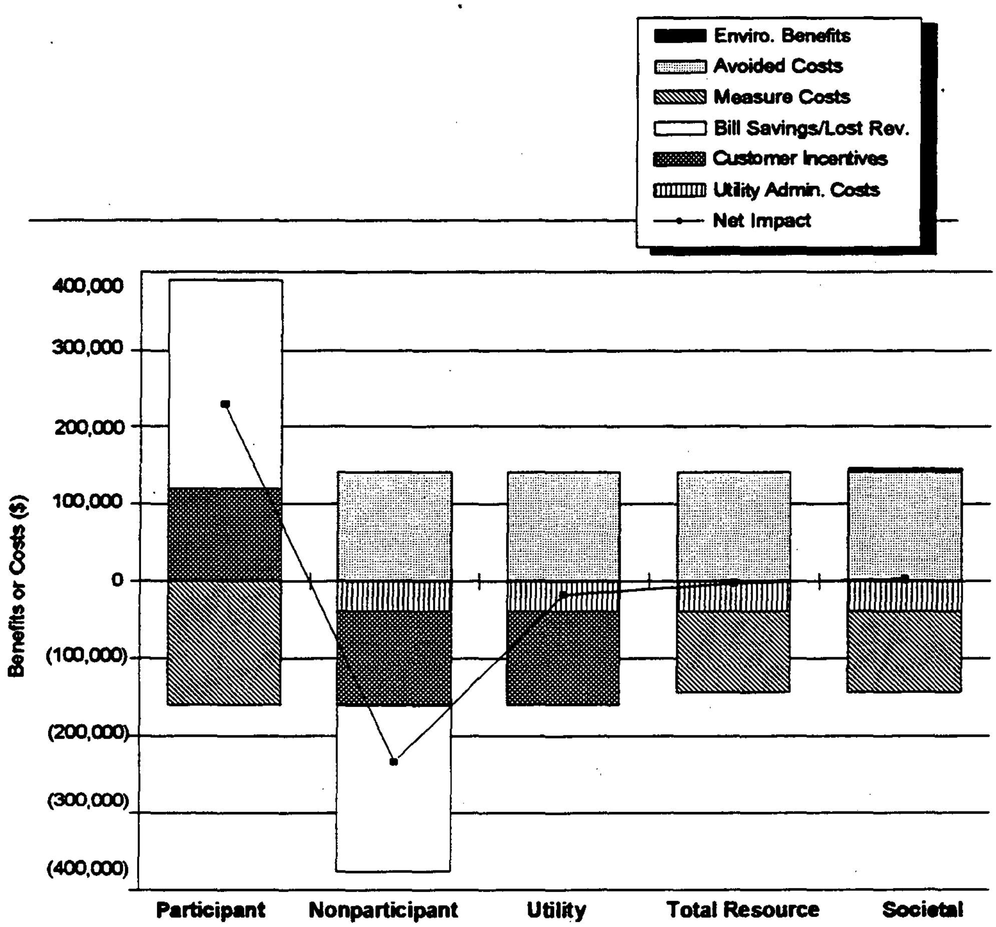
utility rebate. Another example of free drivership is when participating customers pay greater attention to energy efficiency in purchase decisions made subsequent to the conclusion of the utility's program. Free drivers can be incorporated into the benefit-cost tests by either increasing the energy savings attributable to the program and/or decreasing the program incentive payments per unit of energy saved.

6.3.3 Program and Administrative Costs

For purposes of analyzing a proposed DSM program, it is necessary to identify the cost of running a utility DSM program. Program and administrative costs can include several types of costs such as development, start-up, administrative, promotion/advertising, and monitoring and evaluation (M&E).[14] Shareholder incentives, if any, should generally be included in program and administrative costs. Although shareholder incentives are not a "cost" to the utility they are usually considered to be an added cost to nonparticipants,

[14] Utility program and administrative costs should not include the actual incentive paid to the participating ratepayer even if the utility buys or installs the measure itself. Such costs should be measured in the incentive payment (I) term

Figure 6-3. Benefit-Cost Tests for a Residential High Efficiency Gas Furnace Program with Free Riders



Costs and Benefits by Perspective (1993 Dollars)

Component	Participant	Nonparticipant	Utility	Total Resource	Societal
Customer Incentives	120.000	(120.000)	(120.000)		
Bill Savings/Lost Rev.	269.709	(216.114)			
Measure Costs	(160.000)			(104.000)	(104.000)
Avoided Costs		141.896	141.896	141.896	141.896
Utility Admin. Costs		(40.000)	(40.000)	(40.000)	(40.000)
Enviro. Benefits					4.724
Net Impact	229.709	(234.218)	(18.104)	(2.104)	2.620

Note: positive numbers are benefits, negative numbers are costs

Table 6-4. Participation Variables Used to Project Utility Program and Administrative Costs

	Cost Driver		
Cost Item	New Participants	Cumulative Participants	Fixed
Program Management		X	X
Clerical Support		X	X
Field Support		X	X
Audits	X		
Site Visits	X		X
Measure Cost	X		
Measure Installation	X		
Measure O&M		X	
Inspection	X		
One-time Incentive Processing	X		
Ongoing Incentive Processing		X	
Removal & Reinstallation	X	X	
Monitoring	X	X	X
Evaluation	X	X	X

Source: EPRI 1991a

revenue requirements (as measured in the Utility Cost test), and to all ratepayers (as measured by the TRC test).

A challenge in analyzing a DSM program is how to accurately estimate all the utility's program and administrative costs and determine which ones to associate with particular DSM programs. Table 6-4 identifies 14 types of distinct costs and indicates whether the cost is likely to be driven by new participants, cumulative (existing) participants, or is fixed regardless of the size of the DSM program.

Some program costs, such as measurement and evaluation (M&E) costs, are driven by more than one factor. The overall purpose of M&E is to see how the program performs over time and whether it performs as initially estimated. For every new participant, there are costs associated with including the participant in the M&E program. Once included, there are ongoing costs associated with the continuing monitoring of the participants and any control group. Finally, there are fixed costs associated with the overall corporate M&E capability and the analysis of DSM program effectiveness. It may make sense to associate the per participant and cumulative M&E costs with a particular program but assign the fixed M&E costs to the utility's entire DSM portfolio. If the M&E program is set up to reduce the uncertainty surrounding the delivered savings of a particular program or to provide information to make mid-course corrections, then it is clear that the M&E costs should be assigned to a particular program or set of programs. Whether to include these costs as a cost of a particular DSM program or a portfolio of programs can, however, depend on the purpose of the M&E effort. Given that a gas utility DSM programs are relatively novel, some of a utility's M&E function may be considered a type of research and development and should not be associated with any particular program currently proposed by the utility.[15]

If significant effort has been made to accurately estimate utility program and administrative costs one should, for the sake of accuracy, check that similar costs were included in proposed supply options as well.

6.3.4 Analysis of Programs that Affect Multiple Fuels

Many DSM measures can affect the consumption of more than one fuel. For example, in the case of improvements to building shell efficiency there is a reduction in the use of all fuels used to provide heating. Even if gas is the primary space heating fuel, there may be incidental impacts on wood use or electric use. Electricity consumption may be further reduced if the building has an electric air conditioner.

If the effects of a gas DSM measure on the consumption of other fuels is quite small, the impacts are typically excluded from the benefit-cost tests. For some DSM programs, however, a major goal is to impact multiple fuels (e.g., fuel substitution programs that promote a gas technology as a substitute to an electric technology). In such cases, the Participant, TRC, and Societal tests should include the impact of both fuels. This adds complexity to the analysis but is necessary to insure that positive net benefits accrue to participants and to all ratepayers or society as a whole. Although the Participant, TRC, and Societal Cost tests should be evaluated across all affected fuel types, the Nonparticipant test and the Utility Cost test should first be evaluated for the customers of each utility because customers of one affected fuel type may have little or no overlap of customers of another fuel type. Once such single-fuel tests have been computed, it may be useful to combine the Nonparticipant or Utility Cost test across all affected fuels. Combined tests show the average rate impact (Nonparticipant test) or revenue requirement impact (Utility Cost test) of the program within the combined set of utility service territories (see Exhibit 6-3).

[15] Apparently because of the research function that M&E provides, California's *Standard Practice Manual* recommends excluding all M&E costs from the utility's program administration costs (California Public Utilities Commission (CPUC) and California Energy Commission (CEC) 1987).

Exhibit 6-3. Benefit-Cost Analysis for an Electric-to-Gas Fuel Substitution Program

A hypothetical program that promotes the use of air conditioning powered by gas-driven chillers over conventional electric chillers illustrates some issues that arise in the economic analysis of fuel substitution programs. Table 6-5 summarizes assumptions and relevant data on costs, savings, and utility rates. Target customers are operators of commercial buildings that are considering the purchase of an electric chiller either to replace an existing one or because their building is under construction. The incremental cost of a gas driven chiller is $25,000 per building and the utility is offering an incentive of $12,500. Under the utility's tariff, commercial customers pay $0.55/therm, which is a national-average rate. Incremental gas supply costs are lower than the avoided costs presented in Exhibit 6-1 because the increased gas use will occur in the summer. Electric avoided costs and rates are roughly based on an electric utility that has deferrable gas-fired resources in its resource plan. Forecasted escalation rates are from GRI (1993).

To fully analyze program impacts, both gas and electric customers should be considered. For the Participant and TRC tests, the impact of increased gas supply costs and decreased electric supply costs are incorporated. Separate Nonparticipant tests are developed for gas and electric customers, however. Participants have a net benefit of $8.7 million (see Figure 6-4). The benefits come primarily from the electricity bill savings. In comparison, the gas utility's incentive payment is small.

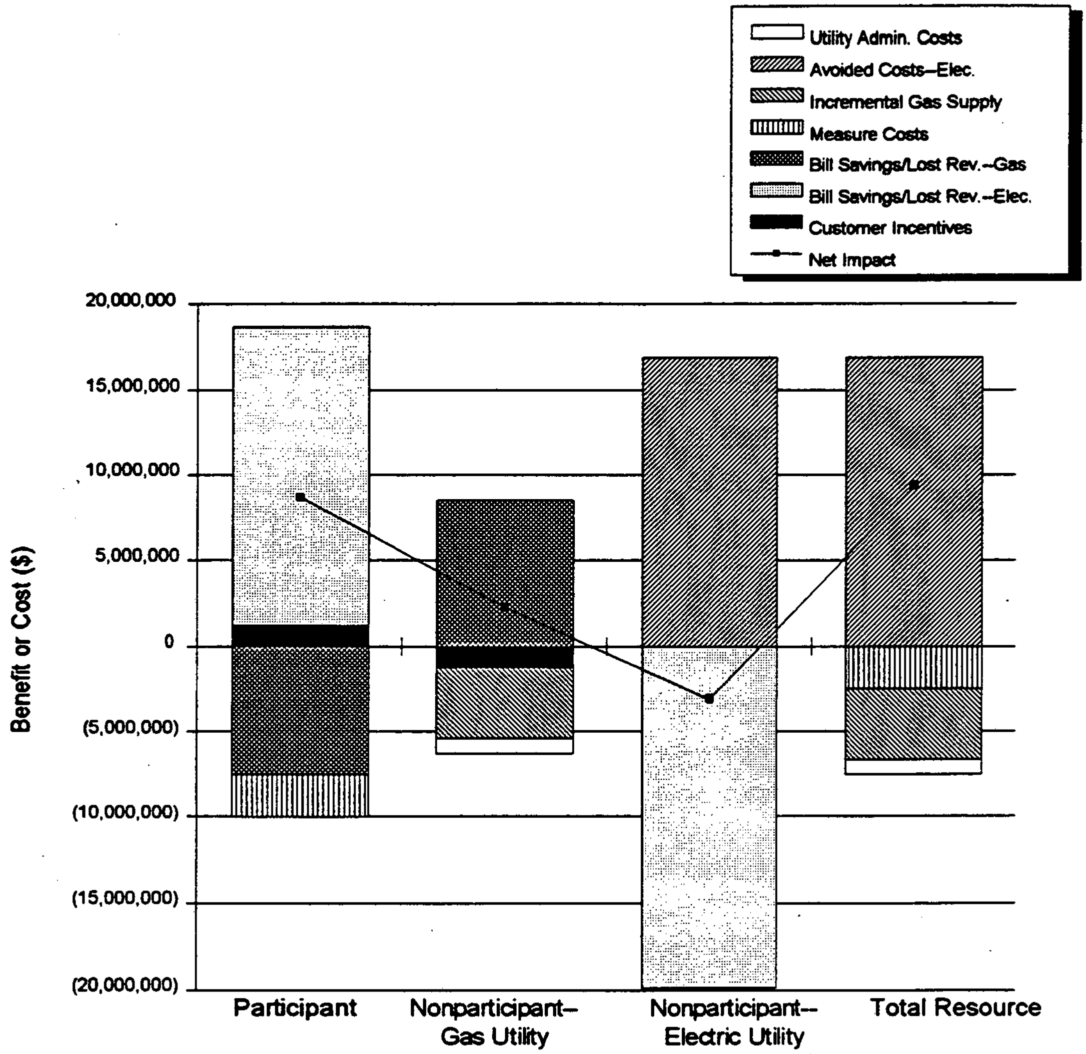
To nonparticipating customers of the gas utility, the program also provides benefits because the incremental revenues outweigh the extra gas supply costs, incentive payments, and program administration costs. The program provides negative benefits to nonparticipating customers of the electric utility, because the avoided cost benefits are exceeded by lost revenues.

From the Total Resource perspective, the benefits of the program are the electric avoided cost savings net of the incremental gas costs, measure costs, and program administrative costs. In this example, the net benefit of the program using the TRC test is $9.4 million.

Table 6-5. Summary of Program Data for an Electric-to-Gas Driven Chiller Program

(1993 dollars unless otherwise noted)	
GENERAL ASSUMPTIONS	
Discount Rates (real)	
Participant	8%
All other perspectives	6%
Rate class of participants	commercial
Number of participants	100
Effective life of measure (yrs)	15
PER CUSTOMER DSM PROGRAM DATA	
Gas load impact, summer only (th/yr)	-15,000
Annual Electric Load Impacts	
Demand summer on-peak (kW)	126
Energy summer on-peak (kWh)	131,888
Energy summer off-peak (kWh)	43,963
Gas-driven chiller incremental cost	25,000
UTILITY COSTS	
Gas utility incentive, per customer (@ $100/ton)	12,500
Gas utility costs, administration	2,500,000
AVOIDED COSTS (AC)	
Gas AC = Incremental Supply Costs	
Summer energy ($/th)	0.24
Real annual escalation in AC	2.50%
Electric AC	
Demand summer on-peak ($/kW/mo)	10.83
Energy summer on-peak ($/kWh)	0.04
Energy summer off-peak ($/kWh)	0.04
Real annual escalation in energy AC	2.40%
RATES	
Incremental summer gas rate ($/th)	0.55
Real annual escalation in rates	0.90%
Incremental Electric Rates	
Demand summer on-peak ($/kW/mo)	16.25
Energy summer on-peak ($/kWh)	0.06
Energy summer off-peak ($/kWh)	0.06
Real annual escalation in rates	1.60%

Figure 6-4. Benefit-Cost Tests for an Electric-to-Gas Fuel Substitution Program: Commercial Gas Cooling



Costs and Benefits by Perspective (1993 Dollars)

Component	Participants	Nonparticipant Gas Utility	Nonparticipant Electric Utility	Total Resource
Customer Incentives	1,250,000	(1,250,000)	0	0
Bill Savings/Lost Rev.–Gas	(7,523,917)	8,562,779	0	0
Bill Savings/Lost Rev.–Elec	17,467,841	0	(19,926,093)	0
Measure Costs	(2,500,000)	0	0	(2,500,000)
Incremental Gas Supply	0	(4,141,756)	0	(4,141,756)
Avoided Costs–Elec	0	0	16,878,331	16,878,331
Utility Admin. Costs	0	(875,000)	0	(875,000)
Net Impact	8,693,924	2,296,022	(3,047,762)	9,361,574

Note: positive numbers are benefits, negative numbers are costs

6.3.5 Interruptible and Transport-Only Customers

Interruptible customers and transport-only customers represent significant amounts of throughput for many gas LDCs. If a utility wishes to offer a DSM program to these customers, special attention should be given to the assumptions used in computing the benefit-cost tests.

Interruptible customers, by definition, are not provided the same degree of reliability as are firm customers. If the avoided costs include any components that are based on supply side projects that provide reliability, they should be excluded from the avoided costs used to evaluate DSM programs provided to interruptible customers. In other words, avoided cost should only include commodity components.

Transport-only customers do not buy gas commodity from the local utility. Further, with the advent of capacity release programs offered by interstate pipelines, the transport-only customer may not even rely on the local gas utility for upstream transportation rights. Thus, the costs avoided by a gas utility promoting a DSM program to transport-only customers may be very low.[16] One way to incorporate these lower avoided costs is to modify the Utility Cost and Nonparticipants tests to include only the utility's avoided costs. Not only should this modification be made for customers who transport their gas today; it should be made for customers who are forecasted to take transport-only service in the future. Unfortunately, such forecasts are hard to make with certainty. The combination of lower avoided costs and uncertainty over the forecasted service choices of customers makes it very difficult for DSM programs offered to current or potential transport-only customers to pass these two tests. In contrast, the Participant, Total Resource, or Societal Cost tests should look at both the utility's and the participant's avoided costs. When the avoided commodity costs of the transport-only customer are considered, a DSM measure may still provide considerable benefits. One of the few states that has authorized its investor-owned gas LDCs to offer DSM programs to industrial customers is California. One California combination utility, Pacific Gas and Electric Company, used the modified Utility Cost test as part of its review of bids under its pilot DSM bidding program.

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[16] Because most gas utilities are effectively obligated to serve transport-only customers when they chose to return to the utility for commodity service, it may be appropriate to credit DSM for the avoided *standby cost* benefits that it provides.

6.3.6 Period of Analysis

Careful consideration should be given to the time frame chosen for the analysis of the DSM program. Usually, one of two time frames is chosen: the length of the expected life of the DSM measure or a fixed planning horizon (RCG/Hagler & Bailly Inc. 1991).

Choosing a time frame equal to the life of the DSM measure is attractive because it is an easy way to capture the full benefits that accrue from the near-term adoption of the DSM measure.[17] In selecting the life of the measure, it is important to take into consideration factors that may affect the useful life beyond its physical life. If the measure is installed in a building, its life may be cut short by remodels, demolitions, and, possibly, ownership changes. Further, as noted in the free rider discussion, above, certain measures may be eventually adopted in due course without a DSM program. Rather than decrease the net-to-gross ratio, it may be more straightforward to simply shorten the effective life of the measures.[18] An added complication occurs when the gas LDC DSM programs serves customers that may bypass the LDC before the end of the effective life of the DSM measure. From the perspective of the utility or nonparticipant, it may be necessary to effectively shorten the life of the DSM measure to account for the fact that the benefits of the measure will no longer accrue to the utility/nonparticipants after the customer leaves the LDC's system.

A fixed-period time frame may be useful when the modeling of DSM programs is more sophisticated or is done in comparison to a specific supply side plan. Time frames ranging from 5 to 20 years are all common. DSM measures may be installed over a period of years, not just in the first year. If the effective life of a measure is less than the planning horizon, a choice must be made regarding its replacement: either the device reverts to the base case efficiency level or the same efficient measure is reinstalled.[19]

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[17] Such an approach was taken in the preparation of the examples in this chapter.

[18] Shortening the effective life of DSM measures is an appropriate way to model free riders who, as a result of the utility DSM program, adopt the measure sooner. Free riders whose consumption was totally unaffected by the program should be modeled as a reduction in net program savings rather than by shortening the effective life of the DSM measure.

[19] It is possible that the base-case technology at the time of replacement may be similar to the efficient technology promoted by the utility in the first place. In this case, even though the efficient technology is reinstalled, it should not add to program-related savings.

6.3.7 Taxes

Taxes may affect the results of the benefit-cost tests in at least four different ways. First, utility incentive payments received by commercial and industrial customers are treated as taxable income and reduce the effectiveness of incentive payments. Rebates made to residential customers are not taxable under federal law so taxes are not a factor for residential programs.

Second, like any other business activity, utilities will pay sales taxes on goods and services purchased for the delivery of demand-side programs. The cost of these taxes should not be ignored when making cost estimates (RCG/Hagler & Bailly Inc. 1991).

Third, utility income is taxed, typically at an incremental rate of 35 percent or more and this rate can have a significant effect on the utility's avoided costs and discount rate. Although income taxes are a real cost to a utility, it may be fallacious to use it in a broad perspective such as the TRC or Societal Cost test. This is because the increase or decrease in DSM activity has probably little or no affect on the federal or state government's budget. One strategy is to remove corporate income taxes completely from the analysis. The easiest way to do this is to remove the effect of income tax on the cost of capital used in either the TRC or Societal Cost tests. If this is done, care must be taken to remove the impact of taxes from not only the discount rate, but any supply- or demand-side capital costs that have been annualized (such as the capacity component of avoided costs).

Fourth, many utilities are charged (and pass on to their customers) taxes that vary with revenues: sales taxes, franchise taxes, gross receipts taxes, and utility taxes. As a result, the bill savings seen by a customer may, in effect, be larger than the revenue reduction seen by the utility. As with the treatment of corporate income taxes, the best treatment of revenue-related taxes is not obvious because the reduction in tax revenues from a DSM program could possibly lead to an increase in the tax rate by the taxing agency or a reduction in the level of service by the agency.

6.4 Policy Issues in the Application of Benefit-Cost Tests

This section addresses some of the broader issues raised by the use of benefit-cost tests. First, the role of the benefit-cost tests in the larger IRP framework is discussed. Second, there is a discussion of the policy debate regarding which is a better primary test: the TRC or RIM test. The heart of this debate depends on estimates of the degree of market imperfections and a framework for assessing such imperfections is provided. Finally, emerging benefit-cost tests are described.

6.4.1 Role of the Benefit-Cost Tests in the IRP Framework

The benefit-cost tests are most useful for screening DSM programs, along with the screening of supply-side resources, in a resource integration phase and in an evaluation of multiple alternative plans (see Chapter 3). At this point in an IRP analysis, other objectives can be considered and items that may have been simplified or ignored in the computation of the standard benefit-cost tests can be incorporated. For example, a DSM program may affect avoided costs or have reliability impacts and both of these impacts should be considered in a full IRP analysis.[20] Further, a full IRP analysis may include an uncertainty analysis, which would test for *potential* benefits and costs not covered in the standard benefit-cost tests framework.

6.4.2 TRC versus RIM: Which Test is Best?

There is a long-standing policy debate over the appropriate tests to use for determining the level of cost-effective DSM that should be pursued by a utility. Most of the debate has been conducted with regard to electric utility participation in DSM programs, but PUCs have also grappled over which test to use for the evaluation of gas LDC DSM programs. The debate is often formulated in terms of which test should be considered primary in the economic analysis of DSM programs: the TRC test or the Nonparticipants test (also commonly known as the RIM test).

Arguments for the TRC Test

Proponents of the TRC test argue that it is a broad test that measures all the private costs and benefits applicable to energy consumers. The TRC test measures the total cost of energy services, including the portion of costs that customers contribute towards the purchase of a DSM measure. Further, if the related Societal Cost test is used, then externality costs and benefits can be added to the private costs and benefits included in the TRC test.

Results of a recent NARUC survey suggest that among those PUCs that responded: (1) the TRC test has broad support (18 of 23 PUCs) and (2) the TRC, Utility Cost, and Societal tests are specified as the primary test most frequently (see Table 6-6). The main reason that the TRC, Societal, and Utility Cost test dominate as primary tests is because

[20] For the interaction of DSM programs and avoided costs, see Energy Management Associates (1992) and Kahn (1992).

Table 6-6. Benefit-Cost Tests Used by 23 Public Utility Commissions for Evaluating Gas DSM Programs

	Perspective					
State	Participants	Non-participants	Utility	Total Resource	Total Technical	Societal
Alabama PSC	P					
California PUC	O	O	O	P		P
Connecticut DPUC	O	O	O	P	O	P
DC PSC				P		
Florida PSC	O	O	O	P		
Georgia PUC		O	O			O
Idaho PUC			P	P		
Illinois CC	O	O	P	P		P
Iowa UB	O	O	O			P
Maryland PSC				P		
Massachusetts DPU						P
Michigan PSC	O		P	O		O
Minnesota PUC	O		P	O		P
Missouri PSC			P	P		
New Jersey BRC				P		
New York PSC	O	O	O	P		P
Nevada PSC	P	P	P	P		
Oregon PUC				P		
Pennsylvania PUC	P	P	P	P		
Virginia SCC	O	O	O	O		
Vermont PSB						P
Washington UTC			P	P		
Wisconsin PSC	O	O	P	P	P	O
Total Primary	3	2	9	15	1	8
Total Other	10	9	7	3	1	3
Total Count	13	11	16	18	2	11

P = Primary Test(s) Used at PUC
O = Other or Nonprimary Test(s) Used at PUC

Source: NARUC (1992) and LBL and GRI data

PUCs want DSM to be treated like any other energy resource. When DSM is treated as a resource, its costs, whether it be to the utility (Utility Cost test) or the utility and the participants (TRC test), are simply compared to supply cost savings that are avoided. The primacy of the TRC/UC tests may also be attributable to the general IRP goal of using the benefit-cost tests primarily as a screening tool that precedes the more complex resource integration phase. In this context, it makes sense to consider only the resource costs of the DSM resource. Many PUCs consider rate impacts important too, but do not require that individual programs pass the RIM test. Instead, overall rate impacts of the *portfolio* of DSM programs is estimated. Under this framework, programs that pass the TRC but fail the RIM test may be pursued so long as the overall rate impacts are tolerable.

Arguments for the RIM Test

Proponents of the RIM test favor it for two reasons. First, the RIM test is a measure of distributional impacts of a DSM program. Proponents of the test claim it is unfair to nonparticipants to approve utility DSM programs that will on balance, bring no net benefits to the nonparticipant.[21] An integrated resource plan that includes DSM programs that pass the TRC test but fail the RIM test will be least-cost, but unfair. Customer classes that do not receive the bulk of the benefits of utility DSM programs, such as large commercial and industrial customers, have tended to support the RIM test as a result. Second, and more controversial, some energy industry participants have argued that the RIM test is a better measure of overall economic efficiency than the TRC test; that is, the RIM test does not just measure the net benefits of nonparticipants but is instead a measure of the overall net benefits of a DSM program (Joskow 1988; Kahn 1991a; Ruff 1992; Caves 1993). Proponents of the RIM test usually believe that markets for energy services work reasonably well and energy customers purchase optimal mixes of energy and energy-using equipment to minimize discounted life cycle costs. Under the assumption of competitive markets, it is unlikely that participants will accrue large benefits from participating in a utility-funded DSM program. Instead, they will be roughly indifferent and, at most, will have net benefits equal to the incentive payment paid to them by the utility (see next section). Thus, programs that pass the TRC test but fail the RIM test are simply "too good to be true" and should be viewed skeptically. By requiring DSM programs to pass the RIM test, utilities are essentially limited to pursuing load building programs and conservation programs where the conserved consumption is

[21] Some parties argue that DSM programs provide *potential* benefits to nonparticipants even if the program fails the RIM test. Environmental benefits, utility planning flexibility, and the development of new technologies have been cited (Centolella 1993). However, if an analyst expects these benefits to occur, they should be considered as a benefit in the Nonparticipant test. If they are considered to be *potential* benefits, then they should be considered in an uncertainty analysis.

priced below a utility's avoided cost. RIM test advocates believe that such limitations on utility involvement are prudent.

6.4.3 A Framework for Understanding Market Imperfections

At the heart of the RIM versus TRC debate is whether PUCs should presume that markets for energy services are competitive or presume that significant imperfections exists. To understand this debate, it is useful to have a framework for understanding markets for energy efficiency and what the impact of market imperfections, if any, are. Figure 6-5 presents supply and demand curves for a hypothetical market for a DSM measure in a particular service territory under two assumptions regarding market imperfections. The Y-axis measures the price or value of the DSM measure and the X-axis measures the quantity of DSM sold (shown in units of therms saved). Under the assumption of competitive markets, the demand for, and value of, the DSM measure are the same.[22] These values are shown as the V = D line. Before the DSM program, Q_o of DSM measures were sold and after the DSM program is implemented, Q_1 are sold. The effective price of the DSM measure to customers in the service territory is shown on the P_{DSM} line. Net value to participants is measured by subtracting the P_{DSM} line from the D = V line. Thus, the total value of the DSM measures purchased as a result of the program is equal to Areas A + B and the value, net of the participants' costs, is Area B.

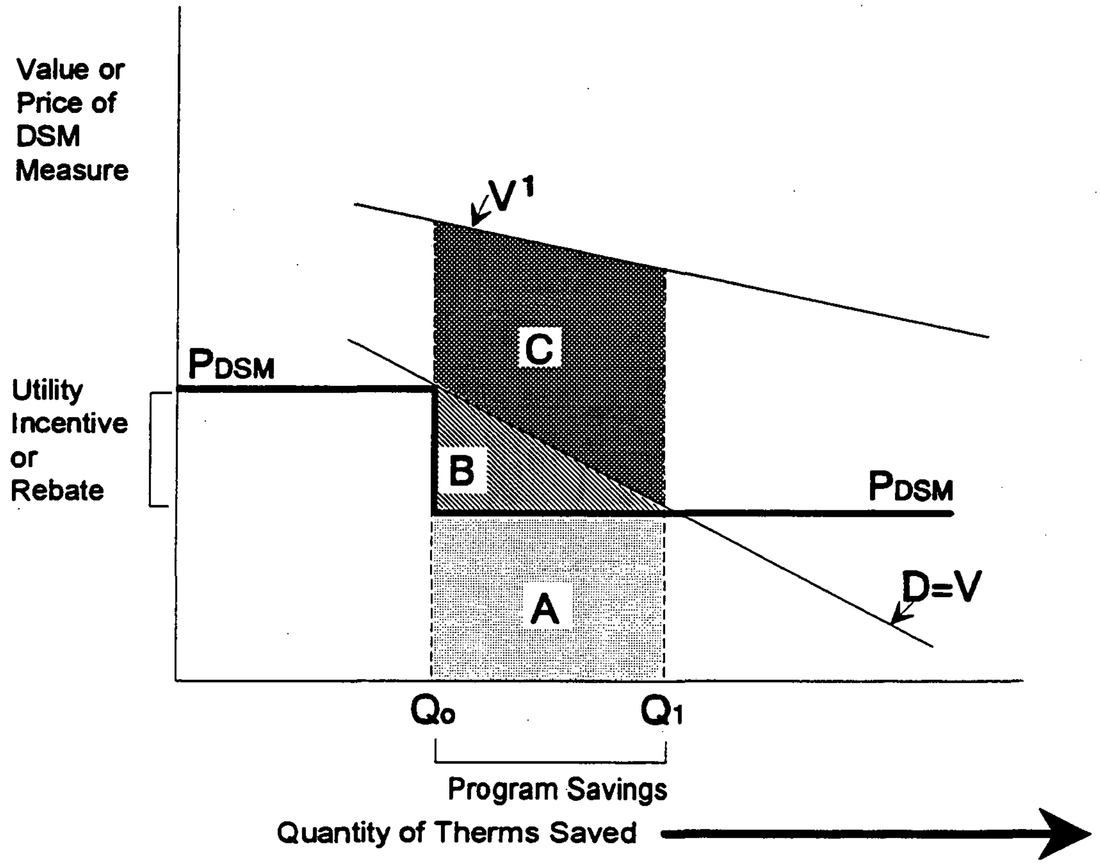
If, however, there are market imperfections or failures, then customers value DSM measures more than what can be inferred from their behavior in the marketplace. Figure 6-5 also shows the value of DSM measures in the situation where market imperfections exist. The line V^1 is the value to program participants under the assumption of market imperfections. It diverges from the market demand curve, D. V^1 is usually estimated as the utility bill savings provided by the adoption of a DSM measure.[23] Total value of the DSM measures purchased as a result of the program in this case is equal to Area A + B + C and, net of participants' measure costs, is equal to Area B + C.

Proponents of the TRC test tend to believe that market imperfections for energy efficiency exist (i.e., $V \neq D$), especially if studies indicate that there are large quantities

[22] This way of estimating participating customers value is based on their observed behavior and is sometimes known as a "revealed preference" methodology.

[23] The V_t line is shown as downward sloping to reflect the fact that some program participants will save more energy than others. Also, it should be noted that other items besides bill savings can affect participant value. A DSM measure's enhancement of quality should also be included if not accounted for explicitly elsewhere.

Figure 6-5. Value of DSM Program to Program Participants



Key to Symbols

D = market demand curve for DSM measure

V^1 = participants' value vased assuming some degree of market failure

V = participants' value assuming no market failures

P_{DSM} = price of DSM measure, including any rebates or incentives offered by utility

Qo = level of energy efficiency before utility program

Q_1 = level of energy efficiency after utility program

Area A+B = net value of DSM measure to participants assuming no market failures

Area B = value, net of cost, no market failures

Area A+B+C = value of DSM measures to participants assuming market failures

Area B+C = value, net of cost, market failures exist of cost-effective DSM. The market imperfections are often characterized as barriers that prevent energy services markets from functioning in a competitive manner. Some of the commonly-cited barriers to economically efficient levels of DSM are described in Table 6-7.[24]

Rather than initially assert that markets work in a competitive manner or exhibit significant failures, PUCs and LDCs should first strive to account for all the costs and benefits that are involved in undertaking a DSM program. Such an accounting should be used in a comprehensive test such as the TRC or Societal Cost test and should include estimates of indirect costs (costs in terms of time lost, hassle, and—for commercial and industrial customers—the value of any lost production) and the impact of quality changes caused by the DSM program. If, after a full accounting of costs and benefits is made, the LDC or PUC still estimates large net benefits from the DSM programs, then it would be appropriate to seriously consider implementing the programs. If the programs have large rate impacts as measured by the RIM, PUCs or LDCs should examine whether the design of the programs can be structured to make participants pay for a larger share of the program's costs (see Chapter 7).[25] The consideration of market imperfections, especially environmental externalities, may, however, lead to programs with net benefits but unavoidable rate impacts. Further, some programs that fail the RIM test may be pursued for public policy objectives other than economic efficiency. As a result, there may be instances where a PUC or LDC will feel confident pursuing a DSM program that fails the RIM test.

6.4.4 Alternatives to the Standard Benefit-Cost Tests

Although the standard benefit-cost tests are widely used, other energy industry participants, mostly economists, have proposed alternative tests that focus on total value or net economic benefits (NEB) in an attempt to develop a more accurate measure of the net benefits of utility DSM programs. As part of a conservation plan, Connecticut Natural Gas (1988) sponsored the work of an economist that developed a set of tests that focused on changes in utility profits, total social costs, and participant benefits; the sum of which measures changes in total social welfare. Later, Hobbs (1991) defined a "most value" test and argued that it should be used instead of the standard tests. Recently, more

[24] It should be noted that the last two market barriers (environmental externalities and federal government R&D priorities) cited in Table 6-7, although potentially significant, may not cause the participants' value line to deviate from their market demand curve. Instead, the impact of externalities and federal R&D costs affect society at large.

[25] Any DSM program that has a significant rate impact on price-sensitive customer classes should also be examined to see what the resulting margin impacts are from the additional lost sales.

Table 6-7. Barriers to an Economically Efficient Market in Energy Efficiency

Barrier 1: Information Gap	Credible information on the performance of energy-related technologies is often lacking. Available information is often not well understood and is sometimes unreliable.
Barrier 2: Payback/Uncertainty Gap	Payback periods required by consumers for investments in energy efficiency are generally much shorter than those required for utility company investments. The gap may reflect the tendency of consumers to perceive the uncertainties of future demand, fuel prices, and the performance of DSM measures to be greater than the utility's perception of the same uncertainties.
Barrier 3: Third Party Transactions	Consumers often must use the energy technologies selected by landlords and others. This leads to an emphasis on first cost rather than life-cycle cost.
Barrier 4: Lack of Capital	Many customers, both residential and commercial, lack enough cash or credit (considering the competing demands on their financial resources) to pay the capital cost of making long-run cost-effective efficiency investments.
Barrier 5: Utility Regulation Imbalance	traditional rate regulation in most states encourages utilities to increase sales, imparting an implicit bias toward pursuing supply-side options.
Barrier 6: Environmental Externalities	In almost all states, the prices that consumers pay for fuels, including electricity, do not fully reflect all environmental and social costs associated with fuel production, conversion, transportation and use.
Barrier 7: Federal Government Policies	Traditionally, the Federal Government has provided greater support for energy production than for energy efficiency, both with respect to tax policies and R&D.

Source: Adapted from Wiel 1991

practical variations of value or NEB tests have been proposed. Braithwaith and Caves (1993) sponsor their own NEB test. Their NEB test adds at least three additional dimensions to the standard tests: (1) it allows flexibility regarding assumptions on the degree of failure in the market for DSM products, (2) it considers the full impact of price changes caused by utility DSM programs on nonparticipants, and (3) it considers the added value provided to program participants from "snapback." Similar to the NEB test is the Value test sponsored by Chamberlin and Herman (1993). The Value test appears to incorporate the NEB test, and, further, allows for the consideration of benefits that the utility DSM program provides to free riders. Although no PUC has yet adopted either the NEB or Value test for gas DSM program evaluation, the NEB/Value tests hold promise as being a more general framework for the analysis of DSM programs. Even environmental or other externalities could be added to the test to give it a societal perspective. The NEB/Value tests explicitly consider the degree of market imperfections, which, as has already been noted, are a crucial factor in the ongoing debate over which standard test is best. The NEB/Value tests do require more assumptions and data: explicit assumptions must be made regarding the degree of market imperfections and data on demand elasticities, snapback, and the characteristics of free riders is needed. These data and assumptions will, however, become increasingly important in the evaluation of DSM programs and the NEB/Value tests allows for an analysis using them.

Chapter 7

Gas DSM Technologies and Programs

7.1 Overview

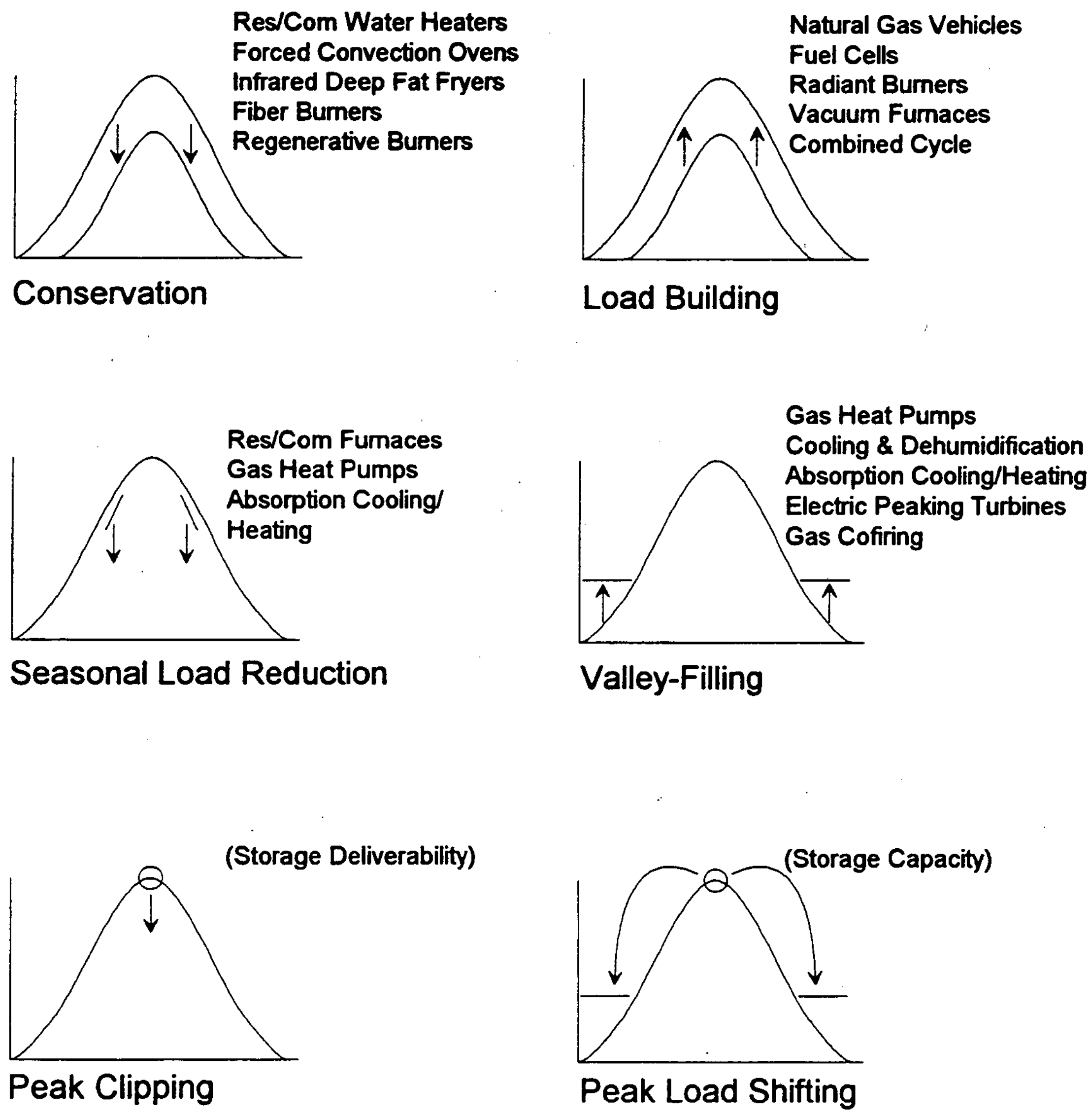
This chapter describes common load-shape objectives for gas utilities and the structure of U.S. gas demand in the residential and commercial sectors, reviews the potential for demand-side management (DSM) for gas utilities as suggested by recent assessments, identifies efficiency and fuel-substitution measures available for promotion in DSM programs, and discusses issues of DSM program design and implementation.

7.2 Load-Shape Objectives

In contemplating demand-side interventions, gas utilities should define their load shape objectives. Figure 7-1 illustrates six common load-shape objectives and gas end-use technologies (as well as supply and capacity options) that can meet these objectives (Samsa 1993).[1] Conservation and load building respectively reduce or increase gas loads throughout the year. Seasonal load reduction and valley filling load shapes respectively lower or raise loads on a seasonal basis. Peak clipping and peak load shifting focus mainly on reducing peak-day demand rather than energy savings. Load-shape objectives of individual local distribution companies (LDCs) will vary depending on their existing system load factor. Some LDCs may prefer to focus on peak clipping and load shifting in order to reduce pipeline demand charges. Other gas utilities believe they can reduce average gas purchase costs by improving system load factor so they may propose load building programs (such as cogeneration) to increase base loads or valley filling programs (such as gas cooling) to increase off-season utilization. This chapter focuses on technologies and programs for meeting three of the six load-shape objectives: conservation, seasonal load reduction, and valley filling.

[1] Many gas technologies do not produce impacts that fit neatly into these load shape categories, but instead they span several categories.

Figure 7-1. Utility Load Shape Objectives



Source: Samsa 1993

7.3 Gas Usage in Residential and Commercial Sectors

The structure of gas end-use demand provides an initial reference point for determining where efforts to improve gas efficiency can best be focused.[2] More than three-quarters of residential gas consumption occurs in single-family dwellings (see Figure 7-2). There is much more diversity of gas consumption by building type in the commercial sector, with mercantile/service and education categories showing the highest levels, followed by office, warehouse, lodging, health care, and assembly categories at roughly comparable levels (see Figure 7-3).

Figure 7-2. U.S. Residential Sector Gas Consumption by Building Type (1990)

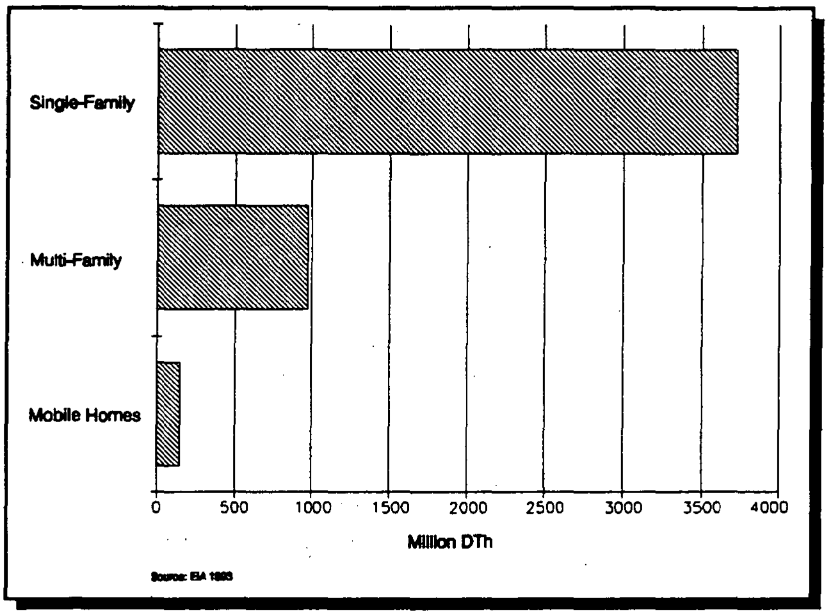


Figure 7-4 compares the end-use distribution of gas consumption in the residential and commercial sectors, shown as a percentage of each sector's total. Space heating dominates in both sectors: 70% of residential and more than 50% of commercial. Water heating is the next most important end-use, accounting for 24% and 15% respectively of residential and commercial sector gas use. Process heat represents 12% of commercial sector gas consumption and cooking represents 10%. The predominance of space heating in the overall demand scheme for natural gas in the U.S. is illustrated in Figure 7-5, which plots monthly gas use by sector. The highly seasonal nature of residential gas demand has a significant effect on gas system load factors as evidenced by the fact that winter peaks in January are more than twice the summer minimum monthly load in June on a national basis.

[2] The structure of end-use gas demand for an individual utility may diverge significantly from the national pattern.

Figure 7-3. U.S. Commercial Sector Gas Consumption by Building Function (1989)

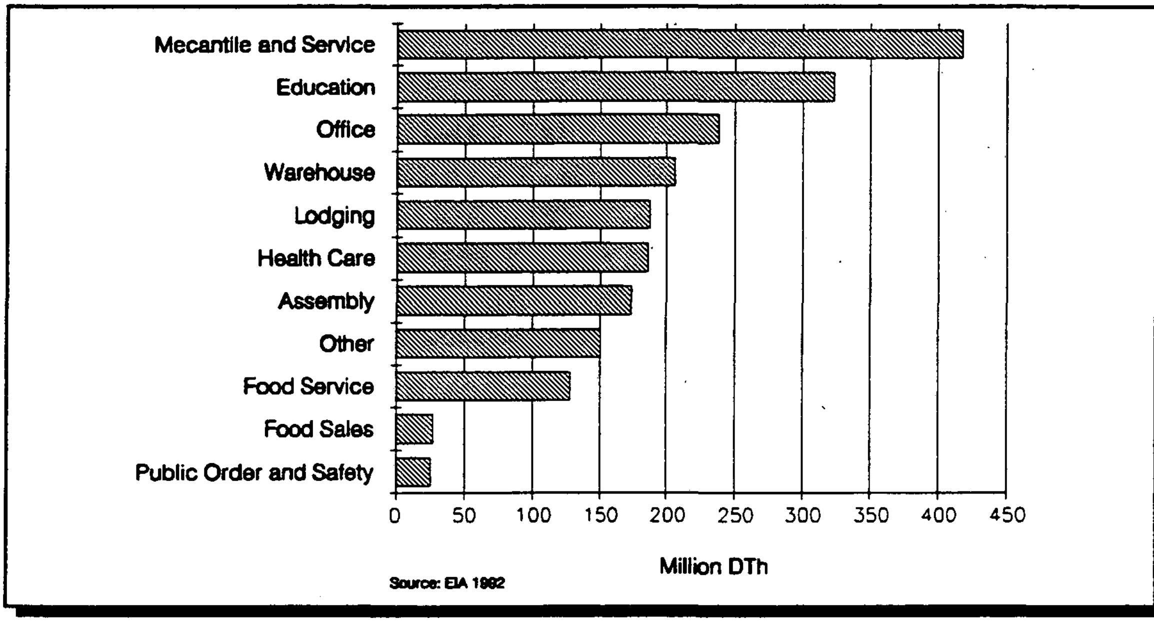
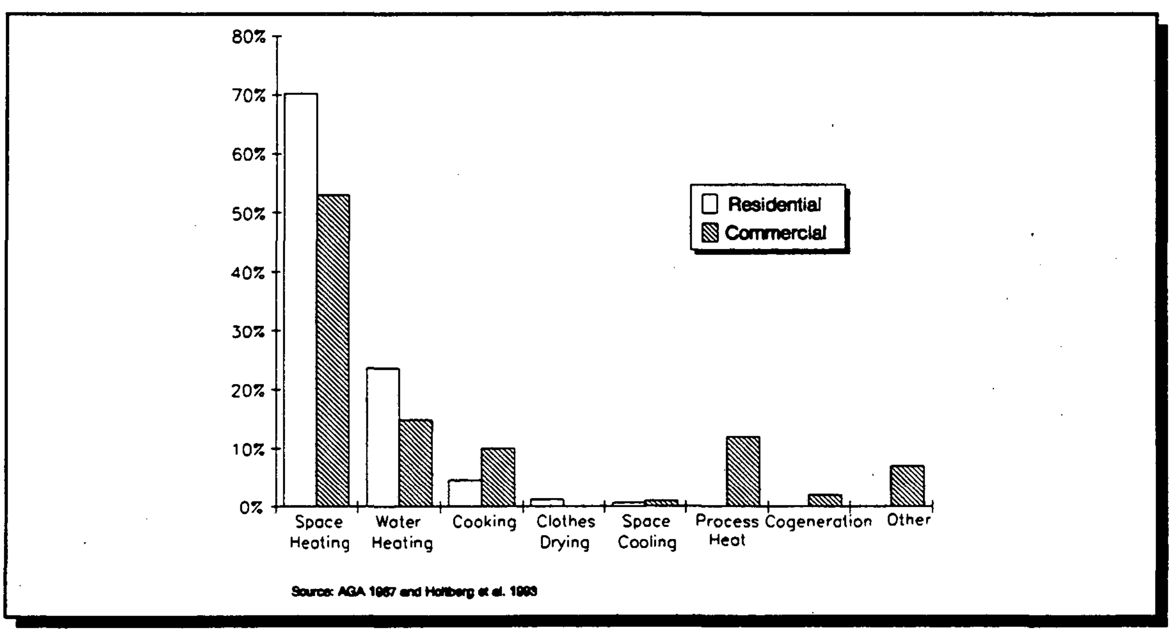
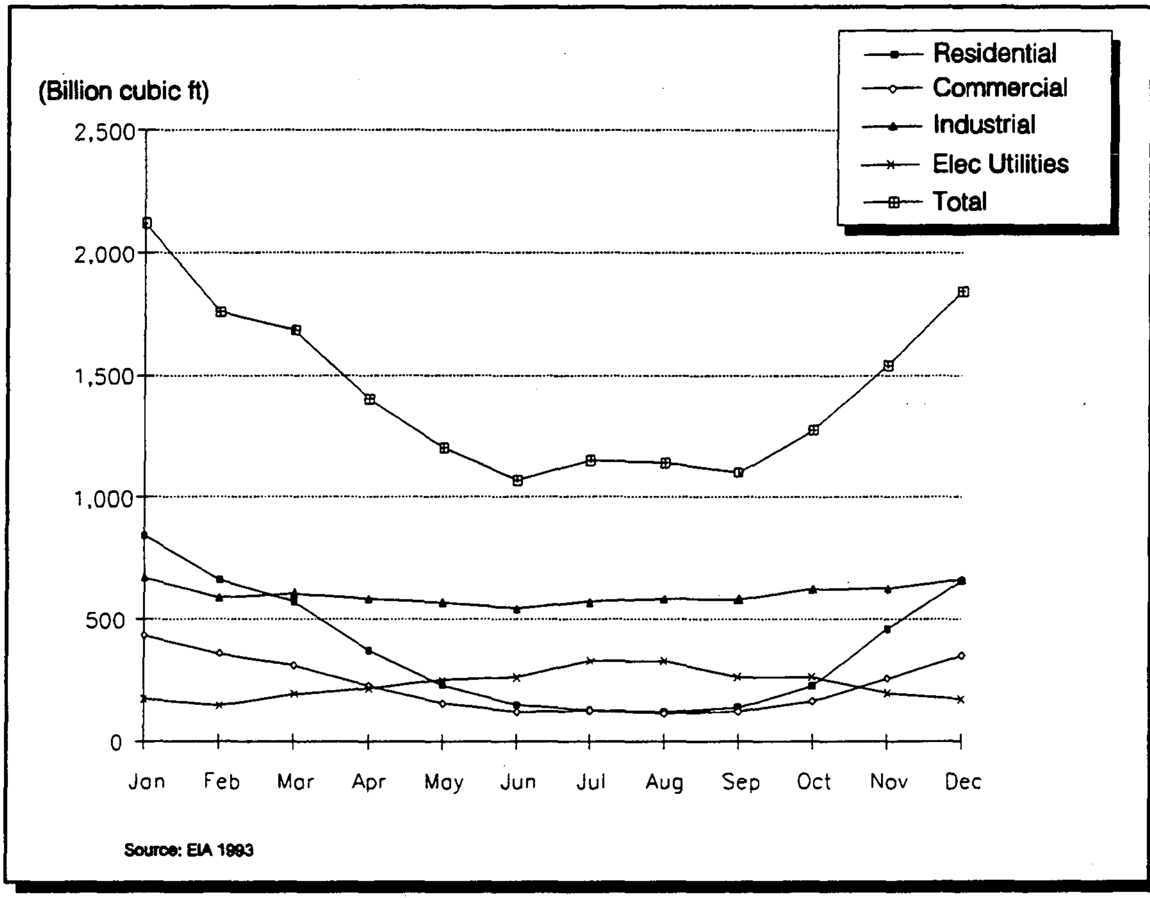


Figure 7-4. End-Use Shares for Gas in U.S. Residential and Commercial Sectors



Overall, gas demand in the residential sector is significantly greater than commercial sector demand (4.5 billion DTh vs. 2.8 billion DTh), with significant regional variations

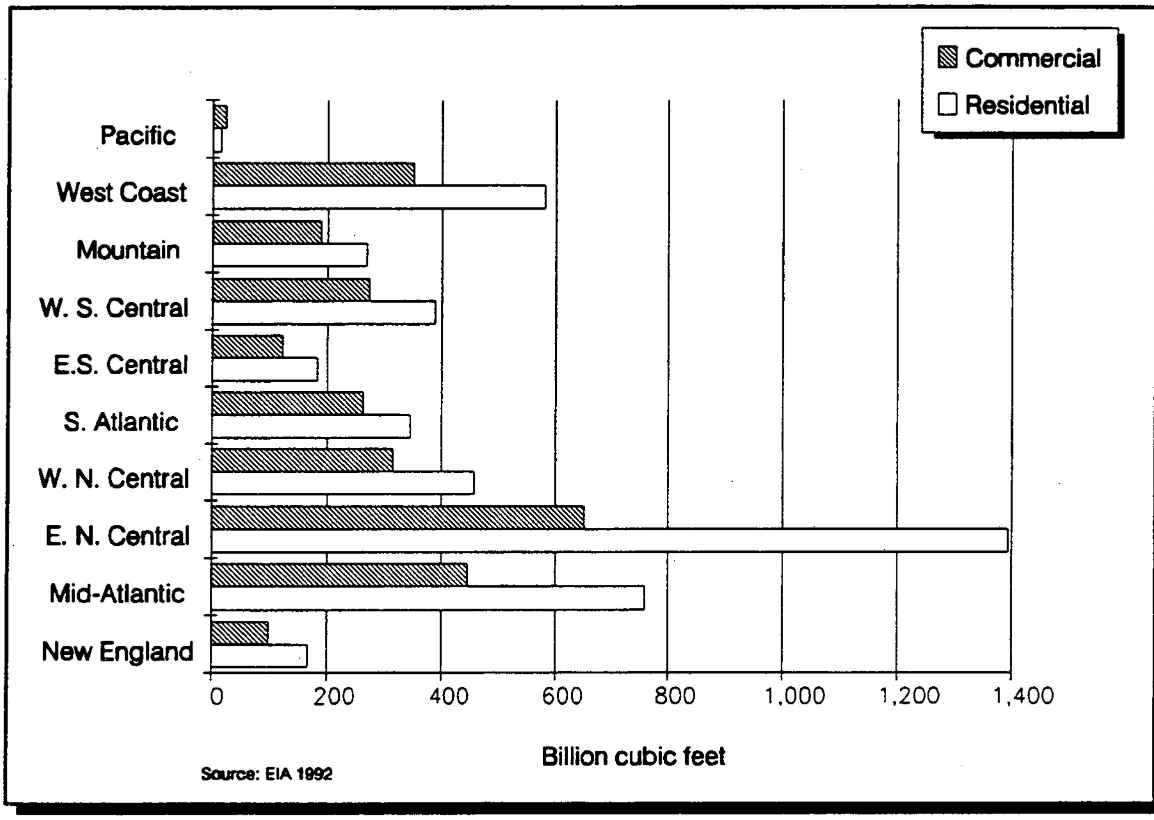
Figure 7-5. U.S. Monthly Natural Gas Consumption by Sector (1991)



(see Figure 7-6).[3] The relative shares of residential and commercial sectors in the overall gas market do not appear to result from climate severity, but from a host of other market conditions.

[3] Residential consumption is higher than commercial consumption in all census regions except for the Pacific (i.e., Hawaii and Alaska).

Figure 7-6. Residential and Commercial Gas Consumption by U.S. Census Region



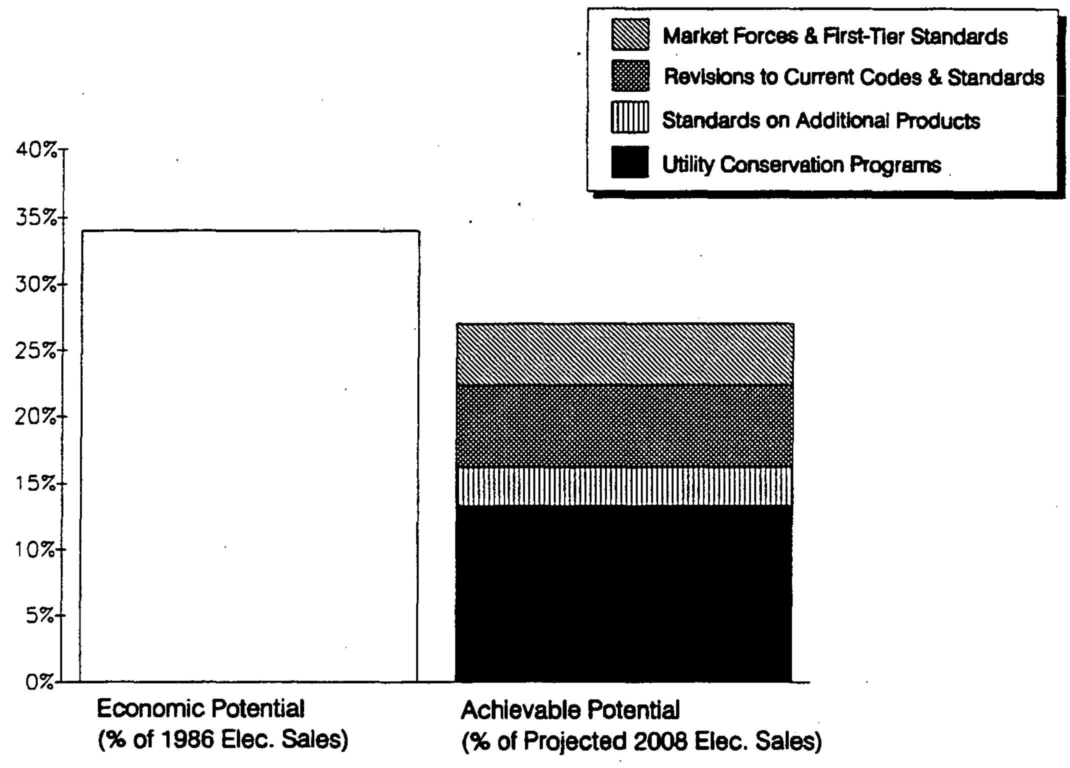
7.4 Opportunities for Increasing Gas End-Use Efficiency

7.4.1 Practical Constraints on Achieving Technical Energy Savings Potential

Energy savings that are achievable for gas utilities through programs aimed at increasing customer energy efficiency are constrained by a number of factors. The question of achievable energy savings potentials sometimes stirs controversy, to a large extent because of semantics. It is useful to distinguish three different types of "energy conservation potentials" cited in the literature.

- *Technical potential* is an estimate of possible energy savings based on the assumption that existing appliances, equipment, building shell measures, and other processes are replaced with the most efficient commercially available alternatives, regardless of cost, without any significant change in lifestyle or output.

Figure 7-7. Economic and Achievable Electricity Conservation Potential in New York State



Source: Nadel and Tress 1990

- *Economic potential* is an estimate of the portion of technical potential that would be achieved if all energy-efficient options were adopted and all existing equipment were replaced whenever it is cost-effective to do so, based on prespecified economic criteria, without regard to constraints such as market acceptance and rate impacts.

- *Program achievable potential* is an estimate of the portion of economic potential that would be achieved if all cost-effective, energy-efficient options promoted through utility DSM programs were adopted, excluding any energy-efficiency gains achieved through normal market forces and compliance with energy codes and standards.

Each type of conservation potential described above is a subset of the one that precedes it, which necessarily results in diminishing opportunities that can be captured by utility DSM programs. Figure 7-7 illustrates this phenomenon, calculated for electric utilities in New York state (Nadel and Tress 1990). The left bar shows the economic potential at 34% of current electricity sales. Achievable potential (which includes savings achieved through standards and market forces), as depicted in the right bar, is somewhat lower at 28% of a future year's sales. In this study, the achievable savings that could be captured by utility DSM programs is about 14%, or about three-fifths lower than the economic potential (on a percentage of sales basis). It is critical to distinguish among these different types of potentials when reviewing and comparing studies of conservation potential.

Results of Gas DSM Potential Studies

Tables 7-1 and 7-2 summarize results from DSM potential studies in the residential and commercial sectors, respectively, of 11 gas utility service territories. Appendix B provides detailed descriptions of the underlying assumptions used in estimating potential savings. The type of savings potential is indicated (see above for definitions) as well as the number of DSM measures and end-uses considered. The savings potential is expressed as a percentage of that sector's current gas sales (not including transport customer gas use). Most studies focused on estimating economic potential and typically considered 20 to 50 individual measures in the residential sector and 13 to 40 measures in the commercial sector.

With one exception, these studies suggest that, in percentage terms, the potential for gas DSM savings is greater in the residential sector than in the commercial sector. For the residential sector, economic savings potentials range from 5% to 47%, with most studies finding around 25%. For the commercial sector, economic savings potentials range from 8% to 23%, with most studies finding around 15%.

A few of the studies also assessed economic fuel-switching potential—switching from electricity to gas at the end use, primarily as a valley filling strategy for the gas utility. The economic fuel-switching potential was estimated to be higher in the commercial sector (2% to 49%) than in the residential sector (2% to 7%), primarily through the promotion of commercial gas cooling technologies to boost summer gas sales.

Avoided costs used in screening the technologies for estimating economic savings potential—arguably the most important variable in the screening process—varied considerably among the studies depending on: calculation method, extent of seasonal differentiation, estimated gas commodity cost escalation rates, and time horizon (see Appendix B). It is quite difficult to generalize from these gas savings potentials results because of methodological differences among studies as well as the diverse structures of gas use among individual LDCs. Nevertheless, the studies suggest the scale of the DSM resource that may be available in U.S. gas utility service territories.

Table 7-1. Residential DSM Potential for Selected Gas Utilities

Residential	LILCO	Brooklyn Union Gas	National Fuel Gas	Orange & Rockland	Southwest Gas	WP Natural Gas	Boston Gas	Commonwealth Gas	Bay State Gas	SoCal Gas	Atlanta Gas Light
Type of Potential											
Technical				36%	32%	24%				X	X
Economic	24-41%	34-47%	27-44%	15%	25%		11-20%	24-32%	32%	6-9%	X
Program Achievable				5%							
Fuel Switching	-3%	-2%	-5%	X	-7%						-2%
Measures Reviewed (#)	62	62	62	22	25	N/A	23	~20	26	28	26
End Uses Considered:											
Space Heating	X	X	X	X	X	X	25%	X	X	X	X
Space Cooling											
Water Heating	X	X	X	X	X	X	14%	X	X	X	X
Cooking	X	X	X								X
Clothes Drying	X	X	X		X						X

Table 7-2. Commercial DSM Potential for Selected Gas Utilities

Commercial	LILCO	Brooklyn Union Gas	National Fuel Gas	Orange & Rockland	Southwest Gas	Boston Gas		Commonwealth Gas		Bay State Gas	SoCal Gas	Atlanta Gas Light
						Com	Ind	Com	Ind			
Type of Potential												
Technical				16%	9%						X	X
Economic	18-19%	15-16%	17-20%	10%	8%	13-17%	9-14%	8-23%	11-23%	23%	8-14%	X
Program Achievable				5%								
Fuel Switching	-28%	-49%	-9%	X	-6%							-2%
Measures Reviewed (#)	40	40	40	16	39	20	21	~20		30	35	13
End Uses Considered:												
Space Heating	X	X	X	X	X	28%	22%	X	X	X	X	X
Space Cooling	X	X	X		X							X
Water Heating	X	X	X	X	X	5%		X	X	X	X	
Cooking	X	X	X					X			X	
Clothes Drying												
Process Heat							6%					X
Other					X							X

Impact of Standards

The potential DSM savings available to an individual gas LDC are determined to a great extent by the unique combination of existing building stock and equipment characteristics, weather severity, energy prices, and other factors unique to a service territory. However, existing and impending federal efficiency standards for gas appliances and heating, ventilating and air conditioning (HVAC) equipment are major considerations for every gas LDC attempting to assess its achievable DSM potential. These standards raise the floor of efficiency levels of gas equipment available on the market, and, over time through equipment replacement and installations in new construction, they increase average stock efficiency as well.

Table 7-3 summarizes minimum efficiency levels and timetables for instituting and updating standards for selected gas appliances and equipment used in residential and commercial applications.[4] At the state and local levels, energy standards for buildings and/or energy-using equipment have also been promulgated as voluntary guidelines or as mandatory regulations, with corresponding implications for gas utility DSM program efforts within those jurisdictions.

Utility DSM programs can accelerate these changes in the existing building stock through retrofit programs that promote early retirement of less efficient appliances and replace them with appliances that comply minimally with the standard. DSM programs can also focus on appliances and equipment that exceed the standard, promoting these in the retrofit, replacement, and new construction markets.

Impact of Previous Retrofits

Another significant factor affecting gas DSM potential is the extent to which customers have taken previous actions or utilities have promoted efforts to raise the efficiency of gas use. Generally each successive DSM measure implemented gives diminishing returns, where interactions among measures make the combined savings less than the sum of the individual savings. Early programs to reduce energy use in homes were conducted in the 1970s and 1980s under the auspices of the Residential Conservation Service; these were mainly focused on building shell measures to reduce home heating and cooling loads. Likewise, electric utilities with overlapping service territories may have already installed building shell measures in customers' homes, or other measures that might

[4] National standards were established by the National Appliance Energy Conservation Act of 1987 (NAECA) with timetables for various residential appliances and HVAC equipment; the Energy Policy Act of 1992 extended efficiency standards to cover commercial HVAC equipment and water heaters.

Table 7-3. Federal Energy-Efficiency Standards Levels and Timetables for Selected Gas Appliances and Equipment

Appliance/Equipment	Min. Level	Effective Date	Update Scheduled
Residential			
Furnaces	78% AFUE	1992	2002
Boilers	80% AFUE	1992	2002
Water Heaters	54% EF	1990	1995
Clothes Dryers	2.67 lbs/kWh	1994 (est.)	n/a
Ranges and Ovens	n/a	1996 (est.)	2000
Commercial			
Furnaces & Boilers		1994	
(> =225 kBtuh)	80%		
Water Heaters	77%	1994	

Notes:

AFUE = Annual Fuel Utilization Efficiency

EF = Energy Factor

Residential water heater EF dependent on storage tank size; listed value for 40-gallon tank.

Units for clothes dryer efficiency level are lbs. of clothes/energy input (in kWh).

Range and oven levels have not yet been mandated by DOE.

Commercial unit heaters not covered in standard.

Commercial water heater standard listed is for storage tanks larger than 100 gals.

Source: Geller and Nadel 1992

affect the savings potential for gas, such as night-setback thermostats or low-flow showerheads.

Time-Dependent End-Use Efficiency Opportunities

Studies of conservation potential often ignore the time dimension associated with any practical effort to capture identified savings. Some measures will only be cost-effective or even possible at the design stage for new buildings or at the time of a major remodeling or equipment replacement. These opportunities are time-dependent in the sense that they occur only when customers are making equipment replacement decisions. LDCs evaluating demand-side opportunities must account for the extended time periods required for these types of DSM programs to have a significant cumulative impact. For example, a study of gas DSM potential in New York conducted by the American Council for an Energy-Efficient Economy found that 40 to 50% of the savings opportunities in the residential sector were achievable through replacement programs; only the remainder were achievable in the short-term through retrofit programs. For the commercial sector, a smaller percentage (i.e., 20%) of the program achievable sector savings were tied to long-term replacement programs (Nadel et al. 1993b).

Persistence of Savings

Another practical issue relevant to the time dynamics of DSM programs is the persistence of energy savings. Persistence has emerged as a significant concern among DSM practitioners (Vine 1992). Previous studies of persistence have tended to focus on technical measure lifetime although both technology and human behavior affect persistence (Jeppesen and King 1993).

Table 7-4 lists factors that influence the persistence of DSM measures and programs, many of which are behaviorally-oriented (Hirst and Reed 1991).[5] Among the behavioral issues, the rebound effect (also known as "snap-back"or "take-back") can be particularly important (i.e., when customers increase their amenity level in response to lowered energy bills from installation of DSM measures). The opposite response can also occur, known as the surge effect where customers, because their awareness of energy-efficiency issues is raised through participation in the program, alter their behavior to lower their energy use or to invest further in DSM measures on their own. A number of strategies have been proposed to ensure the persistence of energy savings, including measurement and verification plans, program design, operations and maintenance, and building commissioning (Vine 1992).

[5] Note that program persistence includes all the measure persistence factors as well.

Table 7-4. Factors Influencing the Persistence of Energy Savings

Measure Persistence	Program Persistence [a]
Technical lifetime	Rebound (snap-back, take-back) effects
Measure installation	Surge effect (additional measures added by customer after initial program participation)
Measure performance or efficiency decay	
Measure operation (behavior)	
Measure maintenance, repair, commissioning	Replacement effect (replacing efficiency measures with less or more efficient measures)
Measure failure	
Measure removal	
Changes in the building stock (i.e., renovations, remodels, alterations, additions)	Energy use by control group
Occupancy changes (turnover in occupants; changes in occupancy hours and number of occupants)	

(a) Program persistence factors also include measure persistence factors.

Source: Misuriello and Hopkins 1992

Summary of Practical Constraints

Energy-efficiency standards, previous government and electric utility conservation programs, time-dependent savings opportunities, and issues related to the persistence of savings are important factors that must be accounted for in assessing the savings potential that can actually be achieved by gas utility DSM programs. Empirical evidence from electric utility DSM experience shows a significant gap between the economic potential for energy efficiency and savings reductions that have been achieved in utility DSM programs.

Table 7-5 compares the performance of the best U.S. electric utility DSM programs in the commercial and industrial sectors by end use in terms of overall savings achieved against the size of the economic resource they were exploiting (Nadel and Tress 1990). Although several of the electric end-use categories are not directly applicable to gas utilities (nor can one assume that LDC DSM programs will exactly parallel those of

Table 7-5. Economic Potential vs. Actual Savings from Best Electric Commercial and Industrial (C&I) DSM Programs

End Use	Economic Potential	Savings from Best Programs
Lighting	60% of lighting use	25% of lighting use
HVAC	51% of commercial HVAC use	11% of A/C & heat pump use
Motors	17% of motor use	5% of motor use
New construction	50% or more	30%
Multiple end-use retrofits	45% in the commercial sector	18-23% in commercial buildings

Source: Nadel and Tress 1990

electric utilities), the general point is that the most successful utility DSM programs are capturing somewhat less than half of the cost-effective resource suggested by economic potential studies. Numerous factors contribute to this difference. Aggregate market penetration levels for a utility DSM program are very dependent on the program's ability to actually influence individual customer decision-making, DSM program budget and manpower levels, and building stock and equipment replacement turnover rates; actual savings are often lower than engineering estimates. Finally, while recognizing that the size of DSM resource that can be captured by utility DSM programs is substantially smaller than is suggested by economic DSM potential studies, unexploited cost-effective DSM resources most likely exist in most gas utility service territories. The next sections focus on end-use efficiency and fuel-switching options that can be promoted by gas LDCs through utility DSM programs.

7.4.2 Gas Efficiency Measures

The studies of DSM potential described above clearly suggest that many individual DSM measures and strategies have been considered by gas LDCs. Table 7-6 lists broad categories of DSM measures for LDCs—equipment, building shell, distribution for the space conditioning system, HVAC system control, and water heating control—and indicates their applicability to the residential and commercial sectors. A more detailed description of gas-fired equipment measures and their relative efficiencies is presented in Appendix D. Measures hold promise for gas savings depending on the demand for the end-use service and the current efficiency of consumption (base-line), both of which

Table 7-6. Gas Efficiency Measures

	Residential	Commercial
Equipment Measures		
High-efficiency furnace	X	
High-efficiency boiler	X	X
Gas engine heat pump	X	X
High-efficiency unit heater		X
High-efficiency water heater	X	X
High-spin-speed washer	X	
High-efficiency clothes dryer	X	
High-efficiency cooking equipment		X
Shell Measures		
Envelope insulation	X	X
Infiltration reduction	X	
Multiple-pane windows	X	X
Low-emissivity, argon gas-filled window systems	X	X
Distribution System Measures		
Distribution system duct or pipe insulation	X	X
Distribution system duct sealing	X	X
HVAC system zoning	X	X
HVAC Control Measures		
Setback thermostat	X	X
Thermostatic steam valves	X	X
Furnace fan thermostat adjustment	X	
Boiler water temperature modulation	X	X
Energy management system		X
HVAC supply-air temperature reset control		X
Water Heating Control Measures		
Water heater tank insulation	X	X
Water heater demand controller	X	
Water heater temperature modulation	X	X
Heat traps	X	X
Horizontal axis clothes washer	X	
Low-flow shower heads and faucets	X	X

are site-specific. Local climate, construction practice, and structure of the economy help dictate the technical feasibility of DSM measures. Also, many gas efficiency measures will have already been implemented through other electric utility, water utility, or government programs, or by normal market adoption of technologies.

7.4.3 Efficiency Measure Cost-Effectiveness

The benefits of high-efficiency gas equipment have to be compared to the cost incurred (if any) in determining cost-effectiveness. It is beyond the scope of this primer to comprehensively analyze the economics of these measures in all applications. However, key considerations for economic screening of *technologies* are discussed, followed by an example of one cost-effectiveness index commonly used in preparing supply curves of conserved energy.[6]

High efficiency equipment measures usually involve tradeoffs between higher first cost than some conventional alternative on the one hand and energy cost savings over the lifetime of the measure on the other. The appropriate costs to attribute to the measure for the purposes of the economic analysis depend on the situation. If the measure is under consideration when equipment is being replaced or selected for use in new construction, then the appropriate cost is the difference between the cost of the efficient technology and the conventional technology that would otherwise be selected. If a standard prescribes some minimum efficiency level, then the appropriate cost is the difference between the DSM measure's cost and the cost of a technology that simply complies with the standard. If the measure is to be installed in place of equipment that still has useful life (i.e., in a retrofit situation), then the full cost of the measure is appropriate to use in the economic analysis.

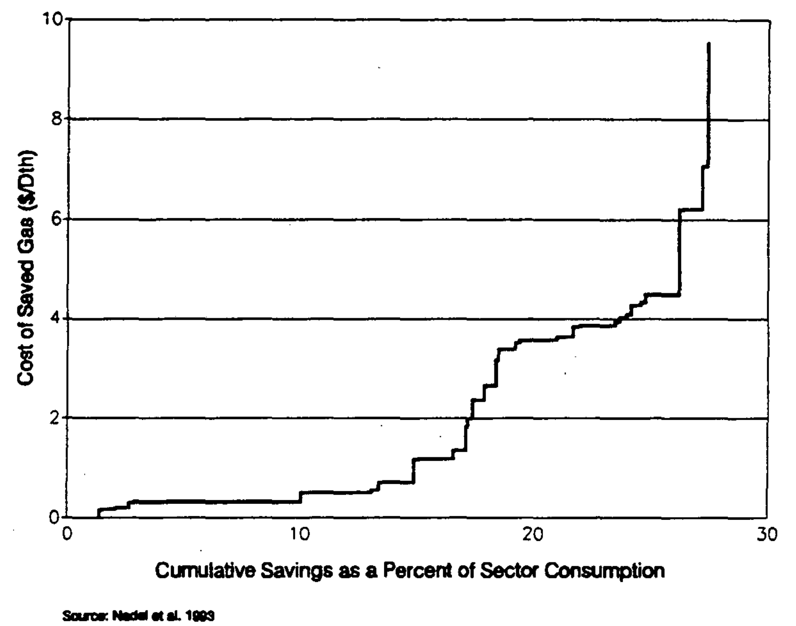
Intensity of use of equipment is a key parameter that drives economic analysis. Efficiency gains in equipment performance will be realized as monetary gains only if the equipment operates enough to generate savings over time. For instance, installing a high-efficiency furnace in Miami may not reap enough savings during the relatively short and mild heating season to justify the increased expenditure; however in Missoula, sufficient savings may accrue over the winter to justify the furnace. Economic analysis also depends on: the differential between conventional and DSM measure efficiencies; the incremental cost of a DSM measure; and fuel prices. Reducing the intensity of equipment use through other DSM or conservation actions can affect the attractiveness of any subsequent investment in efficient equipment. Heating and cooling loads for space conditioning are affected by weather, building construction, building operating hours and conditions, and other uses of energy in the building. Domestic and service hot water

[6] A complete presentation of the standard tests used in DSM *program* screening (i.e. following technology screening and aggregation of technologies into DSM programs) can be found in Chapter 6.

heating, cooking, and clothes drying demands vary by building use and function and can be altered by DSM activities.

A convenient index for ranking and screening DSM measures is the cost of conserved gas (CCG). This index is used to construct supply curves of conserved energy, with the CCG on the vertical axis and savings on the horizontal axis. An example of such a supply curve of conserved gas prepared for a New York LDC is shown in Figure 7-8. CCG is formally defined as,

Figure 7-8. Supply Curve of Saved Gas in Commercial Sector for Long Island Lighting Company



$$Cost\ of\ Conserved\ Gas = \frac{Incremental\ DSM\ Cost\ x\ CRF}{Period\ Savings}$$

where CRF is the capital recovery factor used for amortizing the initial investment into a periodic payment, analogous to a mortgage payment.[7] The CCG is typically calculated based on annual gas savings, but could in principle be calculated on a seasonal basis.

A principal advantage of the cost of conserved energy is that it is expressed in dollars per unit energy and therefore can be directly compared to the cost of the fuel displaced (either at the applicable retail rate or avoided cost). Future energy cost expectations are

[7] Capital recovery factor = $d/(1 - (1 + d)$ ^$-n)$, where d is the discount rate and n is the measure lifetime in appropriate time units, usually years.

also exogenous. A disadvantage is that CCG in its pure form ignores the capacity impacts of DSM measures although this limitation can be mitigated somewhat.[8]

Cost-Effectiveness Calculations for High-Efficiency Gas Furnace

This example shows stylized cost-effectiveness calculations for a high-efficiency (condensing) gas furnace in a typical U.S. residence. A utility might perform this calculation in initial DSM technology economic screening or in constructing a supply curve of conserved gas for the purpose of assessing economic savings potential. While we do not intend to show all the possible intricacies of a heating equipment replacement decision, this example presents the method and some of the sensitivities to input assumptions, in simplified terms.

(1) Located in a mid-Atlantic state, this single-family dwelling with thermal characteristics typical of existing homes in the region has a heating load of 65 MMBtu/yr based on GRI data (Holtberg et al. 1993). The existing 75,000 Btu/hr furnace needs to be replaced, and the homeowner is choosing between a conventional furnace just meeting the NAECA standards (AFUE = 78%) and a high-efficiency condensing furnace (AFUE = 92%), both with 30-year expected lifetimes. The first option will cost \$2,000 installed while the second option costs \$2,400. Assume that the utility uses a 6% *real* discount rate. The cost-effectiveness of choosing the high-efficiency furnace over the NAECA-conforming furnace is as follows:

$$\begin{aligned} Savings &= Heating\ Load\ x\ \left(\frac{1}{AFUE_{std}} - \frac{1}{AFUE_{ee}}\right) \\ &= 65\ x\ \left(\frac{1}{0.78} - \frac{1}{0.92}\right) = 12.7\ DTh/yr \end{aligned}$$

$$Capital\ Recovery\ Factor = \frac{0.06}{1 - (1 + 0.06)^{-30}} = 0.0726$$

[8] One way is to calculate a separate index based on the capacity savings alone so that the denominator is annual peak savings instead of energy savings. Another approach is to incorporate the capacity cost savings into the CCE by subtracting the annual capacity cost savings from the amortized investment cost to yield a composite index.

$$\textit{Cost of Conserved Gas} = \frac{(2400 - 2000) \times 0.0726}{12.7} = \$2.3/DTh$$

The CCG can now be compared to the price of gas for this customer class (as a means of testing DSM measure cost-effectiveness from the recipient's perspective) or to the appropriate gas avoided cost (for a societal or utility perspective); the societal or utility perspectives customarily include program administration costs (see Chapter 4). Because gas tariffs for residential customers are generally higher than assumed here, the high-efficiency furnace appears to be cost-effective from the recipient's point of view.

(2) Now, suppose the home is located in another region with different building practices and local climate, and accompanying change in heating load. The heating load could be lower because of a warmer climate or because the home has higher thermal integrity; energy standards in many jurisdictions require new homes to be built with higher thermal integrity than existing homes. Assuming all other factors remain the same, the cost of conserved gas for these general locations would be:

Location	Annual Heating Load (MMBtu/yr)	CCG ($/DTh)
New England	100	$1.5
Pacific Coast	45	$3.3
Southwest	30	$5.0

This hypothetical situation illustrates the point that the intensity of use (i.e., heating load) is a key factor in DSM measure cost-effectiveness.

(3) Consider whether to retire the existing furnace early and install the high-efficiency furnace in its place. In this case, we are comparing the efficiency of the existing furnace to that of the high-efficiency furnace. Existing gas furnaces in U.S. homes have an average AFUE of around 65%. In the mid-Atlantic region with its heating load of 65 MMBtu/yr, we find annual savings of 29.3 DTh/yr from using the high-efficiency furnace. However, the cost in this situation is the full measure cost, i.e., $2,400. The resulting CCG is $5.9/DTh, which is higher than typical gas avoided cost estimates or residential customers' gas prices, so this application of a high-efficiency furnace does not appear cost-effective. However, the economics would be somewhat more attractive in a more severe heating climate.

(4) Different assumptions regarding furnace lifetime or consumer discount rate have an effect on DSM measure cost-effectiveness. Changes in these assumptions based on the scenario in (1) result in the following:

Real discount rate doubled to 12%:	CCG = \$3.9/DTh
Real discount rate halved to 3%:	CCG = \$1.6/DTh
Furnace lifetime halved to 15 years:	CCG = \$3.2/DTh

7.5 Opportunities for End-Use Fuel-Substitution

High-efficiency gas and electric equipment can substitute for one another in many applications. Like other DSM measures, equipment choices involving a substitution of one fuel source for another can be evaluated as potential DSM resource opportunities in terms of their potential advantages to customers, utilities (both gas and electric) and society.[9] This section focuses on fuel-switching between gas and electricity in the residential and commercial sectors. Assessing the merits of fuel-substitution is more complicated than assessing an intra-fuel technology choice; additional technical, economic, and other issues that should be considered by utilities and PUCs are identified and discussed briefly. The policy implications of end-use fuel-substitution are discussed in Chapter 8.

Figure 7-9 displays the current market shares (on an energy value basis) for natural gas, electricity, and other fuels in the residential and commercial sectors. Natural gas has a larger share of energy consumption than electricity in the residential sector (roughly 45% vs. 30%) whereas natural gas and electricity usage are comparable in the commercial sector. These relative shares reflect the differences in the two sectors in the services demanded, the equipment providing those services, and a host of economic and other considerations historically affecting consumer choice.

Table 7-7 highlights additional technical, economic, and other issues that should be considered in evaluating fuel-switching DSM opportunities.

[9] Each individual application has to be evaluated carefully to account for the particular circumstances, i.e., the characteristics of the technology/fuel combination that is being replaced or compared to the one under consideration, the relative cost of fuels, etc..

Figure 7-9. Fuel Market Share in the U.S. Residential and Commercial Sectors (1990)

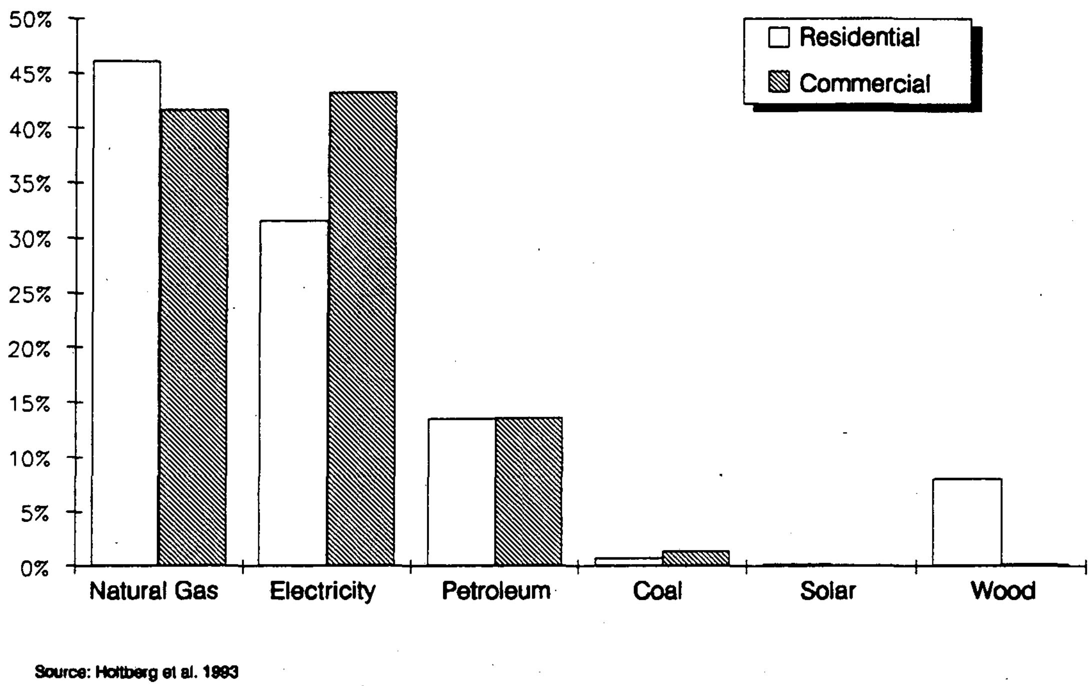


Table 7-7. Issues to Consider in Analyzing Fuel-Substitution Opportunities

Technical	• Relative site and source energy efficiency • Relative risk of savings performance degradation • Parasitic electricity consumption of some gas equipment • Load shape impacts of gas and electric technologies on each utility
Economic	• Relative gas and electric tariffs • Relative gas and electric avoided costs • Relative risk of price volatility and uncertainty • Access to gas service, including hook-up and line extension costs
Other	• Space, noise, and aesthetics • Environmental impacts and tradeoffs

Technical

- *Relative site and source energy efficiency of technologies using each fuel:* By convention, energy efficiencies of equipment or processes in buildings are given at the end use (i.e. site) level, that is, at the point where the fuel is converted into a service such as heat, motive power, etc. Ultimate consumers of energy will primarily be concerned with this measure of efficiency as it directly affects operating costs they incur. However, much of the original energy value of the fuel is lost in resource extraction, processing, and transportation to the point of end use. Source energy efficiency takes account of all losses from the fuel source to the service. One aspect of a societal analysis is full fuel-cycle analysis, which arrives at a source energy efficiency by taking the product of the efficiencies at every step in the cycle.

  For natural gas, losses incurred in the system up to the point of end use have been estimated to be about 9% nationally (Moran 1992). For electricity, the weighted average losses incurred in the system up to the point of end use based on the current national generating mix are estimated between 65% and 75% (Electric Power Research Institute (EPRI) 1992c; Moran 1992). Actual values for a particular utility will undoubtedly be different from these national averages. Losses in electric generation, transmission and distribution also have considerable variation with ambient temperature. On hot days, generator heat rates rise because condenser temperatures rise, and transformer and line losses increase. A further subtlety on the electricity side is that the average generation fuel mix even for a given utility may not be the best basis for estimating source energy efficiency. A more sophisticated and potentially more accurate representation of source energy efficiency would take into account the most likely electricity generation source(s) to serve the end use in question. For instance, the losses associated with a hot water heater operating on a more or less constant annual basis may best be represented by a baseload plant; for an air conditioner operating in a summer peaking utility service territory, they may best be represented by a peaking plant. In some circumstances, one might be able to draw such distinctions on the natural gas side as well. This point is relevant for considering environmental impacts as well.

  In sum, source energy efficiency is the product of the site energy efficiency of the device under consideration and the efficiency of the entire fuel-cycle up to the point of end use.

- *Relative risk of savings performance degradation:* Fuel-substitution DSM theoretically provides more reliable savings for utilities than intra-fuel DSM because it effectively solves problems of savings persistence and snap-back.

However, depending on the application, unanticipated user behavior could in fact lead to savings degradation. Utilities will need to experiment with fuel-substitution DSM to verify that actual savings meet expectations for high reliability.

- *Parasitic electricity consumption of some gas equipment:* Some gas equipment and appliances use electricity for ignition, venting fans, etc., and this consumption needs to be accounted for explicitly in any energy use or economic comparison.

- *Load-shape impacts of gas and electric technologies on each utility:* Making a choice between technologies has an effect on load patterns. The technology selected will create additional load on one utility; the technology that is displaced represents an absence of load on the utility that would have served it. The load-shape impacts of the competing technologies will likely be different and should be properly valued in estimates of avoided cost.

Economic

- *Relative gas and electricity tariffs:* In order for program participants to calculate bill savings and for the utilities who are respectively losing and gaining customers to calculate revenue impacts from a DSM program, the tariffs of both utilities must be addressed in the economic assessment including all applicable seasonal or time-of-use rates and demand or reservation charges.

- *Relative gas and electricity avoided costs:* The difference in avoided costs between the two utilities on an energy services basis is a key measure of the potential societal economic benefits of switching from one fuel source to the other.

- *Relative risk of price volatility and uncertainty:* Different fuels pose varying price risks to ratepayers. Because electricity is typically generated from a variety of fuel sources, the impact of a price change for any one fuel will tend to be dampened in the overall electricity price. However, both electricity and gas utilities are subject to other regulatory and market risks that can translate into price changes, and expectations of these changes should be incorporated into fuel-switching analyses.

- *Access to gas service, including line extension and hook-up fees for electricity to gas switches:* Some DSM programs promoting the substitution of gas in place of electricity may be constrained by lack of access to gas for some otherwise eligible customers. Line extension and hook-up costs should be considered in the economic analysis of these measures.

Other Factors

- *Space, noise, and aesthetics:* Competing electric and gas equipment can have different space requirements, both for size and location (i.e., interior, exterior, near an exterior wall, close to the point of end use, etc .) Noise and aesthetics can be an issue for some equipment in some circumstances, necessitating special consideration and mitigation.

- *Environmental impacts and tradeoffs:* Environmental consequences of energy use are a growing public concern. Land, water, and air pollution stemming from energy consumption can degrade human and ecosystem health. Comparing end-use technologies with this concern in mind should take into account the type of fuel consumed (and all its attendant impacts occurring throughout the fuel-cycle up to the point of end use), the end-use efficiency of the technology (i.e., how much fuel it consumes), the on-site impacts from installation and operation of the technology, and timing of the impacts during the day and from season to season. Ideally, one would account for environmental impacts of manufacturing and disposing of the end-use technology as well (i.e., upstream and downstream impacts) (Electric Power Research Institute (EPRI) 1992c).

  Generally for electric and gas equipment used in the commercial and residential sectors, air pollutant emissions from the combustion of fossil fuels are the area of greatest concern. The air pollutants often cited include carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), nitrous oxide (N_2O), volatile organic compounds (VOCs), methane (CH_4), chlorofluorocarbons (CFCs),[10] total suspend particulates (TSP), and air toxics including mercury, heavy metals, radioactive gases and particles. Air emissions can be classified by whether they are implicated in producing global impacts (as with CO_2, CH_4, CFCs, and N_2O in global climate change), regional impacts (as with SO_2 and NO_x in acid rain), or local impacts (as with NO_x, VOCs, and particulates). Power plant emissions of SO_2, NO_x, and CO_2 have been a primary concern of environmental regulators and more recently, state PUCs. Coal- and oil-based generation produces relatively higher levels of SO_2 and CO_2; gas-based generation produces relatively higher levels of NO_x. For gas-fired end-use equipment, NO_x

[10] CFCs are not a combustion product but are used in refrigeration equipment and as a thermal insulation material.

emissions are the major concern although CO and NO_2 and, occasionally, particulate emissions from unvented equipment can contribute to indoor air quality concerns.

Air emissions at the power plant can be accounted for in a number of ways. One approach is to use an average fuel-mix considering the performance of plants (i.e., heat rate) and the presence of any emissions controls (e.g., selective catalytic reduction for NO_x or flue gas desulfurization for SO_2). A refinement of this approach is to distinguish the mix of generation resources by season because the level of demand and availability of some resources (e.g., hydro) often varies seasonally. The seasonal, average, generation fuel-mix-based emission rates would then be paired with seasonal load impacts of the end-use technology under consideration to arrive at the end-use emissions impact. A second approach is to consider the changes in air emissions that would occur at the margin from eliminating or adding the electric end-use technology, either as a mix of marginal plants or as a single marginal plant (e.g., combustion turbine). Whichever approach is used to account for the emissions of electric power plants serving electric end-use technologies, the geographic location of the emitting plants and the timing of emissions of certain pollutants can be critical to assessing local air quality impacts, a concern in many U.S. urban air-sheds.

For gas end-use technologies, the principal air emissions take place on site.[11] Because LDC residential and commercial customers are mainly located in urban areas, NO_x emissions from their gas-fired equipment and appliances can contribute to smog problems, depending on the coincidence of smog episodes and the use of the equipment. For instance, gas cooling technologies' emissions may be highly coincident with urban smog because many cities experience their worst smog during the hottest summer weather.

Another issue for air emissions impacts from end-use technologies is the evolution of environmental regulation at the federal, state, and local levels. Changes in environmental regulation may alter expectations of future emissions, especially from power plants. In some cases, regulations may effectively preclude some technologies from being marketed and could be incorporated as sensitivities in an analysis. At the federal level, the recently enacted Clean Air Act Amendments will significantly alter the SO_2 and NO_x emissions in some electric utility service territories. Likewise, a recent federal commitment to reduce U.S. greenhouse gas emissions to 1990 levels by the year 2000 is likely to have an impact on electric utility resource portfolios in the future. As an example at the local level,

[11] CH_4 emissions as losses along the pathway from production to end use are the primary off-site emissions.

environmental regulators with jurisdiction over air quality in the Los Angeles area have enacted strict controls over emissions from a variety of sources, including but not limited to power plants. Other urban areas may consider similar actions.

Finally, several state PUCs have adopted or are considering assigning environmental externality cost values to residual emissions (i.e., those not already covered by existing regulations) for use in benefit-cost analyses of resource decisions made by their regulated utility companies. Externality cost values (also known as "adders") for individual pollutants are based on an estimate of the cost of damage caused by the pollutants. Adders derived from this damage function approach are scientifically and ethically difficult to determine, so most PUCs are using a proxy approach that assigns the cost of some known control method for a given pollutant. Externality cost values (generally given in dollars per unit of pollutant emitted) are multiplied by a given technology's emissions to arrive at the externality cost penalty for that technology. To date, externality cost values are only being used by utilities in selecting new resources, although they could in principle also be used in system operation and plant retirement decisions as well. Exhibit 5-1 presents externality cost values and the ways in which they are being used in some jurisdictions.

7.5.1 Fuel-Switching Measures Between Electricity and Gas

This section provides an overview of gas technologies that could be substituted for electric technologies in residential and commercial applications. Many of the equipment measures for increasing gas efficiency listed in Table 7-6 are also candidate measures for fuel-switching from electricity to gas. Table 7-8 lists some of the relevant technologies for switching from electricity to gas and gas to electricity, respectively, indicating their applicability in the residential and commercial sectors. A more detailed description of these technologies and their efficiencies is included in Appendix D.

7.5.2 Fuel-Switching Measure Cost-Effectiveness

A comprehensive economic analysis of fuel-switching options is beyond the scope of this primer because of the many quantitative and qualitative factors that should be considered and because of the wide variability the values of options in different parts of the U.S. Instead, an example illustrating one method for assessing the economic merit of fuel-switching is presented. For the societal or utility perspective, assessing the cost-effectiveness of fuel-switching measures requires gas and electricity avoided cost estimates. There is less consensus about the methods for estimating gas avoided costs than about methods for avoided electricity costs (see Chapter 5). Therefore, in this

Table 7-8. Fuel-Switching Measures Between Electricity and Gas*

	Residential	Commercial
Electric to Gas Measures		
Gas engine heat pump	X	X
Engine-driven vapor compression chiller		X
Absorption chiller		X
Desiccant cooling system		X
Gas to Electric Measures		
Electric ground-source heat pump	X	X
Electric heat pump water heater	X	X
Refrigeration heat reclaim		X
Ozonated laundering system		X

* Measures listed here are in addition to the gas efficiency measures listed in Table 7-6.

example, fuel-switching cost-effectiveness is calculated in terms of a threshold gas avoided cost; actual gas avoided costs lower than the threshold value would indicate that a gas technology is the economically preferable choice. In other words, given an uncertain gas avoided cost, the break-even avoided cost for gas explicitly shows what gas avoided costs would have to be in relation to electricity avoided costs for a technology to be cost-effective. If gas avoided costs are well determined, other methods for fuel-substitution economic analysis could be employed. Like the cost of conserved gas economic indicator used in the previous example, fuel-substitution cost-effectiveness is useful primarily in *technology* screening. The break-even avoided gas cost is derived algebraically in Appendix C.

Break-Even Cost Calculation for Electric to Gas Fuel Substitution

This example shows a sample break-even gas avoided cost calculation for a commercial gas cooling application.[12] The break-even gas avoided cost is the threshold below which gas avoided costs would have to be in order for a DSM measure to be cost-effective. The building is 50,000 square feet with a cooling load of 2,100 MMBth/year (U.S. average cooling load for commercial buildings in this size category per GRI). The building is

[12] The method can be similarly applied in a gas-to-electric fuel-substitution case.

served by a 125 ton electric, water-cooled, reciprocating chiller with a seasonal COP of 3.5; the chiller consumes 175,850 kWh annually.

The proposed alternative cooling system is a gas engine-driven, water-cooled chiller of the same size with a seasonal COP of 1.4; the chiller consumes 1,500 DTh/yr. The gas chiller has a lifetime of 15 years an initial cost of $800/ton. For this example, we assume that the maintenance costs are 0.9¢/ton-hour higher for the gas chiller than the electric chiller. With electric avoided costs of $.047/kWh for energy and $65/kW/yr for demand, the annual avoided electricity cost from switching these two technologies (ignoring parasitic electricity use of the gas chiller) is $16,429.

As presented in Appendix C, the break-even gas avoided cost (BGAC) is (in simplified form for this example)

$$BGAC = \frac{\textit{Incremental Cost x CRF - Annual Electric Avoided Cost - Annual Incremental Maintenance Cost}}{\Delta \textit{ Annual Gas Use}}$$

A capital recovery factor (CRF) of 10.3% is used, which annualizes the initial investment based on a 15-year lifetime and a 6% real discount rate. For equipment replacement at the end of the useful life of the electric chiller, the incremental cost is the difference between a new electric chiller (@ $600/ton) and the gas chiller (@ $800/ton). This results in,

$$BGAC = \frac{\$25{,}000\ x\ .103\ -\ \$16{,}429\ -\ \$1{,}575}{1500} = \$8.2/DTh$$

If the actual gas avoided costs are lower than $8.2/DTh, then replacing the electric chiller with the gas chiller under these circumstances would be advantageous.

Suppose that the electric chiller was displaced before the end of its useful life. In this instance, the incremental cost of the gas chiller is the full cost, i.e., $100,000. This produces a break-even gas avoided cost of $3.0/DTh. In order for this gas cooling application to be cost-effective, avoided gas costs would have to be lower than this amount.

7.6 Issues in Gas DSM Program Design and Implementation

This section summarizes issues that arise when gas utilities implement DSM programs and highlights lessons learned from the experience of gas and electric utilities in designing, delivering, and evaluating DSM programs.

7.6.1 DSM Program Design

DSM programs match end-use technologies, customer segments, and program delivery mechanisms (Hirst 1988a). Several strategic approaches to DSM program design are possible, but it is instructive to identify two ends of the spectrum: "bottom-up" and "top-down."

In the bottom-up approach, a utility starts with a comprehensive set of DSM measures and methodically screens them producing a short list of the best measures. Screening is often performed using both qualitative and quantitative criteria. One gas LDC used the following qualitative criteria: market potential, reliability, load shape objectives, customer objectives, net impact of utility action, expected cost-effectiveness, and balance among customer segments (Synergic Resources Corporation (SRC) 1991). Quantitative criteria often include the multiple benefit/cost tests discussed in Chapter 6, set at some threshold level (e.g., B/C ratio greater than 1.2). DSM programs are then built around measures that pass the criteria, with the measures "packaged" individually or together for specific market segments.

In the top-down approach, a utility begins with strategic market analysis, identifying DSM program opportunities that could satisfy a set of corporate objectives for DSM. These objectives might include: enhancing customer service, promoting equity among all customer classes, increasing system load factor, retaining elastic customers, minimizing rate increases, and maximizing customer participation. Applicable DSM measures are then mapped onto these program concepts and subjected to economic screening.

Program Design Options

Utilities have at their disposal a variety of design options or approaches for inducing changes in customer energy use (see Table 7-9). Types of DSM programs include: information, innovative rates and pricing, rebates, loans, comprehensive direct installation, performance contracting, and competitive bidding (Nadel 1992).

Information programs—brochures, advertising, bill inserts and energy audits—seek to motivate and inform customers about the benefits of increasing energy efficiency. Rebate programs offer anywhere from some nominal fraction up to the full DSM measure cost (provided it is below the avoided cost ceiling). Loan programs usually offer low or zero interest loans to facilitate energy conservation investment on the part of the customer. When given a choice, most customers prefer rebates over loans of equivalent value. Direct install programs provide a turnkey operation for customers offering a comprehensive range of services that typically includes financing, audits, measure installation, and follow-up operations and maintenance of installed measures. Performance contracting programs use third-party private firms, also known as energy service companies (ESCOs), to deliver DSM services to the utility's customers. ESCOs usually compete on the basis of qualifications to provide these services and are compensated by the utility for energy or capacity savings delivered. Bidding programs are similar to performance contracting except that the selection process is more complex and formalized, and bidders themselves propose a payment scheme. Experience with DSM bidding by electric utilities has shown that this type of program is most applicable to the commercial and industrial sectors. For most LDCs, the majority of DSM opportunities are in the residential sector; for this reason, DSM bidding may not be a particularly attractive program design option.

Each of these program mechanisms has different characteristics in eligible customer participation, savings, and cost. Very general comparisons among the DSM program mechanisms are given in Table 7-9, drawn primarily from electric utility experience. This table also highlights three common measures of DSM program success: participation rate, savings per customer, and utility cost per unit savings. At present, financial incentives in the form of rebates have been perhaps the most important element of DSM programs in moving customers toward increasing efficiency in their facilities and homes. Over time, it is likely that there will be increasing emphasis on DSM program designs that maximize cost contributions from the customer.

Rate Impacts

Utilities and regulators must balance the benefits from aggressive energy-efficiency initiatives with competitiveness and nonparticipant impacts in setting goals for DSM program design. Minimizing rate impacts of DSM programs is a major concern of gas utilities. A starting point for minimizing rate impacts is to base rates on marginal costs. The benefit of marginal-cost-based rates is that they improve the energy use decisions of all customers, not just the ones who participate in a DSM program. Cost-based rates, including additional seasonal differentiation where appropriate, should reduce the difference between prices and avoided costs and reduce the revenue loss and associated rate impacts of some DSM programs.

Table 7-9. Summary of Strengths and Weaknesses of Different Program Approaches

	Number of Customers Targeted	Number of Customers Served Per Year	Participation Rate	Savings Per Customer	Utility Cost Per Unit Savings
Information	high	moderate	low	low	varies
Load-Management	high	moderate	moderate	moderate-high	low
Rebate	high	moderate	low-moderate	moderate	low-moderate
Loan	moderate	low	low	moderate-high	moderate
Performance Contracting	moderate	low-moderate	low-moderate	moderate-high	moderate-high
Comprehensive/ Direct Installation	moderate (can be high over long-term)	moderate	high	high	moderate-high

Source: Nadel 1992

Another strategy for mitigating the effects of rate impacts is to allocate the cost of DSM programs only to classes of customers that are offered the programs. Assuming that a program is being offered to customers with relatively inelastic demands, such a strategy would minimize load losses from price-elastic customers to who choose alternative fuels or service providers. See Section 9.5 for examples of the impacts of alternative DSM program cost allocation approaches.

Another strategy for mitigating rate impacts is to recover the bulk of DSM program costs from participants. Several utilities have developed an energy services charge tariff in order to market and deliver DSM programs in a manner that can be considered "subsidy-free" (Cicchetti and Hogan 1989; Cicchetti and Moran 1992); participants pay for the full cost of the DSM although the utility, by selling it as a service, essentially provides the necessary capital and may take on some risk of nonperformance. Such a strategy in theory removes barriers to capital but does not saddle nonparticipants with rebate costs and lost revenues as is the case with more conventional utility rebate programs. Although actual experience is limited with energy service charge program designs, initial evaluations suggest that the energy services approach tends to dampen program

Exhibit 7-1. A Joint Gas-Electric DSM Program Designed to Mitigate Rate Impacts

Southern California Gas (SCG) and Southern California Edison (SCE) are developing a pilot DSM program that involves joint-delivery where their service territories overlap. The Total Energy Efficiency Management (TEEM) program was conceived as a way for both utilities to achieve joint economies while providing customers with a more comprehensive assessment of savings available in their facilities. The economies derive principally from two aspects of the program: (1) saving on program administration costs by operating one joint program rather than two separate, similar programs and; (2) shifting the financing of the DSM measures from the utility to participating customers and third parties without recourse to ratepayers or shareholders of the sponsoring utilities. This second feature addresses the concern over potential rate impacts from utility DSM.

TEEM is designed to provide commercial and industrial customers with "fuel-blind" information and assistance on energy conservation. The services offered through the program include project identification, engineering, construction, monitoring and maintenance, and project financing. The utilities play mainly a facilitation role in the program, matching up customers with technical and financial resources. It is envisioned that energy service companies (ESCOs) will assume a primary role in the delivery of the program's services.

A novel aspect of the TEEM program is its financing. Customers are given three options for funding DSM investments identified in the earlier phases of the project cycle: (1) loan arrangement in which TEEM makes program participants aware of local lending institutions and ESCOs who may wish to provide debt financing, (2) energy service charges on monthly bills with customers bearing performance risk once the project has been demonstrated to deliver savings at the expected level, and (3) energy service charges on monthly bills with the customer bearing no performance risk but sharing measured savings with a third party.

Program costs are to be financed through a 3% marketing fee charged to ESCOs and other trade allies carrying out the program for targeting customers and other utility staff time used in program marketing, a 1% processing fee for placing energy service charges on customer bills under financing option #2, and a 3% fee for bearing performance risk under financing option #3. In this way, the TEEM program is designed to become self-sustaining at a threshold level of participation.

Source: Occhionero 1993

participation rates in certain market sectors. Resolving this drawback is a major challenge for utilities and DSM advocates.

Exhibit 7-1 describes a pilot DSM program, undertaken jointly by Southern California Gas Company and Southern California Edison, that is designed to mitigate potential rate impacts using the energy services charge framework.

Market Niches

Achieving widespread DSM program participation among all customer segments is another way of mitigating the potential equity impacts of DSM-related rate increases. This requires segmentation of customers into appropriate market niches. Utilities can then target marketing, services, and incentives to capture otherwise difficult or otherwise unattainable DSM opportunities within customer classes. For instance, low-income customers may respond very differently to information and incentives than typical residential customers, so reaching each group will require a different approach.

Market Transformation

Utility DSM programs have traditionally focused on customer service and resource acquisition objectives. DSM proponents have proposed market transformation activities in order to accelerate the shift towards energy-efficient products and services. Market transformation can involve early introduction, accelerated adoption, or expansion of the ultimate penetration of energy-efficient technologies (Nilsson 1992). A distinguishing feature of market transformation strategies is that utilities attempt to work directly with and influence "upstream" market actors (e.g., equipment manufacturers, builders) in a concerted fashion.

Schlegel et al. (1993) have developed a conceptual framework for gauging market transformation strategies along two dimensions: which market actors are affected and the mechanisms through which the actors' behavior is altered (see Table 7-10). Market actors include utility customers, trade allies (e.g., dealers, distributors, contractors, engineering and architecture firms, etc.), and manufacturers. The mechanisms that change behavior include altered options, incentives, education, and moral suasion. For any customer class, end use, or technology, the mode of market transformation is likely to vary.

The Super Efficient Refrigerator Program (SERP), also known as the "Golden Carrot" program, is an example of a DSM market transformation program. A consortium of environmental, utility, and government agencies instituted a competition offering a bounty of guaranteed multi-million dollar refrigerator sales and a sharing of development risk. The competition asks appliance manufacturers to develop and market refrigerators that exceed the energy-efficiency levels of federal standards by a specified amount, with the hope that losing manufacturers will feel compelled to offer comparable products to

Table 7-10. Examples of Market Transformation Strategies

How Behavior Changed	Whose Behavior Changed? Customers	Trade Allies	Manufacturers
Change in Actors' Options	•Increasing availability of efficient equipment •Bringing new technologies to market •Codes and standards		•Codes and standards
Change in Actors' Incentives	•Changing market availability of efficient equipment •Permanent financial incentives	•Changing what dealers stock by changing their perception of customer preferences •Building market infrastructure by directly or indirectly increasing demand •Forcing nonparticipants to change behavior to remain competitive •Changing what distributors order or push by changing perceived demand •Building an "efficient dealer" niche	•Golden Carrot approach (SERP) •Changing efficiency mix by changing perceived demand •Changing shipments to area by changing perceived *relative* demand •Accelerating transition to new Federal standards
Change in Knowledge (Education)	•Getting customer to take the crucial "first step" with other steps following •Causing customer to repurchase technology due to satisfactory experience •Making customers more aware of the range of efficient options •Changing customer perceptions of the costs of efficiency	•Making dealers aware of customer preferences •Informing dealers of the characteristics of efficient equipment and the options for energy services	•Making manufacturers aware of what products are needed in the marketplace
Change in Norms, Values, or Attitudes (Moral Suasion)	•Changing what customers perceive to be "normal" behavior	•Changing attitudes and values of business owners •Changing trade ally perceptions of "normal" behavior	

Source: Schlegel et al. 1993

those of the lone winner. Similar types of efforts are now being planned for other appliances (e.g., packaged air conditioners).

Another example of a market transformation program was conducted by Ontario Hydro to transform the market share for high-efficiency motors from 5% to 40% through a combination of education and incentives applied strategically throughout the market chain from manufacturers to vendors to customers.

The DSM efforts of gas utilities in Wisconsin offer an interesting example of (possibly inadvertent) market transformation for a gas appliance. Following years of gas utilities conducting DSM programs to promote pulse combustion furnaces for residential customers, this technology became the norm, achieving up to 90% of the gas furnace market (Kaul and Kihm 1992). A study of the diffusion of these high-efficiency gas furnaces concluded that the indirect effects of the DSM programs may have outstripped the direct effects (i.e., purchases made as a result of a utility incentive) by a margin of 3 to 1 (Schlegel et al. 1992). However, recently it appears that the market for these products in Wisconsin may be regressing (though nationally shipments of these furnaces are growing).

Market transformation programs pose particular challenges in program evaluation. Changes in the focus and methods of current program evaluation practice will almost certainly be required. Unless current methods for determining net savings from DSM programs evolve, utilities could be penalized for successful market-transforming efforts, essentially by obscuring the definition of nonparticipants (Prahl and Schlegel 1993).

Free Riders

Free riders are participants in DSM programs who would have installed the measure anyway without any inducement from the utility. Measures with already high market shares or quick paybacks often lead to high free ridership when promoted through DSM programs (Nadel 1992). Free riders do not diminish the savings accruing to society, but they do influence the savings attributable to the program and therefore the cost-effectiveness of the program from the utility perspective. DSM program design can help to minimize free ridership by offering rebates on only the highest efficiency DSM measures with longer customer paybacks and/or those products with a low market penetration.

7.6.2 DSM Program Delivery

The details of putting a DSM program "on the street" are highly specific to any program and beyond the scope of this primer. However, two issues are particularly relevant from a regulatory perspective and are briefly discussed: the cost of administering DSM programs and the potential for joint gas utility/electric utility DSM program delivery.

DSM Administrative Costs

Sometimes neglected in DSM potentials studies are the indirect costs incurred by utilities in administering DSM programs. Administrative costs could include any or all of the following: (1) program planning, design, analysis, and evaluation; (2) activities designed to reach customers, bringing them into the program and delivering services such as marketing, audits, application processing, and bid reviews; (3) inspections and quality control; (4) staff recruitment, placement, compensation, development, training, and transportation; (5) data collection, reporting, record keeping, and accounting; and (6) overhead costs such as office space and equipment, vehicles, and legal fees (Berry 1989). Many of these items could appear on the ledgers of utility departments other than the DSM program.

A limited national survey by Oak Ridge National Laboratory (ORNL) of electric utility DSM programs found that the cost of administering DSM programs on average—typically expressed as a fraction of the direct measure cost—was between 10% and 35% (Berry 1989).[13] Nadel found that administrative costs added a cost premium of 36% on average, over and above the direct measure costs to the utility in a study of 46 North American electric utilities (Nadel 1990). Another study by Joskow and Marron found administrative costs in the range of 7%-70% from ten U.S. electric utilities' overall DSM program efforts (Joskow and Marron 1992). There are no standardized accounting methods for reporting on DSM program administration costs, so some of the variation shown above is no doubt due to what is and is not included in these computations. In general, DSM program costs will vary according to many factors including: (1) stage of program development; (2) target market segment; (3) market penetration goal; (4) technology; and (5) types of services and/or incentives being offered. For instance, a comprehensive program that involved making site audits, arranging for measure

[13] In this study, the programs with the lowest administrative overhead are commercial lighting programs, in the range of 10% to 15% of direct measure costs; multiple measures programs, including audits and incentives for commercial customers, display higher administrative costs, in the range of 25% to 35%. Residential weatherization programs average administrative costs around 20%. Pilot programs of all types can have administrative costs over 100%.

installation and financing, and doing follow-up verification will entail much greater program administration resources than a standardized rebate program.

Jointly Delivered Gas/Electric DSM Programs

DSM programs delivered jointly by electric and gas utilities with overlapping service territories hold the promise of reducing not only the administrative costs of running separate yet similar DSM programs but also reducing customer confusion about competing utility programs (Nadel 1992). Market segments that focus on "lost opportunity" resources (e.g., new construction) or segments in which it is difficult to design cost-effective programs (e.g., low-income housing) have been suggested as particularly promising areas for joint DSM program delivery (Buckley 1992).[14] A mutually agreed upon method for cost-allocation among utilities would be a critical prerequisite to any such cooperative effort.

Energy service companies (ESCOs) are viewed as an appropriate vehicle by which joint gas-electric utility programs could be delivered. By acting as the joint agent of the two utilities, an ESCO can help to reduce customer confusion about the DSM program and provide some measure of objectivity on the best fuel for a given application, following agreed upon criteria and procedures. The role of ESCOs in providing utility energy services has evolved significantly since the early days of performance contracting to include DSM bidding, standard offers for DSM, and various partnerships with utilities in their DSM program efforts (Wolcott and Goldman 1992). Joint utility DSM program delivery would fit easily into the evolving ESCO industry.

7.6.3 DSM Program Evaluation

Evaluation has emerged as a key component of successful DSM programs, providing critical feedback to the program design process. Initially consigned to a minor role in utility DSM efforts, its importance has grown with the advent of DSM as a major resource in electric utilities' portfolios, and especially with more recent state regulatory initiatives to grant utility shareholder incentives based on measured performance of DSM programs. The audience for DSM program evaluations can include utility staff, ratepayers, PUCs, intervenors in utility regulatory proceedings, and others in the energy services industry.

[14] "Lost opportunities" occur in new construction (both commercial and residential) when DSM measures that are most cost-effective (or even only possible) at the design stage, but not later, are omitted.

The core purposes of DSM program evaluation are: (1) description and characterization, (2) measurement, and (3) optimization of programs.

> *Description and characterization* involve detailing: the operation of a program, the market reached and the market that remains, the interaction of DSM measures with behavior, the DSM resource that remains to be captured, and the reasons for program results.
>
> *Measurement* is made of: energy savings attributable to the program, demand impacts (including coincident peak load reductions), utility and societal costs, and persistence of savings.
>
> Evaluations are also expected to provide the basis for *optimizing* programs. They do this by identifying: bottlenecks in program operation, problems in program goals (especially if goals are not shared throughout the utility), the features that worked well in programs, barriers to participation, barriers to persistence of savings, and measures that may not be performing as well as expected (Kushler et al. 1992).

Two broad categories of evaluation serve these purposes: impact and process. Impact evaluations examine the effects of a program, including the quantitative documentation of the program's costs and benefits, the rate of participation and measure adoption, the performance of the DSM technologies, and the energy and load impacts. *Process evaluations* estimate how well a program has been implemented, including the efficiency of service delivery, the effectiveness of promotional strategies, and the level of customer satisfaction (Electric Power Research Institute (EPRI) 1992d).[15]

Impact evaluation seeks to determine which savings are attributable to a program. The crux of the challenge for impact evaluators is to "compare what happened to program participants with what would have happened to participants if the program had not existed" (Hirst and Reed 1991). This involves determining two types of savings: gross (or total) savings of the participants and net savings. Figure 7-10 shows the distinction between gross savings, which are relatively easily measured, and net savings, which require use of sophisticated sampling and statistical methods to determine the "baseline" energy consumption of a comparative or control group in contrast to the program participants.

A number of approaches are used within each of these types of evaluation. Impact evaluations use engineering methods, statistical methods (often in conjunction with

[15] Market evaluation is subsumed in process evaluation in this framework although some define it distinctly.

customer billing records), surveys (qualitative and/or quantitative and administered by mail, by phone, in person, or through site visits), and metering. Process evaluations employ program information, surveys, in-depth interviews, and observation or case studies (Electric Power Research Institute (EPRI) 1992). For both impact and process evaluations, many of these methods are applied in combination, depending on the needs and constraints of the situation. Excellent methodological reviews can be found in (Hirst and Reed 1991) for DSM evaluation in general; in (Electric Power Research Institute (EPRI) 1991b) for impact evaluation; and in (Electric Power Research Institute (EPRI) 1992e) for process evaluation.

Some of the key issues in DSM program evaluation are identified in Table 7-11. These issues are not just relevant to program evaluation but to the viability of DSM as a utility resource. Each of these topics deserves an entire volume (some already have one); interested readers should refer to (Kushler et al. 1992) for a discussion of several evaluation topics listed in Table 7-11. Exhibit 7-2 describes a comprehensive, multi-year DSM program evaluation (Gas Evaluation and Monitoring Study or GEMS) that is being undertaken cooperatively by several New England gas utilities and was initiated by Boston Gas.

Table 7-11. Key Issues in Program Evaluation

Description and Characterization
Role of behavior in evaluation
Timeliness of information and feedback
Presentation of results—clarity, honesty, and objectivity
Measuring customer value
Determining participant costs
Measurement
Net and gross savings
Estimating coincident peak load savings and load shape impacts
Persistence of savings
Limits to measurement
Dealing with uncertainty
Maximizing precision versus minimizing bias
Assessing market transformation
Quality assurance, confirmation, and validation
Verification versus evaluation of program savings
Optimization of Programs
Predicted versus measured savings
Avoiding lost opportunities and cream skimming
Integration of impact evaluation and process evaluation
Other
The role of process evaluation
Comparability of results (across programs, utility services territories, states, and countries)
Generalizing results from metered subsamples to larger populations
Incorporating environmental externalities
Definition of key DSM program evaluation terms
R&D needs for measuring technology performance

Adapted from Kushler et al. 1992

Exhibit 7-2. A Cooperative DSM Evaluation Study in New England

The Gas Evaluation and Monitoring Study (GEMS) is a cooperative, multi-year effort of 11 gas utilities in four New England states to track the performance of each company's DSM programs. The study, spearheaded by Boston Gas, was conceived as a way to economize on expensive data gathering and analysis by cost-sharing and transferring data and results among the participating LDCs. The study is currently in progress, initially focusing on the residential and multi-family sectors while evaluation plans for the commercial and industrial sectors are being formulated.

GEMS has three elements: impact and process evaluations, and end-use metering of customer facilities (which supports impact evaluation). The main objective of the impact evaluation component of the study is to produce estimates of net gas savings from DSM measures. Net savings are developed using a combination of end-use metered data, survey responses, and monthly billing data.

A central feature of the GEMS analysis is the use of end-use metered data collected from a random sample of customers for estimating "gross" savings. These data are collected on an hourly basis to track gas consumption both before and after installation of DSM measures. The change in gas consumption is then corrected for confounding variables in order to isolate the impact attributable to the DSM measures. Transferability of these data among the cooperating LDCs is a major component of the evaluation design.

For estimating the net savings in residential buildings, a combination of techniques is being employed including:

- stratified sampling by housing type, geographical location, and time of DSM measure installation;
- cross-sectional analysis (i.e., comparisons across a variety of dwellings at one point in time) and pooled time series/cross-sectional analysis (i.e., comparisons before and after DSM measure installation among various dwellings)
- "matched-pair" analysis for multi-family buildings; participant buildings are compared to a control building within the same complex

Specific issues the process evaluation is designed to address include:

- progress toward implementation goals
- effectiveness of marketing strategies
- appropriateness of program design in reaching the target market
- adequacy of data compilation for supporting program management, evaluation, and regulatory needs
- reasons that customers choose to participate or not
- attributes and short-comings of the program
- satisfaction of customers, trade allies, vendors, and utility staff
- changes to the program that would improve implementation success
- explanations for free-riders, free-drivers, persistence of savings, and snap-back effects

Source: Greenblatt 1993

Chapter 8

End-Use Fuel Substitution

8.1 Overview

This chapter focuses on natural gas/electricity sector rivalries in end-use markets. The interfuel substitution issues addressed include the regulatory treatment of:

- electricity to gas end-use fuel conversion;
- gas to electricity end-use conversion;
- gas vs. electricity end-use selection; and
- unregulated vs. regulated fuels in end-use markets (e.g., oil to gas end-use conversion or selection).

Fuel-switching issues related to transportation end-use markets (e.g., use of natural gas or electricity to replace gasoline in automotive vehicles) and industrial customers with multi-fuel capability are not addressed.[1] The discussion also does not include fuel choice issues that arise in the regulation of wholesale electric generation markets (e.g., value of fuel diversity).

Opportunities for end-use fuel substitution occur wherever fuel competition for an end use occurs. The natural gas and electricity sectors compete for the residential space heating, water heating, cooking, and drying equipment markets in many parts of the country. Struggles over market share occur for similar commercial sector end uses and certain industrial processes. Competition is only natural in our society because businesses are built upon differences in product characteristics and prices. Nonetheless, the competition between these two sectors has been and continues to be profoundly influenced by federal and state regulation.

With the advent of IRP and the explicit consideration of DSM as a "supply substitute," PUCs have encouraged utilities (primarily electric utilities) to intervene more actively in end-use markets. Proponents of fuel substitution argue that these interventions should not be de facto restricted to higher efficiency products using the same fuel, but that utilities should identify and recommend (if necessary) cost-effective fuel substitution opportunities for their customers as part of their IRP processes. Opponents argue that mandatory fuel substitution, in effect, requires one utility to subsidize competitors' sales

[1] However, the development of electric and gas vehicle markets will be significantly impacted by the policies and decisions made by state PUCs, energy planning agencies, and local governments, particularly the treatment of utility company investments in retail automobile refueling facilities.

(i.e., competing opposite fuel utility) at the expense of its remaining customers (Kahn 1991b).

For regulators, a central issue is whether the efficient selection of fuels in certain end-use markets by consumers can be improved through an IRP planning process that explicitly considers fuel substitution options or whether current utility practices result in a better social outcome. At a minimum, controversies over fuel substitution policies may result in some PUCs reviewing their policies on promotional practices and DSM program implementation in order to insure that existing utility DSM programs are not introducing undesirable distortions into consumer's fuel choice decisions. The gas industry has raised concerns that electric utility DSM programs have the effect of encouraging customers to adopt electric technologies when gas options would be more economically efficient. In practice, policies on promotional practices and DSM implementation (where applicable) are not always consistent, either within a utility or (especially) between competing utilities. In some cases, a PUC may need to impose restrictions (e.g., limiting the scope or size of rebates) or to mandate new activity.

A primary objective of this chapter is to identify policy approaches on fuel substitution, mandatory or otherwise, that are available to state regulators. We describe types of fuel substitution programs, review the arguments that have been raised by proponents and opponents in the fuel substitution debate, present case studies which summarize the experience of eight state PUCs on this issue, and discuss major policy and programmatic issues that regulators are likely to confront if they address end-use fuel substitution directly. It is clear that differing state political environments and social goals may dictate different approaches.

8.2 Types of Fuel Substitution Programs

In the broadest sense, fuel substitution programs are demand-side management (DSM) programs designed to influence the efficiency and timing of customers' demand for gas or electricity, to shave peak loads, to fill valleys in the utility's load curve, and to lower customers' bills. Fuel substitution tries to achieve these goals by substituting energy-using equipment of one energy with a competing energy source (CPUC 1992d).[2] Fuel substitution programs promote or provide an incentive for efficiency improvements associated with the fuel conversion.

[2] The CPUC has limited "energy source" to utility-supplied electricity and natural gas but noted that this stipulation may be broadened as the analytical constraints for evaluating unregulated alternative fuels become less restrictive.

- *Gas fuel substitution programs* promote the customer's choice of gas service for an appliance, group of appliances, or building rather than the choice of service from a different energy source. These programs increase customers' usage of natural gas and decrease usage of an alternative fuel.

- *Electric fuel substitution programs* promote the customer's choice of electric service for an appliance, group of appliances, or building rather than the choice of a different fuel. These programs increase customers' electric usage and decrease usage of utility-supplied natural gas (CPUC 1992d).

It is useful to distinguish two aspects of fuel choice, which are related to the circumstances and timing of customer decisionmaking: "conversion" and "fuel selection." "*Conversion*" refers to situations in which customers discontinue the use of an existing appliance that uses one kind of energy source and switch to an appliance that uses a competing energy source. The conversion may be either from electricity to natural gas or vice versa and typically occurs at the time of equipment replacement. "*Fuel selection*" refers to situations in which customers are selecting new appliances rather than replacing existing ones. Fuel selection occurs whenever new buildings are constructed and, in some cases, when existing buildings are remodeled or new end uses are added. These concepts of "conversion" and "fuel selection" apply throughout the building sector in residences, businesses, and industries.

Approaches that PUCs adopt towards fuel substitution are often influenced by the context in which these programs are proposed by utilities. In reviewing fuel substitution proposals, many regulators will consider both existing promotional practices policies and the extent to which competing utilities are actively involved in end-use markets as indicated by their DSM programs. Some PUCs have used promotional practice and DSM policies as the basis for determining cost recovery treatment because fuel substitution programs typically have varying load shape impacts and objectives for each utility (e.g., conservation, peak-clipping, valley-filling, load-building). For example, in approving an IRP plan submitted by Atlanta Gas Light, the Georgia PSC found that the cost of DSM programs that result in more efficient and effective use of either electricity or gas could be recovered through a cost recovery rider. Costs of fuel substitution programs judged by the PSC to be primarily load-building in character, because they would result in increased revenues for the gas utility, were not eligible for recovery through the rider; instead, they were treated as a promotional expense and reviewed during the utility's rate case (Georgia Public Service Commission 1993b).[3] Assessing the actual load shape impact(s) and objective(s) of fuel substitution programs is important for

[3] The Georgia PSC categorized each DSM program proposed by Atlanta Gas Light as either being conservation or load-building for cost recovery purposes.

PUCs because of the different financial impacts on utility shareholders. Some may regard these definitional issues as hair-splitting, but they can help PUCs develop consistent policies and treatment for DSM programs that have different financial impacts on utility shareholders and ratepayers.

8.3 Fuel Substitution Debate

The debate on fuel substitution and fuel choice is often couched in ideological terms—the virtues and evils of competition, concerns about hindering or correcting market forces, and warnings for and against regulatory interference in customers' equipment selection choices. Often, proponents and opponents seem to be talking past each other because they are addressing very different questions in some cases (see Tables 8-1 and 8-2).

Proponents of electric-to-gas fuel substitution argue that:

- A key rationale for integrated resource planning—addressing problems of inefficient resource allocation caused either by market imperfections or price signals that do not reflect societal costs—requires that fuel substitution opportunities be considered by utilities as a potential least-cost option.

- In certain end uses, there are major opportunities to reduce customer's utility bills significantly by replacing electric equipment at the end of its useful life with new gas-fired equipment. Often, these opportunities arise because the existing stock of buildings and equipment reflects choices that were made under very different conditions and expectations of absolute and relative prices of electricity and gas. For example, in the Pacific Northwest, a life-cycle cost analysis found that electric water heating equipment should be replaced by gas water heating equipment (WSEO 1993).

- For other end uses (e.g., space conditioning), proponents argue that there are significant opportunities for "win-win" situations for both electric and gas utilities to reduce overall costs and environmental impacts. For example, gas air conditioning can reduce summer electric peak loads while providing a valley-filling option for winter-peaking gas utilities. Load reduction due to end-use fuel substitution can also reduce emissions of SO_x and CO_2 for coal- and oil-based electric utilities.

- Fuel switching can often reduce electric load cost effectively and should be included in electric utility DSM programs. From a DSM planning perspective, fuel substitution options have certain advantages because, in many situations,

Table 8-1. Typical Arguments for Fuel Substitution

Resources:	Significant market barriers currently prevent the efficient use of energy. Fuel substitution is needed to efficiently allocate fossil fuel resources.
Environment:	Fuel substitution reduces environmental emissions from electric generation.
Utility Bills:	Fuel substitution can provide the least-cost energy service to all ratepayers in certain end uses.
Company Impact:	Fuel substitution can reduce electric peak load. In some circumstances, both utilities benefit.
Competition:	Fuel substitution efficiently allocates market share between electric generating capacity and gas capacity.

Table 8-2. Typical Objections to Fuel Substitution

Resources:	Market barriers don't prevent the efficient use of energy. The market already allocates resources efficiently.
Environment:	Utility regulation is not a proper place for environmental regulation; environmental benefits of fuel substitution are often overstated.
Utility Bills:	The greater uncertainty and potential volatility in future gas commodity costs compared to electric rates means that expected bill savings from fuel conversion are problematic.
Company Impact:	A fuel substitution program will retard the growth/market share of the utility losing the customer.
Competition:	It is preferable to rely on competition rather than government regulation in regard to customer's fuel choices.

demand reductions are quite reliable and "persistence of savings" is not an issue, particularly if the electrical equipment has been removed.

Opponents of electric-to-gas end-use fuel substitution argue that:

- The underlying rationale for utility DSM programs is flawed in this context. The rationale typically given is that market barriers and imperfections justify interventions into end-use markets to increase the efficiency of energy use and provide a boost for the creation of a larger market for high-efficiency products that are often underdeveloped. However, there is no evidence demonstrating that there are significant market barriers in the fuel choice market. In fact, gas has substantial market share in many contested end uses and currently there is an active market among competing energy sources.

- Requiring electric utilities to promote fuel substitution is fundamentally different than other types of electric DSM because it results in a lowered long-term market share for the electric utility conducting the program.

- Requiring electric utilities to support their customers switching to other fuel sources moves too far in the direction of centralized, governmental control over specific markets and is anti-competitive. It is inequitable to ask a utility to give its customers financial assistance to induce them to switch their patronage to its competitors, recovering the costs by raising the price of its own products. Relative prices for gas and electric regulated services already provide the proper signals for customers to make efficient fuel choice decisions. It is preferable to rely on competition among different suppliers of competing fuels to best serve consumer interests. This type of competition provides incentives for suppliers of equipment and appliances to refine their goods and keep prices competitive. There is no evidence that managed competition is needed or will improve energy efficiency.

In light of the controversy about interfuel competition issues, this candid statement from the Strategic Planning Manager for the Illinois Department of Energy and Natural Resources accurately reflects the initial reaction of many regulatory agencies to fuel substitution:

> Like a bad dream, we have pushed the thought of confronting interfuel competition issues into a dark corner of the Illinois planning process. The Illinois Public Utilities Act actually suggests that the Statewide Plan is to be a joint gas/electric plan, but because we could not conceive of how we would resolve interfuel policy issues (or perhaps because we could perceive the resolution all too well), the planning process was bifurcated from the start based on arguments of administrative and methodological necessity.
>
> While I continue to believe that a truly integrated planning process incorporating both gas and electricity is methodologically and administratively complex, it is increasingly clear that soon the issues must be addressed. Complexities notwithstanding, the correct way to address them is

through an integrated plan. However, for a variety of reasons, the correct way is not likely to be the way chosen, at least in the near term (Jensen 1991).

One aspect of the dilemma for regulators in sorting out interfuel competition issues is that representatives of the gas and electric industries often present starkly contrasting views. The following stylized summaries attempt to reflect claims often found in the trade press, journals, and hearing rooms:

Many involved in the gas industry believe:

> Replacing gas for electric equipment and appliances in certain end uses represents sound economic and environmental policy for customers, the nation, and even the utility sector. However, the competitive situation currently favors the electric industry because electric utilities are generally larger than gas LDCs in rate base, staff, and number of customers. Moreover, major equipment manufacturers derive the vast majority of their revenues (85%) from electrical equipment and thus may tend to be more responsive to electric utilities. Furthermore, access to electricity is more widespread than gas. High-efficiency gas equipment generally has higher initial cost than corresponding electric equipment. This cost differential favors the electric utility industry, even though lower gas prices often makes gas preferable on a life-cycle cost basis. However, low gas avoided costs mean that the net benefits of gas DSM are smaller, justifying lower customer incentives for gas. The offering of customer incentives for high-efficiency electric equipment distorts the marketplace and adding gas DSM will not correct this distortion. Even with gas DSM, electric equipment and appliances subsidized by an electric utility DSM program will usually end up in a dominant position. Regulatory intervention is needed to assure a true "level playing field."

Many involved in the electric utility industry believe:

> Electric utilities have an obligation to serve all electric end-use customers while the gas industry's more flexible service obligation often provides them with a competitive advantage. The best available electric technologies rate as well as or better than competing products. This competition provides incentives for competing suppliers of equipment and appliances to refine their goods. The benefits of interfuel competition (e.g., additional choices for customers) far exceed the potential societal gains of mandated fuel substitution. Moreover, requiring electric utilities to pay financial incentives to customers to switch to other fuel sources is anti-competitive and runs counter to utility regulators' basic justification for DSM, which is to correct market imperfections.

Fuel substitution raises many tough questions for regulators, which include: Is current fuel selection economically efficient, or are there substantial market barriers/imperfections? Are there significant societal benefits to be realized from end-use fuel substitution? How does one judge from a societal perspective what fuel use is more economically efficient? Do we need to develop new regulatory approaches either to compensate for failure in our gas and electric markets or to assure that there are consistent policies regarding utility interventions in end-use markets? For example, is fuel choice being unduly influenced by utility financial incentives to developers or favorable line extension or hook-up policies? If market barriers or imperfections exist in fuel choice markets, are they large enough to compensate for the efficiency losses that inevitably occur from regulatory intervention? If regulation is desirable, do commissions have the authority to intervene in the fuel choice market?

In the next section, we examine the procedural and analytic approaches that various state PUCs have used to address these questions.

Table 8-3. Vermont Public Service Board (PSB): Assessing Fuel Substitution Opportunities

1. When might fuel switching be cost effective? The PSB asked that potential end-use opportunities be identified, and that assumptions about future relative fuel prices, measure lives, risks, and reliability be made explicit and folded into the analysis.
2. For cases where cost-effective fuel switching is likely, are there market barriers that require intervention?
3. Where barriers exist, what interventions are necessary to overcome them (e.g., information-only, loans, or direct investment)?
4. Who is the most appropriate entity to assist in overcoming each barrier?
5. If some form of financial incentive from the utility is necessary, what is the appropriate incentive and program design for each measure type?
6. If a utility encourages customers to switch to an alternative fuel, should it also pay for other DSM measures associated with that end use? Also, if DSM cannot be guaranteed in conjunction with fuel switching, is society better off keeping the end use as an efficient electric end use?
7. Should a utility be allowed to develop programs for cost-effective fuel switching from nonregulated fuels to electricity?

Source: Raab and Cowart 1992; Vermont Public Service Board (PSB) 1991a

8.4 Case Studies: Experiences with Fuel Substitution Programs

A review of the experiences of various regulatory commissions that have addressed fuel substitution issues provides a useful foundation for understanding alternative approaches. PUCs in five states—Vermont, Wisconsin, California, Oregon and New York—have encouraged or condoned fuel substitution and have developed procedures for it. Fuel substitution is currently being addressed in Nevada, Maine, and other states without resolution. In some states (e.g., Georgia), electric utilities are challenging commission efforts to impose fuel substitution programs. In many states, PUCs have not developed explicit positions on the issue and no commission-approved fuel substitution programs are being conducted.

In Vermont, the state commission mandated fuel substitution even though the electric utility industry was unwilling. In a relatively short time, the Vermont Public Service Board (Vermont PSB) ordered its regulated electric utilities to consider fuel substitution as a demand-side measure and to provide incentives for fuel substitution if it was beneficial to society. Moreover, the Vermont PSB withstood a legal challenge from the utilities, which was resolved by the passage of state legislation affirming the Vermont PSB's authority to mandate fuel substitution. The commission's decisions on fuel substitution were based on the following policy principles:

(1) Cost-effective fuel switching should be identified and actively pursued by utilities as part of their IRP processes,

(2) Utilities should seek to spend as little as possible on fuel substitution opportunities but must be willing to pay to acquire these resources if necessary when they are more cost-effective than expenditures for alternative supply resources (Raab and Cowart 1992).

In carrying out this decision, the Vermont PSB asked utilities to address a set of questions in order to systematically analyze fuel substitution opportunities which, in Vermont, are mostly to unregulated fuels, and better understand the level of utility involvement which was most appropriate (see Table 8-3). Several electric utilities were particularly upset by the Vermont PSB's decision but have proposed programs which they assert comply with the Board's order. The Vermont PSB and utilities are currently addressing several thorny implementation issues, such as how fuel substitution costs and risks should be allocated among utility companies (see Exhibit 8-1).

Georgia provides another example of a state commission proceeding along an aggressive path instituting fuel substitution policies. Electric utility executives as irate as those in Vermont, resisted the Georgia Public Service Commission's directions to consider fuel

Exhibit 8-1. The Vermont PSB Mandates Fuel Substitution

In Vermont, the Public Service Board (Vermont PSB) has historically interpreted a 1973 state land-use law requiring "the best available technology for efficient use or recovery of energy" to require the installation of equipment that minimizes life-cycle cost irrespective of fuel used. Vermont's largest utilities have provided residential customers with information on fuel substitution since the mid-1980s and limited state financing has been available to assist customers who want to switch from electricity to propane, oil, wood, and natural gas for space and water heating. Switching to natural gas in Vermont has been relatively limited as it is not widely available (Raab and Cowart 1992).

The Vermont PSB "expressed its view that fuel switching should be a two-way street in the context of integrated resource planning (IRP), and should be evaluated on the basis of total societal costs and benefits" (Vermont Public Service Board 1990).

In 1990, the Vermont PSB ordered utilities to invest in "efficiency programs that are *comprehensive*, including aiming at cost-effective savings from ... economical fuel switching." Central Vermont Public Service (CVPS) and several nonutility organizations attempted to implement the order through complex settlement negotiations. This resulted in a motion to compel CVPS to acquire cost-effective energy efficiency resources. CVPS opposed the motion and challenged the PSB's legal authority to order a utility to offer financial assistance to its customers for cost-effective fuel substitution. After further investigation, the Vermont PSB ordered CVPS and other parties to analyze the merits of specific fuel substitution measures and file within 45 days a plan for the acquisition of those energy efficiency resources found to be cost effective. CVPS appealed to the Vermont Supreme Court but withdrew its appeal after state legislation was passed in 1991 which affirmed the Board's jurisdiction. A settlement was reached with the nonutility parties in which CVPS agreed to offer a comprehensive fuel substitution audit, to provide information on the costs and benefits of fuel substitution, and to help secure market-based financing for cost-effective fuel substitution (Vermont Public Service Board 1991b).

Since early 1991, five of Vermont's largest electric utilities have included fuel substitution components in their DSM programs. Burlington Electric Department (BED) and Washington Electric Coop offer financial incentives to customers for fuel switching. CVSP, Green Mountain Power, and CUC have committed to helping customers secure conventional bank loans. The roughly 15% cost-effectiveness advantage applied to DSM for its greater flexibility and lower environmental impact has been applied to fuel substitution programs. Disputes about customer incentive levels still remain to be resolved.

The Vermont PSB has resolved a disagreement between BED and Vermont Gas Systems (VGS) over who should pay for a substantial amount of weatherization installed concurrently with fuel substitution installations. The board concluded that VGS should pay because it benefited from the improved efficiency once the customer switched to natural gas, and the remaining BED customers would have no further interest once they had paid for the conversion. The board has also approved procedures authorizing utilities to recover investments in other types of DSM programs from customers who subsequently switch fuel (Raab and Cowart 1992).

Exhibit 8-2. The Georgia PSC Mandates Fuel Substitution, but Georgia Power Objects

The Georgia Legislature passed the Integrated Resource Planning Act in March, 1991 (Georgia Official Code 1992). In December, 1991, the Georgia Public Service Commission promulgated rules implementing the Act (GAPSC 1991). The hearings on the rules were hotly contested, with Georgia Power and Savannah Electric & Power Company, both owned by the Southern Company, objecting to many of the recommended filing requirements. The two companies were vehemently opposed to any provisions regarding fuel substitution. Both companies submitted their first integrated resource plans on January 10, 1992. Neither company included an assessment of fuel substitution opportunities in its integrated resource plan.

The two companies not only questioned the jurisdiction of the commission but also argued that the term "facilities which operate on alternative sources of energy" in the rule refers to supply resources only although several intervenors argued that the term is used in reference to "other...demand-side options" and includes such options. Both utility companies subsequently filed for a waiver from the fuel substitution assessment requirement of the rule. Both requests for a waiver were denied, and the companies were ordered to develop information and perform evaluations of end-use fuel substitution for potential DSM measures, the details of which were to be dealt with in the subsequent certification documents (GAPSC 1992).

In September 1992, each company refiled its application for certification of DSM programs that it had initially submitted in January along with its integrated resource plan pursuant to the rule. Both companies withdrew the bulk of their commercial and industrial demand-side programs, stating their intent to file them at a later time. Neither company submitted an analysis of potential fuel substitution DSM measures. In its orders granting certificates for the primarily residential DSM programs of Georgia Power and Savannah Electric, the commission (1) acknowledged the failure of both companies to fully assess the potential of fuel substitution, (2) stated in the body of the Georgia Power Order that "Georgia Power should continue to assess this potential, and shall be required to include the results of its assessment in its next IRP filing" and, (3) put in motion action to resolve issues surrounding the level of incentives for fuel promotion programs, but did not further address fuel substitution in the ordering language in either order (GAPSC 1993a).

Subsequently, the Georgia Commission addressed the issue of fuel substitution in Atlanta Gas Light Co.'s IRP filing (GAPSC 1993b). The Commission appears to have resolved the fuel substitution issue in its August 1993 Letter Order in Reconsideration in that case by (1) distinguishing between load building (self-promotion) and conservation (promotion of programs which reduce load, including switching to a competitor's product) in both industries, (2) treating conservation as DSM with special cost recovery and treating load building as normal business expense, (3) specifying that DSM incentives are only for efficiency improvements above and beyond code, and (4) balancing the customer rebates offered by the two industries based on savings to the individual utilities.

There has been no experience yet under this ruling.

substitution in their DSM programs. In an August 1993 Order, the Georgia Commission instituted policies designed to ensure balanced competition between the electric and gas utilities (see Exhibit 8-2).

The California Public Utilities Commission (CPUC) has mandated that fuel substitution be considered as a natural element of DSM. California's utilities (including the nation's largest combined utility and the nation's largest all-electric utility) did not object. The CPUC, which initially developed and formalized the standard economic tests that are used by many PUCs in evaluating the cost effectiveness of DSM programs, has revised its standard procedures manual to specifically treat fuel substitution. California utilities have begun to propose fuel substitution programs under the new guidelines (see Exhibit 8-3). These new guidelines are more restrictive than the criteria for other DSM programs and serve the intended purpose of limiting the amount of ratepayer-funded fuel substitution that will occur.

Exhibit 8-3. California Prescribes Fuel Substitution Procedures

In October 1992, the California Public Utilities Commission (CPUC) issued an interim opinion that established rules for evaluating fuel substitution programs. The CPUC concluded that fuel-substitution programs may offer resource value and environmental benefits although fuel switching should only be promoted by utilities if it has a neutral or beneficial effect on the environment. To be considered for funding in California, a fuel-substitution program now must pass the following "three-prong test:"

(1) the program must not increase source-BTU consumption,
(2) the program must have a Total Resource Cost (TRC) benefit-cost ratio of 1.0 or greater...
(3) the program must not adversely impact the environment. To quantify this impact, respondents should compare the environmental costs with and without the program, using the most recently adopted values for residual emissions in the Update (i.e., the CPUC's resource planning process) (CPUC 1992).

The California Commission did not otherwise specify analytical procedures for fuel-substitution programs that are different from those used for other DSM programs.

This "three-prong test" sparked further hearings on implementation methodology. The CPUC subsequently adopted a conservative definition of the baseline reference to be used in the TRC test in order to constrain fuel substitution programs rather than adopting the "existing equipment" standard offered by the utilities intended to foster fuel substitution.

All four of California's major investor-owned utilities began fuel substitution programs in the late 1980s or early 1990s and are now redesigning their programs to fit the new rule. (Only San Diego Gas and Light had initiated a major program.) Little experience has yet been accumulated under the new rules.

Table 8-4. Wisconsin's Revised Interfuel Substitution Principles

1. Total technical costs plus quantified environmental externalities should be used to evaluate fuel alternatives to determine which end uses are served at the lowest cost to society by fuels or energy sources other than electricity.

2. Resource options involving fuel switching or use of other energy sources may have revenue requirement and customer service benefits for an electric utility.

3. Electric utilities can capture those benefits, but they should pay no more than is necessary to get customers to take action.

4. If the supplier of the other fuel or energy source is providing incentives to take the action, the electric utility may show that it is unnecessary to provide further incentives, or some partial incentive may be justified. The principle to be applied is that enough must be provided to induce the action, but no more than that, whatever the source.

5. Electric utilities must give clear, accurate, and current information to customers on the benefits and costs of fuel substitution, or any other energy use question for which information is available. In particular, electric utility advertising, program literature, and presentations should specifically address the availability of incentives for fuel substitution of energy sources other than electricity.

6. Gas utilities should pay a fair share of the incentive to encourage interfuel substitution.

7. The application of these principles should be periodically reviewed on a case-by-case basis.

8. Combined electric and gas utilities should coordinate their programs.

The Wisconsin Public Service Commission (PSC) has also urged consideration of fuel substitution as DSM since around 1989. But the Wisconsin PSC has stopped short of *mandating* consideration of fuel substitution programs. It has focused much of its attention on customer rights to choose, specifically addressing balanced incentives and making available full and unbiased information developed jointly by the relevant utilities. The Wisconsin PSC has issued a set of fuel substitution principles to guide the development of utility fuel substitution DSM programs in Wisconsin (see Exhibit 8-4).

Exhibit 8-4. The Wisconsin PSC Stops Short of Mandating Fuel Substitution

The Wisconsin Public Service Commission (PSC) has urged Wisconsin's utilities to pursue fuel substitution, has provided interfuel substitution principles as guidance, and has approved fuel substitution measures proposed by various utility companies. In September 1992, the PSC mandated a fuel substitution measure, only as a joint utility pilot project.

The Wisconsin PSC addressed fuel substitution directly in its 1989 Order approving Advance Plan 5 (the Wisconsin utility companies' fifth biennial integrated resource plan) with the following statements:

> The commission finds that substituting alternate fuels or energy sources for electricity is likely to produce resource benefits to an electric utility. ... It is not consistent with least-cost planning to deny these benefits to ratepayers. ... It is reasonable and equitable that electric utilities and vendors of other fuels pay fair shares of incentives for fuel switching. ... Utilities which assume the role of energy advisor to customers have an obligation to provide information that is correct and complete on interfuel substitution, as well as other energy issues. ... Electric utilities shall follow the interfuel substitution principles attached... (Wisconsin PSC 1989).

Generally speaking, Wisconsin's smaller, combined utilities did some fuel substitution DSM and the one large all-electric company didn't.

In early 1990, the PSC opened an investigation into methods for evaluating natural gas sales promotion and allocating the costs of programs that cause fuel substitution. In October 1991, the PSC ordered gas utilities to use the TRC test and the total technical cost test where regulated fuels are substituted for each other (Wisconsin PSC 1991). The TRC and total technical cost tests are identical except for the exclusion of DSM program costs from the total technical cost test.

In September 1992, the Wisconsin PSC revised its interfuel substitution principles in its Advance Plan 6 order, strengthening its position on fuel substitution (Wisconsin PSC 1992). The commission's eight principles address: the criteria for evaluation, criteria for designing customer incentives, customer information, sharing of program costs, and coordination of programs by combined electric and gas utilities (see Table 8-4). The PSC specified that the societal cost test is to be used for evaluating competing fuel sources and that "the Commission finds interfuel substitution to be a cost-effective demand-side option. Every major utility's plan contains end uses for which electrical equipment can be replaced with natural gas as a least cost energy service."

The PSC again focused on customer rights to choose using full, complete, and unbiased information developed jointly by the relevant utilities; the commission stopped short of requiring utilities to institute fuel substitution programs. However, the PSC ordered Wisconsin Gas Company and Wisconsin Electric Power Company (WEPCO) to embark on a pilot effort to cooperatively develop a fuel substitution program but only to test the efficacy of such an effort. The PSC praised the current practice of some Wisconsin utilities of allocating fuel substitution program costs. The commission encouraged balancing customer incentives for electric technologies with those for gas technologies and, in order to help achieve this, limited the incentives electric utilities may offer. It also suggested employee incentives to help change corporate cultures.

Wisconsin Gas and WEPCO have responded to the commission's direction to develop a joint pilot program. In March 1993, they announced agreement on a joint pilot program to promote hybrid cooling units to customers as an option to total electric units. The units will use gas during the electric peak to reduce electricity demand and will be eligible for the respective electric and gas rebates (Thomas 1993).

Table 8-5. Madison Gas & Electric Approach to Evaluating Fuel Substitution Options

1. Select low annual load factor electric options
2. See if conversion of gas passes or comes close to passing participant test.
3. Perform electric revenue requirements test to screen option.
4. If option passes, perform electric nonparticipant test to be sure rate impact is lower than rate of inflation or some other acceptable proxy.
5. Perform gas nonparticipant test to assess value to gas utility.
6. If option passes "5," see if total value (benefit) indicated in "5" + "3" is enough to move the market (pass the participant test).
7. If yes, set minimal needed incentive.
8. Assign up to five years' marginal gas revenue (NPV) to rebate. Take remainder needed from electricity revenue in "3." Any good promotional program should pay back in five years or less.

Source : Hobbie 1992

Madison Gas & Electric, a combined utility, has made these principles operational by focusing on options that are cost-effective and attractive to the customer (i.e., relatively short payback with high reliability, convenience, and comfort level), have a low annual electric load factor, and could be converted into high annual load factor gas options (see Table 8-5).

The Oregon PUC, like the Wisconsin PSC, has urged its regulated utilities to consider fuel substitution as an element of DSM and adopted principles to guide the practice but has stopped short of *mandating* fuel substitution programs. In contrast to Wisconsin, no Oregon utilities have proposed fuel substitution programs (see Exhibit 8-5). In Oregon, there are no combination utilities, which may contribute to the lack of activity; combined electric/gas utilities have taken the lead in proposing fuel substitution programs in Wisconsin.

New York provides an example of a state PUC that has relied on an ad hoc approach which has led to the development of several cost-effective fuel substitution programs. The New York Public Service Commission (NYPSC) staff has encouraged fuel substitution, and some New York utilities have implemented fuel substitution programs. Until recently, the NYPSC had not promulgated rules and has not issued general orders or adopted principles regarding fuel substitution. The NYPSC has not required any utility

Exhibit 8-5. The Oregon PUC Invites Fuel Substitution; No One Accepts

The Oregon Public Utility Commission (PUC) has issued standards for evaluating fuel substitution programs filed for approval by its regulated utilities and has publicly stated its "observations" on the subject. No Oregon utility has filed for approval of such a program.

In March 1990, the Commission's staff formed an advisory group that included major stakeholders to examine potential fuel substitution opportunities. With the advisory group's oversight, the staffs of the Commission and the Oregon Department of Energy evaluated the cost effectiveness of converting electric water heaters to natural gas systems and of converting electric forced-air furnaces to either heat pumps or natural gas heating plants. In an August 1991 report to the PUC, the PUC/DOE staffs found that: (1) the conversions appear to be cost effective in most cases, (2) electric utilities should evaluate residential fuel substitution as a resource in their least-cost plans, (3) utilities should compare fuel substitution with other resources on the basis of total resource costs including environmental costs, and (4) the PUC should adopt standards contained in the report for evaluating utility activities that promote fuel substitution (Oregon PUC 1991a).

In October 1991, the Oregon PUC issued a letter adopting standards that require a utility sponsoring a program promoting fuel substitution between electricity and natural gas to demonstrate that:

- the program is economical in terms of a resource cost comparison between electrical and gas service
- the fuel substitution is not occurring rapidly enough without the program
- existing customers of the sponsoring utility will benefit
- the program promotes only fuel substitution that is cost effective
- energy efficiency is aggressively pursued as part of the program (Oregon PUC 1991b).

The PUC encouraged reasonable fuel switching program proposals by any utility—natural gas or electric, invited utilities to file joint programs, and also invited proposals to minimize financial disincentives and provide financial incentives.

As of March, 1993, no Oregon utility had applied to the commission for approval of a fuel substitution program.

to conduct such a program but has approved fuel substitution programs proposed by individual utilities as part of the companies' long-range DSM planning requirements. Several combination utilities and one gas-only utility are currently offering electric-to-gas fuel substitution programs, and some of these programs are quite large. In 1993, based on staff recommendations, the NYPSC got more deeply involved by ordering that any fuel substitution program must pass the TRC test, such programs must be offered to all customers, and consideration must be given to sharing costs and benefits with the affected alternate fuel suppliers (see Exhibit 8-6).

Exhibit 8-6. Easing into Fuel Substitution in New York

The New York Public Service Commission (NYPSC) has not developed formal policies or guidelines on fuel substitution, but its actions approving utility companies' fuel substitution programs beginning in 1989 form a de facto policy of encouragement.

Although the NYPSC had previously promoted the use of natural gas in general, a gas air conditioner program proposed by Consolidated Edison in 1989 was the first fuel substitution program approved by the PSC. This was a major milestone as the program represented a $10 to 14 million annual investment by the utility. Since then, Long Island Lighting Company, Rochester Gas and Electric Corporation, Brooklyn Union Gas Company, and National Fuel Gas Distribution Corporation have also instituted fuel-substitution DSM programs.

Although it is still not officially promoting or mandating fuel substitution programs, the New York PSC is increasing its influence and control in this area. In a recent DSM proceeding, the PSC Staff encouraged the continued implementation and expansion of fuel substitution programs in instances where they would assure more efficient use of the state's energy resources. The PSC accepted the specific recommendation of its staff and did not approve any 1994 fuel switching programs unless the utility submits a satisfactory plan for coordinating efforts and allocating costs and benefits with affected alternate fuel suppliers by January 1, 1994 (NYPSC 1992).

Maryland has had limited opportunity to address fuel substitution issues directly. The Maryland Public Service Commission has not issued generic orders on the subject. It has carefully set its DSM policy to be fuel-blind on the grounds that there may be benefits to customers from competition among alternative energy suppliers. One uncontested fuel substitution program has been approved for Baltimore Gas and Electric Company. The Maryland PSC, like so many commissions around the country, expects to be dealing more directly with the fuel substitution issue in the near future (see Exhibit 8-7).

Nevada, Florida, Massachusetts, Rhode Island, and other states have addressed fuel substitution issues sporadically during the last several years with relatively little resolution. In Florida, electric utilities were initially ordered to engage in fuel substitution strategies, but the commission backed away from this position in response to a challenge to its authority. The District of Columbia specifically prohibits DSM programs that involve fuel substitution, denying recovery of the cost of programs that result in even incidental fuel switching. Some states, including Kansas, Mississippi, and Arkansas, have recently begun to address the issue. A number of PUCs have rules or orders that deal with the fuel substitution issue less directly, requiring their regulated utilities to consider fuel substitution as part of integrated resource planning. Often such a mandate gets lost in the intricacies of the planning process or is too recent to have been

Exhibit 8-7. Maryland's Approach: "Fuel-Blind" DSM

The Maryland Public Service Commission (Maryland PSC) has not dealt with fuel substitution on a generic basis. In general, Maryland's DSM programs are fuel blind, offering incentives for enhanced efficiency of either electric or gas appliances but including no incentive for the selection of one fuel over the other. In 1991, the Maryland PSC approved a fuel substitution program proposed by Baltimore Gas and Electric (BG&E), involving rebates to promote commercial gas air conditioning. The approved rebate is $200 per deferred kW offered to new gas air conditioning customers plus dollar-for-dollar matching of engineering feasibility study costs up to $15,000. This is the same incentive offered under BG&E's commercial cool storage program. In addition, a lower gas air conditioning rate was approved.

As a combination utility, BG&E's purpose in offering the program was to shift almost the entire temperature-sensitive summer load from the electric "peak" to the natural gas "valley," thereby improving load factors on both its gas and electric systems. Technologies eligible for the fuel substitution program are: (1) direct gas-fired absorption chillers with integrated boilers, (2) indirect gas-fired absorption chillers with separate on-site boilers, (3) gas engine-driven chillers, and (4) gas-fired desiccant dehumidification systems. In its proposal to the Maryland PSC, BG&E noted that gas air conditioning was increasingly becoming economically attractive for customers with large cooling needs and special uses for waste heat although the technology was still less efficient than today's electric cooling systems. Other benefits of the program cited by the utility included its potential to reduce Chlorofluorocarbons (CFC's) and offer customers additional energy service options (Baltimore Gas and Electric 1990).

incorporated into practice. However Colorado's experience is an exception; the Colorado Public Service Commission has stimulated improved efficiency through fuel substitution by relying on DSM bidding plus one large collaboration with the Public Service Company of Colorado (PSCo) and local governments (see Exhibit 8-8).

In July 1992, the Washington State Energy Office initiated a project with several of the state's largest electric and gas-only utilities to develop a collaborative model for coordinating gas and electric utility integrated resource planning—also referred to as "fuel blind" IRP. The study, still underway, will soon issue reports on cost-effective opportunities and regulatory, financial, or other barriers to improve efficiency from:

- line extension policies
- joint trenching
- cogeneration facility siting
- district heating and cooling.
- fuel substitution or fuel choice
- pipeline capacity sharing
- fuel cells

Exhibit 8-8. Colorado: A Utility DSM Bidding Program Reveals Fuel Substitution Opportunities

The Colorado Public Service Commission enacted IRP rules in 1992 which require that fuel substitution be considered by utilities in their integrated resource plans. A bidding process established by the PSC in 1988 produced many fuel substitution proposals.

Public Service Company of Colorado (PSCo), a combined utility, is the major supplier of natural gas and electricity in Colorado. PSCo initiated a pilot DSM bidding program in mid-1989 for 2 MW, followed by a 50-MW solicitation for DSM in late 1990. The 50-MW bidding program attracted 63 proposals totaling 131 MW, of which one-third (43 MW) were conversions of electric heating and cooling to natural gas and steam. PSCo awarded thirty-two contracts totaling 55.2 MW, of which 40% (21.5 MW) involved fuel substitution (Chi and Finleon 1993).

The success of PSCo's DSM bidding program, including verification of over three-quarters of the contracted pilot demand reduction, shows that there is a large amount of electricity being consumed in applications where natural gas use appears to be more economically efficient from a societal point of view. Because the avoided costs underlying the bid offer have not yet been formally established, PSCo and the Colorado Commission staff agreed to slow the process by placing a cap on fuel substitution in a second 50-MW DSM solicitation issued in mid-1992, for which bids are currently being evaluated. The 30%-of-demand-reduction cap on fuel substitution was accepted by the commission and is apparently based on concerns about: measures that reduce demand on only the winter peak, equity, and the fact that fuel substitution bids are relatively more attractive financially to the utility than other types of DSM bids (i.e., conservation) given current ratemaking.

In addition to the DSM bidding program, the Colorado Commission has worked cooperatively with PSCo and the appropriate local governments to lower the peak electricity demand of the new Denver International Airport by selecting natural gas chillers instead of electric chillers. The city and county are building a new international airport near Denver, scheduled to open in December 1993. The airport was initially designed to a peak load of 90 MW of which 7.3 MW was for electric chillers. Gas chillers were considered but would have cost an extra $2.4 million. The extra money was not budgeted even though it would have paid back the investment in five to six years from lower operating costs.

When PSCo became aware of the opportunity to cost-effectively avoid 7.3 MW of peak load, there was little time to effect a change in the airport design without delaying the opening. The Colorado Commission provided special treatment to authorize the utility to provide a $1.5 million rebate to the city and county for selecting gas chillers instead of electric chillers and investing an extra $0.9 million. PSCo paid $200 per kW to avoid 7.3 MW of peak power, saving almost $1 million during the next ten years (Alvarez 1993).

Many states have avoided addressing fuel substitution altogether although it is likely that these PUCs will soon be confronted with the issue, because of the attention and controversy generated by fuel substitution.

8.5 Major Policy and Program Issues

In this section, we discuss six policy and programmatic issues that state regulators are likely to confront if they choose to address fuel substitution policies explicitly. These include: (1) alternative approaches to incorporating fuel choice efficiency in an IRP process, (2) economic and other criteria that can be used to evaluate fuel substitution programs, (3) debates over "best" vs. "better" efficiency options, (4) cost allocation and responsibility, (5) customer equity issues, and (6) treatment of unregulated fuels. (Technical considerations related to analysis of fuel substitution options are discussed in Section 7.5).

8.5.1 Approaches to Incorporating Fuel Choice Efficiency in an IRP Process

There are three fundamental approaches available to state PUCs that choose to address fuel choice selection explicitly as part of an IRP process. These approaches derive from how PUCs separate or combine three major functions: (1) setting social criteria, (2) technically comparing and selecting alternatives, and (3) developing a resource plan.

One option is for a PUC to have electric, gas, or combination utilities propose fuel substitution criteria as part of their resource plan preparation. This approach essentially combines all three functions (criteria setting, alternative comparison/selection, and plan development) into a single process. This has probably been the most common approach and has been utilized in Vermont, Georgia, and New York.

A second alternative is for a PUC to preset fuel choice criteria for natural gas and/or electric utility companies to use in their planning processes. The companies then use these criteria to compare and select among fuel substitution programs and to prepare their resource plans. The criterion would be reviewed less frequently than the evaluation of alternatives, which takes place regularly. The California and Oregon have set fuel substitution criteria in separately established proceedings. Other PUCs (e.g., Nevada) have opened dockets for this purpose but have either abandoned the effort or have not yet reached consensus. The Wisconsin PSC established fuel substitution criteria as part of its IRP plan review process. The evolution of ad hoc decisionmaking into formalized guidelines on fuel substitution, as in Wisconsin, is a path that many other PUCs could follow.

Table 8-6. Regulatory Approaches to Fuel Selection

#1	**Utility Selects Fuel and Plans to Its Own Criteria (Utility Designed)**	
Pros	•	Provides frequent opportunity to review criteria
	•	Allows flexibility for utility to compare all fuel-substitution opportunities in any specific setting
	•	Can be initiated relatively quickly by commission order with simpler hearing than #2 or #3, if any
Cons	•	Commission review of fuel comparison and utility plan is complicated by limited analysis of alternative criteria unless appropriate analytical requirements are prescribed
#2	**Utility Selects Fuel and Plans to Preset Criteria (Utility Designed to Commission Standards)**	
Pros	•	Allows planning to known criteria
	•	Allows independent scheduling of criteria review
	•	Allows flexibility for utility to compare all fuel substitution opportunities in any specific setting
Cons	•	Requires longer, two-step process to initiate than #1 but shorter (or at least less contentious) than #3
#3	**Utility Plans to Preset Criteria and Fuel Preferences (Commission Designed)**	
Pros	•	Allows planning to known criteria
	•	Allows independent scheduling of criteria review
	•	Guarantees generally efficient fuel use
Cons	•	Limits flexibility for utility to create new, more efficient fuel substitution programs

A third option is for a PUC or state legislature to predetermine preferable fuel choices. Utilities would then develop their resource plans within the fuel choice constraints imposed by the commission. Such an approach has been used, notably in restrictions or outright bans on electric resistance heating in some parts of the country. However, government specifications regarding fuel use are not in favor in the U.S., and we have found no instances of states considering this approach to resolve controversies about fuel substitution.

Table 8-6 summarizes the major implications for regulators of these three approaches for addressing fuel choice selection. The three approaches are presented as idealized concepts although, in practice, PUCs will have to fashion processes that serve their specific needs.

8.5.2 Selection Criteria for Evaluating Fuel Substitution Programs

In thinking about the criteria that should be used to analyze fuel substitution programs, it is useful to focus on additional considerations for assessing this type of program in contrast to other DSM programs. Fuel substitution programs involve the additional considerations of multiple fuels, often more than one regulated utility company, and complexity in accounting for net environmental impacts. A few PUCs have considered and accounted for fuel shifts outside the company implementing a DSM program in a qualitative fashion when evaluating the proposed program. However, with fuel substitution programs, it is essential that evaluation criteria be applied to the affected utility companies in combination as well as individually.

Table 8-7 illustrates criteria that can be used individually or in combination to evaluate fuel substitution programs. The table also shows the relevant figure of merit (i.e., appropriate economic test) that can be utilized to conduct the analysis as well as the elements involved for a particular criterion. It is important to recognize that the criteria used to evaluate fuel substitution programs are similar to those used in resource integration of demand-side and supply-side alternatives (see Section 3.1).

The Societal and Total Resource Cost (TRC) tests have been favored as the primary analytical tools among PUCs that have addressed fuel substitution directly. California's *Standard Practice Manual*, which provides guidelines for analyzing DSM programs, offers one rationale for this choice:

> For fuel substitution programs, the TRC test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC (and Societal Cost) test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric) (CPUC and CEC 1987).

For fuel substitution programs, either the Utility Cost test or Ratepayer Impact Measure (RIM) test may be applied to affected utilities individually or in combination. However, results from the two tests applied individually to each company have to be interpreted quite cautiously. For example, results from the Utility Cost test for each company provide little useful information because by their very nature, fuel substitution programs will change the number of customers of both the electric and gas companies for the

Table 8-7. Potential Criteria That Can Be Used to Evaluate Fuel Substitution Programs

Criterion	Elements	Figure of Merit
optimize source energy use	energy consumed by utility	total source energy
optimize customer utility bills	utility bills only	Utility Cost test
optimize total customer costs	all private costs	Total Resource Cost test
optimize customer societal costs	private costs plus externalities	Societal test
minimize customer rate increases	utility rates	Nonparticipant test
minimize impact on DSM nonparticipating customers	utility rates	Nonparticipant test
achieve other specific social goals	e.g., remove market barriers, maximize consumer choice, control pollution, minimize unemployment, or protect a utility company's market share	---

relevant end use.[4] The Utility Cost test results for the affected utility companies in combination will give an indication of the change in average combined energy bills, but such information should be used cautiously if customers of the two companies are not in overlapping service territories. The RIM test applied separately to each company provides useful information for allocating costs among the affected utility companies. Reviewing the combined results of the RIM test for both affected companies in

[4] The Utility Cost test indicates changes in average customer bills only so long as number of customers is approximately the same with and without the DSM program.

combination is useful in assessing average net rate increases or decreases and for judging their social acceptability.

8.5.3 Promoting "Best" vs "Better" Efficiency Options

Another aspect of the fuel substitution debate involves differing interpretations of providing least-cost energy services within end-use markets. Some analysts have argued that "the goal of IRP should be to put the least-cost energy service in place for every end use." Efficiency options that have the lowest economic life-cycle costs to customers and society (i.e., "best" option) should be promoted through utility DSM programs (Kaul and Kihm 1992).[5] Within an end use, if a fuel substitution option is determined to be more cost effective than other DSM options, then it should be pursued so that consumers receive the maximum benefit from utility interventions in end-use markets (Raab 1991).

The contrasting view is that PUC policies should allow utilities to promote DSM options that are more economically efficient than the customer's current use for retrofit applications and more efficient than minimum standards for new applications (i.e., the "better" option). In this approach, financial incentives are typically available to customers to upgrade high-efficiency equipment or appliances using either fuel. Arguments for this approach are that it offers customers more choices and limits the potential inefficiencies that may arise from judgments of regulatory bodies.

Both the "better" and "best" approaches are being applied. Wisconsin, for example, allows incentives for the promotion of any appliances that exceed a commission-specified minimum efficiency standard. Vermont, on the other hand, requires that utilities look only to the "most efficient energy use on the market today."

The "best" approach requires PUCs to specify the least-cost energy service for every end use. The "better" approach requires PUCs to balance incentives offered to customers by gas and electric utilities in order to insure that the competition is not artificially tilted toward one company and fuel. In some end uses and sectors, this balancing can be quite challenging.

In end-use markets where market barriers and imperfections might be endemic (e.g., new construction where end users are not the ultimate decisionmakers determining equipment

[5] In most cases, there is a mismatch between lifecycle costs of alternative technologies seen by users and the costs incurred by the respective utilities to serve the same end use. For example, the economics of gas absorption chillers in large office buildings (in Wisconsin) are marginal compared to electric screw or absorption chillers from customers' perspectives (i.e., 10 to 12 year simple payback) but provide significant avoided capacity benefits to a summer-peaking electric utility.

fuel choices), PUCs have to be especially vigilant that equipment/appliance fuel choice is not being unduly and unfairly influenced by utility financial incentives to builders or developers or favorable line extension and hookup policies. Instead, fuel choice should be determined on the basis of technologies and fuels that have the lowest overall life-cycle economic costs to customers and society.

8.5.4 Joint DSM Programs: Cost Allocation

Some DSM advocates argue that PUCs should require electric utilities to aggressively pursue cost-effective fuel switching and have electric ratepayers finance such conversions (Chernick 1991; Boonin 1992; Raab and Cowart 1992). Others maintain that natural gas utilities should promote and pay for incentives to encourage the use of natural gas and that electric utility companies should promote and pay for incentives to encourage the use of electricity because this arrangement maintains the fundamental forces of competition on which a market system is based (Flaim 1992; Tempchin and White 1993).

These perspectives represent the ideological poles in the end-use fuel substitution debate and illustrate the point that DSM program coordination and cost allocation among competing utilities is one of the most contentious program design and implementation issues. Some observers argue that electric and gas utilities should develop and pay for programs jointly if both benefit, but only after correcting gas pricing (Chamberlin and Mayberry 1991). Even if fuel substitution programs are considered to be economically efficient or otherwise desirable, it is difficult for regulators to force joint DSM programs or even coordinated DSM programs between competing utilities. It is also difficult to allocate program costs among competing utilities in a fair and efficient manner. Unlike single fuel DSM programs, fuel substitution programs introduce a new set of utility shareholders and nonparticipants.

Ideally, customers or groups that benefit from a fuel substitution program should pay the bulk of the associated costs, preferably in direct proportion to the benefits that they receive (Flaim 1992). For example, if a large proportion of the benefits accrue to program participants, it would be desirable to have participants pay for the program through an energy services charge or to reconsider the level of the incentive payment. If such changes to program design are not possible or significantly affect program participation, then program costs can be allocated to equalize the rate impacts as much as possible. However, certain societal benefits, such as reduced externalities, are not as easy to allocate among the electric utility and the natural gas company and their respective ratepayers (Weinstein and Pheifenberger 1992).

The debate has been clouded by those searching for a general approach that encompasses all DSM programs. As a practical matter, the cost allocation problem may be separated into four general categories based on the balance of utility revenue impacts. Each category reflects a different set of utility company and customer interests.[6] The issue of who pays the DSM program costs, and especially the contentious issue of who pays the customer incentive portion of program costs, is best addressed separately for each of these four categories.

Both Companies' Net Revenues Potentially Increase

For some fuel substitution options, the customers of both utilities could benefit. This happens in a gas conversion program when the gas company's revenues from its added sales are more than its costs to provide these sales and when the costs avoided by the electric company are more than its revenues would have been from the avoided sales. For example, significant benefits of some types of gas equipment conversions, such as conversion to gas air conditioning for a summer peaking electric utility, often occur on the electric side (Kaul and Kihm 1992). In this situation, there is an opportunity for the two utilities both to promote the same fuel substitution and to share in paying customer incentives without harming customers of either utility.

One economic rationale for this sharing is for the two companies to pay proportionally to their potential revenue impacts on the nonparticipating customers. For example, consider a modification to the fuel substitution program example in Figure 6-4 of Chapter 6 in which the program becomes a win-win situation by changing the electric company's average price to be slightly lower than its costs for the particular sales that are avoided.[7] In this situation, both companies would experience an increase in net revenues before considering program costs and customer incentives. The fuel substitution would potentially add about $4.4 million to the gas company's revenues and $1.7 million to the electric company's revenues. If the responsibility for paying for program costs and customer incentives were then allocated proportionately to this potential revenue impact on nonparticipating customers, the gas company would pay 72% and the electric company would pay 28%.

The computation of this cost allocation is shown in Table 8-8 and is somewhat similar to an approach used by Northern States Power, a combined utility, to determine how fuel substitution program costs would be allocated to electric and gas ratepayers (Kaul and

[6] The customers who change fuel by participating in the DSM program benefit in all four circumstances.

[7] For various business considerations beyond simple shareholder economics, some electric utility executives might still not consider this situation as a "win."

Table 8-8. Rate-Impact-Based Incentive Allocation for "Win-Win" Fuel Substitution

Example: a DSM program replacing electric chillers with gas absorption chillers (see Exhibit 6-3 and Figure 6-4 in Chapter 6)

		Combined	Nonparticipants Gas Company	Nonparticipants - Electric Company
1.	Avoided Supply Cost	$12,736,575	($4,141,756)	$16,878,331
2.	Measure Cost (extra cost of gas chillers)	$(2,500,000)		-
3.	Net Societal Benefit Before Program Costs and Customer Incentives [1.+2.]	$10,236,575	-	-
4.	Utility Sales Impact Net of Lost Revenue Recovery	($6,581,052)	$8,562,779	($15,143,831)
5.	Net Utility Revenue Impact Before Program Costs and Customer Incentives [1. + 4.]	$6,151,523	$4,421,023	$1,734,500
6.	Maximum Available for Program Costs and Customer Incentives [same as 5.]	$6,155,523	$4,421,023	$1,734,500
7.	Fair Share of Actual Program Costs and Customer Incentives[1]	-	72%	28%

[1] Calculated by dividing values in row 6 for gas and electric company by combined value

Kihm 1992).[8]

A sharing approach generally works in this situation because the shareholders of both utilities are likely to benefit from the fuel substitution, depending on the regulatory

[8] However, for the NSP case, short-term rate impacts were used instead of long-term. Rate impact concerns were so dominant that incentives were capped at a level that insured that no rate increases occurred for either gas or electric customers.

treatment of lost sales. The nonparticipating customers of both utilities may also benefit, depending on the level of incentives needed.

Only Gas Company Net Revenues Potentially Increase

For some fuel substitution programs, gas company net revenues will increase while electric company net revenues decrease. This happens when customers switch from electricity to gas and the gas company's revenues rise more than its costs rise while the electric company's revenues decrease more than its costs decrease. For example, conversion to gas air conditioning for an electric utility with average summer rates well above marginal costs might result in little benefit on the electric side. When this situation occurs, there is no easy economic rationale for the two utilities to share in paying program costs.[9] The customers who change fuels still benefit, but to which company should they be associated with—the electric company they are leaving or the gas company they are joining? Under these circumstances, joint participation of the two utilities is more difficult, and allocation of costs is contentious.

Only Electric Company Net Revenues Potentially Increase

It is also possible that a fuel substitution option causes electric company net revenues to increase while gas company net revenues decrease. This happens when customers switch from gas to electricity, and the electric company's revenues rise more than its costs rise, while the gas company's revenues decrease more than its costs decrease. The impacts on the affected utilities are similar to those in the previous case.

Both Companies' Net Revenues Decrease

Regulators might mandate some fuel substitution programs that produce societal benefits even though the net revenues of both companies might decrease. This happens in a gas conversion program when the gas company's costs rise faster then its revenues rise, and the electric company's revenues decrease more than its costs decrease. This is more likely to occur when the societal cost test is used, and program costs exceed net resource benefits (excluding externalities). In such a case, there is little guidance on how to allocate program costs although fairness would suggest an allocation that equalizes the net revenue impacts to the greatest degree possible.

[9] The fuel substitution example presented in Figure 6-4 in Chapter 6 illustrates this situation.

8.5.5 Customer Equity Issues

Balancing equity among customers has always been a central focus of utility regulation. Fuel substitution programs often raise additional customer equity issues, such as the availability of gas service to electric customers and noncoincident service territories. Natural gas customers and electricity customers are often largely, but not exactly, the same people. Is it equitable for the customers to be considered the same? Is it acceptable to ignore the situation of even a few electric customers who do not have natural gas available or connected?

The problem of noncoincident jurisdictional boundaries complicates program design, implementation, and cost allocation even for combined utilities. For example, Baltimore Gas and Electric (BG&E) offers a program that replaces electric chillers with commercial gas air-conditioning equipment. The program is offered to all electric customers within the utility's electric service territory. However, BG&E's gas service territory is smaller, and some of BG&E's electric customers receive natural gas from Washington Gas Light Company. Washington Gas Light has applied to the Maryland PSC for approval to conduct an almost identical program to BG&E's but with a larger incentive. If approved, customers served jointly by BG&E and Washington Gas who respond to the commercial gas air-conditioning programs would apply to BG&E for its incentive and to Washington Gas for the additional incentive payment. Encouraging or requiring utilities to develop fuel substitution programs jointly is another option that regulators may consider if serious implementation problems arise in "coordinated" programs that are offered separately by electric and gas utilities. Electric, gas, and combined utilities in several regions of the U.S. (e.g., California, New York, and Wisconsin) are jointly developing pilot fuel substitution programs.

8.5.6 Treatment of Unregulated Fuels

In regulating utilities, state PUCs have always had to consider the impacts of their policies on unregulated energy service providers. Changes in the rates of any fuel potentially affect the competition among competing energy sources. Similarly, DSM programs that provide financial incentives to purchase high-efficiency gas or electric equipment may also affect the overall end-use market share and fuel mix among gas, electric, and unregulated fuels for that type of equipment. On occasion, fuel oil or propane dealers have intervened in regulatory proceedings to argue that they would be adversely affected by a particular DSM program.[10]

Depending on the availability of gas service, evaluation of fuel substitution opportunities in certain end uses (e.g., space heating) may also involve comparison between electricity and unregulated fuels such as oil, propane, and wood. For example, in Vermont only about 15% of the homes and businesses currently have access to natural gas, and fuel substitution is primarily conversion from electricity to unregulated fuels. In this context, several issues arose when electric utilities were ordered by the Vermont Public Service Board (PSB) as part of their IRP plan to evaluate all potential fuel substitution opportunities. Concerns were raised by utilities regarding: (1) "free riders" in the sense that there was already significant fuel switching away from residential electric space heat as a result of natural market forces, limited financing provided by the state, and information provided by utilities, (2) appropriateness of applying existing environmental externality credits for DSM to fuel substitution because of localized impacts from consumption of alternative fuels, and (3) risk—in the form of potential price volatility from increased reliance on unregulated fuels. Other parties raised concerns about potential "lost opportunities" that outweigh any societal benefits from conversion whenever conversion of electric end uses to unregulated fuels occurs without concurrent installation of cost-effective weatherization measures and efficient new appliances. In the face of these concerns, the Vermont PSB decided that fuel switching should only be required when there is strong evidence that it is cost effective, and that the incremental benefits of a fuel switching measure must exceed the benefits from a nonfuel-switching DSM measure by at least 10% to be eligible for utility-assisted financing (Raab and Cowart 1992).

Despite the extra complexity and uncertainty that unregulated fuels add to the evaluation of fuel substitution, these fuels play an important role in competing with natural gas and electricity in some communities and cannot be ignored in these circumstances.

[10] During the late 1970s and 1980s, many regions and states (e.g., New England, New York, Florida) adopted policies to reduce their oil dependence both in electricity generation and end-use consumption. PUC actions were often intended to implement these policies.

8.6 Summary

Fuel substitution complicates the regulatory process by adding another dimension of "integration" to integrated resource planning (IRP). IRP was originally created to integrate risk and uncertainty considerations into electric utility capital budgeting and to integrate demand-side opportunities into power plant decisions. During the past decade, IRP has achieved this goal in many states. In most cases, it has not integrated planning for natural gas with planning for electricity.

Table 8-9 provides an overview of the current legal and/or administrative status of fuel substitution policies in various states, including our summary of the apparent motivation, the underlying regulatory strategy, and the primary evaluation criterion. It should be clear from the preceding discussion that there is no "right" answer or single course for fuel substitution policies. Electric utilities and industry associations (i.e., Edison Electric Institute) have vigorously opposed fuel substitution programs perceived to be "mandatory" although some electric utilities are willing to look at fuel substitution opportunities on a case-by-case basis. Not surprisingly, combination utilities have been in the forefront of trying out fuel substitution programs. In several states (e.g., Washington, Oregon), regulatory agencies and other interested stakeholders are pursuing innovative strategies that allow electric and gas utilities to look for areas where there are mutual benefits to cooperation. In California, Southern California Edison and Southern California Gas Company are jointly developing a "fuel-neutral" DSM program without regulatory mandate. The program is targeted at large commercial customers and is being pilot tested in one geographic region. Likewise, Consolidated Edison and Brooklyn Union Gas have developed a joint program to promote gas cooling, which has been underway for over a year. Similar programs are being developed by electric and gas utilities in several other states. These efforts are the exception, but they do suggest that it is possible to create "win-win" situations even in the interfuel-competition arena.

Based on the experiences of PUCs and utilities that have already addressed fuel substitution, the following elements are a starting point for PUCs seeking to develop explicit policies on cost-effective fuel substitution:

- The societal efficiency of fuel substitution ultimately depends on the relative costs and performance of respective gas and electric end-use technologies and the relative prices of both electric and gas service. To the extent possible, gas and electric rates should reflect the same relationship to long-run marginal costs.

- For utilities that assume the role of energy advisor to customers, PUCs should ensure that comprehensive and unbiased information be provided to customers on competing end-use equipment and technologies.

Table 8-9. Status of State PUC Approaches to Fuel Substitution

State	Status	Apparent Motivation	Regulatory Approach	Evaluation Criterion	Baseline Approach	Approach to Joint DSM
VT	Consideration Required	Optimize Social Cost	Utility Design	Does it Optimize Societal Costs	Best Technology	Encouraged
GA	Consideration Required	(not addressed)	Utility Design	(not addressed)	Better Technology	(not addressed)
CA	Consideration Required	Environmental Policy	Utility Design to PUC Standards	Must Not Increase Energy; Must Decrease Private Costs; Must Not Increase Pollution		Encouraged (one in progress)
WI	Consideration Encouraged	Customer Treatment	Utility Design to PSC Standards	Does it Optimize Private Costs	Better Technology --	Encouraged based on costs avoided (one in progress)
OR	Consideration Encouraged	(not apparent)	Utility Design to PUC Standards	Does it Optimize Societal Costs		(not addressed)
NY	Consideration Encouraged	(not apparent)	Utility Design	Does it Optimize Societal Costs		Encouraged (a few in place)
MD	Substitution Allowed	Efficient Utility Operation	Utility Design	Does it Optimize Utility Bills	Better Technology	(not applicable)
CO	Substitution Allowed	(not apparent)	Utility/Contract or Design	(not addressed)	(not applicable)	
FL	Policy ordered and then rescinded	-	-	-	-	
NV	Active Docket/No Resolution	-	-	-	-	
MA	Discussed Without Resolution	-	-	-	-	
RI	Discussed Without Resolution	-	-	-	-	

- PUCs should ensure that all DSM incentives offered by utilities are fairly balanced between competing fuel technologies and competing companies.

- Gas and electric utilities should be strongly encouraged to evaluate fuel substitution opportunities as part of their IRP or DSM planning processes. This will involve identifying and analyzing potential options to determine whether they might be cost effective (and under what assumptions) and assessing the extent to which market barriers exist and the types of intervention necessary to overcome barriers. If a fuel substitution program is deemed appropriate, the program should, to the extent possible, be developed cooperatively by gas and electric utilities, including methods to share program costs.

- The regulatory and ratemaking framework should be structured so that electric or gas utilities are no worse off financially as a result of supporting cost-effective fuel substitution.

Chapter 9

Financial Aspects of Gas Demand-Side Management Programs

9.1 Overview

This chapter characterizes the impact of gas demand-side management (DSM) programs on utility finances and describes ratemaking methods that remove some or all of the financial disincentives that may be associated with DSM. The ratemaking methods described include: ratemaking practices to assure recovery of prudent DSM expenditures, net lost revenue adjustment mechanisms, mechanisms that decouple revenues from sales to remove the incremental incentive to market gas, and shareholder incentives for the acquisition of DSM resources. Because many gas consumers are price sensitive, and because competitive impacts can affect gas local distribution company (LDC) profitability, the chapter also examines various methods to allocate DSM program costs among customer classes.

Since 1989, a number of reports, books, and studies have analyzed the disincentives under traditional regulation for electric utilities to pursue energy efficiency and suggested incentive mechanisms to reward utility shareholders for exemplary DSM performance (Moskovitz 1989; Wiel 1989; Nadel et al. 1992). These issues are also beginning to be explored by the gas utility industry (RCG/Hagler, Bailly Inc. 1991). Resolution of financial and incentive issues associated with acquiring DSM resources is critical for many gas utilities because they face flat or declining sales in traditional market segments while large customers have many alternative service options (e.g., unregulated suppliers and bypass options).

9.1.1 DSM and Supply-Side Resources Compared

To a utility, a therm conserved is unlikely to have the same financial impact as a therm sold. Despite the cost effectiveness of certain DSM resources, managers of gas utilities may not seriously consider DSM unless they expect it will bring financial benefits. Thus a serious attempt to treat DSM as a resource requires a review of, and possible modifications to, traditional ratemaking mechanisms. It is important to acknowledge, however, that ratemaking methods and practices significantly vary among PUCs because of individual commission policies and state laws. Key areas of differences among states include: choice of historic versus future test year, frequency of rate cases, presence or absence of provisions to adjust historical or forecasted demands for weather effects, and extent to which utilities are allowed pricing flexibility. Moreover, different cost-recovery mechanisms may be appropriate for different jurisdictions and for various types of DSM programs and may change over time depending on the level and rate of change in DSM expenditures (RCG/Hagler, Bailly Inc. 1991). Many of the ratemaking changes necessary to remove financial disincentives associated with utility-funded DSM programs are more evolutionary than revolutionary and some of the changes have already been employed by other jurisdictions or by the same jurisdiction at an earlier time. In the electric industry, three main forms of disincentives have been noted, and they apply generally to the gas industry as well: (1) failure to recover all DSM program costs, (2) loss of net revenues, and (3) loss of financial opportunity (Reid and Chamberlin 1990).

Failure to Recover DSM Program Costs

Although gas LDCs have long been providers of gas procurement and distribution services, LDC DSM programs represent a relatively new service; thus, DSM program budgets are not a traditional part of LDCs' requested revenue requirements. This may lead a PUC to consider requests for recovery of DSM expenditures outside of general rate cases. Regulatory lag (i.e., delay in the recovery of costs because of the regulatory process) may increase utility reluctance to invest in DSM, particularly in situations where DSM expenditures have been significantly increased and the utility perceives that the risk of under-recovery is high.[1] DSM programs represent a new type of utility-customer interaction, so there is little experience on which to base forecasts of DSM program participation. Under conventional regulation, expenses in excess of those estimated during a "test year," which provide the basis for rates, might not be recovered from ratepayers. Use of a future test year can mitigate this problem, but some method of quickly adjusting rates to cover program costs may be appropriate because the ultimate *market acceptance* of a DSM program can be uncertain. Ways to address the uncertainty of DSM program cost recovery are discussed in Section 9.2.

Net Lost Revenues

Despite a wide array of ratemaking practices, most gas utilities have base rates set in relatively infrequent (every 2 to 5 or more years) general rate cases and the commodity rates set more frequently in purchased gas adjustment (PGA) clause proceedings.[2] Most utilities have a financial incentive to make incremental gas sales because many expenses

[1] DSM will enhance financial health if the reduced demand defers capacity-related projects that have their own disallowance risks. In other words, the risk of recovery of DSM expenditures should be evaluated in comparison to the risks created by a scenario that excludes cost-effective DSM.

[2] Many gas LDCs have been given limited pricing flexibility when providing transportation services to customers in competitive market segments.

included in base rates are invariant of short-run changes in sales, and any increases in unit commodity costs are covered by the PGA clause. Thus, incremental sales typically provide a positive contribution to margin. Even in the longer term, the benefits of DSM in reducing capacity costs may not outweigh the incremental revenue loss. This rate-to-cost relationship can make gas DSM unattractive unless a utility is given assurance that all or most of the lost margin will be recovered in some fashion. Ways to address net lost revenues are discussed in Section 9.3.

Loss of Financial Opportunity

Even if expenditures for DSM programs are recovered and if lost revenues are made up in some fashion, DSM may not be attractive if it makes the utility forego more profitable investments in supply-side resources. Whether a gas LDC favorably views a capacity- or supply-related investment depends on the available options, the utility's authorized rate of return, and the PUC's regulatory procedures for the recovery of supply-side investments. It may be desirable in some cases to consider positive financial incentives for DSM investments in order to overcome real or perceived losses in financial opportunity. Positive incentives for shareholders are discussed in Section 9.4.

9.2 DSM Program Cost Recovery Methods

From the perspective of energy utilities and PUCs considering investment in DSM, three cost recovery issues are critical. First, PUCs must decide whether to base the level of DSM expenditures reflected in rates on activity recorded during a fixed historical test year, on actual expenditures as they are made, or on expenditures set for a forecast test year. Second, to the extent that there is a mismatch between the timing of the DSM expenditure and its recovery, PUCs must decide whether to allow utilities to recover accrued interest. Third, once the decision to recover DSM expenditures is made, PUCs or utilities must set an amortization period.

9.2.1 Timing of DSM Cost Recovery Proceedings

Investor-owned gas utilities often have two rate components, which are authorized in different types of regulatory proceedings. Base rates are set in general rate cases and typically do not change between general rate cases, except for discounts to customers who have competitive alternatives. The frequency of general rate cases can vary from yearly to once every several years. The rate treatment for gas commodity costs typically is handled through a PGA clause, in which rates are adjusted more frequently (e.g., sometimes monthly). Changes to this component usually are automatic, subject to after-the-fact reasonableness reviews, but states' handling of PGA clauses varies widely (Burns et al. 1991).

The type of DSM expenditure can also affect the timing of cost recovery. DSM expenditures may be grouped into four general cost categories: program administrative costs incurred by the utility; utility-to-customer incentives; shareholder incentives, if applicable; and measurement and evaluation costs. There are several general ways that commissions authorize cost recovery, as demonstrated below.

Conventional General Rate Cases

A utility's DSM program budget may be reviewed, along with other nonfuel expenses, in the general rate case. Budgeting DSM expenditures requires adjustments to historic-test-year data or the use of a future test year. The level of program participation is hard to forecast, but it determines a large part of the DSM budget, especially the cost of utility-to-customer incentives. Thus, it is not uncommon for the utility to be subject to some post-rate-case adjustments. For example, in California, if the utility underspends its DSM budget or wishes to reallocate budget monies among programs, it must seek regulatory approval through an advice letter. In some cases, utilities have been required to give back unspent monies. Table 9-1 summarizes the advantages and disadvantages of using general rate cases for DSM cost recovery.

Table 9-1. DSM Costs Recovered through General Rate Cases

Pros	•	Attention to DSM budgets is similar to that given other base-rate budgets; this appears fair and may decrease administrative costs.
	•	The utility has greater latitude in the allocation of its budgets to particular programs and has a cost minimization incentive.
Cons	•	Given uncertainty in utility resource needs, technological change, and program participation, it is difficult to set forecasted DSM budgets for a rate case cycle which may last for several years or indefinitely.

For gas utilities that have the opportunity to earn shareholder incentives for gas DSM program accomplishments, earnings typically are contingent on achievement of measurable savings. Cost recovery for these earnings initially may require a supplemental proceeding to the general rate case until such program evaluation procedures become routine.

Recover As You Go: Using Frequent Rate Cases or Deferred Accounting

Many commissions use frequent proceedings, deferred accounting, or both to allow for accurate recovery of DSM program costs (National Association of Regulatory Utility Commissioners (NARUC) 1992). Frequent rate cases specific only to DSM expenditures are akin to PGA clauses because rates are frequently adjusted in both types of

Exhibit 9-1. Recovery of Incremental DSM Costs Through a Rate Adder

In 1993, The Illinois Commerce Commission (ICC) authorized rate adders for the recovery of DSM program costs for two gas utilities in Illinois: North Shore Gas Co. and The Peoples Gas Light and Coke Co. (Peoples Gas). The adder allowed the utility to recover the following DSM program costs:

- training and educating DSM personnel
- efficiency seminars
- administration
- advertising
- collecting and evaluating data used for cost-benefit analyses
- energy audits
- billings from corporate affiliates, consultants, contractors, and other service providers
- incentives, rebates, or subsidies to customers
- energy conservation measures installed at customer premises
- incremental tax liabilities

The utilities track costs incurred in these categories, which are not already included in existing rates. Every month an adder is computed to all gas volumes, including transport-only volumes, to recover total recorded costs. If the adder is less than a $0.001/Dth threshold, the allowable costs are retained in a deferred account until accrued costs reach the threshold. The ICC retains the right to disallow costs that were improperly recorded to the account, based on a review of the utilities' programs.

Currently, DSM activities offered by these utilities are mostly pilot programs. Peoples Gas, which has an annual throughput of approximately 250 Bcf, has not accrued enough costs yet to hit the adder threshold of $0.001/Dth. Net lost revenues from reduced demand cannot be recovered through the rate adder.

proceedings. In this approach, a utility typically operates programs in conjunction with guidelines that have been approved in general rate cases or integrated resource planning (IRP) investigations. Actual expenses are not put into base rates. Instead, the utility is allowed to add the expenses to its PGA account or some other account that receives rapid cost recovery (see Exhibit 9-1). Although expenses may be recovered quickly, some PUCs (e.g., the Illinois Commerce Commission) still reserve the right to conduct reasonableness reviews. Other states, such as Massachusetts and Wisconsin, effectively preapprove DSM program expenses; poor performance by the utility will primarily influence future program authorizations. Table 9-2 summarizes the major advantages and disadvantages of frequent rate proceedings

Table 9-2. Recovery of DSM Expenditures via Frequent Rate Proceedings

Pros:	• The utility is authorized to pursue particular programs or objectives but is not required to hold to a certain budget until the market response is determined.
Cons:	• DSM is given special treatment.
	• There are few inherent cost minimization incentives because rapid recovery is a form of cost-plus regulation; however, after-the-fact reasonableness reviews can mitigate such behavior.

To mitigate the mismatch between current rates and current DSM expenditures, at least 13 PUCs have established some form of "true-up," balancing, or escrow accounting to allow for the accurate and timely recovery of gas DSM program costs (National Association of Regulatory Utility Commissioners (NARUC) 1992). A deferred account records expenses that are not yet recovered in rates and can exist in several guises. They may be called deferred debit or credit, reconciliation, memorandum, tracking, or balancing accounts. In some cases, differences in terminology represent important differences in presumptions regarding recovery and, thus, risks borne by utility management. For example, a balancing account is a special form of a deferred account that usually guarantees recovery of costs subject only to prudence reviews. Thus, balancing accounts are relatively safe, and utilities typically report undercollections as assets much like accounts receivable. Other deferred accounts, such as memorandum or tracking accounts, may not guarantee recovery. In these instances, a utility must argue for recovery in a specified proceeding and, even if recovery is granted, may only have "one shot" at recovery (i.e., future balancing account protection is not provided).

A deferred account for DSM program costs operates in a manner very similar to PGA clauses operated in many states. A PUC may authorize a set of DSM programs but not a specific level of spending. The PUC may also reserve the right to review expenses before authorizing recovery. To meet these ratemaking goals, the PUC will set up a deferred account that allows certain DSM expenses to be recorded to the account. At some later date, possibly in conjunction with a review of the DSM program's performance, the commission will authorize recovery of dollars recorded to the account. Utilities typically are allowed to earn interest on the account to reflect the time value of money. In some states, such as California, deferred accounts earn only the cost of short-term money. In other states, deferred accounts earn the utilities' approved cost of capital. The appropriate degree of earnings depends on the degree of disallowance risk faced by the utility and the level of financial incentive that the PUC wishes to give the utility for DSM endeavors. Recovery is achieved by taking the balance of the account and amortizing it over a certain rate period. If the account is amortized within a year, it may be seen as a form of expensing. If the account is amortized over a period of time greater than one year and earns the utility's cost of capital, the account becomes a form of ratebasing (see next section).

9.2.2 Expensing versus Ratebasing

Once a utility has made a DSM expenditure and recovery has been authorized, a general decision must be made about whether to treat it as an expense or as a long-term investment. The mechanics of either method are relatively simple in concept. With expensing, allowable expenditures are considered a component of revenue requirements. With ratebasing, the expenditure is put into an asset account, which is depreciated or amortized over time. The utility earns a return on the remaining balance in the account.[3] Annual revenue requirements associated with ratebasing include the depreciation or amortization component, the return component, and any taxes incurred on the return. DSM expenditures in one year will affect revenue requirements for the life of the depreciation or amortization period chosen.

Ratebasing, which spreads DSM program costs over a multi-year time period, is considered as a DSM cost recovery method because DSM measures typically provide energy savings over a multi-year period. Reasons for choosing ratebasing over expensing include: the timing of the recovery in rates better matches the stream of benefits, the economic efficiency of prices are improved, rate impacts are mitigated, and, if the

[3] The appropriate return for investments in DSM should reflect the risk associated with the investment. It may be hard for PUCs to hold utilities at risk for nonperforming DSM investments. If this is the case, then the utility's risk on approved DSM investments is low. On the other hand, investments in DSM are not bondable like supply-side investments and, thus, may require a higher return due to the necessity for equity financing.

authorized rate of return is considered attractive to shareholders, the return provides an incentive to pursue DSM (Reid 1992).

Ownership of a DSM measure is typically given to the customer; thus the physical DSM asset cannot be considered a part of the utility's rate base in a strict accounting sense. However, regulatory agencies that view DSM as a resource can consider the portion of the DSM measure paid for by the utility as a *regulatory asset*. Regulatory assets may be given recovery treatment that makes them as financially attractive as investments in traditional utility assets.

Despite the conceptual attraction of ratebasing DSM, it has not been very popular compared to expensing, for what appears to be several reasons. First, many gas LDCs consider the certain and full recovery of DSM program expenditures, including any accrued interest, to be a top priority. Whether the expenditures are ultimately expensed or ratebased appears relatively unimportant. Second, under the assumption that a utility only receives an authorized return that matches its cost of capital, LDCs may be financially indifferent when choosing between expensing and ratebasing. Third, earnings on ratebased DSM investments may be small relative to the net lost revenues caused by DSM programs. In three states where PUCs authorized enhanced rates of return for DSM investments—Kansas, Washington, and Montana—there is little evidence that gas utilities have vigorously pursued DSM programs as a result of ratebasing.

9.3 Accounting for Net Lost Revenues

DSM programs that reduce gas demand may have a negative financial impact on gas utility earnings. Under most adopted rate designs, a reduction in sales between general rate cases will result in a near-term reduction in contribution to margin. In the long run, utilities may avoid costs that were fixed in the short run; however, prices may be set so that the DSM program still causes a reduction in margin. Therefore, in the short run and possibly in the long run, gas utilities usually experience a negative financial effect from unforeseen reductions in demand. The term *net lost revenues* characterizes these margin impacts. Whether DSM programs cause revenue losses that harm the utility financially depends on, of course, whether the net effect of the DSM program is to increase or decrease sales. If fuel substitution programs are considered in gas IRP, then the net effect of a gas utility's DSM programs may be to increase sales, and earnings will increase rather than decrease. Ratemaking practices can also affect the magnitude of lost revenues. If marginal rates are set close to marginal costs, then net lost revenues will be small. Finally, there will be a lost revenue "problem" only to the extent that reduced demand is not incorporated into the demands used to set rates. Whether the demand forecast incorporates the demand impacts of DSM depends, in part, on whether the PUC sets rates using a historic or future test year.

9.3.1 Measuring Net Lost Revenues

As the introduction to Section 9.3 implies, defining net lost revenues precisely is difficult; however, between general rate cases practical definitions can be made. Usually, net lost revenue is defined as the difference between the incremental revenue impact of a DSM program and the incremental cost impact. An accurate estimate of incremental revenues requires an estimate of the DSM program's impact on participant billing determinants relative to the determinants used to set rates in the last general rate case.[4] The change in billing determinants times the applicable rates is a measure of a DSM program's incremental revenue impact. On the cost side, it would be ideal to use a current estimate of the LDC's avoided costs. As a practical matter, it is most common to simply use the weighted average cost of gas (WACOG) of the LDC's PGA as a proxy.[5,6] Defining net lost revenues beyond the next rate case is more difficult to do (Eto et al. 1993). Many of the costs that are considered fixed in the short run may begin to be affected by a utility's DSM programs. More importantly, the billing determinants used to set rates begin to be affected by DSM programs and, thus, the revenues may no longer be "lost" to shareholders.

If decoupling is used as an approach to respond to net lost revenues (discussed further below), there is no need to "measure" net lost revenues. Instead, the challenge becomes determining which cost accounts to include in the sales balancing account. Those costs are then recovered by the LDC regardless of the impact of DSM programs or other factors that affect sales. In California, where gas sales have been decoupled from revenues, the sales balancing account covers nearly all gas LDC costs *except* purchased gas costs, pipeline demand charges, and certain transition costs.

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[4] Billing determinants are components of demand used to compute bills. For example, if a residential customer buys gas from a tariff with a customer charge and a two-tier inverted block rate design, the customer's consumption in any month will be made up of three billing determinants: its customer count and its first and second tier consumption.

[5] If the DSM program participant is a transport-only customer, then the LDC will receive only transportation service revenues, and incremental costs will not include any purchased gas costs.

[6] For sales customers, it is common to simplify the calculation by setting net lost revenues equal to the DSM program savings (in therms) times the LDC's average base rate (in $/therm).

9.3.2 Historic and Future-Test-Year Ratemaking

Historic year ratemaking is still the norm in most states. According to a recent survey, only 10 PUCs in the U.S. allow for full future-test-year ratemaking for some or all of their utilities (Phillips 1988; National Association of Regulatory Utility Commissioners (NARUC) 1992). There are several ways that the effects of DSM programs can be incorporated by PUCs that rely on historic test years. First, a "known and measurable" demand adjustment could be made to incorporate the effects of DSM programs in the historical test year. Other known and measurable changes have been accepted for other utility budget items; for example, it is standard practice for gas utilities to adjust test-year demands for average weather-year conditions and expected changes in industrial demand, which often fluctuate significantly from year to year (American Gas Association 1987b). Second, frequent rate cases could be conducted; with them, the amount of DSM not reflected in the test-year demands in any given year would be small. Third, a commission could authorize a net lost revenue adjustment or revenue decoupling mechanism to eliminate the disincentives for utility DSM investments.

A future test year can naturally incorporate the effects of utility DSM programs on test-year demands. The potential for net lost revenues still exists, but only to the extent that the future-test-year demand forecast does not accurately estimate DSM program impacts. As with historical test year ratemaking, strategies can be used (e.g., frequent rate cases, decoupling, or net lost revenue adjustment mechanisms) to mitigate net lost revenues if they are a major concern.

9.3.3 Net Lost Revenue Adjustment Mechanisms

A number of PUCs have attempted to remove disincentives to DSM by adopting net lost revenue adjustment mechanisms.[7] Under this approach, utility net revenue losses associated with specific DSM programs are estimated or measured and the utility is allowed to recover these losses in rates. Critics maintain that this approach does not remove the utility's incentive to increase gas sales, limits the type of DSM activities that can be readily accommodated (compared to decoupling), and can lead to perverse incentives for the utility (Moskovitz et al. 1992).[8] Proponents argue that net lost revenue adjustment mechanisms are workable, relatively easy to implement, and represent a less fundamental change in utility regulation than decoupling (Tempchin 1993).

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[7] States that have adopted net lost revenue adjustment mechanisms for electric utilities include Massachusetts, Rhode Island, Ohio, and Indiana.

[8] If net lost revenues are based on estimated savings, the utility could be rewarded twice: once with assumed lost revenues and twice with revenues from therms that were not successfully saved.

9.3.4 Revenue Decoupling Mechanisms

Revenue decoupling mechanisms (RDMs) are ratemaking approaches that make a utility financially indifferent to changes in sales. This approach can be applied to varying degrees. For example, 27 LDCs in 11 states or provinces have some type of weather normalization procedure (Marple 1991; Marple 1992). Most of these weather adjustment mechanisms are *not* full decoupling mechanisms, but they do allow for revenues to be recouped when weather-sensitive customers experience warmer-than-expected winters and for revenues to be returned to customers after colder-than-expected winters.

With a full decoupling mechanism, an LDC is authorized to create a sales balancing account. Revenues intended to recover certain fixed cost accounts (usually base rate accounts) are flowed through the balancing account mechanism. Actual revenues are compared to those authorized in the latest rate case or attrition proceeding, and any deviations are logged to the balancing account rather than flowed through to the LDC's income statement. The end result is that the LDC reports authorized revenues instead of actual revenues. Balances in the sales balancing account are amortized in future rates. Sales balancing accounts protect the LDC from variations in sales but not from variations in base-rate expenses. For example, the LDC is at risk for any increases in wages that are not reflected in the revenues authorized in the last rate case or attrition proceeding.

Decoupling has been adopted for electric utilities in several states, specifically as a way to eliminate disincentives for DSM. For gas LDCs, a full RDM was first adopted by the California Public Utilities Commission (CPUC) in 1978 (Marnay and Comnes 1992). The CPUC's primary rationale for adopting decoupling for gas utilities was to stabilize earnings in response to sales variations caused by wide fluctuations in the price and availability of natural gas, rather than to eliminate financial disincentives for gas DSM. Currently, the CPUC still regards decoupling as an appropriate response to demand fluctuations caused by weather variability and, to a certain extent, alternative fuel competition (see Exhibit 9-2). Since 1988, California investor-owned LDC revenues are fully decoupled from sales for smaller gas "core" customers and are partially decoupled for larger "noncore" customers. As a result, California's gas LDCs have been at risk for some or all of the revenues allocated to noncore customers. Specifically, if sales do not occur as forecasted, the utilities cannot recover all of the lost margin from other customers or future customers. Noncore customers (primarily industrial, electric power, and wholesale) comprise about 20% of the utility's margin and the CPUC has concluded that putting the utility at risk for noncore sales will help keep utilities competitive with alternative fuels and bypass pipelines.

Decoupling mechanisms have been hotly debated by several PUCs and the pros and cons discussed at great length (see Table 9-3). One of the challenges in designing effective decoupling mechanisms is the way in which authorized base-rate revenue requirements

Exhibit 9-2. Revenue Decoupling for California's Gas Utilities

A full decoupling mechanism insulates utilities from all variations in sales, not just those resulting from the implementation of DSM programs. Because of the variability of gas demand in response to weather, decoupling can have a significant impact on prices from year to year. Figure 9-1 shows annual fluctuations in Southern California Gas Company's sales balancing accounts—known as its core and noncore fixed cost accounts—from 1988 to 1993. Full balancing account protection is given on fixed costs allocated to the core, but the protection is only partial for noncore sales. Imbalances in the fixed cost accounts primarily represent fluctuations in sales. In the noncore fixed cost account, imbalances are also caused by the LDC discounting its rates. These imbalances produced average rate impacts of over 10% in certain years. During the time period shown, balances in fixed cost accounts were considerably larger than balances accrued in SoCal's PGA account. These unexpected sales fluctuations have not been disaggregated systematically, but the available evidence indicates that the fluctuations are attributable to unexpected variations in weather, changes in the economy, and alternative fuels competition. The impact of unforecasted demand effects of DSM is estimated to be small compared to these other factors.

Figure 9-1. Recent Sales Balancing Account Activity: Southern California Gas Company

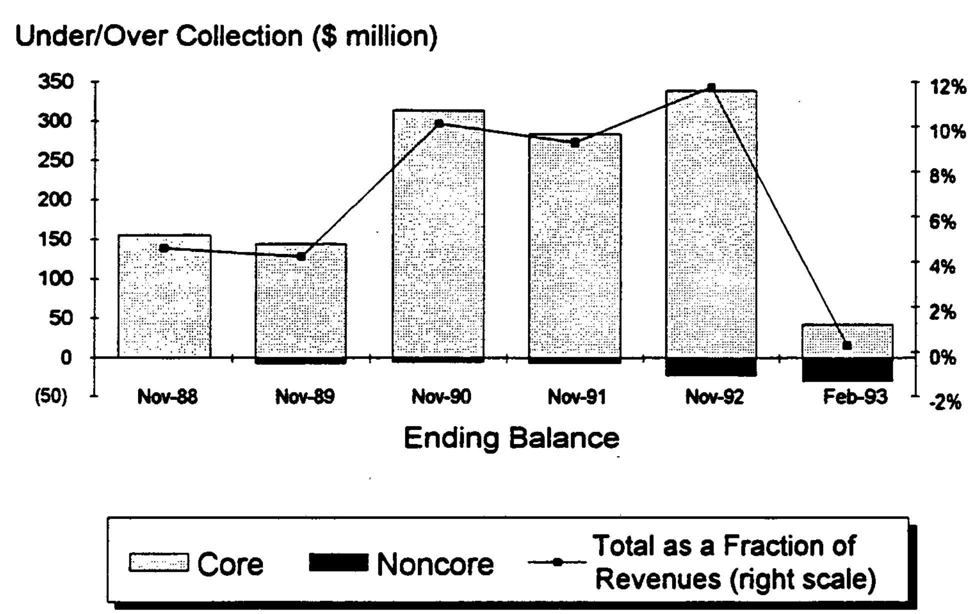

Table 9-3. Decoupling

Pros	•	Makes the utility indifferent to incremental sales, which provides impetus for implementing DSM programs effectively.
	•	Removes short-run incentives to market gas or gas transportation services.
	•	Provides the utility with financial stability including protection from sales variations caused by weather.
	•	Makes innovative rate design easier to implement because errors in forecasted billing determinants do not financially harm the utility.
Cons	•	Requires frequent rate cases, attrition, or "revenue per customer" like mechanism.
	•	Requires frequent, possibly large, year-to-year variations in rates.
	•	If applied to industrial markets, gives the utility a weak incentive to minimize unit costs; utility may lose market share needlessly.
	•	Can cause cross subsidies among customer classes if the under collections caused by one class are reallocated to other classes.

are adjusted on an ongoing basis. Under traditional ratemaking, the revenue requirement was only an intermediate product of regulation and rates were considered to be the final product. Decoupled utilities essentially are guaranteed their authorized revenues regardless of sales. Thus, decoupling requires one of the following: (1) frequent, future-year rate cases, (2) regular proceedings to adjust previously authorized revenues for current conditions (these commonly are known as *attrition* proceedings), or (3) a streamlined or mechanical revenue adjustment process like the "revenue per customer" proposal (Moskovitz and Swofford 1992).[9] Such adjustments to authorized base-rate revenues are necessary to account for inflation and because some base-rate expenses *are* a function of sales or customer growth.[10]

[9] The revenue per customer approach normalizes base rate revenues to the number of customers. Between rate cases, the utility is decoupled but its authorized base rate revenues are adjusted for customer growth at the predetermined revenue-per-customer rate. The revenue per customer approach has been adopted for at least two electric utilities: Central Maine Power Co. and Puget Sound Power and Light Co.

[10] Actual adjustments need only to respond to cost increases that are expected *after* taking into account utility productivity improvements.

Weather and alternative fuels competition can affect gas sales (and earnings) quite significantly, and in relative terms, these are probably more important factors than any unforeseen demand changes from DSM. Commissions that adopt decoupling mechanisms for gas utilities must recognize the potential for large annual rate changes (see Exhibit 9-2). There are at least two ways to mitigate the potentially large rate impacts caused by full decoupling. First, accrued balances could be amortized over periods of time longer than one year. However, longer amortization periods may provide a false sense of security, because it would only delay large rate impacts if a utility continues to record undercollections. Also, if a utility wants to be able to report accrued revenues as current revenues, the amortization period must be two years or less (Financial Accounting Standards Board (FASB) 1992). Second, a utility could attempt to separate the effect of DSM from the other sources of sales variations and only allow the utility to adjust rates for over- or under-collections attributable to DSM.[11]

9.4 Shareholder Incentives for DSM

DSM cost recovery, decoupling, and net lost revenue adjustment mechanisms primarily focus on eliminating regulatory disincentives to the promotion of DSM by gas utilities. Despite the availability of these mechanisms, DSM is a new activity for gas utilities and may still be perceived by gas utility managers to be less attractive than supply-side investments. Thus, many DSM proponents argue that incentives to utility shareholders (or managers) are necessary for the following reasons:

- Shareholder incentives are required to make utility management interested in gas DSM. It is likely that serious management attention will only be given when a utility's DSM programs provide contribute significantly to profits (Moskovitz 1992).

- For many states, disincentives—such as uncertain cost recovery or the absence of net lost revenue adjustment mechanisms—are still a part of prevailing ratemaking practices. Explicit shareholder incentives are one way to overcome such real or perceived opportunity costs of pursuing DSM programs.

- Incentives can be structured to reward exemplary performance and to penalize the utility for inadequate performance. Thus, incentives can provide an opportunity to make the utility not only pursue DSM but pursue it effectively.

[11] At this point, however, the decoupling mechanism will become complicated and begin to operate like a net lost revenue adjustment mechanism.

9.4.1 Types of Incentives

As of May 1993, at least seven PUCs had approved shareholder incentives for gas utilities.[12] There are three general types of shareholder incentives: *incentive rates of return, bounties, and shared savings.*

Incentive Rates of Return

An incentive rate of return probably is the simplest approach to incorporate into existing regulation. For DSM expenditures that are capitalized or amortized with interest, a utility could earn either a higher or lower rate of return, depending on the success of its efforts. A PUC would raise the utility's allowed rate of return if it did a superior job implementing its DSM programs and, conversely, would lower it if the utility's performance was judged inadequate. The incentive rate of return could either be specified in advance and linked to particular accomplishments (similar to the bounty approach), or it could be awarded based on an after-the-fact determination by a PUC. Ratebasing was discussed in more detail in Section 9.2.2.

Bounties

Bounties pay utilities for specified achievements based on a predetermined formula: e.g., X dollars for every therm saved. Exhibit 9-3 describes a bounty approach that has been adopted for Boston Gas. The major advantage of bounty approaches is their administrative simplicity; in addition, bounty approaches do not require explicit forecasts of gas long-run avoided costs (LRACs). This latter advantage is valuable for PUCs and utilities that either have limited experience in developing LRACs or believe that there is substantial uncertainty in their forecast of long-term gas commodity prices. However, it should be noted that many bounty approaches are initially developed by estimating the net resource value of a portfolio of DSM programs, given target participation levels. Thus, estimates of gas avoided costs are implicitly used to determine the bounty (see Exhibit 9-3). Disadvantages of this approach are: the utility has no incentive to minimize DSM program costs and, because bounties are not directly tied to a program's net benefits, the bounty may exceed the value of the DSM program.

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[12] Commissions include California, Iowa, Kansas, Massachusetts, Minnesota, New Jersey, Washington, and Montana.

Exhibit 9-3. DSM Shareholder Incentives: Massachusetts

Shareholder incentives have been approved for five of the eight investor-owned gas distribution companies regulated by the Massachusetts Department of Public Utilities (DPU). Boston Gas's incentive is structured as a bounty. The utility earns no incentive if actual savings are less than 25 percent of the target savings of 451 billion Btu/year (see Figure 9-2). The company receives an incentive of $5.62 per million Btu saved if actual savings exceed the 25% minimum threshold level. The incentive payment at the 100% target level of savings is $1.9 million, which is equivalent to 31% of estimated net resource benefits provided by these DSM programs. With this target incentive payment, Boston Gas will increase its return on equity by about 50 basis points. Boston Gas must demonstrate actual savings per measure and number of installations of each measure type before collecting any incentive payment.

The incentive mechanisms for most other gas LDCs in Massachusetts have used a shared-savings approach, and utility shareholders can receive about 5 to 7% of the net resource benefits provided by the programs for superior performance. Few LDCs actually have received incentive payments yet because the incentives are linked to actual program performance, and the programs have been in place for only a relatively short period.

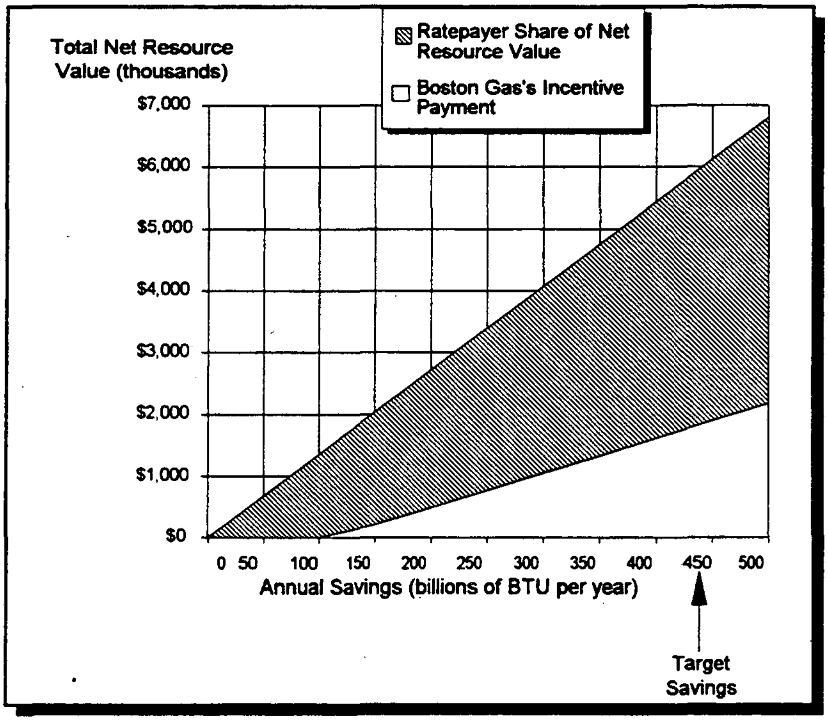
In Massachusetts, DSM program costs are recovered through each utility's Cost of Gas Adjustment Clause (CGAC), which essentially allows program costs to be expensed. Program costs are preapproved as a part of the proceeding that authorizes the programs. Allowable costs also include net lost revenues incurred as a result of reduced sales.

Source: Massachusetts DPU (1990)

Shared Savings

Various types of shared savings mechanisms have emerged as the most popular type of shareholder incentives for electric utilities. With a shared savings mechanism, the utility keeps a fraction (e.g., 5 to 30%) of the *net resource value* provided by a DSM program. Net resource value is computed as the difference between total program benefits and costs. Total benefits typically are estimated by multiplying estimated

Figure 9-2. Bounty Incentive for Boston Gas's Shareholders



(or measured) gas savings by the avoided cost of gas. Some PUCs also include the value of avoided externality costs in their incentive mechanisms. Program costs typically include the utility's administrative costs, financial incentives to customers, and DSM measure costs paid by the participating customer. Thus, net resource value is analogous to the Total Resource Cost test. However, in some cases, the Utility Cost test is used; that is, DSM measure costs paid for by the participating customer are excluded from the determination of net resource value (Eto et al. 1992).

9.4.2 Scope of Incentives

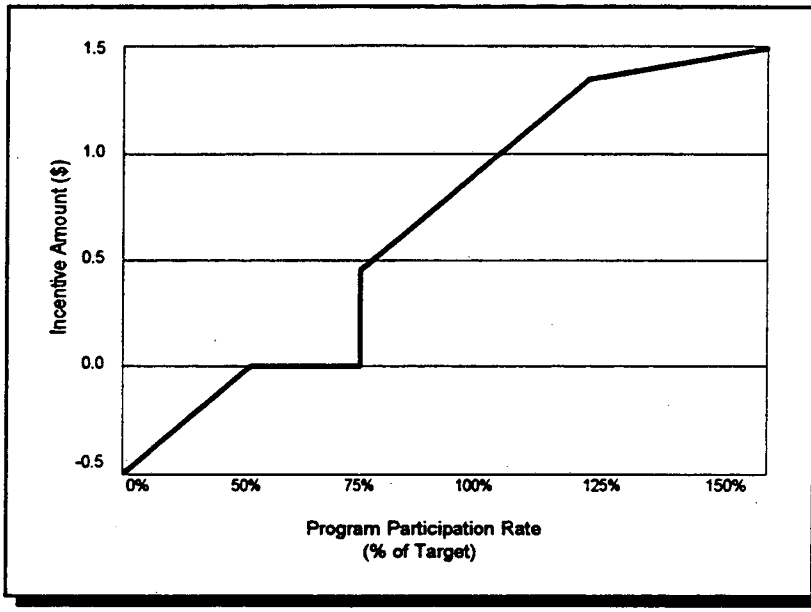
Many PUCs that have offered incentives to utility shareholders for acquiring DSM resources have limited them to certain kinds of programs. Often, incentives are targeted at DSM programs that have "resource value" and reduce the need for supply-side resources. Programs that promote off-peak load building or load building via fuel switching typically are not eligible. Several commissions have found that gas LDCs have sufficient financial or strategic incentives to pursue fuel substitution programs without additional financial incentives. DSM programs that are primarily offered for equity reasons (e.g., direct assistance to low-income customers) or programs that provide general or specific information on DSM opportunities to customers often receive different kinds of incentive treatment. For example, it is difficult to reliably estimate savings attributable to information and audit-type programs. One option is to provide a shareholder incentive that is structured as a "cost-plus" bounty (e.g., the utility receives incentive equal to a fixed percent of program expenditures with a cap on program costs). This approach may be useful in the case of low-income weatherization programs where the net benefits are negligible but the program is offered to address equity concerns.

9.4.3 Establishing the Basis for Incentive Payments: *Ex Ante* versus *Ex Post* Estimates of Energy Savings

Incentive mechanisms can reward or penalize a utility's performance in accomplishing IRP and DSM goals. Defining appropriate performance measure for DSM shareholder incentives has been a controversial issue; specifically, there is debate over the relationship and linkage between measurement and evaluation (M&E) of program savings and shareholder incentive payments. Often, this debate has centered on whether DSM incentive payments should be based on predetermined savings or participation-rate estimates (*ex ante*) or on the actual results of the DSM program (*ex post*).

Those who favor the *ex ante* approach argue that: (1) the primary purpose of M&E studies should be to improve program design and resource planning, (2) M&E studies involve significant time lags, and the results are often subject to interpretation, which can lead to contentious and lengthy regulatory proceedings and increased uncertainties regarding incentive payments, (3) long-term M&E studies are expensive, and it is not feasible to tie shareholder incentive payments to actual measured savings when the DSM measures have 10 to 15 year lifetimes, and (4) because the *ex ante* approach is more straightforward and less risky than an *ex post* approach, shareholders can receive a lower share of the net benefits, all else being equal (Schlegel et al. 1991; Wisconsin Energy Conservation Corporation 1993). In the *ex ante* approach, the utility is placed at risk for program parameters that are relatively easy to measure, such as achieving target participation rates. For example, in Figure 9-3, the utility receives an incentive if participation rates are greater than or equal to 75% of the forecasted target participation rates. The utility's earnings are reduced if participation rates fall below 50% of target levels, and there is a dead-band range, between 50 to 75% of the target participation rate, in which the utility does not earn an incentive. Typically, the utility will receive its share of the net benefits for the program's expected life cycle over a one- to three-year period while the actual benefits are realized over many years.[13] In the *ex ante* approach, results of M&E studies would be used to update and modify prespecified savings estimates only for future program years.

Figure 9-3. Illustrative Shareholder Incentive Payment Mechanism



Proponents of the *ex post* approach argue that (1) paying shareholder incentives based on actual savings as measured over time gives the utility the maximum incentive to acquire long-lasting, cost-effective DSM resources, and (2) *ex post* approaches reduce the risk that ratepayers are worse off after shareholder incentives have been paid if actual savings are much lower than expected. Most *ex post* approaches that have been proposed tie the

[13] Utilities tend to strongly favor accelerated payments of incentives because they believe this overcomes the perceived risk that the commission will later "take back" the shareholder's share of the expected benefits.

shareholder savings to the actual program savings as estimated in an M&E study.[14] When using an incentive mechanism based on the *ex post* approach, a particularly critical issue is the time period and intervals over which program savings are to be measured. At a minimum, benefits could be determined based on M&E studies of first-year savings. The utility would then receive incentive payments based on the estimated net present value of life-cycle savings and a predetermined economic life for each measure. At the limit, multi-year impact evaluations with test and control groups would be required to measure savings over the actual economic lifetimes of the installed DSM measures; this approach may be administratively burdensome and could be expensive in terms of the incremental value of information relative to the additional M&E costs incurred.

9.5 Allocation of DSM Program Costs to Classes of Customers

Cost allocation is the process of assigning a utility's revenue requirement to broad categories of customers known as customer classes. Cost allocation usually is an intermediate step in the ratemaking process because actual rates paid by individual customers are subject to the rate design chosen for each customer class. In reviewing alternative cost allocations, PUCs strive to meet their legal mandate, which is usually to set rates that are "just and reasonable" (Phillips 1988). In practice, setting just and reasonable rates has become a practice of balancing several goals including the goals of efficiency and equity. Efficiency involves making customers pay for the costs they cause on the gas system. Economists attempt to define the goal precisely by saying that efficiency is maximized when prices are set at or as close as possible to marginal costs. Equity, or fairness, is the goal of ensuring that the benefits of the utility system and incremental decisions made by the utility or PUC are shared by all. Often, the ability of a cost allocation to meet equity goals is evaluated in terms of how it satisfies human needs or social justice goals or by how it affects specific customer classes relative to the status quo. [15]

[14] Thus, most ex post incentive mechanisms only protect ratepayers from the risk that DSM savings will be less than expected. Uncertainties associated with future avoided costs are also important. Importantly, if shareholder incentives are based on the present value of net benefits over the program's life cycle, then ratepayers have essentially absorbed all the risk surrounding avoided cost estimates. An alternative ex post shareholder incentive mechanism would be to calculate and pay shareholder incentives over a program's life using actual avoided gas costs rather than forecasted avoided costs.

[15] For example, a regulatory body may take steps to minimize the negative impacts of rate changes on disadvantaged classes or will authorize programs to assist these customers in receiving and paying for utility energy services.

As with any decision regarding cost allocation, a PUC will evaluate DSM cost allocation proposals in terms of their ability to meet efficiency, equity, and other ratemaking goals. Because debates about general allocation policies are far from resolved, no prescriptive guidance can be given for the allocation of DSM program costs. Instead, this section discusses allocation methods and their implications.

9.5.1 Cost Allocation Methods

There are several allocation methods for assigning direct DSM program costs (see Table 9-4). An important related allocation issue is how changes in gas demand resulting from DSM programs affect allocation of base-rate revenue requirements in future rate cases. These methods and the base-rate-revenue reallocation issue are discussed briefly below. Readers who are interested in a more detailed discussion of various cost allocation methods should refer to Centolella et al. (1993), which focuses on the DSM program cost allocation for electric utilities.

Allocation by Number of Customers

Historically, some commissions have allocated gas DSM costs based on a weighted average of number of customers.[16] This approach was used in cases where DSM programs primarily or exclusively targeted smaller (residential) customers.[17] However, as DSM programs become more comprehensive (i.e., are offered to commercial and industrial customers), this approach becomes unattractive because the allocation of costs will be unlikely to match the allocation of benefits provided by the DSM program (Newman 1993).

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[16] Marketing services, customer information, and customer relations expenditures frequently are allocated on a basis of weighted number of customers. The weighting method is typically based on the size of meters and service lines or on customer throughput and, thus, will typically assign more costs to larger customers than would an unweighted customer count.

[17] Because residential customers historically have received almost all of the benefits of DSM programs, major problems were not created when 80-90% of program costs were allocated to the residential class using this method.

Table 9-4 Summary of Methods of Allocating DSM Program Costs

Allocation Method	Description of Method
Number of Customers	• Costs are considered to be a customer cost and allocated by number of customers accordingly.
Participating Customers	• Costs are directly allocated to participating customers. • Method is equivalent to an "energy services" charge.
Customers Offered the Program	• Costs of programs offered to a class are solely allocated to that class; costs are not allocated to nonparticipating customer classes.
Existing Volumetric Allocators	• Some or all DSM program costs are allocated according to each customer class's per-therm sales or throughput. • Method is often equivalent to "equal cents per therm."
Existing Demand Allocator	• Allocates some or all DSM program costs in proportion to the allocators used to allocate capacity costs. • Method is usually used in conjunction with other allocation methods.
Marginal Cost Revenues	• Costs are added to the "residual revenue requirement" and are allocated according to the total marginal cost revenue requirement (capacity and commodity-related) of each class. • Method is applicable only to PUCs using marginal-cost-based allocation methods.

Allocation to Program Participants or Classes who are Offered the Programs

Under this method, the costs of a DSM program are directly allocated to the classes or subclasses of customers who either participate in or are eligible for participation in a program; e.g., residential program costs are only allocated to the residential class. This approach is quite popular and is used by at least 11 PUCs; they favor it because it minimizes concerns that nonparticipating classes are subsidizing DSM programs (National Association of Regulatory Utility Commissioners (NARUC) 1992).[18] If program costs are solely allocated to participants, this type of allocation method is equivalent to an energy services charge that fully charges the participating customer for the cost of the DSM measure.

Equal Cents Per Therm

Broad allocations of DSM program costs, such as equal cents per therm or other volumetric allocations are used because they are considered simple to implement or because there is an expectation that the program provides benefits to all ratepayers. Relative to other allocation approaches, an equal-cents-per-therm allocation will tend to allocate more DSM program costs to high load factor customers.

The equal-cents-per-therm method may be implemented as an adder to the transportation component of all rates or to the PGA rate. For utilities with significant quantities of customer-owned transportation, the choice of the basis for the adder can yield significantly different results. The first method (adder applied to all rates) will allocate some DSM costs to transport-only customers. Such a method has been adopted in Illinois for allocating DSM program costs at two gas LDCs (see Exhibit 9-1). The second method (adder applied to sales only) allocates the DSM program costs only to gas sales customers of the LDC while transport-only customers are not allocated program costs. Overall, a broad volumetric-based allocation is relatively popular among PUCs; at least seven reporting that they use such a methodology.

[18] Of the 51 PUCs (including the District of Columbia) surveyed in the 1992 NARUC survey on utility regulatory policy, 29 PUCs either did not have gas DSM programs, were still undecided on their allocation policy, or did not report an answer. Thus, the 11 PUCs that rely on participating-class-based cost allocation method represent about 35% of the 31 PUCs that responded.

Allocation According to Existing Capacity Allocators

Similar to the logic used for volumetric allocations is the notion that DSM programs offer a certain amount of capacity benefits and, consequently, a portion of DSM program costs ought to be allocated in a manner similar to the way existing LDC or pipeline capacity costs are allocated. No one has proposed to allocate an entire DSM program according to this method, but it has been proposed for use in conjunction with other allocation methods. For example, if a gas DSM program saved therms and reduced peak day demand, the costs of the program could be allocated to customer classes on the basis of their annual throughput and peak-day demands (Newman 1993).

Marginal-Cost-Based Allocation Methods

With marginal-cost-based allocation methods, nongas revenue requirements are first allocated according to marginal costs estimated for each major utility function: commodity-related, transportation, storage, distribution, and customer costs. Usually, the total utility revenue requirement does not equal the revenues that would accrue under marginal cost pricing, so some sort of "reconciliation" is necessary. The most common form of reconciliation is known as equal percentage of marginal costs (EPMC), which means that all residual dollars are allocated in proportion to marginal cost revenues. The residual revenue requirement can also be allocated using the inverse of each class's demand elasticity. This type of method is commonly known as Ramsey pricing. At least two states—California and Massachusetts—use marginal costs in allocating nongas costs, although marginal cost allocation principles have not been extended to purchased gas costs.

Under the general framework of marginal cost allocation approaches, there are at least three ways to allocate DSM program costs. First, the cost of providing utility DSM services can be included in the marginal customer costs, which will have the effect of predominantly allocating DSM program costs to small customers (similar to the "number of customers" allocation method already described). Second, DSM program costs can be excluded from the general nongas allocation and included in the PGA rate component. This is the method used in Massachusetts. Third, DSM program costs can be excluded from the PGA account or any of the marginal cost estimates. The DSM program costs will then, by default, fall into the residual revenue requirement and will be allocated either by EPMC or by inverse elasticities. California uses this third method in conjunction with EPMC. The logic behind a residual allocation using EPMC is that DSM represents an alternative to supply, and its costs should be allocated to customer classes in proportion to marginal supply-side costs.

Reallocation of Base-Rate Expenses in Future Rate Cases

PUCs are obligated to provide utilities with a reasonable opportunity to earn their authorized rates of return. As a practical matter, this means that most commissions allow, in the rate case, for the adjustment of demands in response to DSM programs.[19] Although the effect of the rate case is to give the utility an opportunity to be made "whole," there may be significant impacts on the reallocation of base-rate expenses to individual customer classes. When considering the use of the general allocation methods described above, it is important to consider the interaction of these methods with changes in the levels of the allocators for other components of base-rate revenue requirements. For example, if a DSM program reduces the peak sendout of a customer class, it is reasonable to expect that that class's allocation of peak-day costs should be reduced. The impact of such a reallocation on nonparticipating customers depends to a great extent on the relationship of avoided capacity costs to the average (embedded) capacity costs. If avoided costs are low relative to embedded costs, the nonparticipating customers (or classes) may be adversely affected even if they do not share in the direct costs of the DSM program because they will be allocated more embedded capacity costs than they would receive without the DSM program. Conversely, if avoided costs are high relative to embedded costs, then nonparticipating classes will benefit because the total cost of capacity will drop by more than the increase in the nonparticipating class's percentage allocator. The effect of different assumptions regarding demand allocators is illustrated in the example presented in the following section.

9.5.2 Illustration of Different Cost Allocation Methods

Different cost allocation methods can affect participating and nonparticipating customer classes in significantly different ways, particularly in cases where DSM program expenditures are large. To illustrate the issues involved, three methods of allocating DSM program costs are shown for a hypothetical LDC conducting an aggressive, large-scale residential DSM program. The hypothetical LDC has three customer classes: residential customers with a 40 percent load factor that receive bundled service from the utility (sales and transport), commercial/industrial (C/I) customers that receive bundled service, and C/I customers that are transport-only customers.

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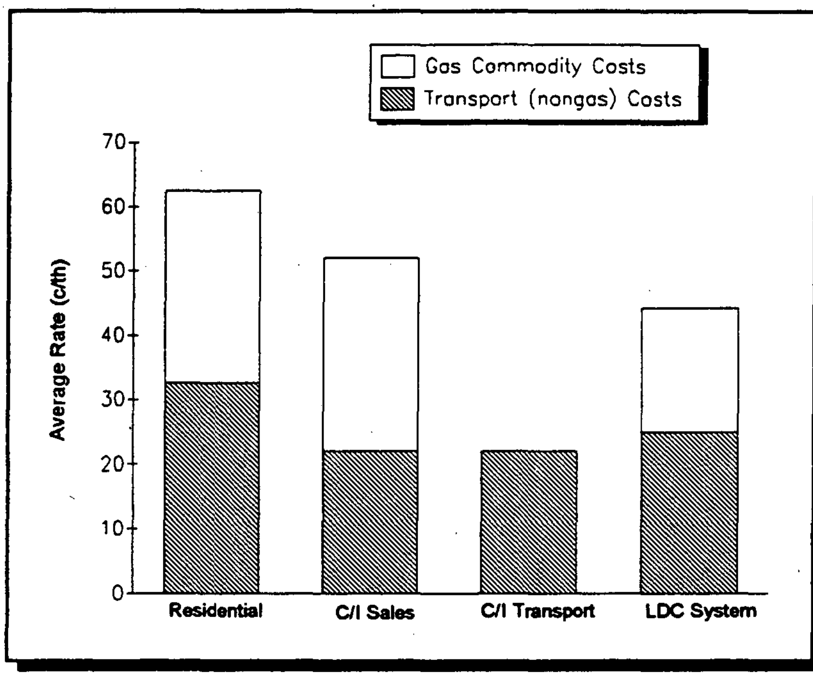
[19] For states that practice historical test year ratemaking and do not allow for adjustments in test year therms to account for DSM program effects, a new rate case may not fully adjust for DSM if the demand effects of DSM programs are growing over time.

The LDC's costs are aggregated into two general categories: commodity costs and nongas costs (i.e., the LDC's margin).[20] Average rates for residential customers are \$0.63/therm prior to the utility DSM program, which occurs in part because of the class's low load factor (see Figure 9-4). Rates for C/I transport customers are the lowest (\$0.22/therm) and the utility's average rates for its entire system are \$0.48/therm.

Figure 9-4. Class Average Rates for a Hypothetical LDC



Assume that the DSM program is targeted only at the residential customer class and reduces residential class sales and demand by 5% annually and on a peak day at a cost of \$0.30/therm to the utility. DSM program expenditures are assumed to be ratebased and amortized for the life of the program. Assume that total avoided costs are \$0.45/therm consisting of \$0.30/therm for marginal commodity costs and \$0.15/therm for marginal nongas costs. These avoided costs are, however, lower than average residential rates, so there is a net loss of revenues to the utility absent a reallocation of costs. Further, it is assumed that, although participating customers may pay for some of the measure's costs on their own, they do not contribute to the utility's DSM program costs, other than their share of program costs allocated to their class.

As long as the LDC is made whole, there is, on average, a 0.5% decrease in bills and a one percent increase in rates regardless of the chosen allocation policy. However, bill and rate impacts significantly vary among the three customer classes depending on the cost allocation method (i.e., costs allocated only to participating class, costs allocated to

[20] Commodity costs are allocated to all sales customers, while nongas costs are allocated according to a weighting of peak day demand and average-year throughput.

all customers on an equal cents per therm basis, and costs allocated to customers that buy only gas commodity service) and varying assumptions regarding whether or not nongas costs are reallocated (see Table 9-5).[21] The impact of these methods on class average rates and bills is shown in Figure 9-5. On average, residential customers receive bill reductions ranging from 0.5 to 3.5%, which is lower than their 5% reduced gas usage because rate increases are required to offset lost margins (see Figure 9-5a).

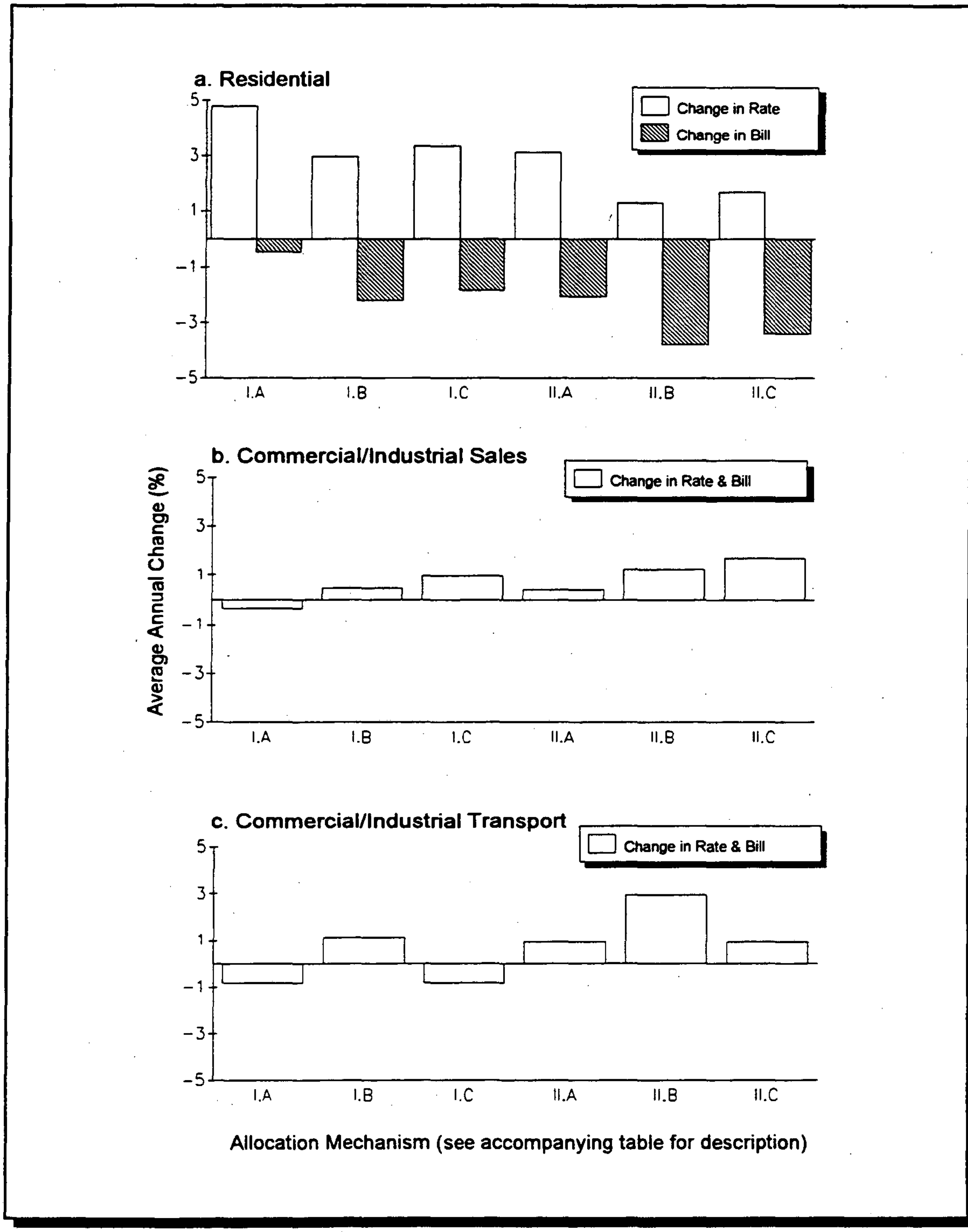
Table 9-5. Identification of Allocation Mechanisms Shown in Figure 9-5

	Change Nongas Allocations in Response to Change in Demand?	
Allocation of DSM Program Costs	No	Yes
Only to Participating Class (Residential Class)	I.A	II.A
Equal Cents per Therm	I.B	II.B
Equal Cents per Therm to Sales Customers Only	I.C	II.C

The residential customer class receives the highest bill reductions in the type "II" allocations, which change the nongas allocators to reflect the demand impacts of the DSM program. C/I sales customers (who are nonparticipants) receive a rate reduction only under allocation mechanism I.A, which allocates all DSM program costs to the participating class (i.e., residential customers) and does not reallocate nongas costs (see Figure 9-5b). With other cost allocation methods, rate and bill increases range from 0.05-2%. C/I transport-only customers (also nonparticipants) receive a rate reduction only under allocation mechanisms I.A and I.C (see Figure 9-5c). Bills and rates increases for transport-only C/I customers range from 1-3% if nongas cost allocators are changed.

[21] In this example, if nongas costs are reallocated, then each class's base rate is adjusted to incorporate demand impacts of DSM.

Figure 9-5. Impact of DSM Program on Average Rates and Bills Using Alternative Allocation Methods



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Glossary

Action Plan - A component of a utility's integrated resource plan, describing specific utility actions in the short-term (about two years) to meet supply- and demand-side objectives of the plan.

Annual Fuel Utilization Efficiency (AFUE) - Efficiency measure for gas heating equipment based on testing procedures defined by the Department of Energy.

Avoided Cost - Incremental cost that a utility would incur to purchase gas supplies and capacity equivalent to that saved under a demand-side management (DSM) program. Components of avoided cost may include energy, capacity, storage, transmission and distribution. Avoided cost has been used as a yardstick to assess and screen the cost-effectiveness of DSM programs and supply-side resources.

Base Load - As applied to gas, a given sendout of gas remaining fairly constant over a period of time, usually not temperature sensitive.

Base Rates - Gas utility rates designed to cover nongas costs. *See also Purchased Gas Adjustment (PGA) Clause and Nongas Costs.*

Bcf - 1,000,000,000 cubic feet; billion cubic feet.

British Thermal Unit (Btu) - The amount of heat required to raise the temperature of one pound of pure water one degree Fahrenheit under stated conditions of pressure and temperature.

Broker - A person acting as an agent for a buyer or seller of gas in a transaction. The broker does not assume title to the gas.

Burner-Tip - Generic term commonly used to indicate the ultimate point of consumption for natural gas.

Buyout/Buydown - The costs of contract realignment by a pipeline company. Specifically, they represent the negotiated costs of altering or walking away from contracts.

Bypass - Construction of a physical connection between a large end user and a supplier, other than historic or common suppliers, when the economics dictate; that is, the system supply price of the local utility supplier is higher than the total price of off-system supplies available through the market and separate transport of the purchase via the alternative (bypass) delivery point.

Capacity, Peaking - The capability of facilities or equipment normally used to supply incremental gas under extreme demand conditions; sometimes available only for a limited number of days at a maximum rate.

Captive Customer - Natural gas user who cannot readily leave or switch a system supplier due to physical or economic factors, availability of alternative fuels, or lack of fuel-switching capability. *See also Core Customer.*

Casinghead Gas - Unprocessed natural gas containing natural gasoline and other liquid hydrocarbon vapors produced from oil sell. *Synonyms: Wet Gas, Associated Gas (but not all wet gas or associated gas is casinghead gas).*

City Gate - Generally, a location at which gas changes ownership, from one party to another, neither of which is the ultimate consumer. It should be noted, however, that the gas may change from one system to another at this point without changing ownership. *Also referred to as city gate station, town border station, or wholesale delivery point.*

Combination Utility - A utility which supplies both gas and some other utility service (electricity, water, etc.).

Commodity Price - The current price for a supply of natural gas, charged for each unit of gas supplies, as determined by market conditions or tariff.

Compression - Increasing the pressure of gas in a pipeline by means of a mechanically driven compressor station to increase flow capacity.

Compressor Station - Any permanent combination of facilities which supplies the energy to move gas at increased pressure from fields, in transmission lines or into storage.

Conservation Supply Curve - A graph showing the quantity of energy savings of individual efficiency measures on the X-axis and the total cost-per-unit-of-energy saved on the Y-axis.

Contract Demand (CD) - The maximum daily, monthly or annual quantity which the supplier agrees to furnish, or the pipeline agrees to transport, and for which the buyer or shipper agrees to pay a demand charge.

Core Customer - Customer designation originally defined in California to represent smaller customers without alternative fuel capability. Typically made up of residential and small commercial classes.

Cost Allocation - Distribution of functionalized facility costs and operating expenses to rate classes or other identifiable customer groups on the basis of peak demand and energy use characteristics of the customer groups. Allocation may be calculated for historical or future periods and may be average or incremental for that period.

Cost-of-Service - Total cost of providing utility service to a system or to a customer group including operating expenses, depreciation, taxes, and a return on invested capital.

Cream Skimming - Designing and implementing only a limited set of the most cost-effective DSM measures while disregarding other cost-effective opportunities. Cream skimming becomes a problem when lost opportunities are created in the process, which means that it is either uneconomic and/or impractical to return at a later time to that facility to implement additional measures that were cost-effective at the time of the initial site audit. *See also Lost Opportunities.*

Cubic Foot (cf) - The most common unit of measurement of gas volume. It is the amount of gas required to fill a volume of one cubic foot at a temperature of sixty degrees Fahrenheit (60°F) and at a pressure of fourteen and seventy-three hundredths pounds per square inch absolute (14.73 psia).

Curtailment - A restriction or interruption of gas supplies or deliveries. May be caused by production shortages, pipeline capacity or operational constraints or a combination of operational factors.

Cushion Gas - The gas required in a reservoir, used for storage of natural gas, so that reservoir pressure is such that the storage gas may be recovered. *See also Working Gas.*

Demand-Side Bidding - A process in which a utility issues a request for proposals (RFP) to acquire DSM resources from energy service companies (ESCOs) and customers, reviews proposals, and negotiates contracts with winning bidders for a specified amount of energy savings.

Demand-Side Management (DSM) - Deliberate effort to decrease, shift or increase energy demand through organized utility activities that affect the amount and timing of gas use.

Design Day - A 24-hour period of demand which is used as a basis for planning gas capacity requirements.

DSM Potential

> **Technical Potential** - Estimate of possible energy savings based on the assumption that existing appliances, equipment, building shell measures, and industrial processes are replaced with the most efficient commercially available units, regardless of cost, without any significant change in lifestyle or output.
>
> **Economic Potential** - Estimate of that portion of the Technical Potential that would occur assuming that all energy-efficient options will be adopted and all existing equipment will be replaced whenever it is cost-effective to do so based on a prespecified economic criteria, without regard to constraints such as market acceptance and rate impacts.
>
> **Achievable Potential** - Estimate of amount of energy savings that would occur if all cost-effective, energy-efficient options promoted through utility DSM programs were adopted. Achievable potential excludes those efficiency gains that will be achieved through normal market forces and by existing or future standards or codes.
>
> **Market Potential** - Estimate of the possible energy savings that would occur because of normal market forces (i.e., likely customer adoption over time of various actions without a DSM program).

Economic Carrying Charge Rate (ECCR) - A method of allocating capacity costs over time in such a way that the annual value stays constant in real terms.

Econometric Model - A set of equations, developed through regression analysis and other quantitative techniques, that mathematically represents relationships among data.

Electric Fuel Substitution - Programs which promote the customer's choice of electric service for an appliance, group of appliances, or building rather than the choice of service from a different fuel. These programs increase customers' electric usage and decrease usage of an alternative fuel.

Energy-Efficiency Options - Measures or strategies that reduce energy consumption by substituting more efficient equipment or operating practices without degrading services provided.

Externalities - Cost and benefits that are not accounted for in the market prices paid for a good or service. For example, costs of physical damage from the presence of certain pollutants are negative environmental externalities.

Federal Energy Regulatory Commission (FERC) - An agency of the Department of Energy (DOE) charged with regulation of interstate sales and transportation of natural gas, wholesale electric rates, hydroelectric licensing and oil pipeline rates.

Firm Service - Service offered to customers (regardless of Class of Services) under schedules or contracts which anticipate no interruptions. The period of service may be for only a specified part of the year as in Off-Peak Service. Certain firm service contracts may contain clauses which permit unexpected interruption in case the supply to residential customers is threatened during an emergency. *Compare to Interruptible Service and Off-Peak Service.*

Force Majeure - An unexpected event or occurrence not within control of the parties to a contract which alters the application of the terms of a contract; sometimes referred to as "an act of God." Examples include severe weather, war, strikes and other similar events.

Free Drivers - Customers who take recommended actions because of a DSM program but who do not impose a cost on the program (e.g., they do not claim monetary incentives offered by the program). Free drivers also include customers that enhance their consideration of energy efficiency in nonprogram purchase decisions after their participation in a utility program.

Free Riders - DSM program participants who would have undertaken DSM measures, even if there were no utility DSM program.

Gas Fuel Substitution - Programs which promote the customer's choice of natural gas service for an appliance, group of appliances, or building rather than the choice of service form a different energy source. These programs increase customer usage of natural gas and decrease usage of an alternative fuel.

Gas Inventory Charge (GIC) - A charge by a pipeline assessed for standing ready to serve sales customers. The Gas Inventory Charge is designed to prevent the occurrence of take-or-pay liability by charging the customer for all the costs associated with maintaining a gas supply.

Gas, Natural - A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

> **Associated** - Free natural gas in immediate contact, but not in solution with crude oil in the reservoir.
>
> **Dissolved** - Natural gas in solution in crude oil in the reservoir.
>
> **Dry** - Gas whose water content has been reduced by a dehydration process. Gas containing little or no hydrocarbons commercially recoverable as liquid product. Specified small quantities of liquids are permitted by varying statutory definition in certain states.
>
> **Liquefied (LNG)** - Natural gas which has been liquefied by reducing its temperature to minus 260°F at atmospheric pressure. It remains a liquid at -116°F and 673 psig. In volume it occupies 1/600 of that of the vapor.
>
> **Liquids** - Those liquid hydrocarbon mixtures which are gaseous at reservoir temperatures and pressures but are recoverable by condensation or absorption. Natural gasoline and liquefied petroleum gases fall in this category.
>
> **Nonassociated** - Free natural gas not in contact with, nor dissolved in, crude oil in the reservoir.
>
> **Sour** - Gas found in its natural state, containing such amount of compounds of sulphur as to make it impractical to use, without purifying, because of its corrosive effect on piping and equipment.

Sweet - Gas found in its natural state, containing such small amount of compounds of sulphur that it can be used without purifying, with no deleterious effect on piping and equipment.

Wet - Wet natural gas is unprocessed natural gas or partially processed natural gas produced from strata containing condensable hydrocarbons. The term is subject to varying legal definitions as specified by certain state statutes. (The usual maximum allowable is 7 lbs./MMcf water content and .02 gallons/Mcf of Natural Gasoline).

Heating Degree-Day - A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a baseline temperature, usually 65° Fahrenheit. A daily average temperature usually represents the sum of the high and low readings divided by two.

Hydrocarbon - A chemical compound composed solely of hydrogen and carbon. The compounds having a small number of carbon and hydrogen atoms in their molecule are usually gaseous; those with a larger number of atoms are liquid, and the compounds with the largest number of atoms are solid.

Incremental Cost - In economic analysis of DSM, difference in price between an efficient technology or measure and the alternative standard technology.

Injection - The process of putting gas into a storage facility. Also called liquefaction when the storage facility is a liquefied natural gas plant.

Integrated Resource Planning (IRP) - A planning process, used by regulated energy utilities, to assess a comprehensive set of supply- and demand-side options in order to create a resource mix that reliably satisfies customers' short-term and long-term energy service needs at the lowest total cost.

Interruptible Service - Low priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the claim of firm service customers and higher priority users. Gas is available at any time of the year if the supply is sufficient and the supply system is adequate. *Synonym: Nonfirm. See also Noncore.*

Interstate Pipeline - Natural gas pipeline company that is engaged in the transportation, by pipeline, of natural gas across state boundaries, and is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act.

Linear Programming - A mathematical method of solving problems by means of linear functions where the variables involved are subject to constraints.

Line Pack, Gas Delivered from - That volume of gas delivered to the markets supplied by the net change in pressure in the regular system of mains, transmission and/or distribution. For example, the change in the content of a pipeline brought about by the deviation from steady flow conditions. *Synonym: Pipeline Fill.*

Liquefaction - Any process in which gas is converted from the gaseous to the liquid phase.

Liquefied Natural Gas (LNG) - *See Gas, Natural.*

Load Duration Curve - An array of daily peak-day sendouts observed that is sorted from highest sendout day to lowest to demonstrate both the peak requirements and the number of days they persist.

Load Factor - The ratio, in percent, of average load of a customer, a group of customers, or an entire system, to the maximum load. Load factor can be calculated over various time periods (e.g., monthly, annual).

Load Forecasting - Projections of customer energy and peak day demand requirements on either a short-term or long-term basis.

Local Distribution Company (LDC) - A utility that purchases gas for resale to end-use customers and/or delivers customer's gas supplies from interstate pipelines to end-users' facilities reducing pressure from pipeline levels to appropriate delivery levels.

Looping - The construction of a second pipeline parallel to an existing pipeline over the whole or any part of its length, thus increasing the capacity of that section of the system.

Lost Opportunities - Efficiency measures which offer long-lived, cost-effective savings that are fleeting in nature. A lost opportunity occurs when a customer does not install an energy efficiency measure that is cost-effective at the time, but whose installation is unlikely to be cost-effective later.

Mcf - A unit of volume equal to a thousand cubic feet; see *Cubic Foot.*

MDQ - Maximum Daily Quantity

MMBtu - A unit of heat equal to one million British thermal units (Btu). It is also approximately equivalent to 1,000 cubic feet of gas.

MMcf - 1,000,000 cubic feet; million cubic feet; see *Cubic Foot.*

MMth - 1,000,000 therms; see *Therm.*

Margin - Revenues minus incremental operating expenses over the time period specified *See also Nongas Costs, Base Rates.*

Multi-Attribute Analysis - A method which allows for comparison of options in terms of all attributes which are of relevance to the decision maker(s). In IRP, common attributes are financial cost, environmental impact, social impact and risk.

Natural Gas Vehicle (NGV) - May be dedicated, meaning that the vehicle runs only on natural gas, or dual-fuel, which means that the vehicle is equipped to operate on natural gas or gasoline.

Net Energy Demand Forecast - The Gross Energy Demand Forecast less the effect of all DSM.

Net Lost Revenues - Utility lost revenues resulting from a DSM program net of avoided supply and capacity cost savings. May also be defined as the net margin impact of a DSM program. *See also Margin, Lost Revenues.*

Nomination - The scheduling of daily gas requirements.

Noncore Customer - Customer designation originally defined in California to be customers that consume more than 250,000 therms per year and have alternative fuel capability. *See also Core Customer.*

Nongas Costs - Gas utility expenses net of purchased gas costs and, often, pipeline demand charges. *See also Purchased Gas Adjustment Clause (PGA) and Base Rates.*

Nonparticipants test - Test used to evaluate the benefits and costs of utility DSM program from the perspective of utility customers who do not participate in the program. *Also called Ratepayer Impact Measure (RIM) and No-Losers test. See also Total Resource Cost test.*

Off-Peak Service - Service made available on special schedules or contracts but only for a specified part of the year during the off-peak season.

Open Access - The nondiscriminatory access to interstate pipeline transportation services. This enables end-use customers the option of securing their own gas supplies rather than relying upon local distribution companies.

Participants test - Test used to evaluate the benefits and costs of utility DSM program from the perspective of utility customers who participate in the program. *See also Total Resource Cost test.*

Peak Day - The 24-hour day period of greatest total gas sendout assuming a specific weather pattern. May be used to represent historical actual or projected (budget) requirements.

Peak-Day Curtailment - Curtailment imposed on a day-to-day basis during periods of extremely cold weather when demands for gas exceed the maximum daily delivery capability of a pipeline system.

Peak Shaving - The process of supplying gas for a distribution system from an auxiliary source (typically of limited supply and higher cost) during periods of maximum demand to avoid exceeding the demand on the primary source and to reduce wide fluctuations in gas takes. *Synonym: Needle Peaking.*

Persistence - Refers to any decline in energy-saving effectiveness that may take place over a conservation measure's life. This is a function of both consumer behavior and equipment degradation.

Pipeline - All parts of those physical facilities through which gas is moved in transportation, including pipe, valves and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies.

Program Evaluation - Activities related to the collection, analysis, and reporting of data for purposes of measuring program impacts from past, existing or potential program impacts. Activities include program-specific evaluations as well as activities which evaluate more generic issues which are relevant to more than one program.

Propane (C_3H_8) - A gas, the molecule of which is composed of three carbon and eight hydrogen atoms. Propane is present in most natural gas and is the first product refined from crude petroleum. It has many industrial uses and may be used for heating and lighting. Contains approximately 2,500 Btu per cubic foot.

Propane Air - Propane mixed with air and natural gas to allow burning in a natural gas system to supplement natural gas supplies for customers on peak days.

Purchased Gas Adjustment (PGA) Clause, Rate, Provision, or Account - A rate, account, or ratemaking mechanism that allows for frequent updating of gas utility rates to reflect changes in purchased gas costs. Usually, but not always, includes pipeline demand charge expenses in addition to gas commodity costs.

Rate Base - The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return. Generally, this represents the amount of property used and useful in public service.

Reserves, Energy - Refers to the bank of natural resource, such as natural gas, natural gas liquids, petroleum, coal, lignite, and energy available from water power, and solar and geothermal energy.

> **Estimated Potential Natural Gas Reserves** - Refers to an estimate of the remaining natural gas in a specified area which are judged to be recoverable.
>
> **Estimated Proved Natural Gas Reserves** - An estimated quantity of natural gas which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs, under anticipated economic and current operating conditions. Reservoirs that have demonstrated the ability to produce by either actual production or conclusive formation test are considered proved.

Saturation, Appliance - Ratio of the number of specific types of appliances or equipment to the total number of customers in that class, expressed as a percentage. For example, gas space heat saturation refers to the fraction of homes and buildings with gas space heating.

Sendout, Gas - Total gas produced, purchased (including exchange gas receipts), or net withdrawn from underground storage within a specified time interval, measured at the point(s) of production and/or purchase, and/or withdrawal, adjusted for changes in local storage quantity. It comprises gas sales, exchange deliveries, gas used by company and unaccounted for gas. Expressed in various units such as therms, Btu's, cubic feet, etc.

Sendout, Maximum Day - The greatest actual total gas sendout occurring in a specified 24-hour period.

Service Area - Territory in which a utility system is required or has the right to supply gas service to ultimate customers.

Service Line or Pipe - The pipe which carries gas from the main to the customer's meter.

Shrinkage, Natural Gas - The reduction in volume of wet natural gas due to the extraction of some of its constituents, such as hydrocarbon products, hydrogen sulfide, carbon dioxide, nitrogen, helium, and water vapor.

Societal Cost test - Cost determined from a social perspective as opposed to a private perspective. All externalities should be included, if their monetization is feasible.

Spot Market Gas - Gas purchased under short-term agreements as available on the open market. Prices are set by market pressure of supply and demand.

Storage, Local - The storage facilities, other than underground storage, that are an integral part of a distribution system, i.e., on the distribution side of the city gate.

Storage Mains - Those mains used primarily for injection and withdrawal of gas to and from underground storage.

Storage, Underground - The utilization of subsurface facilities for storing gas which has been transferred from its original location for the primary purposes of load balancing. The facilities are usually natural geological reservoirs such as depleted oil or gas fields or sands sealed on the top by an impermeable cap rock. The facilities also may be artificial or natural caverns.

Aquifer Storage - The storage of gas underground in porous and permeable rock stratum, the pore space of which was originally filled with water and in which the stored gas is confined by suitable structure, permeability barriers and hydrostatic water pressure.

Base Gas - The total volume of gas which will maintain the required rate of delivery during an output cycle. *Also called Cushion Gas.*

Current Gas - The total volume of gas in a storage reservoir which is in excess of the base gas. *Also called Working Gas.*

Extraneous Gas - *See Stored Gas, this section.*

Foreign Gas - *See Stored Gas, this section.*

Native Gas - The total volume of gas indigenous to the storage reservoir.

Storage Reservoir - That part of the storage zone having a defined limit of porosity and/or permeability which can effectively accept, retain, and deliver gas.

Stored Gas - Gas physically injected into a storage reservoir.

Ultimate Reservoir Capacity - The total estimated volume of gas that could be contained in storage reservoir when it is developed to the maximum design pressure.

Working Gas - Gas in an underground storage field that is available for market. *May also be called Current Gas.*

Take or Pay - The clause in a gas supply contract which specifies amount of gas required to be purchased whether or not delivery is accepted by the purchaser. Some contracts contain a time period in which the buyer may take later delivery of the gas without penalty.

Tariff - A published volume of rate schedules and general terms and conditions under which a product or service will be supplied.

Tcf - 1,000,000,000,000 cubic feet; trillion cubic feet.

Therm (th) - A unit of heating value equivalent to 100,000 British thermal units (Btu).

Total Resource Cost (TRC) test - Test used to evaluate the benefits and costs of utility DSM program from the perspective of all utility customers. Test excludes externality costs or benefits. *See also Societal Cost test.*

Trade Allies - Organizations (e.g., architects and engineering firms, building contractors, appliance manufacturers and dealers) that influence the energy-related decisions of customers who might participate in utility DSM programs.

Transportation Gas - Gas purchased from a source other than the pipeline which delivers it. This gas is purchased either directly from the producer or through a broker and is used for either system supply or for specific end-use customers, depending on the transportation arrangements.

Unaccounted for Gas - The difference between the total gas available from all sources and the total gas accounted for as sales, net interchange and company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly due to measurements being made at different times. In cycle billings, an amount of gas supply used but not billed as of the end of a period. *Compare Sendout, Gas.*

Utility Cost test - Test used to evaluate the change in total costs to the utility (i.e., the utility's revenue requirement) caused by a DSM program. *See also Societal Cost test. See Nonparticipants test, Total Resource Cost test.*

Vaporization - Any process in which gas is converted from the liquid to the gaseous phase.

Weather Normalization - Method for adjusting gas consumption to remove the effects of weather, which usually involves estimation of the average annual temperature in a typical or "normal" year based on examination of historical weather data. The normal year temperature is used to forecast utility sales revenue under a procedure called sales normalization.

Weighted Average Cost of Gas (WACOG) - The average price paid for a volume of gas purchased from a pipeline based on the prices of individual volumes of gas that make up the total quantity supplied. WACOG is sometimes equal to the total PGA rate. *See also Purchased Gas Adjustment (PGA) Clause.*

Withdrawal - The process of removing gas from a storage facility, making it available for delivery into the connected pipelines. Vaporization is necessary to make withdrawals form an LNG plant.

Working Gas - *See Storage, Underground.*

Appendix A

Major Federal Regulatory Policy Reforms on Unbundling of Interstate Pipeline Transportation

Date	*Order/Case*	*Summary*
1983	Special Marketing Programs (SMPs) Transco 4/83 Columbia 11/10/83 Tenneco 11/20/83 Panhandle/Trunkline 3/19/84 Texas Eastern 6/29/84 El Paso 8/24/84 Various Producers 1983-85	Transco established first SMP as part of rate settlement. Under Industrial Sales Program, Transco purchased and set prices for gas. Producer-suppliers and eligible end users who wished to participate could then sell gas to or by gas from the program. Transco's SMP expanded in June 1983 to include Contract Carriage Program (CCP). CCP allowed producers and end users to enter into direct sales agreements with the pipeline company acting as transporter. Transco's two programs were models for all later SMPs. As of April 1985, more than 30 SMPs had been approved. The programs were aimed primarily at fuel-switchers, so captive customers could not purchase this market-priced gas.
8/83	FERC Order 319 - Blanket Certificates to Transport Gas for High Priority Users	Allowed interstate pipeline companies to use blanket certificates to transport gas for high priority end users (process, feedstock, commercial, essential agricultural users, school, hospitals).
8/83	FERC Order 234-B - Blanket Certificates to Transport Gas for Non-Priority Users	Allowed interstate pipeline companies to use blanket certificates to transport gas for users covered by Order 30, in effect creating a spot market of direct sales from producers and other intrastate suppliers to industrial boiler fuel users. Gas could be sold and transported for up to 120 days without prior approval. Longer agreement required prior notice and allowed for protest.
5/84	FERC Order 380	Required pipelines to remove variable costs from minimum commodity bills; these costs represented up to 90% of minimum commodity bill.

9/84	Extension of SMPs	Term of SMPs extended for one year to 10/31/85. Conditions substantially eased: purchases could be made for gas originally priced at less than the system WACOG as long as the contract price remained above that of NGPA Section 109 gas; reporting requirements reduced; SMP gas could by used to serve up to 10 percent of the pipeline company's core market.
5/10/85	Maryland People's Counsel v. FERC F. 2nd No. 84-1019	Courts ruled SMPs in current form illegal because they discriminated against core customers.
5/10/85	Maryland People's Counsel v. FERC F. 2nd No. 84-1090	Courts ruled blanket certificate transportation for end users illegal as then conducted because it discriminated against pipeline company core customers. The two Maryland People's Court cases, in effect, outlawed any spot market not open to all buyers.
10/85	FERC Order 436	Issued in response to Maryland People's Counsel cases, allowed interstate pipelines to become "open-access" transporters for gas bought directly from producers. For open-access pipelines, Order would separate pipelines' merchant and transportation functions.
6/23/87	Associated Gas Distributors et al. v. FERC, No. 85-1811 et al.	U.S. Court of Appeals for D.C. Circuit remanded Order 436. Strongly affirmed open-access transportation and rate conditions of Order, but reversed and remanded nondiscriminatory access and Contract Demand (CD) reduction/conversion on grounds they aggravate pipeline take-or-pay problems.
8/7/87	FERC Order 500	Interim response to Court's vacating Order 436. Readopted 436, with modifications including: (1) producers must offer to credit gas transported by pipeline against pipeline's take-or-pay liability; (2) pipelines may seek to recover take-or-pay buyout/buydown costs associated with past liability; (3) pipelines allowed to design future gas supply charges to prevent further take-or-pay liability; and (4) eliminates CD reduction provision of Order 436.

2/5/88	FERC Order 490	Allowed sellers and purchasers to automatically abandon all first sales of natural gas under Section 7(b) of the Natural Gas Act, upon 30 days' notice, where the underlying contract has either (1) expired, or (2) been terminated or modified by mutual agreement of the parties. Promoted open-access transportation by making possession of Order 436/500 certificate a prerequisite for pipelines to abandon purchases unilaterally.
4/2/92	FERC Order 636	Mandates unbundling of basic pipeline merchant function and implements straight fixed-variable rate design. Unused LDC capacity claims released back to pipeline for brokering.

Source: Energy Information Administration (EIA) 1989

Summary of Gas DSM Potential Studies

B.1 Overview

Tables B-1 and B-2 (see end of this Appendix) summarize results from recent DSM potential studies of various gas local distribution companies (LDCs). The studies include the residential and/or commercial sectors. In most cases, the studies were conducted by consultants working for LDCs, while in one case, the project was jointly sponsored by a state research agency (New York State Energy Research and Development Authority) and a utility industry group (New York Gas Group). In this appendix, we discuss the procedures used by LBL in compiling information shown in the various columns of Tables B-1 and B-2, and provide an annotated description for individual studies. Key findings and overall trends are discussed in more detail in section 7.2.

B.2 Field Definitions

Definitions used and explanatory information to interpret data presented in Tables B-1 and B-2 are as follows:

Type of Potential - The definition and distinctions between technical, economic, and program achievable DSM potential are defined in Chapter 7. In most cases, studies estimated either technical or economic potential, although there are a few examples where more than one type of DSM potential was estimated. Based upon the review of each study, LBL calculated percentage savings for a particular sector (residential or commercial) or end use (e.g., space heating, water heating) where possible. In cases where it was not possible to estimate percentage savings by end use, those that were nonetheless included in the utility's overall sectoral results are indicated by an "X".

Decision rules used in calculating percentage savings varied by type of DSM potential study and data availability:

(1) For technical potential studies, percent savings are typically calculated based on overnight savings potential divided by current (base) year gas sales.

(2) Percentage savings were calculated in various ways for the economic potential studies because of data availability problems in defining the baseyear. In one case (Southwest Gas), percentage savings were calculated

based on projected savings and forecast sales values ten years into the planning period because these data were available. In several studies (the American Council for an Energy Efficient Economy (ACEEE) study of three New York utilities and studies conducted by Energy Investment for three Massachusetts utilities), percentage savings were calculated based on overnight replacement of all measures divided by recent (base) year sales.

It is important to note that suppressing the time dynamics in the calculation of percentage savings will tend to overstate savings potential somewhat because savings that are realized in the future (e.g., 10 years) are estimated relative to current year sales, rather than future year sales. For example, if gas sales are growing at 2%/year, future year sales will increase by 22% in year ten, absent a DSM program. If the DSM savings potential were estimated at 15% of current year sales, the savings would represent about 12.3% of sales in year ten.

Fuel Switching - Several studies included estimates of the potential for fuel switching from electric equipment and appliances to high-efficiency gas equipment. A negative sign indicates an increase in gas use as a result of fuel substitution. Percentage savings are typically calculated based on their impact relative to current (base) year gas sales within the corresponding sector.

In addition to the efficiency of the existing building and equipment stock and the size of heating and cooling loads (which are strongly influenced by climate severity), the following factors related to the scope, methodology, and key input assumptions used in the studies that may affect the magnitude of gas efficiency or fuel-switching potential are given in the tables.

Number of Measures Reviewed - The total number of individual measures considered in the potential study is reported as an indicator of the studies' comprehensiveness.

End Uses Considered - The end uses under which efficiency measures were covered. Differences among utilities reflect variations in gas end uses that are significant for various LDCs, whether the focus of the study was on fuel substitution opportunities (e.g., space cooling), and possibly degree of comprehensiveness.

Avoided Gas Costs - The magnitude of the DSM economic and achievable potential is influenced to some extent by the current or projected level of avoided gas costs. Information on the utility's estimated avoided costs are differentiated by season: "year-round," "winter," and "summer." The "Basis of Costs" line indicates the time horizon of the avoided cost forecast and whether the costs are levelized or not. Where range of avoided costs are reported, these represent the initial year and last year of the forecast period. "Gas Escalation Rate" indicates the annual rate at which the winter gas commodity portion of avoided costs is increasing.

The ACEEE study of three New York utilities and the WP Natural Gas study reported levelized avoided costs. The other utilities included yearly values of avoided costs over the study time horizon in real or nominal terms:

- Orange and Rockland calculated real summer and winter avoided costs for twenty years.

- Southwest Gas reported a range of nominal avoided costs for different end uses over 20 years. Space heating values were used for "Winter," and clothes drying values were used for "Year-round."

- Boston Gas reported real total avoided costs and measure life for each type of measure. Average annual avoided cost for each measure was calculated by dividing the total avoided cost by measure life. Space heating measures were assigned to "Winter" and water heating measures to "Year-round."

- Commonwealth Gas and Bay State Gas reported a range of average annual avoided costs based upon measure lifetime. Commonwealth's avoided costs are in real dollars, while Bay State's avoided costs are in nominal dollars. Both companies reported space heating values, which were used for "Winter," and annual base load values, which were used for "Year-round."

- Southern California (SoCal) Gas reported a 20-year range of nominal avoided costs that include environmental externalities.

- Atlanta Gas Light reported avoided costs in nominal dollars for a ten-year period.

Gas Escalation Rate - The assumed average annual rate at which gas commodity prices are assumed to escalate over the analysis period, which is embedded in the avoided cost calculation.

Discount Rate - The rate used to present value future benefits and costs attributable to DSM programs.

Nets Measure Interactions - A "Yes" in this row indicates that the study accounted for the interactive effects in determining savings per building when more than one measure is used in a building.

Externality Costs - A "Yes" in this row indicates that the study included the costs of environmental externalities in one or more of its screening tests.

Sensitivity Analysis - Indicates whether the study analyzed changes in potential savings from varying critical inputs. For example, many studies evaluated potential savings levels given a range of avoided costs, expected measure savings, and program costs.

B.3 Results

B.3.1 Residential Sector

Technical Potential

The Orange & Rockland Utilities (ORU), Southwest Gas (SWG), and WP Natural Gas studies estimated the DSM technical potential in the residential sector at 24%, 32%, and 36% respectively. While the aggregate estimate of technical potential are comparable for ORU and SWG in the residential sector, the end use sector potential varies significantly, primarily because of climatic differences. ORU, which is located in New York state, reported that 79% of the estimated savings potential were from space heating measures, while Southwest Gas, which is located in Nevada, reported that 69% of the savings potential were from water heating measures.

Orange & Rockland and WP Natural Gas estimates assume overnight adoption of available measures. The study conducted for WP Natural Gas, whose service territory spans across the states of Washington and Oregon, drew heavily on a 1990 Washington State Energy Office report that estimated savings associated with weatherization measures. WP Natural Gas also estimated savings associated with furnace upgrades. Eligible households in which measures could be installed were estimated based on a study performed for the state of Oregon. Technical potential was calculated by multiplying the number of measures (equal to the number of homes) by the savings-per-measure.

Southwest Gas reported savings for each year between 1991 and 2010. Percentage savings are calculated based on 1997 savings divided by 1991 residential sales. The year 1997 was selected because it is after the program ramp up period. Southern California Gas and Atlanta Gas Light calculated technical potential for a range of measures, but did not present results in aggregate.

Economic Potential

Estimates of the DSM economic potential varied substantially among studies. The American Council for an Energy Efficient Economic study of three New York utilities represents the upper end with savings ranging between 29-42% of current sales, assuming levelized avoided gas costs of \$2.50/Dth, and 44-48% of current sales assuming avoided costs are in the \$4.00/Dth range.[1] About half of the savings are only cost-effective at the time of equipment replacement. The ACEEE study used a TRC test to set the cost-effectiveness threshold and incremental measure costs were increased by 50% to account for estimated program administrative costs.

Orange and Rockland's estimate of DSM economic potential at 15% is substantially lower than the ACEEE study. At first glance, this large discrepancy is surprising given that all of the utilities are located in New York. Several factors partially account for these differences: (1) the ACEEE study included more individual measures and additional end uses than the ORU study, (2) ORU reduced its economic potential to account for savings attributable to codes and standards, and (3) ORU assumed measures would be implemented gradually, while ACEEE assumed immediate implementation of measures.

SoCal Gas estimate of DSM economic potential is substantially lower, ranging between 5-9% of current sales (depending on the base year upon which savings are based).[2] Of the total economic potential, water heating and space heating accounted for 60% and 30%, respectively. One reason for the relatively low economic potential is Southern California's warm climate, which reduces space heat savings.

Percentage savings values were calculated for each utility as follows:

- The ACEEE study of Long Island Lighting, Brooklyn Union Gas, and National Fuel Gas - The economic potential value is based on overnight replacement of all measures and 1991 sector sales.

- Southwest Gas - Savings potential is based on savings and sales in year 2000. Southwest Gas study does not explicitly account for measure interactions.

[1] It should be noted that the ACEEE study is a draft report and that the utilities don't necessarily endorse the ACEEE findings.

[2] Economic potential for SoCal Gas ranges from 5% in 1994 to 9% in 2010. Their report did not include sufficient information to calculate percentage savings in terms of savings divided by forecasted sales in year ten.

- Orange and Rockland reported future savings, but future sales were not provided. Accordingly, their economic potential is based on 2003 savings and 1993 sales.

- Boston Gas, Commonwealth Gas, and Bay State Gas contracted separately with Energy Investment Inc. to develop estimates of DSM economic potential. For all three companies, economic potential is based on overnight savings. The lower values reported for Boston Gas and Commonwealth Gas represent sensitivity analysis which discounts the engineering estimate of savings-per-measure by 20%, while the higher value assumes 100% of projected savings. For Bay State Gas, LBL reports the average of savings associated with low income, single family, and 2-plus family houses, all of which were close to 32%.

- Atlanta Gas Light calculated economic potential for a range of measures, but did not present an aggregate estimate of savings for the service territory.

Program Achievable Potential

Orange and Rockland reported DSM program achievable potential of 5%, based on 75% market penetration evenly distributed over 20 years. The program achievable potential is based on 2003 savings divided by 1993 sales.

B.3.2 Commercial Sector

Technical Potential

The two utilities that developed estimates of the DSM technical potential in the commercial sector reported lower values (9-16%) than their estimates for the residential sector (32-36%).

Percentage savings values were calculated for each utility as follows:

- Orange & Rockland assumes overnight adoption of available measures.

- Southwest Gas reported savings for each year between 1991 and 2010. Southwest Gas' technical potential is expressed as 1998 savings divided by 1991 commercial sales. The year 1998 was selected because it follows the program ramp up period.

- Southern California Gas and Atlanta Gas Light calculated technical potential for a range of measures, but did not present an aggregate estimate of savings in their service territories.

Economic Potential

The DSM economic potential ranged between 8-24% of total commercial sector sales among the nine utility case studies. Savings potential was more comparable across utilities than those in the residential sector and typically focused on only three end uses (space heating, water heating, and cooking).

Percentage savings values were calculated for each utility as follows:

- The ACEEE study of Long Island Lighting, Brooklyn Union Gas, and National Fuel Gas based economic potential value on overnight replacement of all measures and 1991 sector sales. The range of savings reported is based on two avoided cost values. The low value assumes an avoided cost of $2.50/DTh, while the high value assumes an avoided cost of $4.00/DTh. As for the residential sector analysis, the ACEEE study used a TRC test to set the cost-effectiveness threshold and incremental measure costs were increased by 50% to account for estimated program administrative costs.

- Southwest Gas' economic potential, which does not account for measure interactions, is based on savings and sales in 2000.

- Orange and Rockland reported future savings, but future sales were not provided. Accordingly, their economic potential is based on 2003 savings and 1993 sales. They added an 18% premium to measure costs to reflect average program costs.

- For Boston Gas, Commonwealth Gas, and Bay State Gas, economic potential is based on overnight savings. The lower values reported for Boston Gas and Commonwealth Gas represent sensitivity analysis which discounts the engineering estimate of savings per measure by 20%, while the higher value assumes 100% of projected savings.

- Southern California Gas' economic potential ranges from 8% of current sales in year 1994 to 14% of current sales in year 2010. Their report did not include sufficient information to calculate the intermediate ten-year value.

- Atlanta Gas Light calculated economic potential for a range of measures, but did not present consolidated savings estimates.

Program Achievable Potential

Orange and Rockland reported DSM program achievable potential of 5%, based on 75% market penetration evenly distributed over 20 years. The program achievable potential is based on 2003 savings divided by 1993 sales.

B.3.3 Fuel Switching: Residential and Commercial Sectors

Six of the eleven DSM potential studies included estimates of the potential for fuel switching in the residential sector, while five studies included estimates in the commercial sector. Only the potential for switching from electricity to gas were estimated in these studies. As in the assessments of savings from efficiency measures, different types of fuel switching potential (e.g., technical, economic, achievable) were estimated in the respective studies. LBL calculation of percentage impact relative to gas sales varied among utilities depending on the availability of data:

- ACEEE study of Long Island Lighting, Brooklyn Union Gas, and National Fuel Gas assume an overnight change from electricity to gas and are based on 1991 gas sales levels.

- The Southwest Gas value is based on fuel switching potential in 2005, which is after their program ramp-up period. In the residential sector, it should be noted that space cooling, which does not pass the TRC test, represents 96% of Southwest Gas' fuel switching potential. Thus, this estimate of fuel switching primarily represents a technical potential.

- Atlanta Gas Light - Value represents existing program fuel switching potential.

- Orange and Rockland examined fuel switching in their study, but did not report any consolidated numbers.

Table B-1. Residential DSM Potential for Selected Gas Utilities

Residential	LILCO (1) & (2)	Brooklyn Union Gas (1) & (2)	National Fuel Gas (1) & (2)	Orange & Rockland (3)	Southwest Gas (4) & (5)	WP Natural Gas	Boston Gas (6)	Commonwealth Gas (6)	Bay State Gas (7)	SoCal Gas (8)	Atlanta Gas Light (9)
Type of Potential											
Technical				36%	32%	24%				X	X
Economic	24-41%	34-47%	27-44%	15%	25%		11-20%	24-32%	32%	5-9%	X
Program Achievable				5%							
Fuel Switching	-3%	-2%	-5%	X	-7%						-2%
Measures Reviewed (#)	52	52	52	22	25	N/A	23	~20	28	28	26
End Uses Considered: (10)											
Space Heating	X	X	X	X	X	X	25%	X	X	X	X
Space Cooling											
Water Heating	X	X	X	X	X	X	14%	X	X	X	X
Cooking	X	X	X								X
Clothes Drying	X	X	X		X						X
Avoided Gas Costs (11)											
Year-round ($/Dth)					3.32-14.61	4.10	3.02	2.90-3.61	3.80-12.96	4.53-9.68	1.60-4.32
Winter ($/Dth)				3.05-6.22	5.21-18.87	4.98	3.56-4.93	3.23-4.85	4.37-15.40	3.63-7.98	1.39-20.88
Summer($/Dth)				1.61-3.47							1.39-3.60
Basis of Costs				22yr range	20yr range	30yr level	20yr range	20yr range	25yr range	18yr range	10yr range
Gas Escalation Rate				4%	10%			8%	4%	4%	4%
Key Assumptions											
Discount Rate	5.0%*	5.0%*	5.0%*		10%	9%		11%	10%	9%	9-12%
Nets Measure Interactions	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	
Externality Costs	No	No	No	No	No	Yes	No	No/Yes	Yes	Yes	Yes
Sensitivity Analysis	Yes	Yes	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes

(1) Economic potential and fuel switching based on overnight savings divided by 1991 sector sales.
(2) Range of economic savings based on avoided costs of $2.50/DTH AND $4.00/DTH and incremental measure cost + 50% scenario.
(3) Technical potential based on overnight savings and 1993 sales; economic potential based on 2003 savings and 1993 sales; achievable potential based on 2013 savings
(4) Technical potential based on 1997 savings and 1991 sales; economic potential based on 2000 savings and sales.
(5) Fuel switching based on 2005 technical potential and sales. The number reported reflects potential that passes the TRC test.
(6) Economic potential based on overnight savings; low value assumes 20% discounted savings; high value assumes 100% of savings.
(7) Economic potential based on overnight savings.
(8) Economic potential based on 1994 and 2010 savings.
(9) The range of discount rates includes societal, corporate, and participant discount rates.
(10) Percentages represent estimated savings for that end use.
(11) Southwest Gas, Bay State Gas, SoCal Gas, and Atlanta Gas Light used nominal $'s; all others used real $'s.

* Real Value

Sources: Nadel 1993, Orange & Rockland 1993, Southwest Gas 1991, WA Water Power 1993; WP Natural Gas 1993; Boston Gas 1990; Commonwealth Gas 1991; Bay State Gas 1991; SoCal Gas 1992; Atlanta Gas Light 1992.

Table B-2. Commercial DSM Potential for Selected Gas Utilities

Commercial	LILCO (1) & (2)	Brooklyn Union Gas (1) & (2)	National Fuel Gas (1) & (2)	Orange & Rockland (3)	Southwest Gas (4) & (5)	Boston Gas Com (6)	Boston Gas Ind (6)	Commonwealth Gas Com (6)	Commonwealth Gas Ind (6)	Bay State Gas (7)	SoCal Gas (8)	Atlanta Gas Light (9)
Type of Potential												
Technical				16%	9%						X	X
Economic	18-19%	15-16%	17-20%	10%	8%	13-17%	9-14%	8-23%	11-23%	23%	8-14%	X
Program Achievable				5%								
Fuel Switching	-28%	-49%	-9%	X	-6%							-2%
Measures Reviewed (#)	40	40	40	16	38	20	21	~20		30	35	13
End Uses Considered: (10)												
Space Heating	X	X	X	X	X	28%	22%	X	X	X	X	X
Space Cooling	X	X	X		X							X
Water Heating	X	X	X	X	X	5%		X	X	X	X	
Cooking	X	X	X					X			X	
Clothes Drying												
Process Heat							6%					X
Other					X							X
Avoided Gas Costs (11)												
Year-round ($/Dth)					3.32-14.61	3.02		2.90-3.61		3.80-12.96	4.53-9.68	1.50-4.32
Winter ($/Dth)				3.05-6.22	5.21-18.87	3.56-4.93		3.23-4.85		4.37-15.40	3.63-7.98	1.39-20.88
Summer($/Dth)				1.61-3.47								
Basis of Costs				22yr range	20yr range	20 yr range		20yr range		25yr range	18yr range	1.39-3.60 10yr range
Gas Escalation Rate				3.66%	9.54%			6%		4%	4%	4%
Key Assumptions												
Discount Rate	5.0%*	5.0%*	5.0%*		9.84% 0.0984			11%		10%	9%	9%
Nets Measure Interactions	Yes	Yes	Yes	Yes	No	Yes		Yes		Yes	Yes	Yes
Externality Costs	No	No	No	No	No	No		No/Yes		Yes	Yes	Yes
Sensitivity Analysis	Yes	Yes	Yes	No	Yes	Yes		Yes		Yes	Yes	Yes

(1) Economic potential and fuel switching based on overnight savings divided by 1991 sector sales.
(2) Range of economic savings based on avoided costs of $2.50/DTH AND $4.00/DTH and incremental measure cost + 50% scenario.
(3) Technical potential based on overnight savings and 1993 sales; economic potential based on 2003 savings and 1993 sales; achievable potential based on 2013 savings
(4) Technical potential based on 1998 savings and 1991 sales; economic potential based on 2000 savings and sales
(5) Fuel switching based on 2005 technical potential and sales.
(6) Economic potential based on overnight savings; low value assumes 20% discounted savings; high value assumes 100% of savings.
(7) Economic potential based on overnight savings.
(8) Economic potential based on 1994 and 2010 savings.
(9) The range of discount rates includes societal, corporate, and participant discount rates.
(10) Percentages represent estimated savings for that end use.
(11) Southwest Gas, Bay State Gas, SoCal Gas, and Atlanta Gas Light used nominal $'s; all others used real $'s.

* Real Value

Sources: Nadel 1993, Orange & Rockland 1993, Southwest Gas 1991, WA Water Power 1993; WP Natural Gas 1993; Boston Gas 1990; Commonwealth Gas 1991; Bay State Gas 1991; SoCal Gas 1992; Atlanta Gas Light 1992.

Calculating the Breakeven Avoided Cost of Gas for DSM Measures

Lifecycle costs of electric versus gas technologies cannot be calculated without a well-defined avoided cost for gas. However, since the other costs required by such a lifecycle analysis can be specified, for example, the capital and operating cost of both technologies, the real discount rate, and the avoided cost of electricity, a breakeven gas avoided cost can be calculated by determining the price of gas at which the lifecycle costs of competing electric and gas options are identical. At this price, one would be indifferent (on economic grounds) to the choice of technology. Thus, if the actual avoided cost of gas is lower than the breakeven price, then the gas technology would be more cost-effective than the electric technology and vice versa. Whether the base technology is a gas or electric technology switching to the other, the breakeven avoided cost is interpreted in the same way: as the gas avoided cost level below which the gas technology is preferred, and above which the electric technology is preferred.

To better understand this concept, a simplified algebraic derivation of the gas breakeven avoided cost is provided (adapted from Nadel et al. 1993b). The breakeven gas price is always calculated in reference to the lifecycle cost of an electric technology compared to a gas technology. For the total lifecycle costs (LCC) of the competing base and alternative technologies (gas or electric) to be equal:

$$LCC_{bse} = LCC_{alt} \tag{C-1}$$

The total lifecycle cost of each option is the sum of the capital and installation costs of each option (CI), its nonfuel operating and maintenance cost (OM), its electricity cost (EL), and its gas cost (GS). That is:

$$LCC = CI + OM + EL + GS \tag{C-2}$$

Since a societal perspective on the economics of fuel switching is desired, the costs of electricity and gas are evaluated using long-run avoided costs for both energy sources and future operating costs are present-valued using an appropriate real discount rate.

Of course, the gas cost is unknown, since it is the product of the quantity of gas consumed (GQ) times the long-run avoided cost for gas (GAC) which is unknown.

$$GS = GQ \times GAC \tag{C-3}$$

The breakeven gas price is based on the concept that, if the two lifecycle costs are equal, simple algebraic manipulation of the terms will allow one to solve for the unknown GAC. That is, substituting Equation (C-3) into Equation (C-2), and Equation (C-2) into Equation (C-1) yields,

$$\begin{gathered} CI_{bse} + OM_{bse} + EL_{bse} + GQ_{bse} \times GAC = \\ CI_{alt} + OM_{alt} + EL_{alt} + GQ_{alt} \times GAC \end{gathered} \tag{C-4}$$

Then, solving for GAC:

$$GAC = \frac{(CI_{alt} + OM_{alt} + EL_{alt}) - (CI_{bse} + OM_{bse} + EL_{bse})}{GQ_{bse} - GQ_{alt}} \tag{C-5}$$

Equation (C-4) says, given that two options have different nongas lifecycle costs, the price of gas that will make the total lifecycle costs of the two options equivalent is just this difference in nongas lifecycle costs divided by the difference in gas consumption.

A high breakeven gas price means that the gas technology will be generally cost-effective compared to the electric competitor. Conversely, if the gas breakeven cost is lower than the likely range of gas avoided costs, the electric technology would remain more cost-effective than the gas technology. Put another way, under this latter scenario gas must be very cheap for the gas technology to compete successfully against the electric technology. If the gas breakeven cost, for example, is negative, then the gas alternative will never be cost-effective at any gas price.

Gas DSM Technologies

D.1 Overview

This appendix reviews gas measures and technologies for energy efficiency and fuel substitution between electricity and gas. It is not intended to be comprehensive, but rather to highlight potentially attractive gas savings opportunities for further investigation. The focus is primarily on gas-fired equipment measures for the following reasons. First, equipment measures are generally specific to natural gas and thus uniquely relevant to LDCs, whereas other types of measures that reduce loads for space-heating or cooling, or water-heating, are independent of the type of fuel consumed for meeting those loads. Second, many PUC and utility staff are more familiar with building shell retrofits because these measures have often been implemented through first-generation gas utility audit programs, electric utility DSM programs, or government programs such as Residential Conservation Service or state building energy codes.

The measures include those that are commercially available, or likely to be marketed in the near future. Because of the myriad technologies, applications, operating environments, and other site specific variables, the performance of equipment is described where possible with generally agreed upon measures of efficiency. Seasonal efficiency indices determined in industry standard test procedures are relied upon where available, although where such indices are not in use, other figures of merit are used (e.g., savings as compared to some base technology) as a way of comparing the relative performance of different DSM measures.[1]

This appendix approaches the subject of gas efficiency measures and strategies at the level of technology screening akin to the level at which a technical potential assessment would be approached. Obviously, the economics of gas DSM are critical and many of the measures presented here would not pass cost-effectiveness tests in particular circumstances. One should not interpret the focus on technical efficiency as a denial of the overriding importance of cost-effectiveness in judging the desirability of these technologies. However, a comprehensive economic analysis of each technology on a national scale is beyond the scope of this primer.

The first section reviews gas efficiency measures, followed by electric-to-gas fuel substitution measures, and finishes with gas-to-electric fuel substitution measures.

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[1] For some types of equipment, no such measures exist. In those cases, savings estimates are based on literature reviews, though caution is urged in extrapolating these estimates to other circumstances.

D.2 Gas Equipment Efficiency Measures

D.2.1 Residential Space Heating

A number of space heating technologies exist or are near commercialization for improving gas efficiency in residences (see Table D-1). The estimated seasonal efficiency of existing gas warm air furnaces and hot water (hydronic) or steam boilers in the current U.S. housing stock ranges between 60-68% (Dutt 1990; Holtberg et al. 1993).[2] This conventional unit is likely to be of the type that has a continuously burning pilot and in which exhaust gases from combustion are vented using the natural buoyancy effect (also known as "atmospheric" venting). A buoyancy driven exhaust process requires high stack temperatures (in the neighborhood of 300- 500°F) in which a significant portion of the heat of combustion is lost to the outdoors.

This basic design has been improved upon in a number of ways. Gas can be saved by replacing the pilot with an intermittent ignition device (IID) and by installing a damper in the vent to reduce heat losses when the burner is not operating, which improves the seasonal efficiency of a unit equipped with these devices to about 75%. By adding a fan or power burner to induce or force vent gases up the stack, more heat can be extracted from the exhaust stream and seasonal efficiency can be further increased to around 80%. The most dramatic efficiency improvements in gas heating equipment come from modifications to the combustion process and/or extraction of heat from that process.

Condensing furnaces and boilers condense some of the moisture from the flue gases in order to extract part of the latent heat of water vapor that would otherwise be lost with the other exhausted combustion products. Systems designed in this way can achieve seasonal efficiencies in excess of 90%. The dew point of natural gas combustion products is 140°F and so combustion gases must be cooled to this level or below for condensation to occur. It is difficult for boilers to maintain temperatures this low since the return water temperatures are often well above 140°F and for this reason, boilers are usually of the near condensing type. Near-condensing systems exhibit seasonal efficiencies around 82%.

Pulse combustion technology alters the steady flow of gas and air into the burner and continuous operation of conventional burners to operating on a series of periodic (60 to

[2] Seasonal efficiency is determined by means of a DOE test procedure applied to residential central furnaces. Called the Annual Fuel Utilization Efficiency, or AFUE, it differs from the maximum capacity steady state or thermal efficiency in that it accounts for warm-up, cool-down and off-cycle losses. Off-cycle losses include any standing pilot losses as well as room air losses through the venting system due to air flow through the combustion chamber and draft diverter.

Table D-1. Residential Space and Water Heating Efficiencies

Technology	Efficiency (%)
Residential Space Heating	(AFUE)
Typical Existing Furnaces/Boilers	60-68[1]
IID and vent damper	75[2]
Condensing furnaces	85-96[3]
Modulating furnaces	92[4]
Condensing hydronic boilers	84-91[3]
Near-condensing steam boilers	82[4]
Gas engine heat pumps (heating only)	120-150[5]
Residential Water Heating	(EF)
Typical Existing Storage Heaters	54[1]
IID and vent damper	54-61[6]
2" jacket insulation	57[6]
Flue baffling and power venting	66[6]
Submerged combustion chamber and power venting	72[6]
Eliminate center flue and indirect heating	74[6]
Pulse combustion, condensing	80[6]
Condensing unit	86[6]
Instantaneous Heaters	70[4]
Typical MF combo SH/DHW boilers	40-45[4]
Dedicated DHW boiler in MF	65[4]

Sources:
[1] Holtberg et al. 1993
[2] Dutt 1990
[3] GAMA 1993
[4] Nadel 1993b
[5] Klausing et al. 1992
[6] Paul et al. 1991

70 times per second) ignitions that are self-perpetuating. Very high heat transfer coefficients are achieved, leading to correspondingly high thermal and seasonal efficiencies. Pulse combustion systems can also be condensing, and achieve the seasonal efficiencies shown in Table D-1.

Another alternative burner design is the modulating type. Burners used in furnaces and boilers are typically designed to fire at full capacity and track heating demand by cycling on and off. Modulating systems operate the burner at less than full capacity thereby producing savings by firing closer to the demand; these systems can achieve seasonal efficiencies of 92%. At present, only two-stage modulating type furnaces are available, which operate at low or high firing rates and achieve seasonal efficiencies around 90%.

An emerging technology for gas space heating (as well as space cooling) is the gas engine heat pump (GEHP). GEHPs operate on the same vapor compression refrigeration cycle that electric heat pumps operate on except that the compressor is powered by a natural gas-fired internal combustion engine instead of an electric motor. GEHPs are technically attractive in the heating mode because their efficiencies have been shown to exceed those of the technologies cited above based on direct-fired combustion heating. Waste heat recovered from the engine jacket and exhaust supplementing the vapor compression cycle in the heating mode and variable-speed operation both boost seasonal efficiency. Heat pump efficiency is subject to a number of factors, the most important of which are the outdoor temperature regime and the indoor temperature setpoints, but GEHPs have realized heating mode seasonal efficiencies in field tests between 120- 150% (Klausing et al. 1992).

GEHPs were commercially introduced in Japan in 1987, where currently about 35,000 units per year are being sold. In the U.S., GEHPs are nearing commercialization with one manufacturer expected to bring some residential units to market in 1994. Due to the lack of field experience, concerns have been raised about likely maintenance burdens and the lack of infrastructure for servicing this new technology.

GEHPs are discussed further in Section D.3.1 as a fuel switching technology because when operating in cooling mode, GEHPs would be displacing electric technologies in a market that electricity currently dominates.

The National Appliance Energy Conservation Act of 1987 (NAECA) requires a minimum seasonal efficiency (as measured by the Annual Fuel Utilization Efficiency, i.e., AFUE) of 78% for gas furnaces and 80% for gas boilers manufactured after 1992.[3] Therefore, only the more advanced gas savings measures pertain to the space heating equipment replacement market because the standard will result in naturally-occurring efficiency improvements up to these efficiency levels as existing equipment are replaced.

A number of operational issues arise with the advent of newer, more efficient designs in furnaces and boilers. Proper venting of exhaust gases is particularly important, with specific recommendations depending on vent pressures and whether or not condensation is expected. Condensing and near-condensing type units have experienced past problems

[3] Because the rating for furnaces is determined by a slightly different test than for boilers, the standard specifies a roughly similar efficiency level for the two equipment types.

of corrosion of flue pipes and heat exchangers from acidic condensate. These problems have been mitigated by the use of corrosion resistant materials such as high temperature plastics, stainless steel, or ceramics, but are more expensive than conventional materials used for these system components.[4] With these types of systems, condensate drains also have to be installed and this increases total installed system cost (though condensing furnaces are often paired with air conditioners and use the same condensate drain, thus saving costs overall).

In some cases, either local codes specify or manufacturer's recommend that outdoor air be provided for combustion with heating equipment located indoors. Because off-cycle losses have been significantly reduced in high-efficiency equipment, oversizing apparently has a lower energy penalty associated with it than with conventional units.[5] Past design practice of many existing furnaces and boilers led to oversizing relative to the loads they served. With oversized units, the excessive cycling occurs with attendant increased standby losses, leading to degraded energy performance. This condition is exacerbated by the later introduction of building shell measures to reduce heating loads. An additional benefit of replacing an existing furnace or boiler with a new, energy efficient unit is the opportunity to more closely match the capacity to the load, thereby reaping additional efficiency improvements.

Finally, while not specific to high-efficiency equipment, duct and piping heat losses will decrease overall efficiency of the heating *system* and reduce the potential benefits from implementation of equipment efficiency measures and can lead to moisture and indoor air quality problems as well.

[4] A related problem sometimes occurs when an old gas furnace sharing a flue with another combustion device (typically a water heater) is replaced with a new, efficient furnace that vents exhaust gases elsewhere, leaving the "orphan" appliance with inadequate stack conditions to properly vent its gases. This can cause corrosion in the existing flue and necessitate additional expense to correct the problem—a hidden cost of the new technology.

[5] An exception to this is with condensing boiler units where oversizing may increase return water temperatures and thereby reduce condensation and the efficiency gains associated with it.

D.2.2 Residential Water Heating

Hot water loads are a function of the volumetric demand for hot water, the inlet water temperature (which varies by location and time of year), and the temperature setting (typically in the range of 110-140°F). Storage type water heaters with 30-60 gallon tank and a standing pilot light dominate the U.S. market for residential gas water heating. Slightly over 50% of the residential-scale water heaters (i.e., with heating capacity less than 75,000 Btu/hr) sold each year in the last decade have been gas-fired (Gas Appliance Manufacturers Association (GAMA) 1992). The NAECA standards require all new gas water heaters to have an efficiency of approximately 54% (as measured by the Energy Factor) which varies somewhat depending on the unit size.[6] Technologies for improving water heater efficiency include: increasing jacket insulation, IID and flue damper, increased flue baffling and power venting, multiple flues, submerged combustion chamber, pulse combustion, and condensation of flue gases (Paul et al. 1991). The efficiencies of each of these design options are shown in Table D-1.

Instantaneous or "tankless" gas water heaters can save gas by eliminating the standby losses from the hot water tank during idle periods. The savings have been estimated for versions with IIDs to be in the range of 30-50% of total water heater gas use depending on hot water draw quantities (Nadel et al. 1993a), and Energy Factors are estimated to be around 70% (Nadel et al. 1993b). Widely used in Europe and Japan, instantaneous gas water heaters have little market share in the U.S due to the challenge of locating exhaust vents near the unit and the perception that they possess inadequate heating capability. Also, the current versions on the U.S. market use pilot lights and therefore offer significantly less savings than those quoted above.

In multifamily buildings where a central boiler provides both space and water heat, substantial energy savings can be produced by installing a dedicated high-efficiency boiler for water heating alone. Savings for this measure depend highly on the particular circumstances, but have been estimated to improve efficiency from 40% or 45-65% (Nadel et al. 1993b).

Measures to reduce hot water loads include low-flow faucets and shower heads, horizontal-axis clothes washers, and low-water-use dishwashers. A horizontal-axis clothes washer saves hot water by allowing the clothes drum to operate with roughly half the water used for a comparably-sized load in a conventional vertical-axis clothes washer. Potential gas water heat savings over a conventional unit are estimated to be 64% (Nadel

[6] The Energy Factor defines an overall efficiency for water heaters while delivering 64.3 gallons of hot water per day in a standard test procedure. It takes into account both the effectiveness of the burner in transferring energy to the water during firing and standby losses when the burner is not operating.

et al. 1993a). Manufactured as either front or top loading, horizontal-axis clothes washers are widely used in Europe but are reported to have only 5% or less of the U.S. market. DOE is purported to be considering horizontal-axis technology for the 1999 NAECA standard for clothes washers.

Low-water-use dishwashers save energy beyond those meeting the 1994 NAECA standard primarily through savings in hot water use of approximately 25% (Nadel et al. 1993a). Dishwashers of this type are just beginning to enter the U.S. market.

D.2.3 Residential Cooking

Relatively little gas is consumed in residential gas ranges and ovens, particularly since the NAECA standards stipulated new units equipped with an electrical connection use nonpiloted burner ignition. Most new residential gas ranges use IIDs as their ignition device, though ovens commonly use a hot surface ignition device ("glo-bar") that draws close to 400W of electricity while the burner is on. While replacing the glo-bar with an IID in the oven unit would save energy, it is technically not a gas saving device. Other design options for reducing cooking gas use in conventional ranges and oven include thermostatically controlled burners, insulation and reflective surfaces for the range and/or oven, reduced vent size, reduction of thermal mass, forced convection during cleaning, and use of an oven separator. Infrared burners for ranges have also been touted as a gas saving technology, but the claim has not been substantiated using standard test procedures. Given the small quantity of gas used for cooking, besides IIDs few of these technologies are viewed as attractive for increasing efficiency in this area (Nadel et al. 1993b).

D.2.4 Residential Clothes Drying

While gas appliances have a relatively low penetration in the residential clothes drying market, there are a number of potentially attractive gas savings measures applicable to them (shown in Table D-2). As with other gas appliances using pilot lights, savings can be achieved through replacement of pilots with IIDs (annual savings of about 30 therms have been estimated for this measure) (Meier et al. 1983).

Automatic shutoff controls that are either temperature or moisture activated can produce savings of about 12% over conventional dryers that operate on a timer cycle and rely on user guesswork to set the cycle duration (Nadel et al. 1993b).

A significant clothes drying load reduction measure is the use of a high spin speed washer that reduces the water content of clothes from a typical 70-40%. Removing

Table D-2. Residential Clothes Drying Savings

Technology		Savings
Residential Clothes Drying		
	Electronic ignition	30 therms/yr[1]
	Automatic shutoff control	12%[2]
	High spin-speed washer	40%[3]

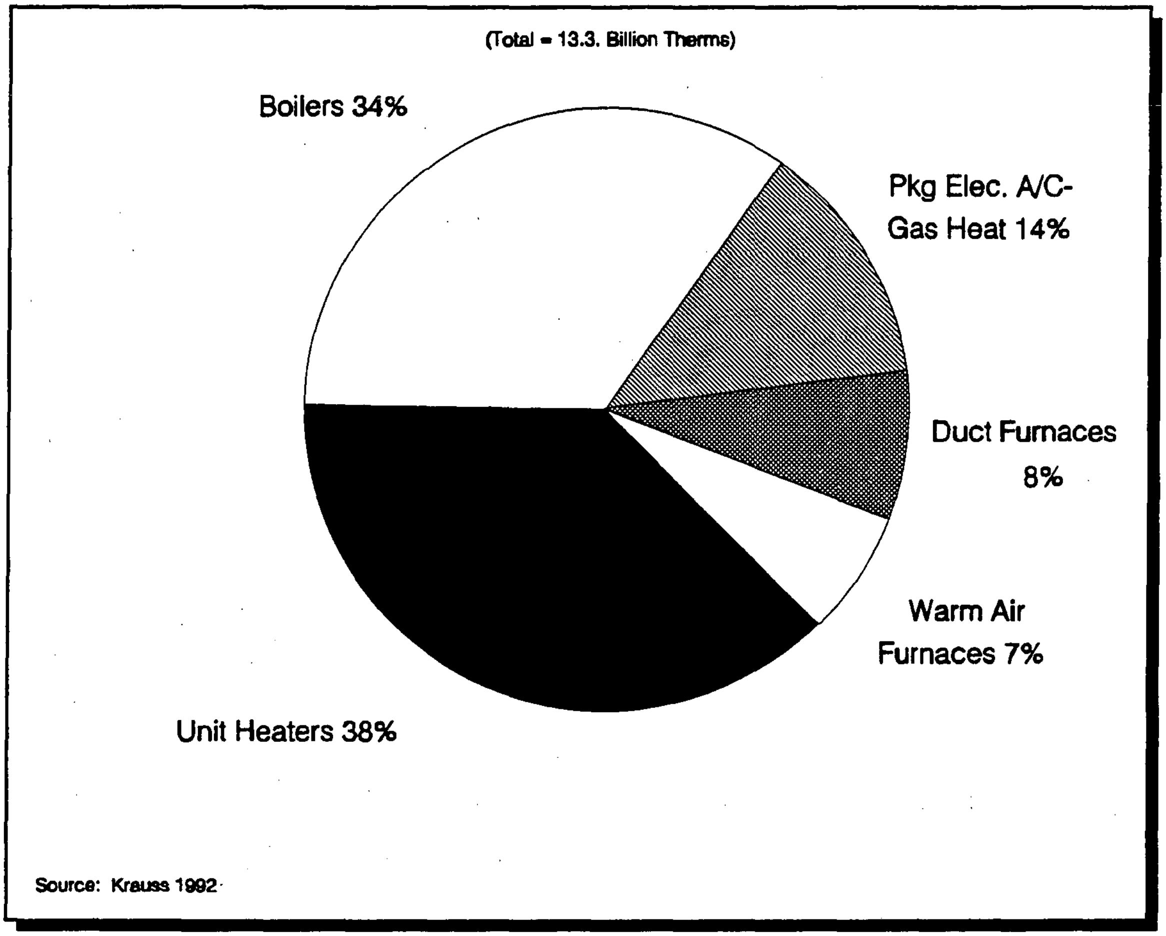
Sources: [1] Meier et al. 1983
[2] DOE 1990
[3] Nadel 1993a

moisture from clothes in this range by spinning is far more energy efficient than thermal drying. Gas clothes drying savings have been demonstrated in the range of 28- 47% from this technology (Nadel et al. 1993a).

D.2.5 Commercial Space Heating

Space heating requirements in the commercial sector are met by a variety of equipment types fueled by natural gas. Figure D-1 shows the market share (by annual gas consumption) for unit heaters, boilers, packaged gas heating/electric cooling units, duct furnaces and warm air furnaces. Unit heaters serve the largest portion of the current market for commercial heating applications, followed by hot water and steam boilers. Together, these two types of equipment make up nearly three-quarters of the commercial space heating market, so our discussion of suitable energy efficiency measures focuses on these two types of equipment. This section on commercial space heating equipment and measures draws extensively upon a detailed study conducted by (Krauss et al. 1992).

Figure D-1. Annual U.S. Commercial Gas Heating Share by Equipment Type



Unit Heaters

Gas-fired unit heaters provide warm air for space heating by means of a furnace typically suspended above the floor or work area. They are most often used in open spaces such as repair facilities, warehouses, or where aesthetics are not a large concern. Unit heaters come in three major types: gravity vented, power vented, and separated combustion. Gravity vented unit heaters are reported to account for 75-80% of shipments annually. Therefore, this type constitutes the conventional technology against which more energy efficient types are compared.

Table D-3. Commercial Space and Water Heating Efficiencies

Technology	Efficiency (%)
Commercial Space Heating	
Conventional Boiler	50-81[1]
Pulse Combustion Boiler	86-95[1]
Condensing Boiler	95[1]
Near-Condensing HW Boiler	84-88[1]
Conventional Unit Heaters	62-64[1]
Power-Draft Unit Heaters	80-83[1]
Condensing Pulse unit Heater	90-95[1]
Commercial Water Heating	
Typical Boiler	80[2]
Pulse Combustion Boiler	85[2]
Typical Stand-Alone Water Heater	54[2]
IID, Power Burner Water Heater	72[2]

Sources: [1] Krauss et al. 1992
[2] Nadel 1993b

As shown in Table D-3, the seasonal efficiency of conventional unit heaters is around 63%.[7] Power vented and separated combustion unit heaters represent an improvement in the seasonal efficiency up to around 80%. Power vented types make up only 15-20% of annual sales of unit heaters, while separated combustion types achieve only about 5% of sales (apparently primarily for reasons other than energy efficiency). A condensing pulse unit heater is commercially available with an AFUE purported to be in the range of 90-95%, but with less than 1% of the national unit heater market due in part to a limited range of sizes currently offered.

[7] Note that for these and other commercial heating equipment there are currently no industry-standard test procedures for determining seasonal efficiency. The numbers quoted in this section are based upon test procedures used for residential-type equipment.

Retrofit options for unit heaters include vent dampers, intermittent ignition devices, and setback thermostats, with savings varying depending on the existing equipment, the usage pattern, and local weather.

Boilers

For purposes of understanding energy use of boilers, they can be classified by distribution medium, heat exchanger material, or burner type. The market trend is towards the use of hot water as the distribution medium for boilers in commercial space heating applications, with estimates as high as 95% in new construction. Hot water boilers tend to have higher seasonal efficiencies than steam boilers because the former have lower return water temperatures and are often better controlled and matched to loads. Steam boilers are apparently sold primarily for retrofit steam heating and process applications. Cast iron heat exchangers form the overwhelming majority of boilers sold in commercial sizes (i.e. above 200,000 Btu/hour output rating), with steel and copper heat exchanger-based boilers serving a relatively minor market segment. Among burner types, roughly half of the boilers sold for commercial heating applications are equipped with atmospheric burners and half with power burners.[8] Boilers with power burners offer efficiency advantages over atmospheric burners through better control of the fuel to air ratio in combustion and reduction in standby heat losses.[9] In Table D-3, the upper range of conventional boiler efficiency comprises hot water boilers with power burners, while the lower range comprises steam boilers with atmospheric burners. Boilers equipped with condensing or near-condensing technology are commercially available in efficiencies upwards of 85% also shown in Table D-3. Currently these are only manufactured as hot water boilers.

Boiler retrofit measures for increasing efficiency include a number of options for improving the control of the equipment. Reset devices provide better control of the water temperature to match the heating load. Outdoor cutout controls shut off the boiler when the outdoor temperature is above some set level, thus saving energy during those periods in the swing seasons (Spring and Fall) when the boiler would otherwise be running in standby mode. Thermostatic zone temperature controls can produce savings by more closely meeting the diversified loads in distributed zones rather than treating the building as a single (or few) zones. Thermostats often also provide nighttime temperature setback capability.

[8] Other burner types are available, one of which we discuss later, but they collectively hold a small share of this market (2-5%).

[9] No standard test procedure exists for boilers in sizes above 300,000 Btu/h so the seasonal efficiencies cited here are approximate and for comparative purposes only.

Boiler energy use can be reduced by employing a modular design approach in which a number of smaller boilers are used instead one large one. Large boilers often have poor part-load efficiencies, so savings accrue from operating smaller boilers closer to their rated capacity where their efficiency is highest. These modular boilers are staged in such a way to bring them online with heating demands. One NBS study showed the savings from a modular system over a single boiler to range from 5-15% depending on the degree of oversizing. As a retrofit option for the modular boiler approach, a "front-end" boiler can be added to meet smaller loads and staged with the larger existing boiler.

General maintenance of the distribution system to reduce hot water or steam heat losses also offers potentially cost-effective savings potential, but is very site specific.

More than a third of all boilers sold are not listed as dedicated gas-fired equipment, but rather are dual fueled using either oil or gas. Many of these are purported to use gas as the primary fuel and oil as the backup.

Other Equipment

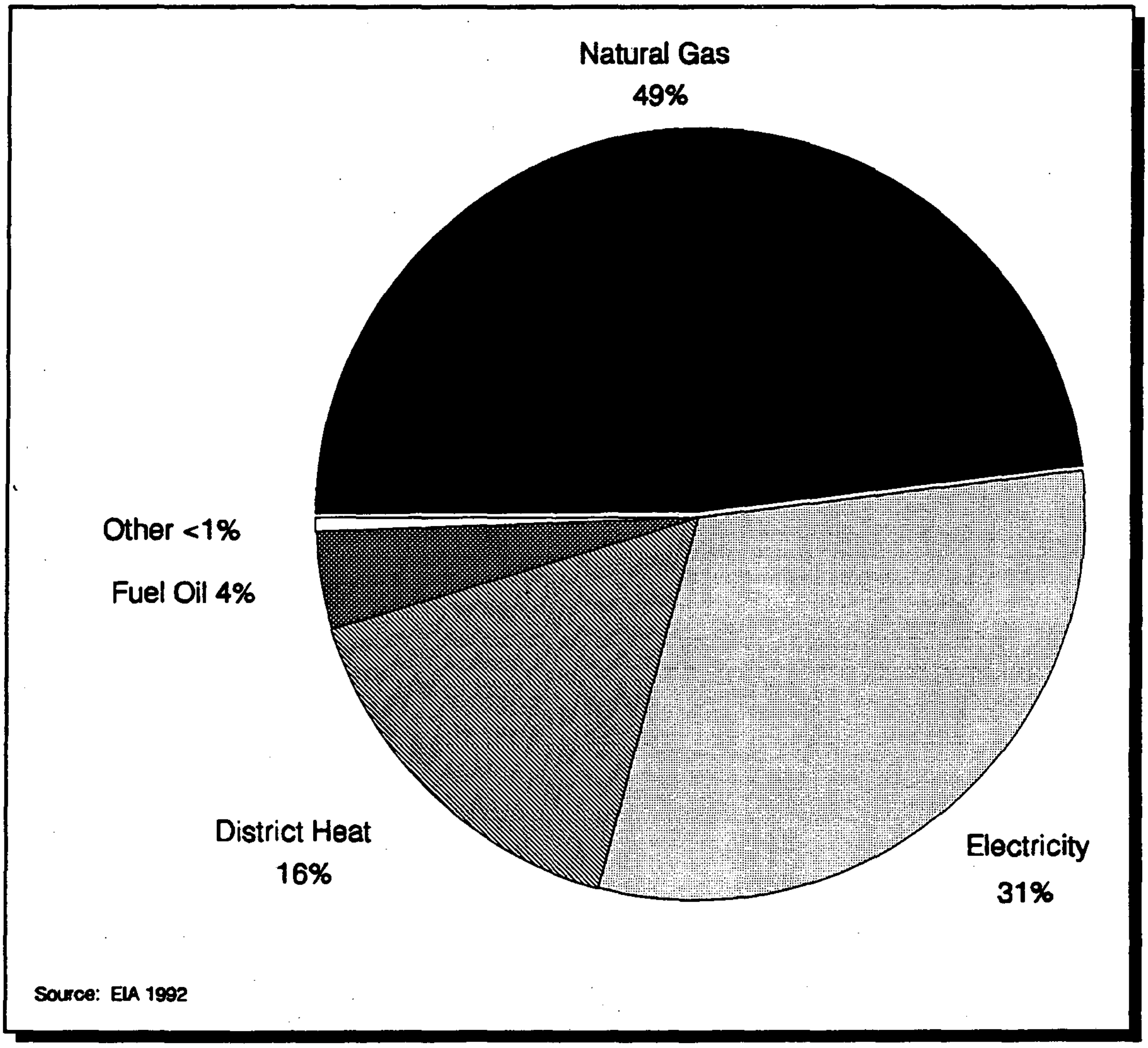
Packaged gas heating/electric cooling equipment currently consumes the third largest portion of gas for space heating (i.e., 14%). These units are typically equipped with IID and power venting and as such, offer fewer gas savings opportunities compared to other types of gas heating equipment. However, units using pulse combustion technology packaged with high-efficiency air conditioning are under development. Also, gas heat pumps, described previously under residential space heating measures, are under development for serving the same small commercial market as combination gas/electric packaged units (also known as unitary equipment) currently serve.

D.2.6 Commercial Water Heating

Water heating is the second largest gas end use in the commercial sector and gas has the largest market share in this sector (see Figure D-2). Shipments over the last decade of commercial-scale, storage-type water heaters using gas have ranged from 82-90% of the total storage-type market (Gas Appliance Manufacturers Association (GAMA) 1992).[10] Still, by comparison to the residential market, the market for commercial storage water heaters is small. In 1991, manufacturers of gas-fired equipment shipped nearly 4 million residential units compared to less than 100,000 commercial units. It is estimated that 80% of water heater sales are replacement units in existing commercial buildings

[10] Little market information is available for other commercial water heating system types.

Figure D-2. Annual Shares of Fuel Consumption for Commercial Water Heating in the U.S.



(Electric Power Research Institute (EPRI) 1992b).

Many small commercial buildings or applications in larger commercial buildings with modest demands for hot water employ equipment similar to that found in residences (i.e., storage-type water heaters), in which case the efficiency measures discussed under residential water heating apply to these applications as well. Instantaneous water heaters (also described under residential water heating) have potential application in the commercial sector as well.

In large commercial hot water systems, a boiler and storage tank configuration is typical, where the boiler heats the water in the storage tank directly or indirectly through a heat exchanger.[11] In such systems, the efficiency measures germane to commercial boilers used for space heating apply to those for water heating too. In some boiler/tank systems, the same boiler is used for both water heating and space heating. This can be inefficient when the weather is mild and the boiler is being used exclusively to heat water. A gas conserving strategy in these instances is to install a stand-alone water heater, with savings estimated at 65% (Nadel et al. 1993b).

D.2.7 Commercial Cooking

Commercial ranges, fryers, griddles, and ovens make up almost 90% of both annual gas consumption and the market for new commercial food cooking equipment, of which about two-thirds is replacement equipment (Lobenstein and Hewett 1991). At present, there is no standardized rating system for comparing the efficiency of commercial cooking equipment, though test procedures are under development through an industry-wide cooperative effort involving representatives of the gas and electric utility industries and the food service industry (among others). For this reason, Table D-4 presents typical savings over "standard" equipment of each type as reported in the literature.

Table D-4. Commercial Cooking Savings

Technology		Savings (%)
Commercial Cooking		
	Direct Convection Oven	30-50[1]
	Infrared Fryers and Griddles	20-40[2]
	Power Burner Range	24[2]

Sources: 1 Nadel 1993b
2 Lobenstein and Hewett 1991

One technology for improving the efficiency of gas use in ovens of all kinds is the direct convection oven which circulates heated air inside the oven by means of a fan while

[11] Boilers made out of cast iron or steel are subject to corrosion if continuously exposed to fresh, oxidized water. Thus, such systems typically use indirect means of heating water in the storage tank.

reclaiming some of the heat from the flue gases. The savings for this measure over a standard oven are estimated at 50% (Nadel et al. 1993b). The market for these ovens is fairly strong already and so there may be limited opportunity for increasing their penetration (Lobenstein and Hewett 1991).

Ranges equipped with power burners instead of atmospheric burners can save an estimated 24% (Lobenstein and Hewett 1991).

Infrared fryers and griddles use a technology that transfers heat directly to the food by means of electromagnetic radiation. This technology has a savings potential estimated in the neighborhood of 30-40% applied to fryers, and 20-40% for griddles (Lobenstein and Hewett 1991). Market penetration of this technology appears to be low. While not currently available due to practical concerns, griddles and fryers utilizing pulse combustion technology offer potentially high savings.

D.3 Electric to Gas Fuel-Switching Measures

This section provides an overview of gas technologies that could be substituted for electric technologies in residential and commercial applications. Of course, many of the high-efficiency gas measures described previously are also candidate measures for fuel-switching from electricity to gas. The discussion will not duplicate presentation of those technologies but focuses instead on technologies whose principle application would be in substituting for electricity.

D.3.1 Residential Space Cooling and Heating

Gas-engine heat pumps (GEHPs) are regarded by the gas industry as an important technology for space cooling (and heating), an end use in which electricity currently dominates. Moreover, over three-quarters of new single-family dwellings in the U.S. are equipped with air conditioning. Heating mode performance of GEHPs was discussed in section 7.4.2. Seasonal cooling mode efficiency of GEHPs has been demonstrated in the range of 90-120% (Klausing et al. 1992). On a *site energy basis*, the cooling performance of GEHPs is below that of electric technologies (as measured by coefficient of performance), although on a *source energy basis* GEHPs compete with electric technologies served by a national average power generation fuel mix (Walrod 1992).[12]

[12] The distinction between site and source energy is that the latter encompasses the energy content of the fuel consumed to produce electricity. Therefore the GEHPs operating in cooling mode are expected to just meet or slightly exceed the equivalent of the 1993 NAECA standard in terms of total source energy consumed of

One study showed that GEHPs had the highest source energy efficiency over a range of climates of any competing air-source technology (or combination of technologies) (L'Ecuyer et al. 1993).

Heat pumps in heating mode operate like an air conditioner in reverse: they extract heat from the outdoors and dump it indoors. At very low temperatures, as the heat pump efficiency decreases and the heat loss of the residence increases, some form of backup heating is required. With electric heat pumps the backup heating is electric resistance. For a winter peaking utility with a large residential heating load, this resistance heating from heat pumps can be highly coincident with, and a significant contributor to the system peak. One fuel-substitution approach is to "replace" the electric heat pump with a gas furnace, using the heat pump exclusively for air conditioning. An alternate technology is to bundle gas-fired heating coils as auxiliary heating with electric heat pumps (also known as the dual-fuel heat pump) instead of using electric resistance as the auxiliary heating.[13]

Another measure for shifting from electricity to natural gas for residential heating is a gas furnace or boiler replacing electric resistance heating. In a retrofit or replacement application of a gas warm-air furnace, the feasibility of such a conversion would depend greatly on whether there was existing ductwork for warm-air distribution, or on the features of the site for installing ductwork. For a gas hydronic boiler replacing electric resistance baseboard heating, baseboard hot water distribution systems are commercially available.

D.3.2 Residential Water Heating, Cooking and Clothes Drying

For these end uses the opportunities for switching from electric appliances to gas appliances are straightforward. Options include gas storage water heaters that meet the future NAECA standard or have higher efficiencies that replace electric resistance storage water heaters and gas ranges or clothes dryers that can replace their electric appliance counterparts.

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minimum complying electric heat pumps served by electricity generated using an average fuel mix of electric utilities nationwide.

[13] While this does provide some market for gas that otherwise would be served by electricity in a conventially configured electric heat pump, the gas sales from the duel-fuel heat pump would come only during colder periods when some gas utilities experience their highest capacity and commodity costs, and could lead to lower load factors. Given typical rate-making practice, revenues paid by these customers would not be likely to cover costs.

There are situations in which special opportunities may exist for electric to gas fuel switching depending on particular equipment configurations for space and water heating. If, for example, there is a gas hydronic boiler serving space heating loads and an electric resistance storage water heater, the gas boiler can be connected to meet the water heating load too, effectively converting the water heater into a storage tank. A gas hydronic boiler system serving both hot water and space heat needs could also be employed to replace an electric resistance baseboard heat and storage water heater configuration.

D.3.3 Commercial Space Heating and Cooling

Electric boilers, electric resistance baseboard, air-source heat pumps, packaged electric resistance heating and compressive cooling are the primary electric technologies used for space heating in the commercial sector. Gas heating technologies that could potentially replace these electric technologies include the gas boilers discussed in Section D.2.5 under commercial heating efficiency measures.

Considerable attention has been paid to examining the potential for gas-fired cooling technologies to displace electric powered cooling. Gas utilities looking to improve system load factors regard gas cooling as an opportunity to increase gas usage in the typically low load summer and swing season periods. Meeting space cooling loads also contributes significantly to peak demands for some electric utilities. Thus shifting from electricity to gas could be potentially advantageous for both utilities.

Electric technologies currently dominate the market for commercial space cooling. This was not always the situation. Prior to the 1960's and the advent of increasingly efficient electric cooling technologies, gas served a considerable share of this market. In recent years, gas cooling technologies have evolved to the point where they can compete with electric cooling in many instances.

There are three main technologies for gas-fired cooling: absorption, engine-driven vapor compression, and desiccant cooling. Gas engine-driven cooling technology use the same refrigeration cycle as electric vapor compression machines but substitute the electric motor powering the compressor with a gas-fired engine. The gas engine drive has improved part load performance because of the inherent variable speed capability of the gas engine. Seasonal COPs of gas engine chillers are currently as high as 1.6 to 1.7 (American Gas Cooling Center (AGCC) 1992). Waste heat from the engine jacket and exhaust can be harnessed to further increase the effective COP to greater than 2.0 depending on the amount of useable waste heat (American Gas Cooling Center (AGCC) 1992). In the future, gas turbines are anticipated to replace the reciprocating engines used today for further efficiency gains.

Table D-5. Efficiencies of Commercial Gas Cooling Equipment

	Seasonal COP
Engine-Driven Vapor-Compression Chiller	1.62-1.71[1]
with Heat Recovery	>2.0[1]
Absorption Chiller (direct & indirect)	
Single Effect	0.67 - 0.70[1]
Double Effect	0.95-1.2[1]
Triple Effect	1.4-1.5[2]
Desiccant Cooling System	0.7-1.5[2]

Sources: [1] AGCC 1992, [2] EPRI 1992

Absorption cooling works on a different refrigeration cycle from vapor compression, replacing the compressor with an absorber, generator and two working fluids (i.e., the absorbent and refrigerant). Absorption systems were the earliest commercial gas-fired cooling technology. Absorption systems are classified by whether they utilize waste heat (indirect) or burn fuel (direct) to power the generator. They are also classified by the number of generators staged in the absorption cycle as single-effect, double-effect, and triple-effect.[14] Higher efficiencies are achieved with the double- and triple-effect technologies. Typical COPs of absorption machines are shown in Table D-5.

Desiccant cooling uses a substance with highly absorbent properties to absorb water vapor and its associated latent heat, dehumidifying (and warming) the air it comes in contact with. This air may then be cooled by indirect and/or direct evaporative cooling or by conventional air-conditioning. In contrast, vapor compression and absorption cooling systems provide dehumidification by cooling air below the dew point, condensing water vapor on the cooling coils. This latter process can lead to overcooling in order to achieve the desired humidity level, thus necessitating reheating to maintain desired ambient temperature level. Desiccant cooling is particularly suited to applications where the latent portion of the cooling load is high, such as in hot and humid climates in buildings with high fresh air requirements or in supermarkets, restaurants or sports

[14] Triple-effect absorption chillers are not yet commercially available. At least one manufacturer has them under development but they are not expected to be available on the market for several years.

facilities. Natural gas is used in the desiccant cooling process to generate heat to drive off the collected moisture and regenerate the desiccant for further absorption. Desiccant cooling systems have approximate COPs in the range of 0.7 to 1.5 (Electric Power Research Institute (EPRI) 1992a).[15] Desiccants can be paired with evaporative cooling systems as a packaged "total" desiccant cooling system or in a hybrid desiccant/ vapor compression (or absorption) system.

Gas cooling technologies can be configured together with different equipment depending on the application and strategy, either as packaged or built-up systems. Packaged heating and cooling systems are commercially available in which one or both of the space conditioning functions utilize gas instead of electricity, either with gas-fired heating and electric compressive cooling, or with gas-fired heating and gas engine-driven cooling. GEHPs for small commercial applications mentioned earlier are also options for fuel-substitution. Gas and electric cooling equipment can be combined together in the same central system and staged to meet cooling loads in the most cost-effective manner, tuned to the local utility tariffs.

Finally, though not strictly end-use fuel-switching *per se*, gas-fired cogeneration systems can be advantageously configured to utilize the waste heat from the electricity generator prime mover put towards an absorption cooling (indirect system), desiccant regeneration, or water heating application.

D.4 Gas to Electric Fuel-Switching Measures

This section describes several electric DSM options that could be substituted for gas technologies.

D.4.1 Residential Space Heating

The majority of electric heat pumps sold in the U.S. use outdoor air as the source of heat (i.e.,"air-source"). Electric ground-source heat pumps (GSHP) are also available that draw heat out of some external source of heat other than air, such as groundwater, surface water, city water, stored solar energy, or the ground itself. The advantage of ground-source over air-source heat pumps is the temperature constancy of the heat source; U.S. groundwater temperatures range from about 42-77°F (Electric Power Research Institute (EPRI) and the National Rural Electric Cooperative Association 1989).

[15] Calculating COP for desiccant systems is not strictly equivalent to the COP calculated for other refrigeration systems.

On the other hand, air-source heat pumps suffer degraded efficiency and capacity during cold weather and must utilize supplementary heating (typically electric resistance heating). The increased performance of GSHPs comes at a cost, however, as the first cost of ground-source heat pumps is considerably higher than air-source types (L'Ecuyer et al. 1993).

D.4.2 Residential Water Heating

Electric heat pump water heaters are an option for exploiting the efficiency advantages of vapor-compression technology for residential water heating. The technology is fundamentally no different than that used for space heating and cooling except that these units operate only in the heating mode. Energy factors for units now on the market are in the range of 1.5 to 2.5 (Gas Appliance Manufacturers Association (GAMA) 1993). At present, electric heat pump water heaters have less than 1% of the residential water heating market.

D.4.3 Commercial Water Heating

Electric heat pump water heaters are also an option for commercial water heating applications. COPs of 2.0 to 5.0 are common in commercial applications (Electric Power Research Institute (EPRI) 1992b). In addition, with minor modification and connections, they can provide useful space cooling as a by-product of the process.

Refrigeration heat reclaim is a related option for water heating because the heat rejected from food storage refrigeration or air-conditioning systems can be reclaimed for water heating.[16] The heat is reclaimed by means of a heat exchanger connected to the condenser of the "host" equipment. Large chillers and heat pumps are available with heat recovery features as a standard option. Whether refrigeration heat reclaim is desirable or not will depend on the specific circumstances at the commercial facility. A limiting factor of this type of system is that the heat is available only when the host equipment is operating, although storage and/or diversity of host equipment can mitigate this disadvantage (Electric Power Research Institute (EPRI) 1992b). A more generalized form of the same concept is waste heat water heating which utilizes the unused heat from fluid streams in commercial facilities, though these may not necessarily originate from electric equipment.

[16] Because virtually all refrigeration equipment is powered by electricity, this is considered an electric fuel-switching option.

For commercial laundering, an ozonated system has been developed that significantly reduces or even eliminates the need for hot water (Nadel et al. 1993a). Because this technology consumes electricity that would in most instances be displacing gas (given its position in the commercial water heating market) this is also a gas-to-electricity fuel-switching option. In this system, which also virtually eliminates the use of detergent, the wash water is saturated with ozone, a powerful oxidant that is widely used to disinfect drinking and swimming pool water. The technology is currently in the prototype phase, but in two field demonstrations has reduced gas usage for hot water by 50-76%.