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Resource Planning for Gas Utilities: Using a Model to Analyze Pivotal Issues

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Acronyms and Abbreviations

AC	Avoided cost
DSM	Demand-side management
DTh	Decatherm
EIA	Energy Information Administration
EPAct	Energy Policy Act of 1992
ESCO	Energy Service Company
EWG	Exempt wholesale generator
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FT	Firm transportation
GRI	Gas Research Institute
HDD	Heating degree-day
IRP	Integrated resource planning
IT	Interruptible transportation
LDC	Local distribution company
LP	Linear programming
LT&D	Local transmission and distribution
Mcf	Thousand cubic feet
MDQ	Maximum daily quantity
MFV	Modified fixed variable
MMcf	Million cubic feet
MW	Megawatt
NUG	Non-utility generator
NYMEX	New York Mercantile Exchange
PGA	Purchased Gas Adjustment
PG&E	Pacific Gas & Electric Company
PUC	Public Utility Commission
PUHCA	Public Utilities Holding Company Act
PURPA	Public Utilities Regulatory Policies Act
SFV	Straight fixed variable
TMC	Targeted marginal cost
VOS	Value of service
WACOG	Weighted average cost of gas

Executive Summary

Background and Objectives

With the advent of wellhead price decontrols that began in the late 1970s and the development of open access pipelines in the 1980s and 90s, gas local distribution companies (LDCs) now have increased responsibility for their gas supplies and face an increasingly complex array of supply and capacity choices. Heretofore this responsibility had been shared with the interstate pipelines that provide bundled firm gas supplies. Moreover, gas supply and deliverability (capacity) options have multiplied as the pipeline network becomes increasingly interconnected and as new storage projects are developed. There is now a fully-functioning financial market for commodity price hedging instruments and, on interstate pipelines, a secondary market (called *capacity release*) now exists. As a result of these changes in the natural gas industry, interest in resource planning and computer modeling tools for LDCs is increasing. Although in some ways the planning time horizon has become shorter for the gas LDC, the responsibility conferred to the LDC and complexity of the planning problem has increased.

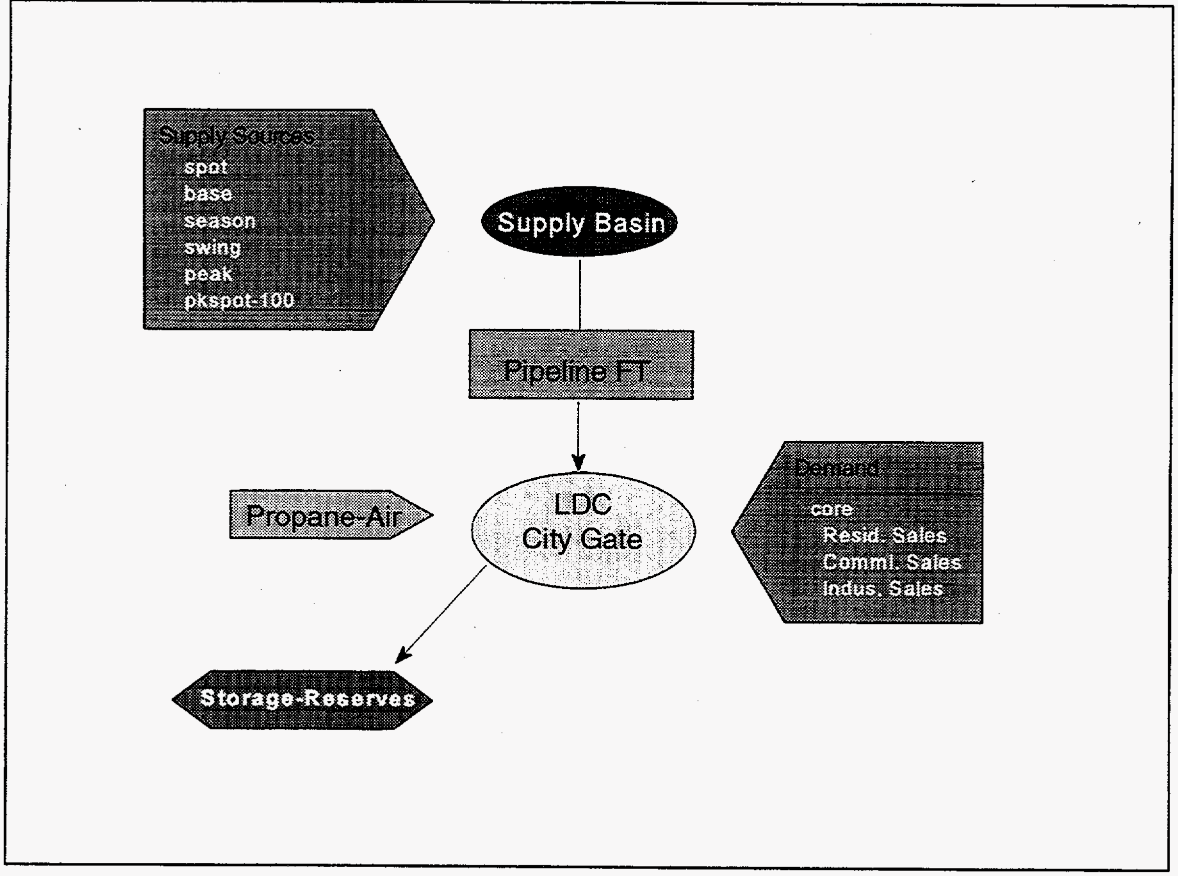
We examine current gas resource planning issues in the wake of the Federal Energy Regulatory Commission's (FERC) Order 636. Our goal is twofold: (1) to illustrate the types of resource planning methods and models used in the industry and (2) to illustrate some of the key tradeoffs among types of resources, reliability, and system costs. To assist us, we utilize a commercially-available dispatch and resource planning model and examine four types of resource planning problems: the evaluation of new storage resources, the evaluation of buyback contracts, the computation of avoided costs, and the optimal tradeoff between reliability and system costs. To make the illustration of methods meaningful yet tractable, we developed a prototype LDC and used it for the majority of our analysis.

Approach

We use the Sendout® model of EDS Utilities Division. Sendout is a linear programming (LP) model, capable of performing global optimization to minimize total system cost given specified physical limitations and contract constraints. Sendout employs an algorithm that uses a full LP along with a network optimization to solve the gas supply planning problem. We constructed our LDC prototype using data from several cooperating LDCs and publicly-available data (Figure ES-1). We defined customer demands and base-case supply resources over a ten-year period. Below, we summarize major assumptions.

- Demand. We decided to create an LDC that primarily serves core customers. We explicitly excluded noncore and transport-only loads because many

Figure ES-1. Network Diagram for the Prototypical LDC



resource decisions made for these types of customers are not completely controlled by the LDC. Annual base-year demand of the prototypical LDC was scaled to match the mean of a survey of 70 LDCs in terms of supply disposition serving their own customers. Demand was broken down into residential, commercial, and industrial customer class portions and distributed over the months of the year based on national average data. Using representative data on load factors and peak-day response factors, our LDC prototype has a design peak-day load of 1,200 MDTh.

- Gas Supply. We defined five basic types of supply contracts: baseload, seasonal, swing, peaking, and spot contracts. Each of the contract types vary in their ratio of fixed to variable costs, seasonality, minimum takes and, in the case of spot, reliability. From our sample of contracts from cooperating utilities, we constructed composite contracts representative of each contract type. In addition to natural gas, our prototype has 300 MMDTh/day of capability from a propane/air plant. Using historical ratios, initial natural gas and propane commodity prices were tied to current NYMEX natural gas futures prices and the ten-year forecast of commodity prices was three percent/year real, consistent with a recent forecast made by the Gas Research Institute.

- Gas Transportation and Storage. Transportation for the prototypical LDC's supply was modeled as a single pipeline contract for firm transportation from the supply basin to the city gate (see Figure ES-1). Transportation prices were set at the mean of published pipeline tariffs of 44 U.S. pipeline companies. Underground storage was modeled as a single depleted gas or oil reservoir connected directly to the city gate. The size and the cost of the storage facility were chosen to be typical for existing storage fields in the U.S., which primarily provide seasonal capacity. New storage resources in the U.S. are often of the high-deliverability type and we test the value of such resources in our analysis of incremental storage (below).

- Other Assumptions. Our prototype LDC's supply system is primarily defined upstream of the city gate station; i.e., we did not explicitly model local (on-system) transmission, distribution, and customer service facilities. While this is a limitation, we believe the simplification is reasonable because most resource planning decisions of interest in regulatory proceedings concern upstream facilities and commitments.

With our prototype defined, we generally solved for resource selection and costs using Sendout's optimization routine. In most cases, we actually conducted two "runs;" one to size deferrable resources (including a 5% supply contingency resource margin) and the other to dispatch supply resources, holding the capacity of facilities constant. This is done because spot gas, while too unreliable to be solely relied upon for capacity planning purposes is inexpensive and desirable on an as-available basis. By limiting the amount of spot gas available in the first run, we assured a reliable resource mix. Then, in the dispatch run, we allowed the model to chose as much spot gas as is economic to be taken, subject to the minimum take conditions of other contracts.

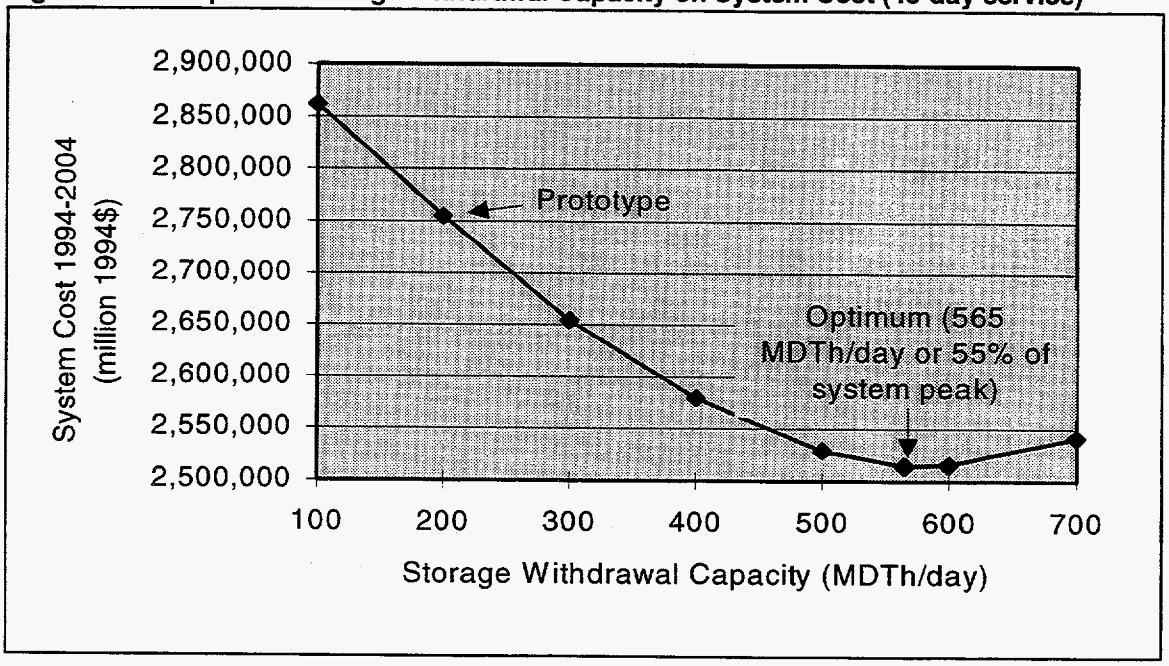
Storage Resource Evaluation

Storage is a key strategic resource in an LDC's resource portfolio. In the last two years, many LDCs and regulatory commissions have evaluated commitments to storage resource options in light of storage's unbundling from pipeline service, its de-tariffing by FERC, and the move to straight-fixed-variable (SFV) rate design on interstate pipelines. For this study, we conducted several types of analyses of storage using our LDC prototype.

A typical problem faced by utilities especially in light of the rate design changes on pipelines is whether their existing levels of market area storage are optimal. Our LDC prototype contains 200 MDTh/day of storage. This level of deliverability, which represents approximately 16 percent of the LDC's peak load, was considered representative of typical U.S. LDCs. The two most common type of storage in the U.S. are depleted oil and gas fields and fields developed in aquifers. On average, these types of storage fields require an inventory (working gas) to deliverability ratio of about 60 to 70 days. This ratio is commonly known as *days of service*. For this reason, these types of storage resources are often labeled seasonal. Salt dome storage has a much lower inventory-to-deliverability ratio. For this reason it is labeled high deliverability storage. Although relatively uncommon today, high deliverability storage makes up approximately 50 percent of all storage projects under construction, which is an indication of the desire by many to use storage for reducing peak loads and to perform short-term rather than seasonal cycling.

Using costs that are representative of seasonal storage, we computed total system costs at alternative levels of storage capacity. For our prototypical utility, we found that 565 MDTh/day, or about 55 percent of the system's peak, was the optimal amount (Figure ES-2). At that level, present value system costs of the LDC prototype decrease 9 percent from the base case. If we allow the model to consider high deliverability storage instead of seasonal, we still find that significant increases in the amount of storage are cost effective. Although our LDC prototype explicitly excludes transport-only and noncore loads, which increase an

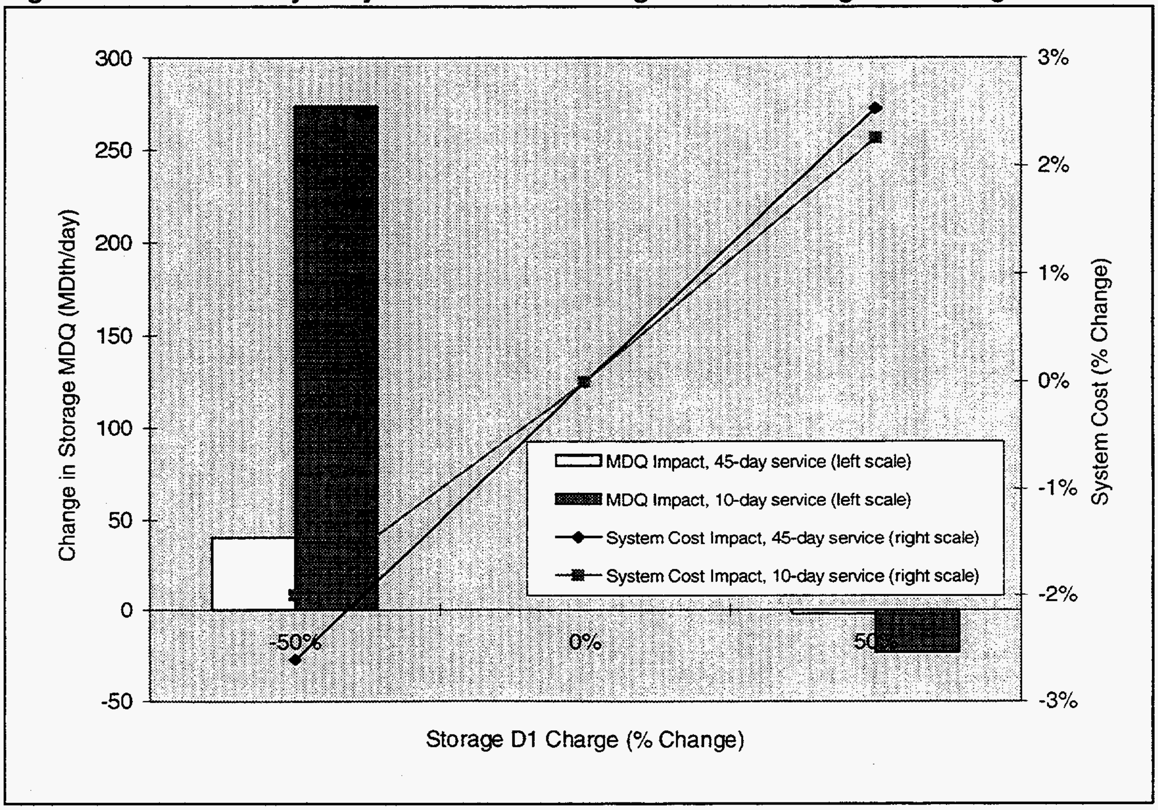
Figure ES-2. Impact of Storage Withdrawal Capacity on System Cost (45-day service)



LDC's overall load factor, our results indicate that consideration of storage investments may be fruitful for many LDCs.

Storage is a cost-effective resource because it provides peak-day deliverability at lower fixed costs than its alternatives, which is usually pipeline capacity. If low enough in cost, storage can also be competitive with propane/air. As more and more storage is chosen, however, its cost effectiveness for the last unit acquired decreases. The point at which incremental storage is no longer cost effective depends on the day-to-day and month-to-month load shapes of the utility's customers. We considered the optimal level of storage under sensitivities where we both raised and lowered the demand charge rate for storage (Figure ES-3). Changes in system cost as a result of demand charge savings are roughly linear. For both ten- and 45-day storage, system cost increases two percent for a 50 percent change in the storage D1 charge (Figure ES-3, line series). The impact on the selected resource is not nearly as simple, however. A 50 percent increase in price has a much lower impact on the optimal MDQ than does a 50 percent decrease. This is especially true in the case of the ten-day storage. In this case the storage resource not only displaces some pipeline capacity, but also displaces the prototype utility's propane/air facility. These sensitivities illustrate how resource planning models can help estimate tradeoffs between resource prices and system costs and resource

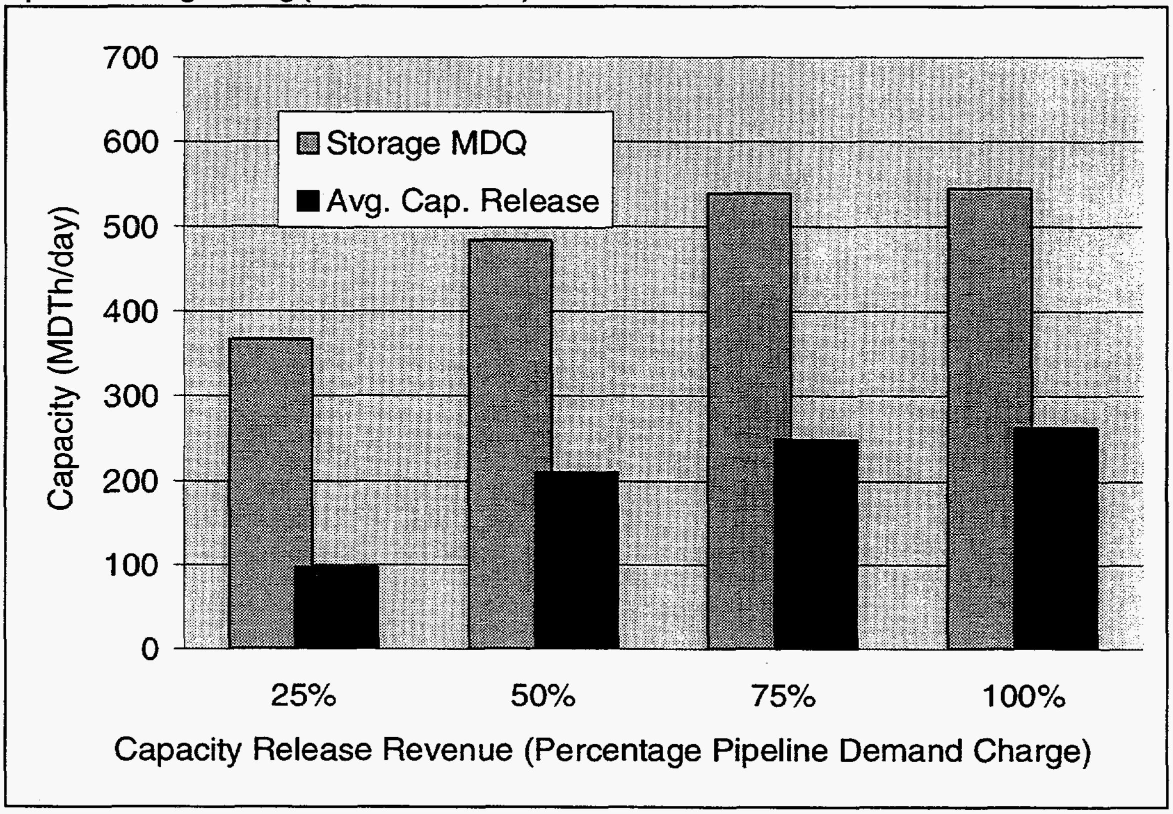
Figure ES-3. Sensitivity of System Cost and Storage MDQ to Changes in Storage Cost



prices and resource quantities. In the case of our LDC prototype, the impact on costs was mostly linear, but there was an asymmetric impact on quantities.

With pipeline capacity release (resale), pipeline capacity is now a more fungible resource. As a result, the potential for capacity release revenues should be considered in any storage resource evaluation. We considered what the prospect of both short- and long-term releases would have on the amount of storage resources that are optimal. As might be expected, we found a positive correlation between capacity release price and the quantity of pipeline capacity released. Figure ES-4 shows the results assuming that the capacity releases are for terms of one year. The figure also shows that more storage is required as pipeline capacity release volumes increase. Basically the utility is finding it economic to release pipeline capacity even though it has to acquire more storage to ensure reliability.

Figure ES-4. Impact of Pipeline Capacity Release Revenues on Release Amount and Optimal Storage Sizing (Annual Releases)



Buyback Contracts

One of the more recent contractual innovations for gas LDCs is the buyback contract. In buyback contracts, a gas LDC buys limited right of recall from a customer with firm capacity. Usually the buyback rights are for ten to 30 days per year. In many cases the LDC actually holds the primary pipeline service agreement for the capacity and has released the capacity to its customer. Buying back the limited recall rights from the customer is a way for the LDC to keep capacity rights for times when it needs them the most. By retaining access to peaking capacity, the LDC is able to serve low-load-factor core loads at a lower cost. As such, buyback arrangements can help motivate the LDC to unload uneconomic quantities of pipeline capacity. The customer selling the buyback capacity still retains near-firm rights to it. The LDC may also be obligated to pay the incremental cost of alternative fuel during those times that it actually curtails the customer selling the buyback capacity.

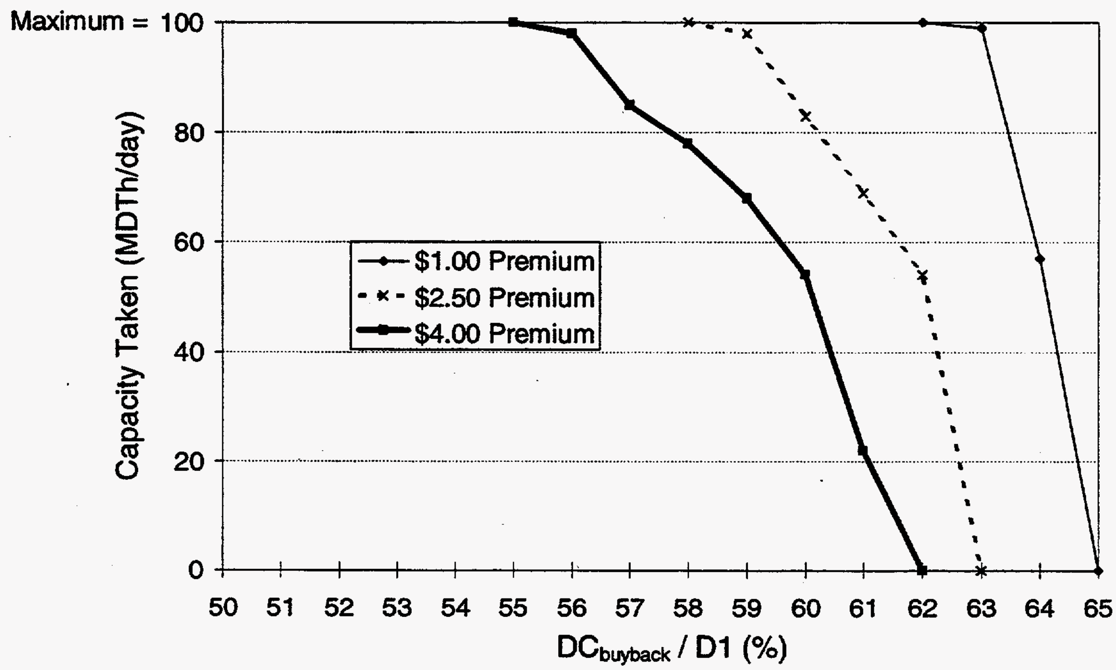
Using our LDC prototype as a starting point, we estimated the value of a buyback contract to the LDC. From its perspective, the LDC should be willing to buy buyback capacity so long as the price it pays for the pipeline capacity plus its expected alternative fuel payments are less than simply buying pipeline firm transportation on its own. Using Sendout, we were able to capitalize upon the existing detailed data on demands on and around the peak day and compute the optimal amount of buyback capacity for the LDC at various rates for the capacity. This allows for an accurate estimate of the buyback contract's value as its size is increased. Using various alternative fuel premiums between \$1/MMBtu and \$4/MMBtu, we found that buyback capacity was economic at rates at or below 55 percent (Figure ES-5). As might be expected, the model found more buyback capacity to be economic as the buyback rate or the alternative fuel premium is decreased. Anecdotal evidence of existing buyback contracts suggests that sellers of buyback capacity are willing to do so for relatively low percentages of the pipeline's D1 Rate. Thus our analysis indicates that buyback contracts may represent a fruitful arrangement between an LDC and its near-firm customers.

Resource Evaluation Using Avoided Costs

Avoided costs equal the change in cost resulting from a change in demand over a specified time period. Avoided costs are computed so that the value of potential new resources may be easily evaluated. We focus on DSM programs but avoided costs can also be used to evaluate alternative supply resources.

We explore gas avoided costs by computing them using different methods and by varying the time of year the demand impact occurred. For gas LDCs, avoided costs include several components: commodity costs, capacity (or deliverability) costs to the city-gate, local transmission and distribution costs (LT&D), and customer-related costs. In general, our analysis focuses on the estimation of commodity- and capacity-related avoided costs. We

Figure ES-5. Optimum Economic Quantity of Buyback Contracts at Different Alternative Fuel Premiums and Demand Charges



Note: Premium = P_{alt} - P_{gas}

explored gas avoided costs calculated using five commonly accepted methods (1) average cost, (2) DSM in/out, (3) increment/decrement, (4) proxy, and (5) marginal cost. *Average cost* methods require that the modeler specify which components are marginal and which are not. Of those components considered marginal, such as gas supply, an average cost is computed. *DSM in/out* and *increment/decrement* are very similar; they both are computed by calculating the finite change in cost in response to a finite change in demand. The difference between the two methods is how the demand change is specified. In DSM in/out the demand change is the size of the estimated DSM program or set of programs and this "with" case is compared to the "without," or base case. In increment/decrement, the demand change is a positive and negative perturbation of demands around the base case. In the *proxy* method, the planner chooses the resource or set of resources that it believes is deferrable. Avoided cost using the proxy method represents the change in cost as a result of the delay or cancellation of the deferrable resource. Finally, marginal cost methods attempt to compute the change in cost in response to an infinitesimal change in demand. Most resource planning models compute energy marginal costs, which do not include capacity costs. In our estimate of marginal cost we added the marginal energy cost produced by the model and added it to a proxy for the marginal capacity cost.

For all marginal cost methods, it is important to specify the daily or seasonal shape of the LDC's load change. Whether the DSM program has an impact on all days or just some days can significantly affect avoided cost. To illustrate the importance of load shapes, we compute avoided costs using four load shapes: baseload, heating season, summer cooling and peak day.

Using our LDC prototype we computed illustrative marginal costs for each of the four generic load shape impacts (Table ES-1). We found the DSM in/out and increment decrement methods to produce nearly identical results so we show just the DSM in/out results in this summary. For two of the methods (DSM in/out, marginal cost) we also show results for our peak-day load shape.

Table ES-1. Summary of Marginal and Avoided Costs for LDC Prototype (1995$/DTh, 10-year average)

	Load Shape			
Method	Baseload	Heating Season	Cooling	Peak Day
Average System Average	3.78	2.70	4.57	not available
Average Cost WACOG	2.52	1.70	3.12	not available
DSM In/Out	2.30	3.94	2.06	163.40
Marginal Cost	2.44	2.76	2.14	40.33

Table ES-1 clearly shows that different methods produce different results. Average cost methods appear the most counterintuitive. Our LDC prototype has a strong winter peak and limited storage, thus resources are almost certainly more scarce in the winter relative to summer or year-round (baseload) demands. Despite these facts, average cost methods produce marginal costs that are *lower* in the winter than in the summer (Figure ES-6). This is because we include fixed costs in our average cost calculations as they are charged in their respective supply contracts and pipeline line tariffs. As a result, the average cost of supply is higher in the summer than the winter because there are less therms to spread the fixed charges over. DSM in/out and marginal cost produce what we believe are more sensible results. The results are highest in response to winter heating load shape impacts and are lowest in response to valley-filling summer load shape impacts. Both methods produce baseload values that are lower than the average cost values. This is an indication that the resource planning models have determined that not all upstream costs are avoidable. However, DSM in/out and marginal cost differ significantly on the peak day (Figure ES-7). Using DSM in/out, peak-day avoided costs are $163/DTh, reflecting that a change in load that day results in expensive, long-term commitments to new pipeline capacity and gas supplies. Our marginal cost method captures the relatively higher cost of peak-day supplies but, because it relies on a capacity proxy, does not pick up on the significant cost impact of peak-day load impacts. On balance we put the most faith in the DSM in/out and increment/decrement methods.

Figure ES-6. Simulation Results: Marginal and Avoided Costs by Method and Load Shape

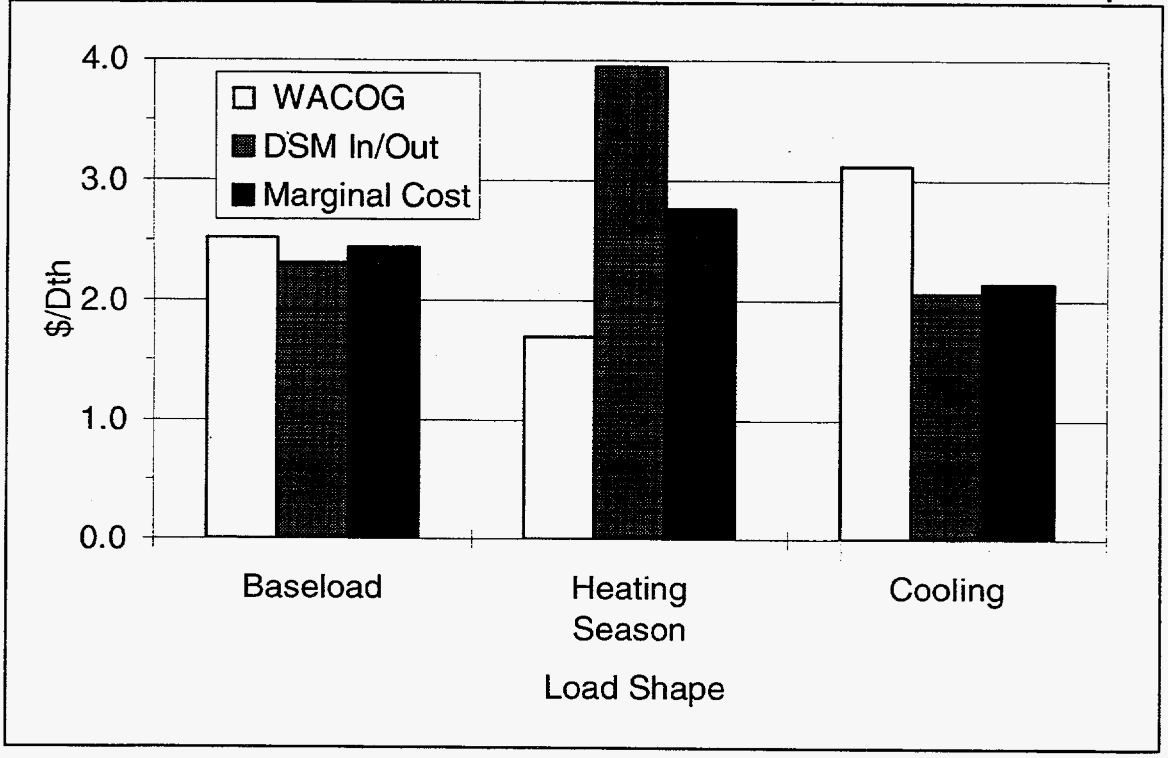
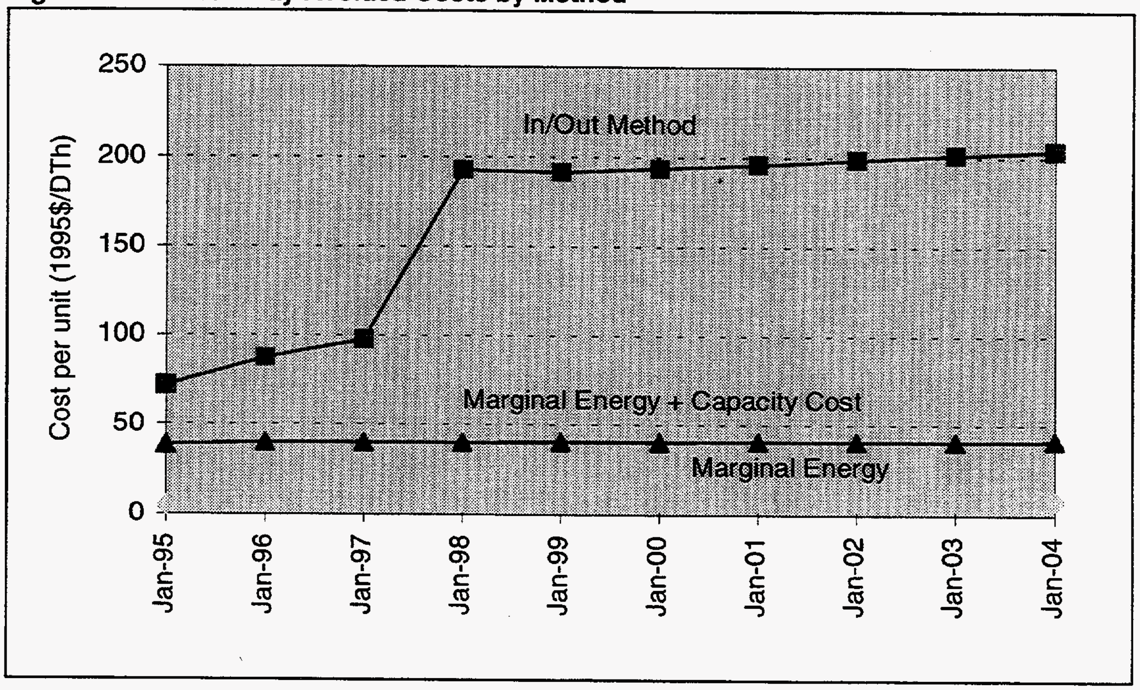


Figure ES-7. Peak-Day Avoided Costs by Method



Although they require the use of resource planning models to determine what resources change as a result of load changes, we believe they are best able to predict the changes in system costs in response to different types of changes in loads.

We also conducted a series of sensitivities to see the impact of changes in assumptions and methods on avoided costs. In one of our sensitivities, we allowed the LDC prototype to release capacity in years that its holdings are in excess of demand. In our base case, the LDC prototype is allowed to renegotiate its pipeline holdings only a couple of times. Between those times, it has some degree of excess capacity because it must acquire capacity in anticipation of future load growth. The existence of capacity release increased avoided costs by approximately 11 percent in those years where excess capacity existed. Thus, if capacity holdings are "lumpy;" i.e., they may be renegotiated only infrequently, our analysis indicates that capacity release increases avoided costs by a modest but not insignificant amount.

Core Reliability Planning

LDCs have always had the responsibility to secure adequate gas supplies and pipeline and storage capacity to provide reliable service. Commitments to meet this responsibility are, however, being reviewed by many LDCs in light of requirements to unbundle services and the changeover to straight-fixed-variable rate design. The former (unbundling) requires the LDC to explicitly articulate what capacity is reserved for core customers. Heretofore, capacity could be held for both the benefit of core and noncore customers, giving the LDC more reasons to justify a particular capacity holding. The latter (move to SFV) makes pipeline capacity relatively more expensive, which also motivates a reevaluation.

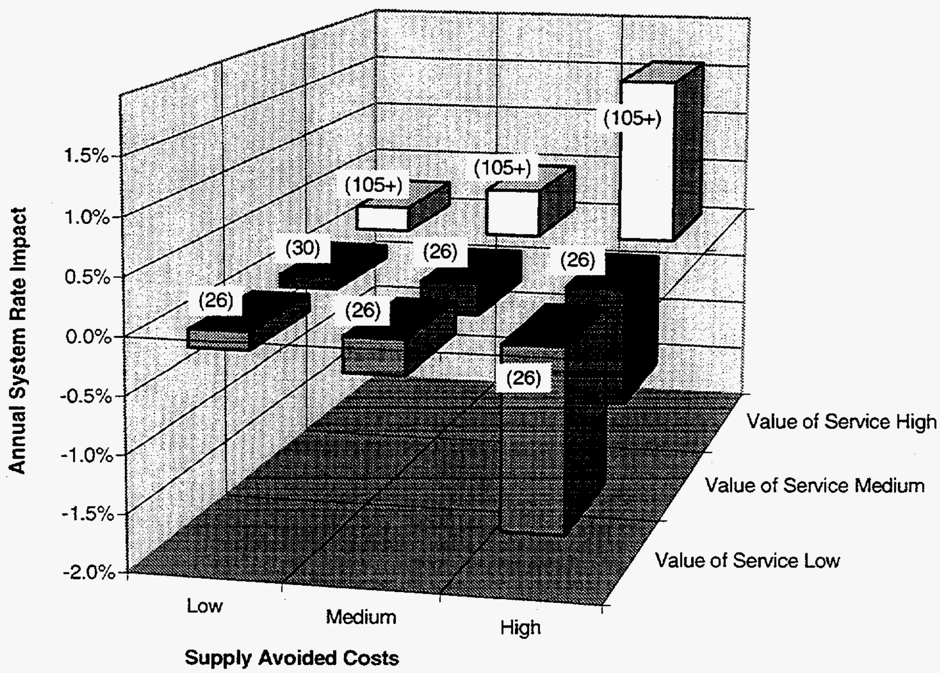
Unfortunately, because core loads are typically temperature-sensitive, reliability can never be provided in absolute terms; instead it must be defined by a probability of curtailment. Many utilities work around this uncertainty, by planning for the coldest recorded temperatures and by adding reserve margins to account for uncertainty in both demand and supply. While this planning criteria has a strong appearance of prudence, it does not guarantee service, as record-breaking cold weather can always materialize, and ignores the question of whether the last units of capacity were cost effective relative to the value that customers' place on the service provided by it. We believe it is better to use a method that explicitly compares expected marginal value of service (VOS) with the marginal cost of providing service. Although the method is not common to gas LDCs it is used in the electric industry and has already been used by at least one gas utility. We attempt to illustrate the method using data representative for U.S. LDCs, including our LDC prototype.

The value of service method of reliability planning is basically a four-step process. First, existing reliability of service is evaluated by considering existing facilities, per-customer demands, and expected customer growth. Reliability of service is measured by the number of expected years between curtailments (also known as a *recurrence interval*) and this value depends heavily on the frequency of extreme temperatures in a given service territory. Second, VOS on an extreme day is estimated using surveys or analyses of core customer end uses. Basically, these analyses estimate the economic harm and liability created when a core customer is actually curtailed. Third, possible increases or decreases to system capability are articulated and their cost and reliability impacts are estimated. Fourth, the net benefits of each capability alternative are evaluated. For each level of system capability, incremental cost relative to the base capability is compared to the increase in customer VOS. The best investment decision is the one that produces the greatest VOS net of incremental costs.

For our illustration, we conducted a literature search to bound the range of commonly-found estimates of both VOS and incremental supply costs. The range in values is wide, reflecting differences in methods and the variety of supply and demand situations across the U.S. For value of service, we found three studies with median values of $16, $62, and $1,820 per customer per day of curtailment, which we labeled "low," "medium," and "high," respectively. The medium estimate is based on a formal VOS survey conducted by PG&E on its core customers in 1994. On the supply side, we use estimates of avoided cost to come up with representative estimates of the savings from increasing or decreasing system capability. We found $47, $89, and $311 per peak-day DTh to be reasonable low, medium, and high estimates. The low estimate is based on the cost of a propane/air plant, the medium estimate is based on upstream-only marginal cost studies conducted by California LDCs, and the high estimate is based on our LDC prototype for upstream avoided costs *plus* the marginal costs of LDC on-system avoided costs, based on other studies conducted by California LDCs.

Using these ranges of estimates of VOS and avoided costs, we computed the optimal level of reliability using demand data for our utility prototype. Figure ES-8 shows the impact on rates (bars) and the optimal recurrence interval (number in parenthesis) as a result of going from a 50-year recurrence interval to the optimal level. Rates may be impacted by as much as 1.6 percent for our prototype by going from the base-case recurrence interval to the optimal recurrence intervals of more than 105 years. A conclusion that may be drawn from Figure ES-7 is that the range of optimal level of reliability is wide--optimal levels are found to be from 12 to more than 105 years. Although this variation is potentially disconcerting, we believe that individual utilities can work to reduce the range of uncertainty and estimate optimal levels of reliability that can assist the utility in investment and service unbundling decisions. Also, it appears that the cost of reliability, in terms of rate impacts, may be modest.

Figure ES-8. Rate Impact of Changing to Optimal Level of Reliability (Optimal Recurrence Interval Shown in Parenthesis)



Note: Rate impacts are relative to a base-case resource plan with a 50 year recurrence interval.

Concluding Thoughts

In general, we found resource planning models to be well-suited for answering a variety of questions that are relevant to today's LDCs. We examined new storage resources, buyback contracts, avoided costs, and core reliability. The purpose of this study was not to give answers or prescribe methods but, to instead, provide the reader with a better understanding of alternative methods, to assess the efficacy of resource planning models, and to point out the important tradeoffs among resources and costs when planning for an LDC.

A legitimate question is whether such analysis will be needed in the future in light of ongoing LDC restructuring, including LDC service unbundling and increased competition with electric utilities. Some of the changes in LDCs' business environments, such as the advent of shorter-term markets for commodity supplies, have decreased the resource planning responsibility of the LDC, while others, such as the unbundling and de-tariffing of pipeline supply service, have increased it. Integrated resource planning (IRP) is being used by some state regulatory commissions as a way to manage change and to help improve the quality of decisions they, and the LDCs they regulate, make. For these states, we believe that gas resource planning models are useful tools for guiding the regulatory planning process. Other states have chosen not to make IRP an explicit regulatory process. However, gas utilities will still conduct strategic business planning and regulators will still be concerned with the prudence of utility resource commitments, especially those commitments made on behalf of its captive core customers. Although these processes are likely to be less formal and public, we believe resource planning models are likely to be of value in these situations as well.

CHAPTER 1

Introduction

Gas local distribution companies (LDCs) face significant changes in their business environment. Brought on by market forces unleashed through the last decade's series of Federal Energy Regulatory Commission (FERC) decisions and new regulatory demands at the state level, LDCs are adapting to new challenges and opportunities.

Perhaps the activity in the company where these changes are most clearly manifest is in resource planning. Formerly, under the old gas industry structure, interstate pipeline companies purchased gas from producers and resold it along with transportation service as a bundle to LDCs. The supply planning function primarily resided in the pipeline company and LDC resource decision-making was relatively straightforward. All that has changed. Presently, interstate pipeline companies no longer perform the gas merchant function and responsibility for procuring and transporting gas has been passed to LDCs.

This increased responsibility for resource planning becomes further amplified as public utility commissions (PUCs) in some states propose requirements that gas utilities engage in integrated resource planning (IRP). Integrated resource planning involves systematic consideration of a comprehensive set of objectives and resources, including demand-side management (DSM) resources, to reliably meet customer energy needs at least cost. IRP for gas utilities is somewhat controversial, with some critics claiming that the direct and indirect costs far outweigh the benefits (Kretschmer and Mraz 1994), while others cite its virtues in the face of such criticism (Jensen 1993). However, the bottom line is, whether the activity is called "IRP" or strategic business planning, it is still an activity that LDCs will need to engage in to survive and prosper.

All of this places a premium on the analytic capabilities of LDC resource planners, who are turning to new, sophisticated models to manage their expanded roles. Resource planning models are tools to model physical and financial stocks and flows for the purpose of making resource commitments. Because of their longer time horizon, they are necessarily more simplified in some ways than actual accounting or operational models which assist in the day to day operations of the LDC. However, by taking on the task of prediction and forecasting, resource planning models must tackle the difficulties of modeling upstream conditions and future events. Further, the proliferation of resource options makes integration and optimization more challenging.

Given the increased pressure on gas LDCs to make independent resource decisions, we analyze some of the most important problems faced by resource planners and try to characterize the major issues and key tradeoffs. We do this by using a commercially available resource planning computer model and apply it to problems faced by a prototypical LDC that we developed. Our report is organized as follows: In Chapter 2 we provide background on the forces shaping an increased role for gas resource planning. In Chapter 3, we develop a typology of gas resource planning models. In Chapter 4, we describe our method of analysis, including a description of the resource planning model we use and our prototypical LDC. In the next four chapters we analyze major planning issues many LDCs face for which planning models can be useful tools. In Chapter 5, we analyze avoided costs for DSM, reviewing different methods and comparing results obtained. In Chapter 6, we explore the value of storage to our prototypical LDC system. In Chapter 7, we analyze an alternative peaking resource some gas utilities have developed which is a pipeline capacity buyback arrangement with an independent power producer with alternative fuel capabilities. In Chapter 8, we assess the value of changes in the reliability standard for capacity planning. In Chapter 9, we draw conclusions from these analyses.

Background

Any discussion of gas resource planning models can not occur without acknowledging the dramatic changes that have occurred in the industry in the last 17 years.[1] Below we identify some of the major current trends that are affecting gas LDCs today and conclude the chapter by describing the implications of these trends on resource planning and modeling.

2.1 Gas Industry Restructuring

2.1.1 FERC Order 636

FERC Order 636 was adopted on April 8, 1992 and was implemented on most pipelines by November 1, 1993. Although nearly all LDC's have taken advantage of gas transportation and spot gas since the mid-1980s, most still relied on pipeline sales service to meet demand during critical periods of demand. FERC Order 636 required an end to this relationship because it required the unbundling of sales and transportation service. Thus, significant restructuring of contracts between LDC's and their pipelines, marketers and producers was required.

In terms of its impact on LDC's, FERC Order 636 had four main components. First, it required pipelines to unbundle commodity, storage, and transportation services. Pipeline transportation services remain FERC-regulated and are now more uniformly open access. Commodity prices were deregulated and, where market power could be demonstrated to be absent, so also were storage services. Second, FERC settled on a process for trading existing capacity rights though its capacity release program. Under capacity release, all holders of capacity can put capacity up for resale on electronic bulletin boards operated by the pipelines. Under this closely monitored resale market, the price is prohibited from rising above the pipeline's tariffed, or *as-billed,* rate. Third, Order 636 completed the transition to straight-fixed-variable (SFV) rate design, which, relative to most previous rate designs, puts more of a pipeline's costs in its demand charges. Thus, pipeline and storage capacity became relatively more expensive. Fourth, to accommodate the unbundling of pipeline commodity contracts, the elimination of commodity rate regulation, and the recovery of facilities either required or stranded as a result of FERC Order 636, the order allowed for the identification and recovery of transition costs. As of late 1993, the total estimated transition costs of 636 equaled $4.8 billion (Energy Information Administration (EIA) 1994, pp. 50). At an annual

[1] We mark the beginning of modern restructuring with the Natural Gas Policy Act of 1978. See Goldman et al. (1993) for a thorough description of industry structure and restructuring.

amortization rate of 16 percent, this transition costs is equal to approximately 4 percent of investor-owned LDC revenues.[2]

In response to FERC Order 636, LDCs were required in many cases to rebuild their portfolios with unbundled transportation and storage from the pipelines and new commodity contracts with either pipeline affiliates, producers, or marketers. In some cases they bought "rebundled" supply and transportation capacity from marketers at their city gate. This transition necessarily occurred quickly and two winters have passed since the Order 636's implementation. Continued revision of LDC capacity and supply holdings is still occurring, however. In particular, many LDCs and their regulatory commissions are still evaluating whether to hold all the pipeline capacity they have. The capacity has become more expensive, relative to prices under MFV rate design. Load growth continues in parts of the country, however, and LDCs have the option of releasing the capacity rather than completely letting it go. For most LDCs that have significant temperature-sensitive core loads, evaluating pipeline capacity holdings requires a determination of need given a reliability criterion. Thorough, PUC-reviewed, reliability plans has yet to emerge for most LDCs.

2.1.2 In-State Unbundling

As a result of FERC Order 636, many industry participants now declare restructuring to be complete, the process of unbundling now continues within the LDC's city gate. Although most LDCs offer some sort of transportation service for larger commercial and industrial customers, its overall reliability is lower than that provided to sales customers of the LDC. Further, nearly all LDCs have their commodity costs regulated, usually via a Purchased Gas Adjustment (PGA) clause mechanism

Several states have had or have ongoing gas utility unbundling dockets, including California, New Jersey, Maryland, and New York. These proceedings consider what services should be unbundled and which customer classes should be offered unbundled services. For unbundled competitive services, such as commodity service, these proceedings consider whether and how the monopoly LDC should be allowed to participate. Should it be allowed to participate at all and, if so, what should be the form of price regulation? There is also the issue of obligation to serve: Are LDCs still required to provide service after a customer has purchased unbundled services from nonutility providers?

Another major issue in LDC unbundling proceedings is the evaluation of an LDC's existing pipeline capacity holdings. If a customer wants firm, transport-only service, can it use the LDC's pipeline capacity via state-regulated LDC tariffs or must the LDC release it and make the customer try to get it in the FERC-regulated release market? If the LDC and the PUC

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2 A 16% amortization factor is based on a 10% discount rate and a 10-year recovery period. Investor-owned distribution company revenues are reported in AGA (1994), Table 12-1.

choose the former route and the LDC sells the upstream capacity bundled with distribution and, possibly storage and commodity service, how does the LDC assure competitors and the FERC that the LDC is not exceeding the as-billed cap for the pipeline capacity? How each LDC will handle these issues depends on the needs of the LDC's customers, its initial capacity position, the policies of its state PUC, and the emerging policies at the FERC. Given that LDC's are a large holder of existing, depreciated pipeline capacity, it is no surprise that they are generally unhappy with the as-billed restriction on pipeline capacity release (Mooring, 1995).

2.1.3 Bypass

There are several reasons why LDCs still have great concerns over bypass even though LDC's have, by now, long learned to live with providing transport-only service to larger commercial and industrial customers. FERC Order 636 along with additional FERC case law has made it easier for industrial customers to completely bypass the LDC by taking interstate pipeline service directly.[3] Further, core customers (small commercial and residential) are attempting to move to transport-only service through core aggregation programs. Electric industry restructuring (discussed below) will likely only increase the pressures of alternative fuels, such as electricity.

2.1.4 Coordinated Commodity Markets and Financial Contracting

Coincident with the development of federal industry restructuring initiatives was the increased coordination of gas commodity markets and the development of financial contracts for natural gas. Commodity market coordination means that prices in each producing basin appear, more so than in the past, to be predictable compared to other basins (Vany and Walls 1993). Such price coordination is evidence of ample transportation capacity and of increased commoditization of gas supply. Increased coordination allows gas buyers to rely more on published market prices as there is less customer-to-customer variation in the market. The development of market hubs are one institution that is enabling this trend. Market hubs are points of supply, storage, or pipeline interconnections where multiple sellers offer gas. Market hubs simplify the business of bringing buyers to sellers, thus increasing liquidity to the market and the degree of competition.

Financial contracts include any contracts that, when used in conjunction with a contract for the physical delivery of gas, affect the overall price paid for gas commodity. Financial gas contracts include exchange-traded futures contracts, forward contracts, options, and swaps. These contracts all provide ways for LDCs to mitigate the price risk of gas commodity.

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[3] For example, Atlanta Gas Light lost 8% of its load when one customer, Arcadia, bypassed the LDC and took service from its local interstate pipeline. See EIA (1994), pp. 74.

LDCs have not been big consumers of financial contracts but they are affected by them nonetheless because they are used heavily by producers and marketers that sell to LDCs.

Before the emergence of these physical and financial market trends, LDCs asked for and received from their PUCs purchased gas adjustment (PGA) clauses that mitigated the risk of gas price fluctuations by passing the risk onto customers. PGA's required case-by-case reasonableness reviews because only an intense review could determine the prudence of a gas LDC's decisions. The existence of coordinated markets and financial contracts will likely cause LDCs and their regulators to reassess the regulation of commodity costs. Simply put, PGA's may no longer be necessary. Commodity price deregulation or incentive regulation may be more appropriate than cost of service regulation in light of the appearance of meaningful commodity price benchmarks.

2.2 Energy Policy Act of 1992

The Energy Policy Act of 1992 (EPAct) included provisions that could affect the regulation and planning functions of LDCs. Specifically, EPAct, which amended the Public Utilities Regulatory Policies Act (PURPA) in Section 115, requires state utility regulatory commissions to consider removing disincentives to utility investment in DSM and instituting integrated resource planning processes for natural gas utilities under their jurisdictions with annual sales exceeding ten Bcf. Certain standards of what is to be considered in gas DSM and IRP are laid out in the legislation and PUCs can adopt or reject the standards as they see fit.

Figure 2-1 shows the status of gas IRP and DSM rulemakings by state PUCs as of February 1995 (GRI 1995). Twelve states have adopted gas IRP regulations or requirements, while eight states have formally rejected gas IRP.[4] Gas utilities in thirteen states have filed DSM plans with their commissions. Although not shown, commissions in eleven states have opened dockets to consider gas IRP. These and other state commissions have yet to rule upon either of these gas utility provisions of EPAct, but will presumably do so in the next few years.

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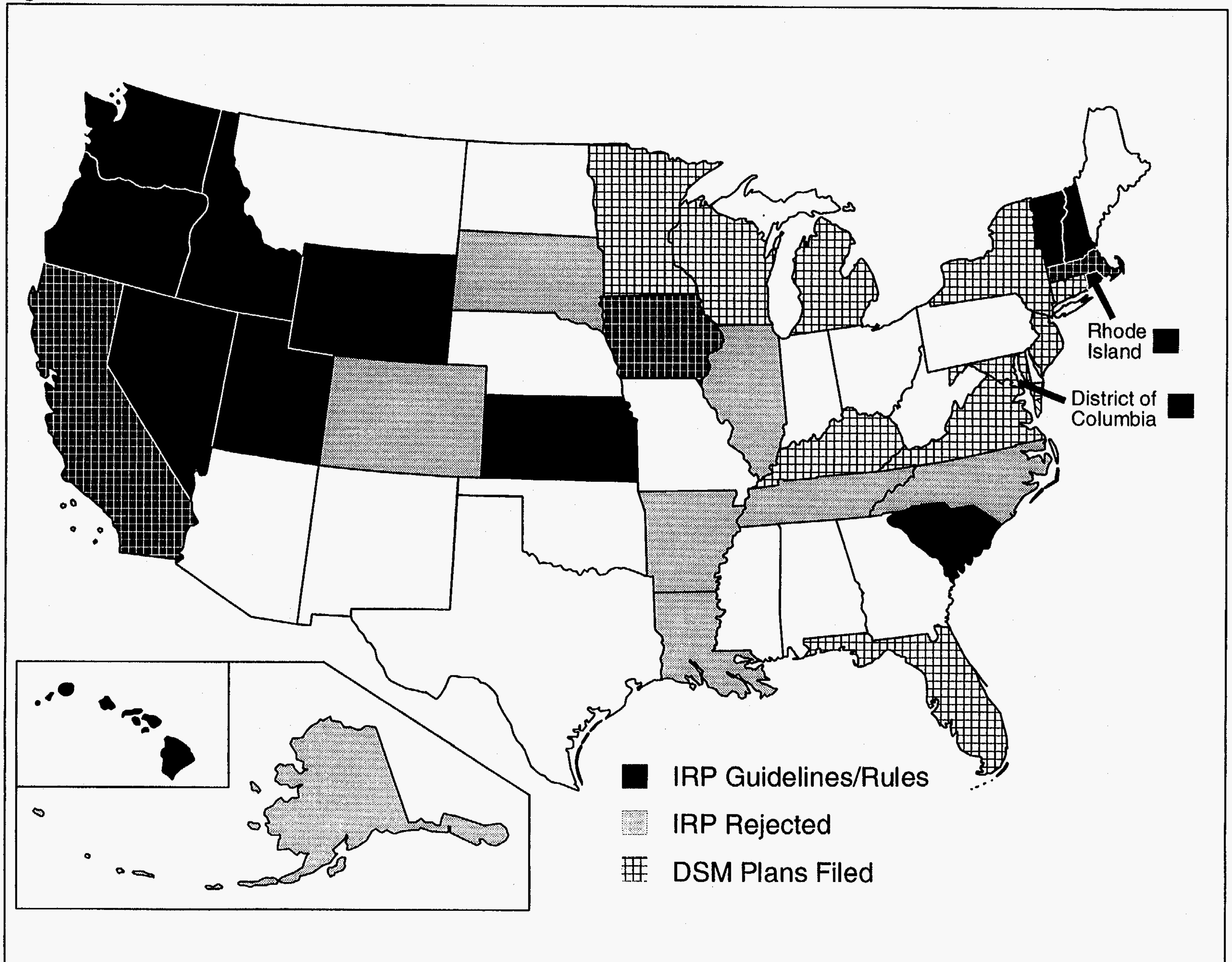
4 It is important to note that one rejecting state, Illinois, was one of the first states to require gas IRP, but later dropped its requirements because it found, in part, their chosen process to be too cumbersome (see Goldman et al. 1993, p. 28).

Figure 2-1. Status of Gas IRP in the U.S.



2.3 Electric Industry Restructuring

The Energy Policy Act of 1992 made some important changes to the electricity industry. It reformed, in addition to PURPA, the Public Utilities Holding Company Act (PUHCA) and the Federal Power Act (FPA). First, it allowed for the creation of exempt wholesale generators (EWGs). Second, it requires electric utilities to provide transmission service to requesting parties at cost-based rate. Third, by indicating that retail wheeling was *not* within the FERC's jurisdiction, it opened the door for states to require retail wheeling. Primarily as a result of EPAct, California and other states have begun proceedings to investigate ways of increasing wholesale and retail competition in the electric industry.

The issues created by electric industry restructuring are huge and beyond the scope of this report. A few implications for gas LDCs are clear, however. First, if electric industry restructuring succeeds in making the electric industry more efficient on an ongoing basis, it will only increase the competitive pressures placed on gas LDCs as electricity competes with natural gas in every one of gas's major end-use markets. Second, an emerging player in the electric restructuring debate are electricity marketers, many of which started in the gas marketing business. It is likely that an industry of energy marketers will emerge that provide both electric and natural gas services on regional or nationwide bases. The relative importance of LDCs with their specific service territories will decrease as marketers begin to hold the primary contracts with energy resources (electric generation and gas supply) and provide a large fraction of value-added services to the final gas customers. A likely response by LDCs will be to either vertically integrate with the marketers or horizontally integrate and become larger monopoly franchises.

2.4 Insights from the Electric Experience with Integrated Resource Planning

With the first generation of integrated resource plans from gas utilities filed in only a handful of states, the bulk of the experience with the process resides with electric utilities. The analogy between electric and gas IRP has been vigorously debated in the last few years (Samsa 1992; Lerner and Piessens 1992). Differences in industry structure and operation, planning practices and time horizon, end-use market characteristics, benefits of DSM as measured by avoided costs, and access to retail utility service have all been identified as salient reasons why gas IRP has to be approached differently from electric IRP (Goldman et al. 1993). Nevertheless, the electric utility experience with IRP can provide insights into the process for gas utilities.

First, utility resource decisions that used to pass easily through the regulatory process are now hotly contested, due to the openness of the IRP process and public involvement, and need to be justified. Often these justifications come in the form of detailed analyses conducted with sophisticated models, which are in turn subjected to increased scrutiny along with their inputs (Kahn 1993). Second, increasing the scope of the traditional supply planning process to include DSM significantly increases the burden of resource planning, both in terms of data and computation. It involves gathering detailed data and modeling the impact of DSM technology and program design on customer energy use. A crucial element in assessing the economic benefits of DSM involves estimating avoided costs, which involves using supply planning tools in new ways. Finally, explicitly incorporating environmental and social welfare issues in the planning process along with the traditional economic issues further increases the number of objectives that utilities are trying to simultaneously meet, many of which are conflicting.

Interestingly, as electricity markets move towards a more competitive model (i.e. down the path the gas industry has recently trod), the impetus for traditional electric IRP is now weakening, although it remains to be seen how electric utilities and PUCs will adapt the process to the new environment.

2.5 Implications for Gas Utility Resource Planning and Modeling

The major industry trends described above place multiple, sometimes conflicting, forces on the resource planner and modeler. On the one hand, gas LDCs face more resource choices than ever before. Upstream interstate pipelines no longer act as resource portfolio managers. Further, new transportation and storage capacity, capacity release markets, gas supply market hubs, new energy efficient technologies, and financial contracts provide the LDC with fundamentally more resource options. On the other hand, increased competition and unbundling make it harder to forecast the future with any degree of precision. First, there are more decision makers involved. It is becoming harder to predict the outcome of events which are contingent on the actions of many parties. Second, more and more data are becoming proprietary. Third, the terms of supply contracts appear to be shortening.

There are several possible outcomes as a result of these countervailing forces. First, the increase in complexity and resource options will result in an increase in the need for resource planning and detailed computer modeling by the LDC. In light of ever changing information, however, resource planning will need to be more adaptive, compared to the traditional notion of IRP and focus more on the short term. Second, resource planning and modeling may become more of a proprietary, strategic planning tool for gas LDCs rather than a tool used in public IRP processes. In a competitive or semi-competitive market, LDCs will be less willing to release demand and cost information than they have in the past. Third, LDC planning models may be used in novel ways. LDCs may begin using the models to predict competitor costs as well as their own costs. Gas marketers may use the tools to dispatch their supplies over multiple pipeline and LDC systems. Finally, gas resource planning models may be used as a tool in antitrust cases. Antitrust laws, rather than administrative law agencies like PUCs, begin to play a more important role in industries that are deregulated.

Overview of Gas LDC Planning Models

Resource planning models are tools used by natural gas local distribution companies (LDCs) to model physical and financial stocks and flows for the purpose of making resource commitments. They are necessarily more simplified than actual accounting or operational models which assist in the day-to-day operations of the LDC. However, by taking on the task of prediction and the analysis of many resource possibilities, they take on a different form of complexity.

This chapter describes the major types of models that are relevant for gas utility resource planning. We focus on methods and potential uses of the methods. We do not discuss the data collection aspects of the models, but that does not mean data is unimportant. Any results from a model are only as good as the data used and the assumptions made. Modelers should pay constant attention to underlying assumptions and quality of input data.

To assist in the understanding of the universe of models relevant to natural gas resource planning, we divide gas resource planning models into five general types: (1) demand forecasting, (2) DSM screening, (3) gas system physical network simulation, (4) gas system dispatch, and (5) gas system contract and facility optimization (Table 3-1).

3.1 Demand Forecasting

Any resource planning process begins with a forecast of demand. Demand forecasting is its own discipline and we do not attempt to survey the topic here.[5] For purposes of gas utility resource planning, two forecasts are usually conducted: a peak-day forecast and a requirements forecast. The peak-day forecast is usually estimated for design temperature conditions. The requirements forecast is usually estimated annually by customer class and is then fit to monthly and or daily demand profiles for the purposes of system modeling. Multiple requirements forecasts may be made to incorporate various assumptions such as a range of annual temperatures ("warm" year, "cold" year) or economic conditions (recession, boom). Also customer demands need to be categorized in two additional dimensions: sales versus transport-only and firm versus interruptible.

There are two distinct methods for estimating demand: econometric or end-use. Econometric models rely on historical data to find the statistically "best" fit. The econometric model may then be extrapolated into the future for forecasting purposes. Many generic econometric

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5 See Goldman et al. (1993) Chapter 3 for an overview description of demand forecasting methods. For an example of a gas utility using end-use demand models, see Washington Gas (1992). For an overview of econometric demand forecasting methods, see Pyndick and Rubenfeld (1981).

Table 3-1. Typology of Gas Resource Planning Models

Type of Model	Primary Purpose & Results	Examples of Commercially-Available Models (& Vendors)
(1) a. Econometric Demand Forecasting	•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
(1) b. End Use Demand Forecasting	•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
(2) DSM Screening	•Track end-use data •Estimate DSM program savings •Compute benefit-cost tests •Model market diffusion processes	•COMPASS (SRC) •DSManager (EPRI) •DSM Planner (BCI) •ECO (Tellus Institute) •LOADCALC (Applied Energy Group) •Energy 2020 (Illinois Dept of Energy and Nat'l. Resources)
(3) Gas System Physical Network 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.) •Gas Works (Brad Bean)
(4) Gas System Dispatch or Sequencing	•Determine the optimal use of *existing* gas supply facilities & contracts •Compute average costs, marginal costs •Estimate curtailments	•GasPlan (Competitive Systems Advantage) •Sendout (EDS Utilities Division) •DOM (Future Scope, Inc.)
(5) Contract Portfolio and Facility Optimization	•Compute optimal choice of supply- (& possibly demand-) side resources over a multi-year time frame •Assess costs and benefits of contracts with minimum takes vis a vis spot gas •Produce least-cost supply plan & long-run avoided costs	•ContractMix (Decision Focus) •GasOpt (Competitive Systems Advantage) •GasPlan (Tellus Institute) •ROGM (Raab Economic Consulting) •Sendout (EDS Utilities Division) •UPlan-G (Lotus Consulting Group) •MOM (Future Scope, Inc.)

Source: Adapted from Goldman et al. (1993)

computer packages are available. End-use demand forecasting models perform a "bottom-up" assessment of demand based on demographics, stocks of gas consuming appliances, efficiencies, and consumer behavior. They generally allow the user more intuitive insights into the nature of demand. Further, they allow for the explicit modeling of events that are not reflected in historical data. For example, end-use models are particularly good at estimating the impact of appliance rebate programs because they can explicitly estimate the change in demand that would result from the change in appliance stock and efficiency. On the down side, the data requirements of end use models are very large. For gas LDCs, end-use modeling for gas LDCs is still in a developmental stage. At least one LDC, Washington Gas, has adapted for its own use end-use models originally developed for electric utilities.

3.2 DSM Screening

DSM screening models are useful for developing a portfolio of DSM programs. Many commercially-available DSM screening models are available to compute standard benefit-cost tests The benefits of DSM programs are expected program energy savings times an LDC's supply-side avoided costs. The costs of a DSM program include rebate costs, customer contribution costs, and program administration and evaluation costs (Goldman et al. 1993, Chapter 6). Commercially-available DSM screening models often include default values for some of these inputs and typically calculate the standard economic tests for DSM programs (Goldman et al., 1993, Chapter 6). Some DSM screening models, such as Compass, include market diffusion models, which can be useful for estimating the market penetration of DSM technologies.

3.3 Gas Systems: Physical Network Simulation

Gas system simulation programs (Table 3-1, item (3)) 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 a compressible fluid (natural gas) in a network system. To simplify the complex problem these models solve, they typically simulate the gas utility system using only daily or hourly demands for limited periods of time at design conditions. Network simulation models have generally not been used into regulatory 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 one of these models.

3.4 Gas System Dispatch or Sequencing

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. 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. More simplified representations of dispatch are needed for medium- and long-term resource planning purposes. Dispatch models may be used to make detailed forecasts of an LDC's contract mix and purchased gas budget one month to approximately 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. 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, several commercially-available models are also available (Table 3-1, item (4)).

Gas dispatch models used for planning purposes must address the highly variable loads that are common to LDCs. Most gas LDCs address this variability by generally using expected monthly or daily demand data and then splice onto this expected demand profile the profile of peak day. With this hybrid demand profile, the model can compute a least-cost dispatch for the expected year and indicate whether adequate supply and capacity are available on the peak day.[6] Demand variability is also addressed by performing multiple dispatch model runs for each year under different weather scenarios.

3.5 Contract Portfolio and Facility Optimization

As the time horizon grows to periods greater than one year, the LDC faces the problem of optimizing the mix of contracts and facilities in addition to the problem of economic dispatch. It is this longer term resource planning problem that is the focus of much of the analysis in this report. Contract and Facility expansion models are designed to address this problem.

Two general approaches to solving the capacity expansion problem are iterative simulation and automatic 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

[6] Although the practice of splicing the design day onto a typical year is common, it is important to remember that the probability of the peak day is actually much lower: on the order of one day in 30 years to one day in 100 years.

objectives. Some trial and error is involved in selecting plans for simulation. It is not uncommon for LDCs to use the iterative approach using in-house models.

In the automatic optimization approach, the planning model automatically selects and sizes facilities and computes total cost. The models find the optimal expansion plan using linear programming, Monte Carlo simulations, or other optimization techniques. An important distinction between different optimization methods is whether they are *deterministic* or *stochastic.*

3.5.1 Deterministic Optimization Models

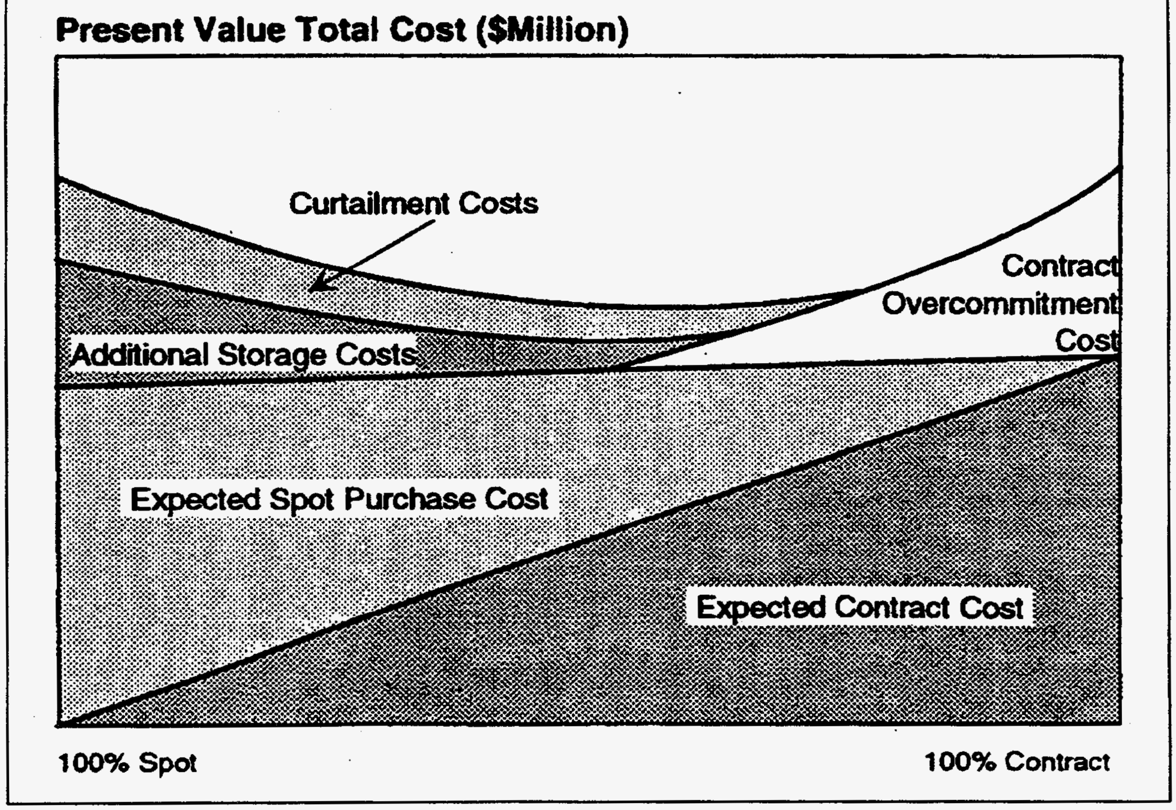
Deterministic models consider many resources and their attributes, and find the least cost mix of resources that satisfies a specified demand. Although many resource options are considered, all of the variables are treated as certain. Natural gas demand, which is generally considered to be uncertain, must be set at expected levels for each optimization run. To capture the effects of greater-than or less-than expected demand, multiple scenarios must be run. Generally speaking, any gas model that uses a linear programming solution methods is deterministic. Examples of deterministic, linear programming models include ROGM, UPlan-G, GasPlan, GasOpt, and Sendout. We use the latter model to conduct analyses presented later in this report. To treat uncertainty explicitly in a deterministic model, multiple runs must be condensed. This can be done by conducting multiple scenarios that vary demand, price, and resource availability. Internally consistent combinations of assumptions may be identified as scenarios and the results may be compared to each other or weighted to arrive at an expected value.

3.5.2 Stochastic Optimization Models

Stochastic models treat one or more variables as random. Multiple values for the random variables may be articulated and probabilities assigned. These models allow for the explicit consideration of uncertainty, which is desirable given the highly variable demand of many LDCs and the uncertainty associated with many gas supply contract parameters such as the future price and reliability of spot supplies relative to contract gas. ContractMix is one example of a stochastic optimization model (DFI 1991). One application of a stochastic optimization model is that it can directly address some of the most vexing questions regarding gas supply portfolio mix. As shown in the illustrative range of portfolios in Figure 3-1, LDCs must trade of higher storage costs and potential curtailment costs caused by spot purchases with higher minimum-take (overcommitment) costs caused by firm contracts.[7]

[7] Spot gas may cause storage costs to be incurred if it is deemed to be less reliable than firm contract supply.

Figure 3-1. Illustrative Output from a Stochastic Optimization Models: Total Expected Cost of a Range of Spot/Contract Portfolio Combinations (Source: DFI, 1991)



These models also allow for explicit modeling of demand uncertainty. Today, supply services are being differentiated by their notice requirements and "no-notice" services generally cost more than scheduled services. Thus, stochastic models also provide estimates of the cost implications of higher or lower demand uncertainty. Although stochastic models are conceptually superior and used by some electric utility fuel procurement departments, they are not widely used in the natural gas industry. The relative unpopularity of stochastic models is somewhat puzzling. They do require more data-- specifically, they require that key assumptions be defined in terms of a distribution of values rather than just point estimates-- but they automatically incorporate the effects of uncertainty which can affect decisions.

Methodology

The methods used to analyze representative LDC planning problems are described below. Our approach involves the development of a prototypical local gas distribution company for input into a commercially-available resource planning model. We describe the model used to simulate gas supply and demand of this LDC, the process of developing the prototypical LDC, and the resultant base case.

4.1 Resource Planning Model

This study uses the Sendout® model of EDS Utilities Division (1995). This model was chosen over other commercially-available resource planning models because its capabilities and features were adequate for analyzing the types of planning issues addressed here and because of its large market share, being used by nearly 60 LDCs in North America.

Sendout is a linear programming (LP) model, capable of performing global optimization to minimize total system cost given specified physical limitations and contract constraints. Sendout employs an algorithm that uses a full LP along with a network optimization to solve the gas supply planning problem.

Sendout can view the designated study period as one optimization interval or as a series of intervals regardless of length (e.g., one year or many years). An optimization problem is set up to balance supplies against demand for the interval. To solve the problem, the model determines the supply contract takes, storage injection and withdrawal schedules, and transportation dispatch that together minimize total variable operating cost, given the physical and reliability constraints. Costs taken into account include: supply contract costs and provisions such as minimum takes and penalties, transportation rates, capacity release revenues, storage injection, withdrawal, and carrying costs, and fuel losses.

The model typically uses monthly demand forecasts where loads are broken down by class and into heating and base portions. Loads can be defined for different areas within the system. Classes can be assigned different priorities of service by assigning them different values for the cost of unserved load. The heating portion of demand is allocated among the days of the month by heating degree days. Sendout breaks time into units called "subperiods" to optimize the dispatch. A subperiod can be as long as one month, in which all demand and flow constraints are aggregated into monthly numbers; as short as one day; or any value in between. Multi-day subperiods result in a subperiod "x" days long, where the demand each day is equal to the average demand over all *x* days. Generally, the user will define greater detail (shorter subperiods) in the winter when loads have more variability and less detail (longer or monthly subperiods) in the summer when loads are flatter.

Supply resources are modeled with standard contract prices and terms including variable and demand charges, constraints such as maximum and minimum flows on a daily, monthly, seasonal, or annual basis, and penalty costs for violating minimum flows. The pathway for a supply is defined by specifying the receipt and delivery interconnections with the pipeline network.

The transportation network is defined in terms of nodes (i.e. interconnects) and segments. Costs for pipeline tariffs include standard fixed and variable contract cost terms, flow constraints, and fuel losses that are modeled for each segment of the transportation network. Capacity releases can be modeled by specifying the expected revenue per unit of released capacity, the period of interest, and whether or not right of recall of capacity during periods of need is included in the release agreement, and the optimum amount of releasable capacity at that rate is calculated.

Storage resources are defined in terms of working gas capacity, minimum and maximum injection and withdrawal rates, fuel losses, and costs, inventory carrying costs, and monthly or daily minimum and maximum inventory levels. Volume-dependent deliverability can also be modeled, which is an important feature given that many types of storage withdrawal rates depend on inventory level. The model determines the optimal pattern of injections and withdrawals to minimize total cost subject to constraints.

Sendout can model LDC operations in two different ways. In the first, all facility sizes are fixed and the model dispatches facilities to minimize total variable cost. In the second, the user specifies a set of available resources and the model will choose their sizing and dispatch them to minimize total fixed and variable cost over the planning horizon.

4.2 Development of the Prototypical LDC

Every local gas distribution system is unique. In essence, no single LDC is ideal for the purpose of illustrating gas planning modeling issues. Furthermore, most LDCs are reluctant to share information at the level of detail needed for resource planning except under restricted confidentiality conditions. For these reasons, we developed and modeled a hypothetical LDC prototype rather than use a real company. We based our LDC prototype on data and statistics of actual U.S. gas distribution companies. Our prototypical LDC draws heavily upon modeling data provided to us by several cooperating gas utilities.[8] These data were synthesized into inputs that together provide a sound basis for key aspects of the prototypical LDC. Figure 4-1 diagrams the LDC system network with the resources that were modeled.

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8 These utilities requested anonymity and confidentiality of their Sendout data. However, in some cases data were publicly available in IRP filings, in which case we cite the utility and data source.

Figure 4-1. Network Diagram for the Prototypical LDC

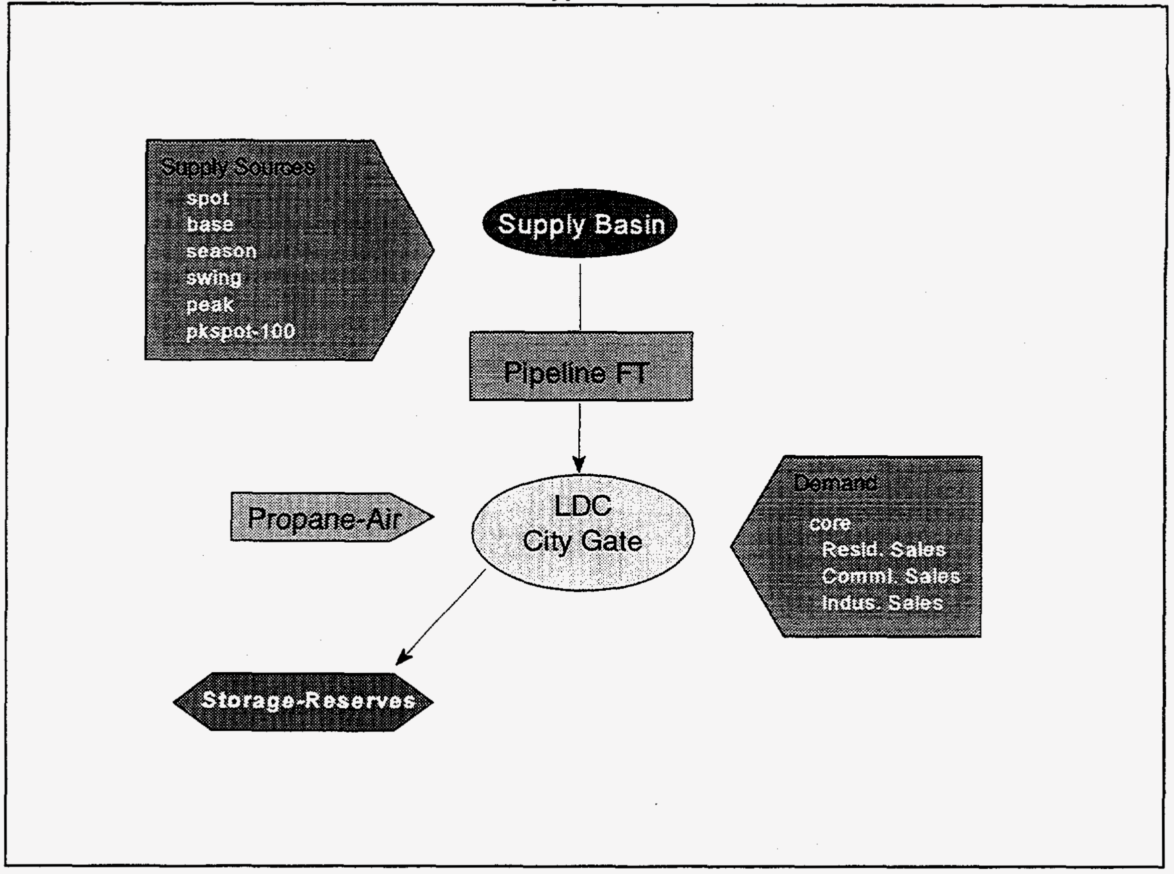


Table 4-1 summarizes the key demand, supply, transport, and storage resources of the LDC prototype. The basis of these assumptions are described further below.

Table 4-1. LBNL Prototypical LDC: Summary of Model Inputs and Optimal Resource Mix

Demand	Annual Sales (MDTh)	Base Peak Day (MDTh)	Load Factor			
Residential	61,100	667	25%			
Commercial	28,900	270	29%			
Industrial	24,200	91	73%			
Total	114,200	1,028	30%			
Supply	**MDQ (MDTh/day)**	**Daily Min. (% of MDQ)**	**Commodity ($/DTh)**	**Demand D1 ($/DTh/month)**	**Daily Penalty ($/DTh)**	
Base	164	77%	1.74	8.38	1.13	
Seasonal	172	97%	1.81	7.57	1.49	
Swing	124	20%	2.00	6.42	1.19	
Peak	50	-	3.63	9.68	0.65	
Spot	100	-	1.96	-	-	
Peaking Spot	100	-	3.72	-	-	
Propane-Air	300	-	6.47	2.78	-	
Transport	**MDQ (MDTh/day)**	**Demand D1 ($/DTh/month)**	**Variable ($/DTh)**	**Fuel Use (%)**		
Firm Transport	623	7.81	0.031	5%		
Storage	**With/Inj MDQ (MDTh/day)**	**Working Gas Capacity (MDTh)**	**Demand D1 ($/DTh/month)**	**With/Inj Rate ($/DTh)**	**Volume ($/DTh)**	**Carry-ing Rate (%/yr)**
Depleted Oil/Gas Reservoir	200	9,000	2.76	0.014	.03	10%

4.2.1 Planning Assumptions

- Ten-year study horizon (1994-2004).
- The downstream boundary for analysis is the citygate, which means that intra-service territory costs and flows are not accounted for.
- All prices are expressed in real terms (i.e., deflated by the inflation rate).

- All present-worth calculations use a six percent real discount rate.

- Only core customer demands are used; transport customer demands are not modeled.

- Supply and transportation capacities are sized to meet core customer peak-day demands plus a five percent reserve margin for supply contingency purposes.

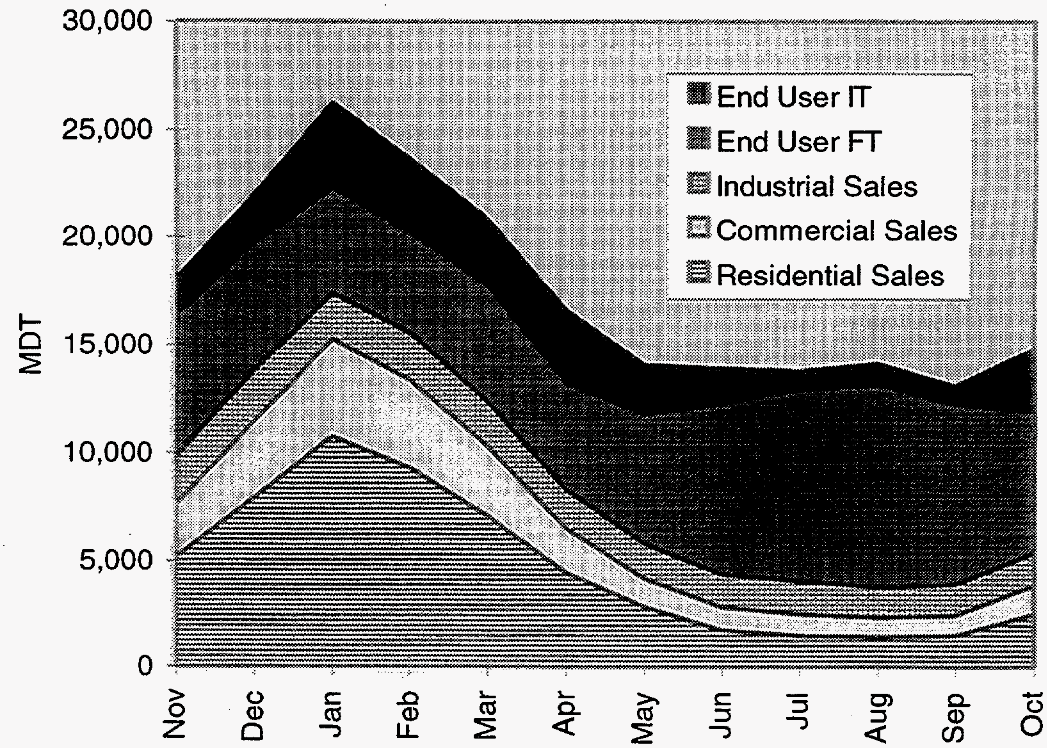
4.2.2 Demand

Annual base year demand of the prototypical LDC was scaled to match the mean of a survey of 70 LDCs in terms of supply disposition serving their own customers (EIA, 1995a). Supply disposition from that source includes both sales and transportation volumes. Total demand was broken down into residential, commercial, and industrial customer class portions and distributed over the months of the year based on national average data (EIA, 1995c). Commercial and industrial loads were further segregated into sales and transportation customer portions based on the breakdown from one of the cooperating utilities since its breakdown was the only Sendout input that characterized demand in that way and because there were no comparable national data available. Only the sales portion of demand was used in our analysis. Further, we modeled sales demand as firm; i.e., the utility has an obligation to serve all loads. Figure 4-2 shows the monthly demand profile for the prototypical LDC, including end-user transportation which was not explicitly modeled.

Monthly class loads were broken into base and heating portions by subtracting the lowest monthly consumption (which occurred in August for each class). Heating degree days for Spokane, Washington, were used to allocate the monthly heating portion of demand by days of the month. The Spokane weather data is a composite of historical data where each month is an actual month of heating degree days that most closely matches 30-year normals for that month. In order to capture weather extremes for capacity planning purposes, an extreme-cold peak day was grafted onto the month of January. This peak day is, again, based on historical temperature response ratios observed for Spokane. The resultant peak-day sendout using these data was 1,028 MDTh. Demand growth was two percent per year for all classes based on GRI projection (1994).

The model was set to perform daily dispatch for the five highest demand days in each winter month (i.e., November through March) and the three highest demand days in October and April. For the remaining days in the winter and swing months, and for the whole of each summer month, a single dispatch is performed on an average day load calculated for that period.

Figure 4-2. LBNL Prototype Demand Profile



Note: Core (residential and commercial) sales do not include extreme peak day.

4.2.3 Supply

Supply resources were based on actual LDC supply contracts drawn from the Sendout files of cooperating utilities. In reality, a variety of supply contracts exist. We observed five basic types: baseload (or base), seasonal, swing, peaking, and spot contracts. Each of the contract types vary in their ratio of fixed to variable costs, seasonality, minimum takes and, in the case of spot, reliability. Prices and contractual terms of each supply contract from cooperating utility modeling data were used to develop a single composite contract of each type of supply defined above (Table 4-1). Contract terms modeled include commodity and demand charges, minimum and maximum takes, and penalty charges associated with violating minimum takes. All price terms, including demand charges, were tied to NYMEX gas futures prices as multiplicative factors based on current ratios of contract price to spot price. NYMEX gas futures prices used were based on settle prices quoted out to October 1996.[9] Beyond the NYMEX futures time horizon, GRI (1994) gas price forecast of three percent real was used to extend the price trajectory out to October 2004.

Only one supply contract of each type was modeled. However, each supply contract was sized annually to simulate the effect of many smaller contracts expiring and being renegotiated at annual intervals. Contracts were sized using the optimization feature of Sendout, but with the following constraints applied to the optimization to meet reliability and portfolio management criteria: the maximum daily quantity(MDQ) of spot gas was limited to ten percent of peak supply capability (e.g. 100 MDTh/day), while minimum sizes of at least five percent of peak supply capability (e.g. 50 MDTh/day) were enforced for peaking and swing supplies. Thus, Table 4-1 shows that base, seasonal, and swing MDQs were chosen by Sendout's optimization module.

Prices for spot gas vary over the year. This effect is captured in our modeling in the NYMEX futures prices. However, during extreme cold weather conditions, spot prices for gas can—and historically have — risen significantly above those quoted for the month. Since LDCs with access to spot gas are likely to avail themselves of it during peak periods if the price is right, but for planning purposes may not want to count on it, we separately model a peaking spot gas facility in addition to the regular spot gas facility. The peaking spot gas is not put in the mix during capacity planning simulations (see Section 1.4 Modeling Approaches below). Peaking spot gas is priced at 1.9 times the NYMEX spot price which, after transportation costs are added, is slightly less than the dispatch cost of propane/air.

4.2.4 Transport

Transportation for the prototypical LDC's supply was modeled as a single pipeline contract for firm transportation (FT) from the supply basin to the city gate.[10] Transportation prices were set at the mean of published pipeline tariffs of 44 U.S. pipeline companies (Zinder Assoc. 1994). Applying the mean of pipeline tariffs accounts for the range in vintage and distance between supply and demand interconnects, and the price implications of those factors. Variable transportation charges were escalated as above for supply using NYMEX futures prices extended by the GRI Baseline forecast. Fixed transportation charges were assumed to track inflation (i.e. zero percent real growth).

Unlike supply, transportation was modeled as a longer-term commitment. Initial

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9 For the period up the present, prices are based the NYMEX gas futures quotes on the last day of trading for the month drawn from *The Wall Street Journal.*

10 Other types of transportation capacity that are generally available to LDCs are seasonal (Winter only) FT, released FT, and interruptible transportation (IT). For simplicity, we did not make such resources available to our prototype LDC.

transportation capacity was assumed to be committed through the third year (i.e., until October 1997) of the ten-year planning horizon, at which time the prototypical LDC's contract with the pipeline was up for renegotiation. It was further assumed that the pipeline capacity holding would be renegotiated for a five year period ending October 2002 and renegotiated again to extend until the end of the study period (e.g., October 2004). Pipeline tariffs were held constant in real terms throughout the time horizon. Transportation was sized to meet peak demand requirements plus a five percent reserve margin for supply contingency purposes.

4.2.5 Storage

Storage was modeled as a single depleted gas or oil reservoir connected directly to the city gate. The working gas capacity of the reservoir was based on the mean capacity of 14 storage facilities of our sample of cooperating LDCs. Maximum withdrawal and injection capacities are identical and set to provide 45 days of service at peak withdrawal capability. The 45 days of service level is the average of LDC-owned storage in the U.S. (EIA 1995). Costs are based on the mean value for seasonal storage (i.e., days of service greater than 30) located in market areas of a survey of 79 storage service offerings in the U.S. (Allemandou 1995).

4.2.6 Propane/Air Peaking

A single propane/air plant provides peaking service for the prototypical LDC.[11] Due to technical problems associated with large concentrations of propane mixed in with natural gas in a gas system, the size of the facility was fixed and limited to 30 percent of the peak-day sendout in the base year. Propane prices were indexed to the NYMEX gas futures price and GRI forecast based on the historical relationship between the two fuels (i.e. propane/natural gas price ratio of 3.3). Fixed costs of the propane/air plant are based on those quoted by R.J.R. Rudden (1993) amortized over 30 years at an 8 percent real discount rate.

4.3 Modeling Approach

Each of the planning issues analyzed in the next chapter uses the Sendout model and prototypical LDC just described. Our modeling approach involves each "run" or "case" being actually a sequence of two simulations: the first to size the facilities and the second to dispatch resources. In the first simulation, transportation and supply contracts are optimally

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11 Liquid natural gas (LNG) storage and vaporization plants represent another common peaking resource. For simplicity, we chose only propane/air for inclusion in the prototype LDC.

sized to meet design peak demand (base peak + a 5% reserve margin for supply contingency) without any peaking spot gas available. In the second simulation, contract sizes are fixed based on the first simulation and resources are dispatched against base demand (i.e, without the 5% supply contingency reserve margin) and with 100 MDTh/day of peaking spot gas available. The rationale for inserting peaking spot gas between the two simulations is that for reliability planning purposes, LDCs may not want to rely on peaking spot gas during extreme cold weather conditions, but may want to use spot gas during such episodes if there is excess pipeline capacity available (which is likely with the reserved margin used in the first simulation) and the dispatch cost is less than other resources available to them at the time.

4.4 Base Case

Table 4-2 summarizes the base case prototypical LDC simulated costs.

Table 4-2. Summary of Prototypical LDC Base Case Dispatch and Costs in the First Year ($ Thousand, except where noted)

Supply	
Base Contract Take (MDTh)	58,967
Season Contract Take (MDTh)	25,817
Swing Contract Take (MDTh)	13,924
Peak Contract Take (MDTh)	204
Spot Take (MDTh)	10,552
Peaking Spot Take (MDTh)	66
Propane/Air Take (MDTh)	205
Commodity Cost	161,018
Reservation Cost	39,981
Total Supply Cost	200,999
Transportation	
Variable Cost	2,760
Demand Cost	56,764
Total Transportation Cost	59,524
Storage	
Injection Cost	113
Withdrawal Cost	102
Carrying Cost	654
Other Variable Cost	1,390
Total Variable Cost	2,260
Demand Cost	6,440
Total Storage Cost	8,700
System Cost	269,223
City Gate System Average Cost ($/DTh)	2.58

Avoided Costs for DSM

5.1 Introduction

Avoided costs are the costs the LDC would otherwise incur but for the implementation of alternative supply or demand-side resources. The concept of avoided costs grew out of national legislation known as the Public Utilities Regulatory Policy Act (PURPA) of 1978. The intent of Section 210 of PURPA was to encourage private investment in the electric power industry by mandating that electric utilities purchase power at a rate called avoided cost. Since then, the use of avoided costs has expanded to become the value standard for screening both supply and demand resources (CPUC and CEC 1987) and used in rate design (Stutz et al. 1994) in the electric industry. In the natural gas industry, the dominant application for avoided costs is in evaluating demand-side management programs.

Avoided costs are comprised of several components: commodity costs, capacity (or deliverability) costs to the city-gate, local transmission and distribution costs (LT&D), and customer-related costs. The largest single component of avoided costs by far is the commodity cost, followed by capacity cost. We focus exclusively on these latter two components of avoided cost and the methods for calculating them.[12]

Methods are described in detail in Goldman et al. (1993). Gas LDC experience with estimating and using avoided costs is limited; at present no single method has emerged as the generally accepted superior approach. Every method has advantages and disadvantages and which method is the most appropriate one to use depends in the goals and specific needs of the application and the resources at hand. Beyond the specific methods, there are a host of analytical issues that need to be addressed in any avoided costing exercise (Lerner and Sloan, 1994; Feingold 1992).

The analysis undertaken here describes several avoided cost methods, estimates avoided costs for our prototypical LDC using these methods, and performs sensitivities of the results to various assumptions.

12 Many LDC resource planning models can capture local transmission segments and costs, which would leave distribution and customer-related costs to be handled exogenously.

5.2 Modeling Issues

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 block can influence the resulting estimates of avoided cost. Generally speaking, 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. Likewise, the quantity of cost-effective DSM resource is dependent on avoided cost. Therefore, there is an interdependence between decrement block size and avoided cost that calls for an iterative solution in which an equilibrium is 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.[13] It is imperative that the initial size of the resource block be verified through subsequent DSM resource screening in order to arrive at a plausible estimate of avoided cost.

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, as a practical matter, LDCs usually assume some characteristic shape (or set of shapes) in developing avoided costs. Figure 5-1 depicts two characteristic block shapes as decrements superimposed on a load duration curve. One is a "rectangular" or "baseload" block with the same load impact throughout the period, which would correspond to the impact one might expect from efficient commercial cooking DSM programs that would have constant impacts over the year. The other is a proportional block that is a fixed percentage of the base case system load shape, which would correspond to the impact of programs targeting end-uses sensitive to outdoor temperature, such as DSM programs that promote furnaces.

Classic generic load shapes used to develop DSM avoided costs include, in addition to the baseload and proportional blocks described above, heating season, peak day, and summer load building (for gas cooling) blocks. These load shapes will be used in our analysis covered below.

The final modeling issue concerns the time resolution of avoided costs. In theory, avoided costs for gas could range from daily to annually. The appropriate time resolution depends on the needs of the application. Software tools for screening DSM programs generally have characteristic time steps that dictate how avoided costs are input. Perhaps more importantly,

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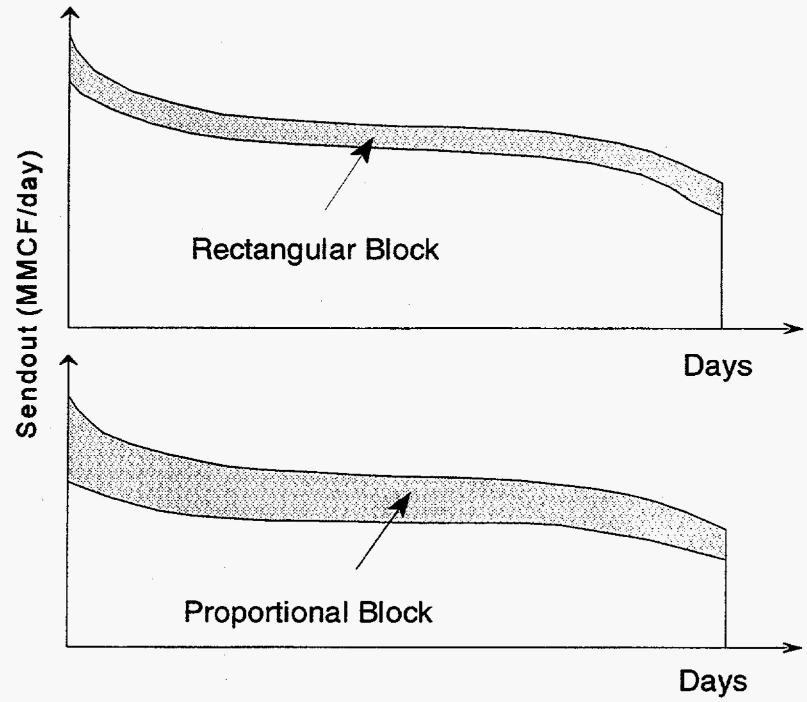
13 An initial guess of resource block size is used to estimate avoided cost, which is then used to screen DSM programs. The quantity of cost-effective DSM passing the screen is then compared to the original resource block size. If the quantity of cost-effective DSM is smaller than the resource block, then the resource block size is reduced (or vice versa) and the procedure is repeated until equilibrium is reached.

Figure 5-1. Load Shapes of Decrement Blocks



the inherent variability of the avoided costs should influence the chosen time resolution. If avoided costs vary little over some time period, then aggregating them loses little information, but if they vary a lot, then aggregating them could introduce inaccuracies in their use. At one end, the gas planning model used for calculating avoided costs will limit how fine a time resolution is possible. For instance, Sendout performs a daily dispatch so daily avoided costs would be finest level of time resolution possible with this model. Also, some gas planning models may be limited in their reporting capabilities such that it may be impossible to calculate avoided costs to the same time resolution as dispatch is performed. Here, we have chosen to report avoided costs on a monthly basis.

5.3 Methods of Computing Avoided Costs

5.3.1 Average Cost

With average costing methods, incurred costs are counted and divided by the total gas sendout over some period. The costs included vary by the measure. For instance, the weighted average cost of gas (WACOG) customarily includes supply costs incurred at the city gate including any supply fixed charges and costs of storage operations, but does not typically include pipeline transportation[14] or local transmission and distribution (LT&D) costs. System average unit costs may be inclusive of all costs or include only some parts. In all, average cost methods are the most straightforward and simple of all avoided costing approaches because the data are readily available and depending on the particular circumstances, a sophisticated model may not have to be used in order to make credible estimates of future average unit costs.

Here we calculate two average cost methods. Using Sendout, we calculate WACOG in the manner described above. We also calculate a City Gate System Average Cost that includes all supply, storage and transportation charges incurred at the city gate, but none within it.

5.3.2 Marginal Cost

Marginal costs are the change in costs due an infinitesimal change in gas demand. Because the load change is small—infinitesimal to be exact—no structural change to the mix of resources serving gas loads is considered. For this reason, this method is sometimes referred to as the instantaneous avoided cost approach because it measures the static cost response to demand of the system as it exists and envisioned under base case conditions. It measures the variable costs of the next unit of gas not dispatched. System marginal cost is a standard output of many gas system planning models.

The instantaneous method produces what is essentially a short-run marginal cost and may only be valid for short-term valuation of small gas DSM programs. This method lends itself to easy time-differentiation but depends on the specific capabilities of the planning model being used.

When using the marginal cost method, it is customary to use the base case as the basis for estimating avoided costs. The rationale for this states that to use a case other than the base case which already incorporates DSM would underestimate the value of load reductions at the margin for conservation (and visa versa for load building). While there is some dissent on this point (Parmesano 1987), we will follow conventional practice in reporting base case marginal costs.

The Sendout model calculates marginal cost as the variable supply and transportation costs at the city gate of the next unit of gas not dispatched. The LDC prototype is configured to simulate dispatch based on representative days in each month, with more detail in the winter and less in other months. This results in five marginal cost estimates for each winter month, three marginal costs for each swing month (i.e. April and October), and one each for the

14 Fuel losses and/or in-kind gas used in transporting supply to the city gate may be included in WACOG depending on how these are accounted for between parties.

summer months. We averaged these results into monthly marginal costs for reporting purposes.

5.3.3 DSM In/out

This method calculates the cost difference between two LDC system simulations: one with the DSM impacts (i.e., the "in" simulation) and one without it (i.e., the "out" simulation which is the base case). Invariably this method relies upon the use of an LDC resource planning model in order to accurately capture these cost differences. Because this method directly examines the cost impact of the change in load brought about through the contemplated DSM program (or programs), it comes the closest of any method to embracing the spirit of the concept of avoided cost. In practice this method still entails making simplifying approximations to make analysis tractable. These approximations principally take the form of generic load shape and magnitude changes instead of the actual forecasted DSM program impacts. Then, when evaluating the cost-effectiveness of particular DSM programs, one chooses the set of avoided costs based on the generic load shape or combination of generic shapes that most closely match those of the program (Rudkevich and Hornby 1994).

The DSM in/out method can produce either short-run or long-run avoided costs depending on what type of modeling is undertaken. If gas supply and transportation facilities are held constant for the two simulations, then the resulting avoided costs will be short run avoided costs. If the supply and transportation facilities are optimally sized for the two simulations, then the resulting avoided costs will be long-run avoided costs. Since the full tradeoff of fixed and variable costs are captured in the gas optimization model, this long-run DSM in/out method is identical to the method known as *differential revenue requirements* sometimes used in the electric industry. Our application of the DSM in/out method uses this latter, long-run avoided cost approach.

The mechanics of performing the DSM in/out avoided cost methodology are as follows. Each in/out simulation is done in two steps.[15] First, the model is used to optimize the system using a five percent reserve margin and with no peaking spot gas assumed available. Second, based on the results of the optimization, the supply contract sizes and pipeline capacity are fixed and the gas system is dispatched using core customer demands only (with no reserve margin) and with peaking spot gas available. The presence of storage makes monthly cost accounting slightly more complex. We adjust the system cost of the in/out runs for the value of gas injected into or withdrawn from storage for any given period. Also, below we show a sensitivity case of the DSM in/out method where the demand impact is also adjusted for net storage withdrawals for any given period (see Figure 5-13).

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15 Since the DSM out case is actually the base case, only the DSM in case follows this procedure. However, the base case was developed in an identical manner.

5.3.4 Increment/decrement

The increment/decrement method is similar to DSM in/out except that instead of using the base case in the DSM out run, an increment run is performed if the DSM in run is a decrement (i.e., conservation or peak-shaving), or a decrement run is performed if the DSM in run is an increment (i.e., load building). Another way to think of the increment/decrement avoided cost is that it evaluates the cost impact of load changes *about* the base case, rather than between the base and DSM cases as the DSM in/out method does.

5.3.5 Proxy

In proxy approaches, 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 DSM could entirely displace specific resources in the supply mix, and these displaced resources theoretically serve as proxy for the value of DSM. The proxy resource could be the most expensive supply and capacity facilities or the last supply resources (and its associated transportation) dispatched.

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. The challenge of selecting a proxy resource is not unlike the decision of selecting appropriate decrement blocks (discussed above).

When load-reducing DSM is placed in the resource mix, proxy resources are either canceled outright or deferred.[16] 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).[17] 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. Instead of being canceled altogether, the date on which the proxy resource is introduced into the supply mix can also be delayed as a result of DSM. Determining how long to defer the proxy resource and the value of that delay is more complicated; a discussion of that procedure can be found in Goldman et al. (1993).

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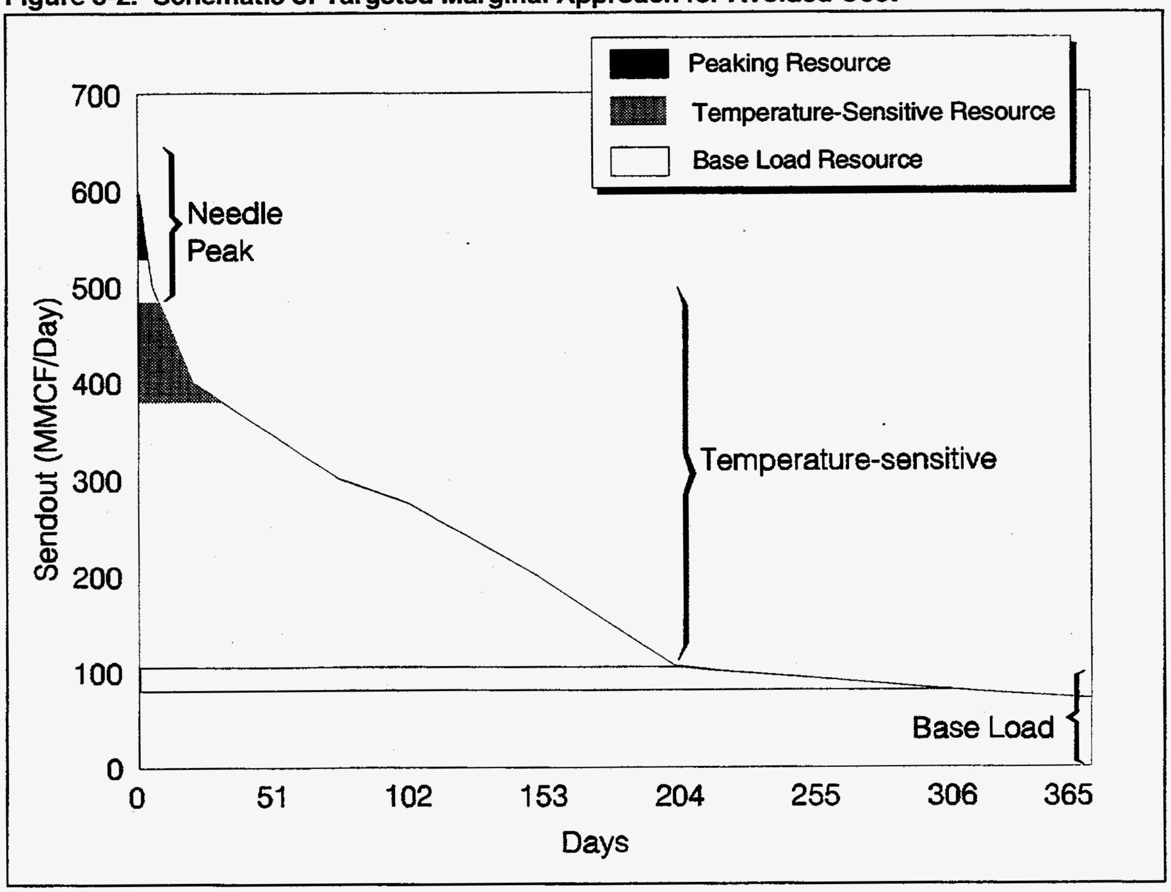
16 This description of the proxy methodology assumes load-reducing DSM but is applicable to load-building DSM with appropriate adaptations.

17 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.

A noteworthy variation of the proxy approach is the targeted marginal cost (TMC) method. 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 5-2 shows a schematic annual LDC load duration curve with loads segmented into three categories and with the last resource dispatched in each category 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.

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 what would emerge from an explicit supply

Figure 5-2. Schematic of Targeted Marginal Approach for Avoided Cost



planning process, so this benefit depends heavily on the skill of the analyst to accurately disaggregate and match up appropriate supply and demand elements.

Proxy methods are mentioned for completeness, but are not analyzed further in this report. Next we turn to results of calculating avoided costs using the above methods (save the proxy method) with our prototypical LDC.

5.4 Results

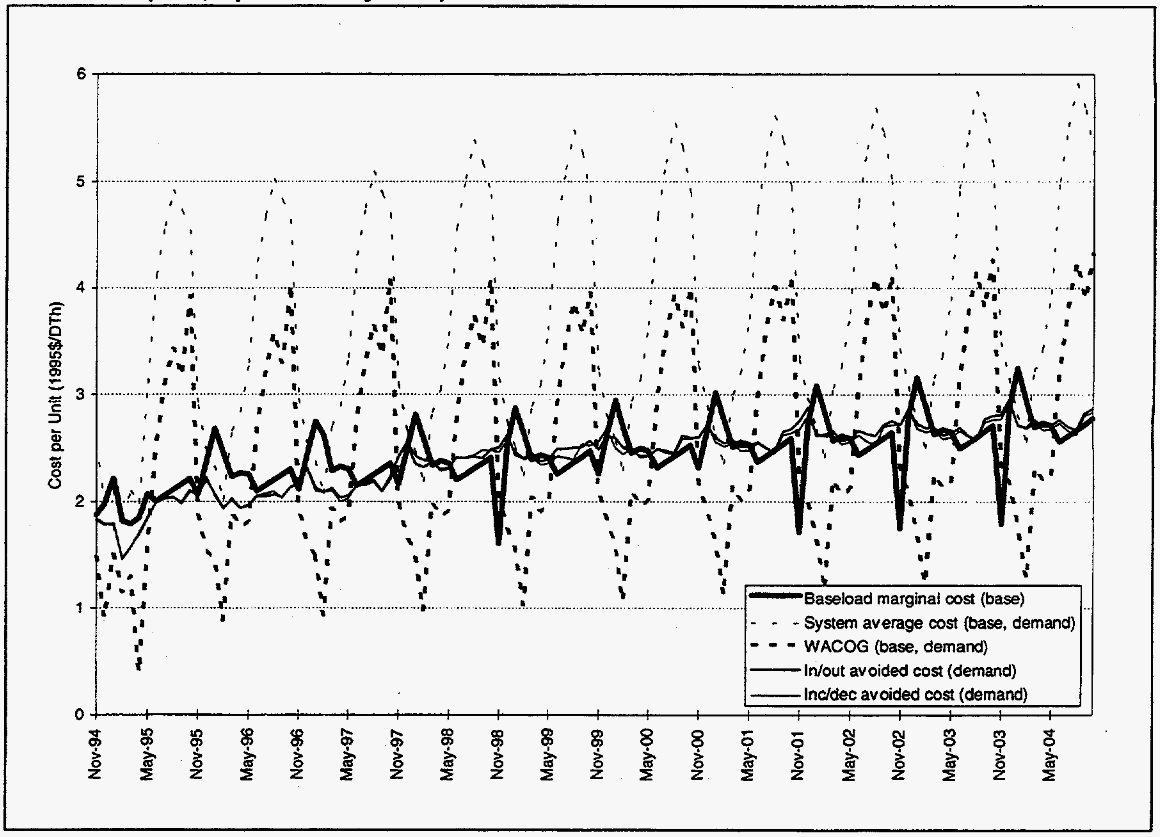
Monthly avoided costs were calculated using average cost, marginal cost, DSM in/out, and increment/decrement methods for the prototypical LDC. As described above, the latter two methods require a load shape for computing load impacts relative to the base case demand forecast. We calculate DSM in/out and increment/decrement avoided costs using baseload, heating season, peak day, and cooling/summer load building load shapes. For the marginal cost method, Sendout only reports marginal energy cost. Marginal capacity cost is calculated as follows. For baseload and heating DSM, the marginal capacity cost is based on the firm transportation demand charge adjusted by the load factor for the respective decrements (assumed to be 100% for baseload, 49% for heating) and increased by a five percent reserve margin for supply contingencies. For peak DSM, the marginal capacity cost is based on the capital cost of a propane-air plant (i.e., $33.31/DTh/day) (R. J. Rudden Assoc. 1993). In all cases, avoided costs are calculated for costs incurred *at the city gate* and not within the boundaries of the LDC.

5.4.1 Baseload

The first set of avoided costs are estimated for baseload DSM. The decrement is ten DTh/day, which is one percent of peak-day demand and three percent of annual demand.[18] Figure 5-3 shows the different measures of avoided cost calculated on a per unit demand impact basis. WACOG and system average cost, averaging $2.52 and $3.78 /DTh, respectively over the ten-year time horizon, also fluctuate over a large range over any given year, from around $1 to $7/DTh. During the summer months, WACOG is high due to the combination of low demand (the denominator) and the cost of storage injections made in anticipation of winter demands (the numerator). For similar reasons system average cost is high and also because fixed costs are spread over fewer gas sales. Marginal costs, averaging $2.44/DTh, generally fluctuates annually over a range of 1.5 to 3 $/DTh. DSM in/out avoided cost exhibits the least annual swings (except for the initial year due to higher gas price fluctuations in that year), averaging $2.30/DTh over the time horizon.

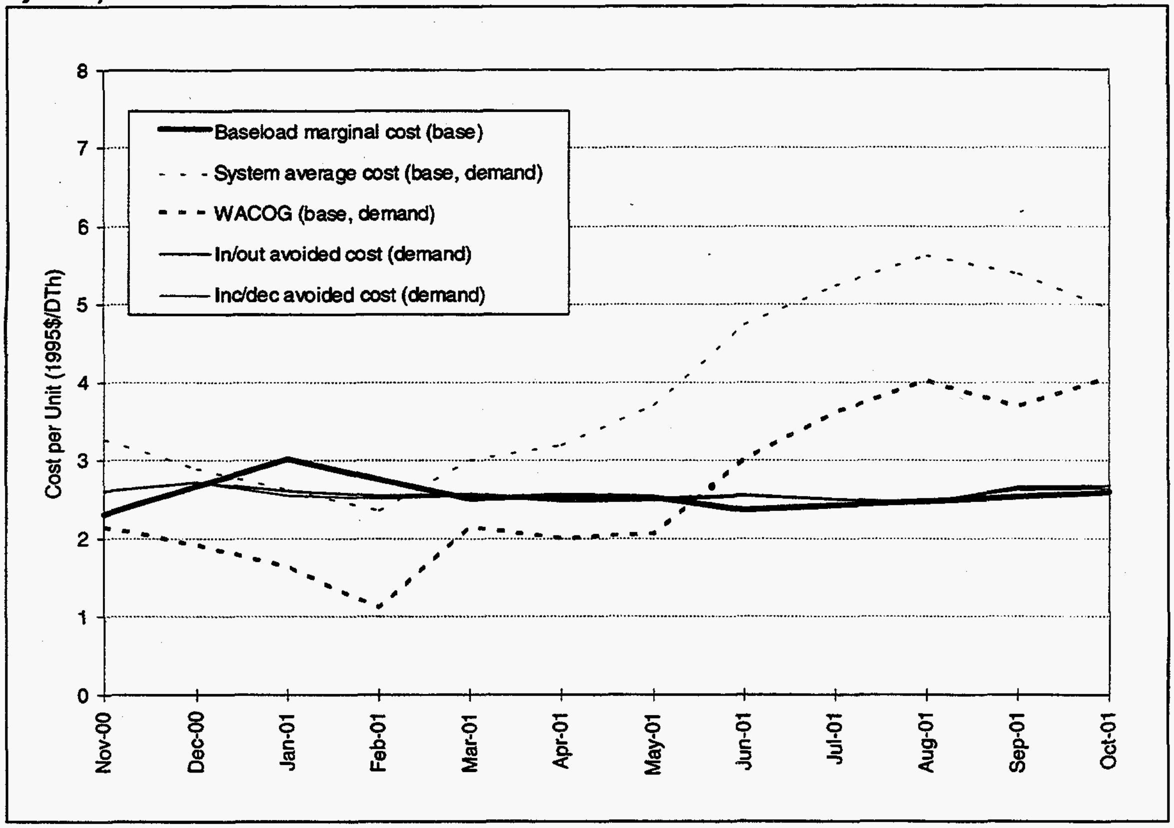
[18] Note that we report marginal cost and average cost (i.e., system average cost and WACOG) results from the base case, which are, therefore, not dependent on the scale or type of DSM decrement.

Figure 5-3. Baseload DSM Avoided Costs (baseload decrement @ 10 MDTh/day; per unit demand impact; optimized system)



To magnify the annual patterns, Figure 5-4 focuses on avoided costs in one heating year (2000/01) in the middle of the planning horizon. System average cost is consistently high, particularly during the low demand summer months when fixed charges are spread among lower gas volumes. WACOG fluctuates over a relatively wide range over the course of the year because of storage injections and withdrawals. Marginal cost also fluctuates though not to the extent or with the same pattern as WACOG. DSM in/out remains comparatively flat over the year for either the per unit demand or per unit supply impact measure. Increment/decrement avoided costs are nearly identical to DSM in/out avoided costs at the ten MDTh/day decrement level. These annual patterns are typical for baseload DSM avoided costs throughout most years of the planning period.

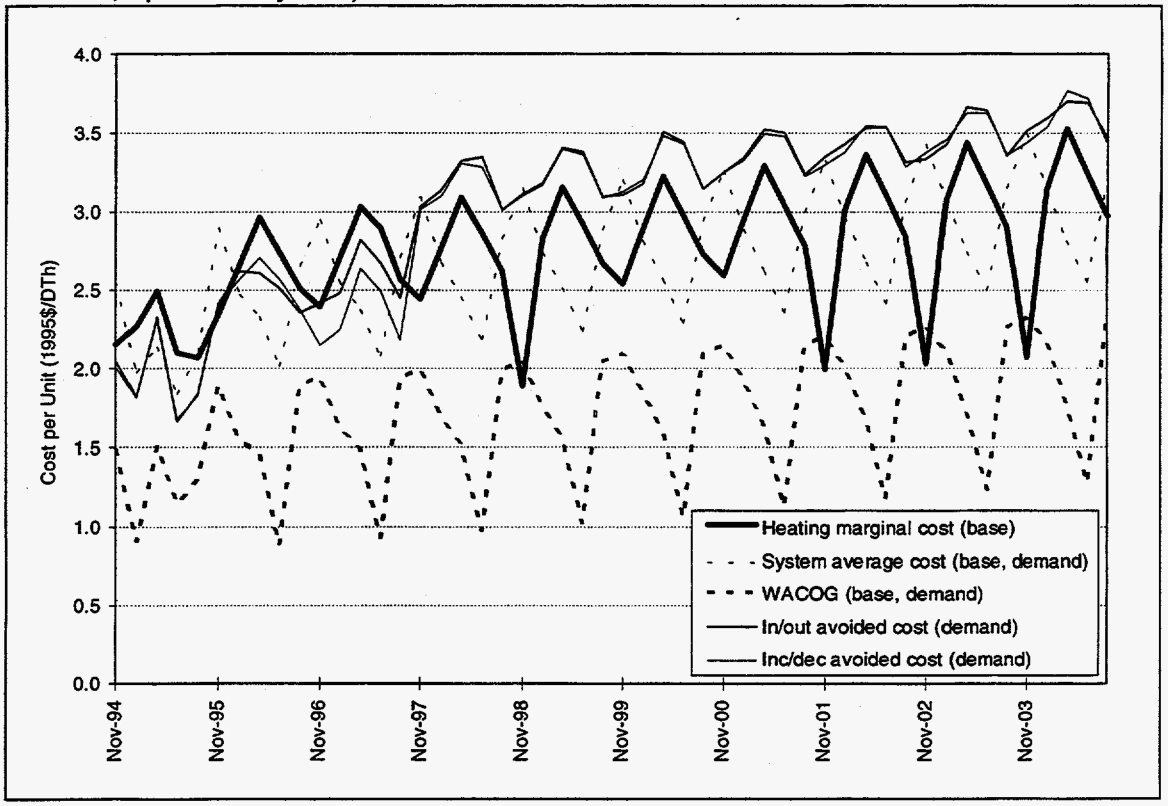
Figure 5-4. Baseload DSM Avoided Costs (baseload decrement @ 10 MDTh/day; optimized system)



5.4.2 Heating Season

Most U.S. gas LDCs sell a significant proportion of their gas during the winter heating season—November through March. Changes in loads during this period should have larger cost impacts than those occurring during the rest of the year; hence avoided costs should be higher as well. This is borne out for all but the average cost calculations presented in Figure 5-5. DSM in/out avoided costs average $3.94/DTh and marginal costs average $2.76/DTh. The average cost methods produce lower heating avoided costs because high throughput in this season reduces unit costs. Accordingly, system average cost is $2.70/DTh and WACOG is $1.70/DTh.

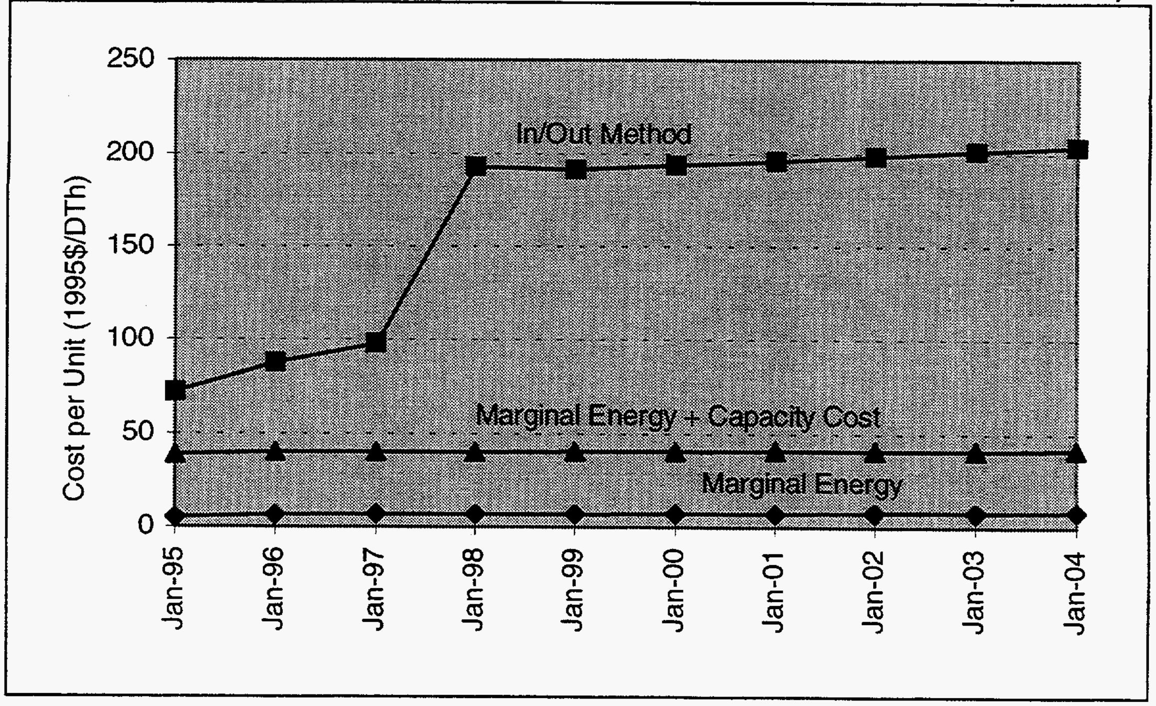
Figure 5-5. Heating DSM Avoided Costs (heating decrement @ 10 MDTh/day average Nov-Mar; optimized system)



5.4.3 Peak Day

Capacity to deliver gas to customers is designed to meet expected peak-day loads. (In Chapter 8, we examine the criteria by which "expected" peak-day gas loads are often determined and the economic implications of varying those criteria). Depending on the combined demand profile of the customers the LDC is obligated to serve (and hence provide high reliability through sufficient deliverability capacity), much of the capacity needed to meet peak-day loads may be highly underutilized for the rest of the year. Avoided costs for peak-day DSM are typically much higher than for baseload or heating season DSM, often by one or even two orders of magnitude, essentially due to the high capacity cost component. Figure 5-6 shows peak-day marginal cost and DSM in/out avoided costs. The distinction between these two avoided cost measures is striking, with DSM in/out averaging $154/DTh and marginal cost averaging $40/DTh. The large shift upward of DSM in/out avoided cost occurs in the year the LDC's current pipeline capacity holding is renegotiated upon expiration of their agreement. The peak saving decrement of 10 DTh allows for a corresponding reduction in the LDC's pipeline commitment that incurs year-round costs, and this is reflected in peak saving DSM avoided costs approaching $200/DTh. The marginal cost

Figure 5-6. Peak-Day Avoided Costs (DSM in/out method; 10 MDT decrement; optimized)

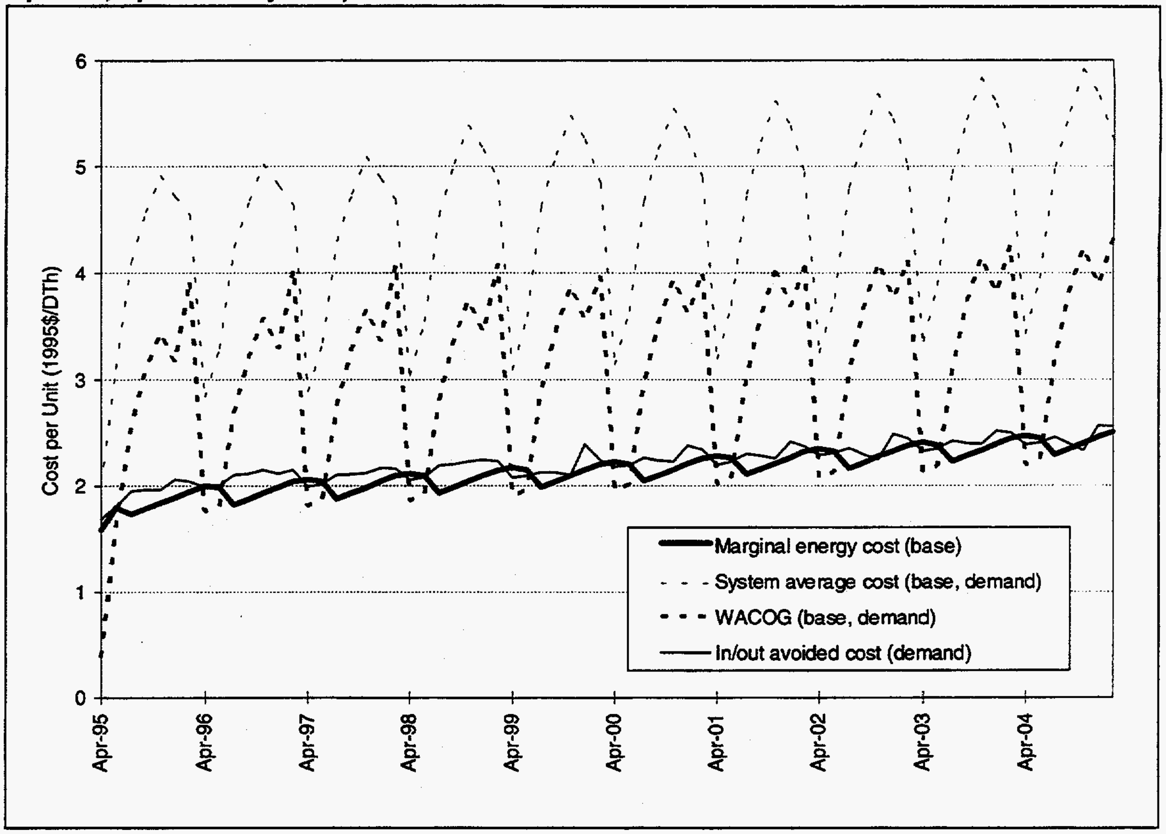


approach does not capture this dynamic of the planning process and is a key disadvantage of relying upon it for avoided cost estimation.

5.4.4 Summer Cooling

For many gas LDCs, increasing gas demand during the traditionally low summer season is an attractive way to get better utilization of resources and increase the system load factor. DSM programs promoting gas cooling technologies for residential and commercial customers are seen in this light. Because relatively low cost supplies are available during this time of year, avoided costs should be relatively cheaper than during other times of the year. Avoided costs in this context are calculated based on a load increment since the intent of the DSM program is to build load. In terms of how they are used in benefit/cost tests, cooling DSM avoided costs fall on the cost side, while the benefits come from increased revenues of incremental gas sales. Figure 5-7 shows DSM avoided costs for the cooling season covering the months April through October. System average cost and WACOG vary over an extremely wide range and are considerably higher overall (4.57 and 3.12 $/DTh, respectively) than marginal cost or DSM in/out due to the cost of storage injections and low gas sales over which to spread costs (especially fixed costs). Marginal costs, averaging $2.14/DTh, are generally the lowest of the methods shown except for a few months in each summer season where they overlap with DSM in/out, averaging $2.06/DTh. Note that the marginal cost method only incorporates the energy component of avoided costs since capacity is so underutilized during this period that any change in summer demand has no influence on capacity requirements.

Figure 5-7. Cooling DSM Avoided Costs (cooling increment @ 10 MDTh/day average Apr-Oct; optimized system)



5.4.5 Summary of Results by Method

Overall, increment/decrement and DSM in/out methods differ little in pattern or magnitude for the size of DSM impacts studied here. These two methods also exhibit the least monthly variation over the applicable season of any of the methods studied. Marginal costs are generally lower than DSM in/out or increment/decrement avoided costs and show more monthly variability. Average cost methods give the wrong cost signals, undervaluing savings during winter and peak periods and overvaluing savings during the summer period. Average cost avoided cost methods are thus the least desirable of those presented here.

5.5 Sensitivities

Scale effects of DSM in/out avoided cost from decrement size are shown in Figures 5-8 and 5-9 for baseload and heating decrements, respectively. The previous analyses were based upon a decrement size of 10 MDT/day. These figures show four decrement sizes from 10 to 40 MDT/day. Earlier we posited that larger decrements would lead to lower avoided costs. Our calculations show virtually no scale effects of decrement size on DSM in/out avoided cost. This is probably a consequence of how supplies and transport are modeled for our prototypical LDC. Supply contracts of each type (e.g. base, seasonal, swing, etc.) are aggregated together into one large contract. Transportation is similarly aggregated into one composite pipeline. This type of configuration masks the diversity and range of contract prices which changes in decrement size might unveil in avoided costing. Thus, for LDCs with a diverse portfolio of supplies of each type and transportation options articulated in the resource model, decrement size should influence avoided cost more than shown here.

For gas utility avoided costing purposes, assumptions regarding commodity and capacity price escalation are among the most important. In the base case, commodity prices are assumed

Figure 5-8. Baseload DSM Avoided Cost at Different Decrement Levels (DSM in/out method; baseload decrement; optimized system)

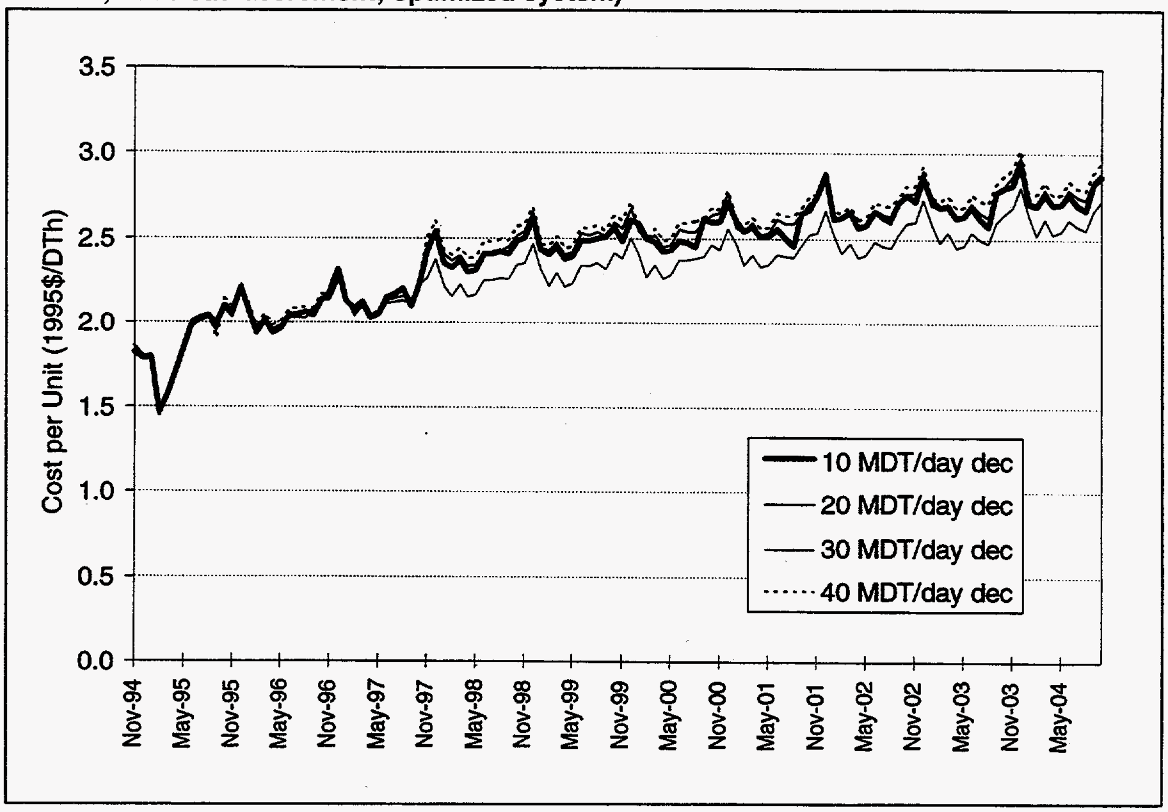
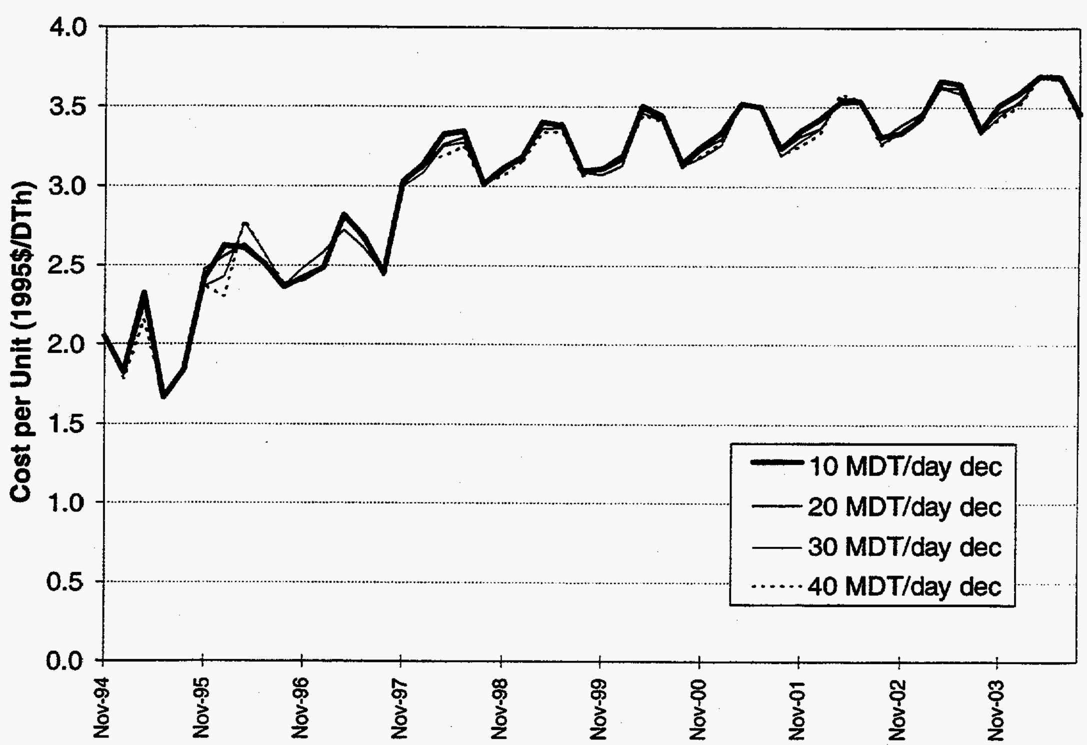
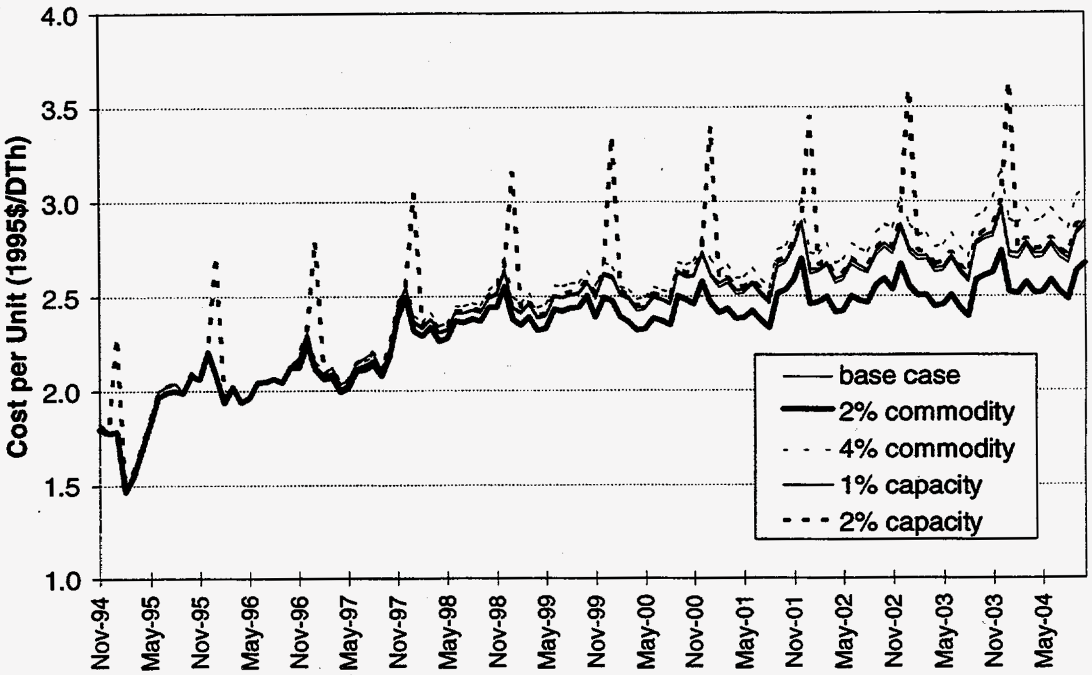


Figure 5-9. Heating DSM Avoided Cost at Different Decrement Levels (DSM in/out method; heating decrement; optimized system)



to escalate in real terms over the ten-year planning horizon at an average of three percent based on the most recent GRI forecast (GRI 1994), while fixed pipeline and storage costs are assumed to track inflation (i.e., escalate at 0% in real terms). We examine variations to these assumptions where commodity prices escalate at two and four percent, and capacity costs escalate at one and two percent shown in Figure 5-10. Using DSM in/out avoided costs as the basis for comparison, commodity price escalation changes cause the largest impact overall. Raising the commodity price escalation rate one percent causes a 3.1 percent increase in the ten-year average DSM in/out avoided cost, whereas a one percent decrease in the commodity price escalation rate causes a 3.8 percent decrease in avoided cost. Because our avoided costs are ten-year averages, it is no surprise that a one percent change in the annual escalation rate has a greater than one percent impact on the avoided cost. A one percent change in the capacity price escalation assumption causes only an 0.6 percent increase in avoided cost, whereas a two percent capacity escalation causes an 3.6 percent increase. Most of the avoided cost impact of the latter case occurs in the month of January of each year, the month in which the peak day occurs and around which most capacity decisions are made. We believe the ability to capture the relationship of avoided costs to escalation rate assumptions is one rationale for using resource planning models for avoided cost estimation.

Figure 5-10. Price Escalation Sensitivity of DSM In/Out Avoided Cost (baseload decrement @ 10 MDTh/day; optimized system)



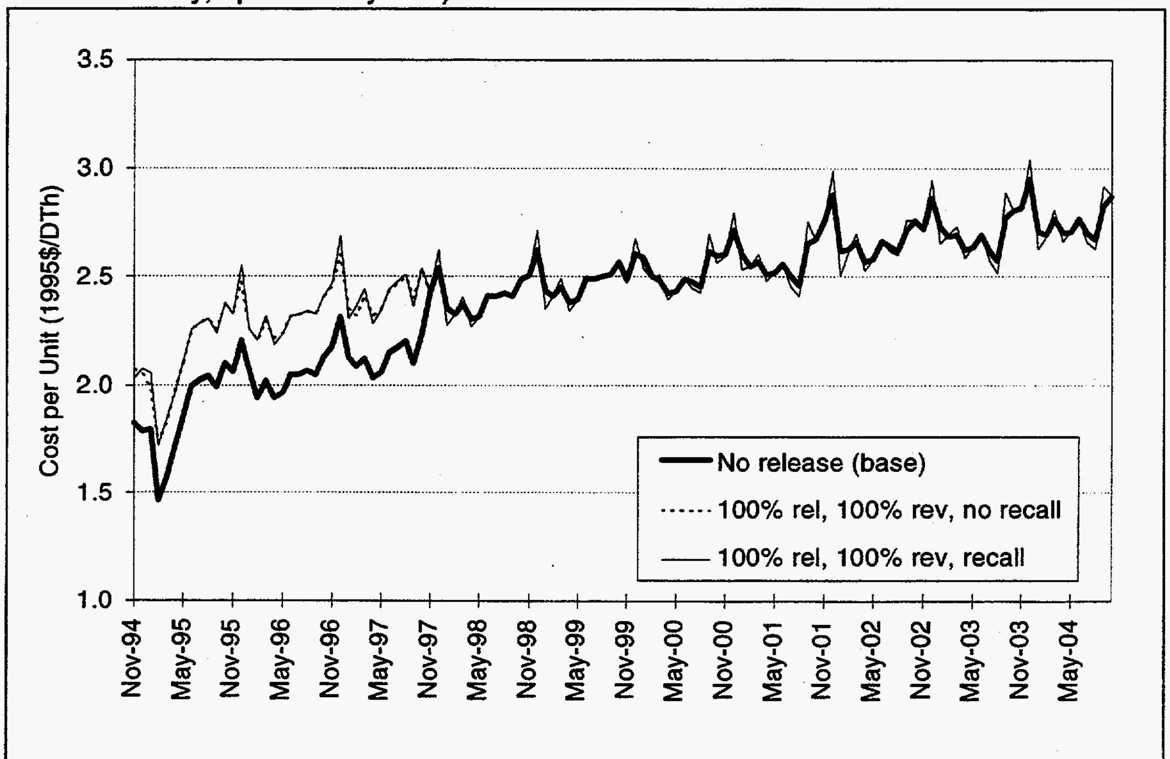
Note: Base case: commodity escalation 3% real, pipeline and storage capacity escalation 0% real.

Many LDCs are participants in the capacity release market created by FERC Order 636. This market allows holders of pipeline capacity rights to release their capacity to third parties in exchange for market-determined prices (subject to maximums of no more than the FERC-approved pipeline charges). The existence of such a market for unused capacity could influence avoided costs of DSM by essentially making near-term capacity commitments more liquid or avoidable. The impact on avoided cost will be influenced by a number of factors including: the amount of excess capacity, the proportion of the full capacity costs recovered in the secondary market, the amount of potentially releasable capacity the LDC is willing to release at any given time, the frequency of entering into capacity release agreements and their duration, and whether the right of recall during times of need is part of the agreement. We assume the LDC makes a capacity release decision once per year over the planning horizon and releases capacity for one year. In order to show the maximum impact of capacity release on avoided costs we consider cases where the utility releases 100 percent of available capacity and recovers 100 percent of capacity costs in the secondary market.

Figure 5-11 compares DSM in/out avoided costs of the base case (with no capacity release) to two cases: one with and one without right of recall. Avoided costs are higher with capacity release in the years prior to renegotiating the pipeline capacity holdings (i.e., November 1997). The reason is that the DSM decrement does not defer the fixed costs of this excess capacity, but the capacity release mechanism allows the LDC to recuperate these costs, and furthermore the DSM decrement enables the LDC to reap greater revenues over this pre-renegotiation period. However, after the pipeline capacity holding is renegotiated to the actual requirements of the LDC—in both the base and decrement cases—then there is little difference between the net costs (system costs less capacity release revenues) with or without capacity release. Whether or not the right of recall is part of the capacity release agreement has no impact on avoided costs. While the absolute level of capacity release revenues are significantly different between the two cases since right of recall allows the LDC to release much more capacity, the net revenues from the DSM decrements are nearly identical. In sum, the presence of an active secondary market for excess LDC capacity affects avoided costs only insofar as the LDC is unable or unwilling to adjust its pipeline capacity holdings to changes in demand.

Finally, we examine sensitivities of avoided cost results to a few modeling issues. The first issue concerns whether or not the supply and capacity portfolio is held fixed in running the decrement or increment simulations. In the cases covered above, the portfolio is optimized

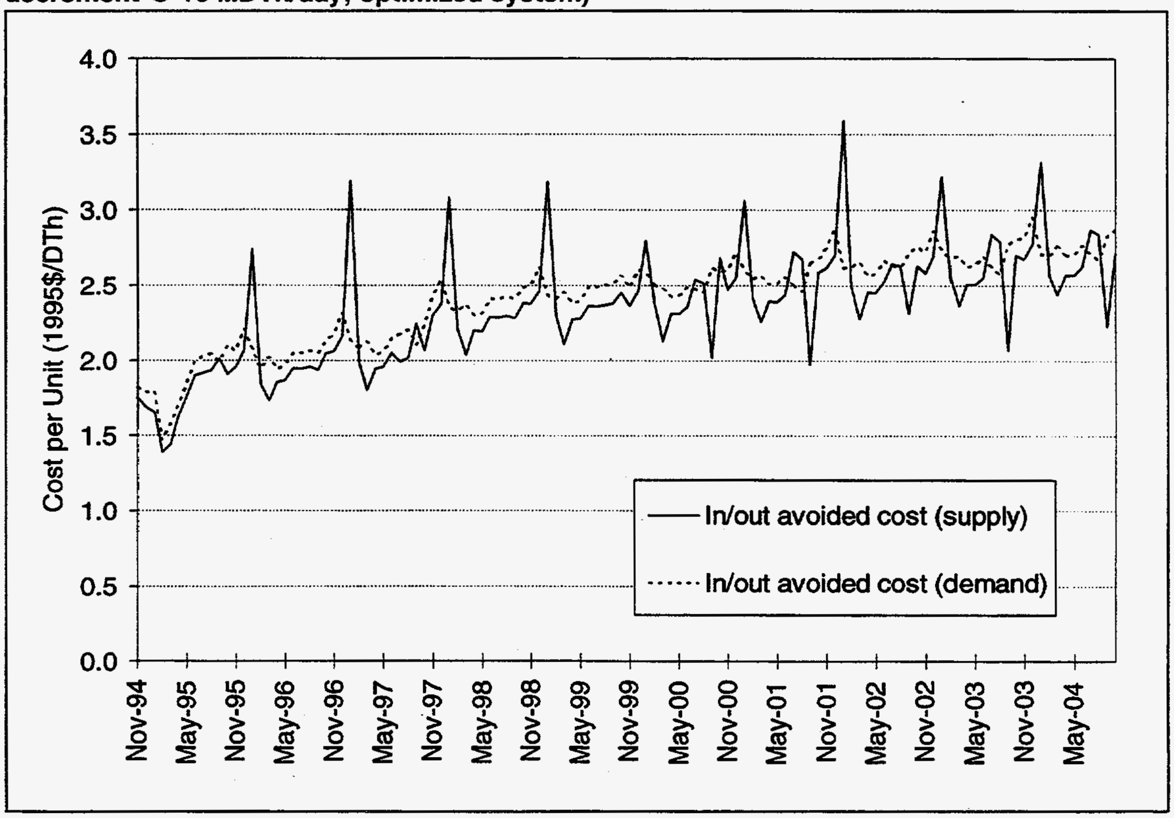
Figure 5-11. Capacity Release Sensitivity of Avoided Cost (DSM in/out; baseload decrement @ 10 MDTh/day; optimized system)



in all simulations. The case where the portfolio is held fixed would be analogous to a situation in which long-term commitments were the norm and therefore the supply and capacity mix could not be readily adjusted to changes in demand. This type of situation is similar to that faced by electric utilities with large capital investment in plant. Figure 5-12 shows the effect of holding the portfolio fixed on baseload DSM in/out avoided costs. They are generally lower and more erratic than avoided costs from an optimized portfolio. It is expected that they would be lower since the fixed costs of supply and capacity would not be avoided by the decrement; only the variable costs would be saved. The variability is more problematic. The variation in month-to-month variable supply costs is large, much like the behavior of WACOG we have already observed, and this is the cause of the variability of the avoided costs for the fixed system. Since a fixed system is not very realistic over a ten-year time frame for most gas LDCs, avoided costs for the fixed system probably contains little meaningful information for resource planners.

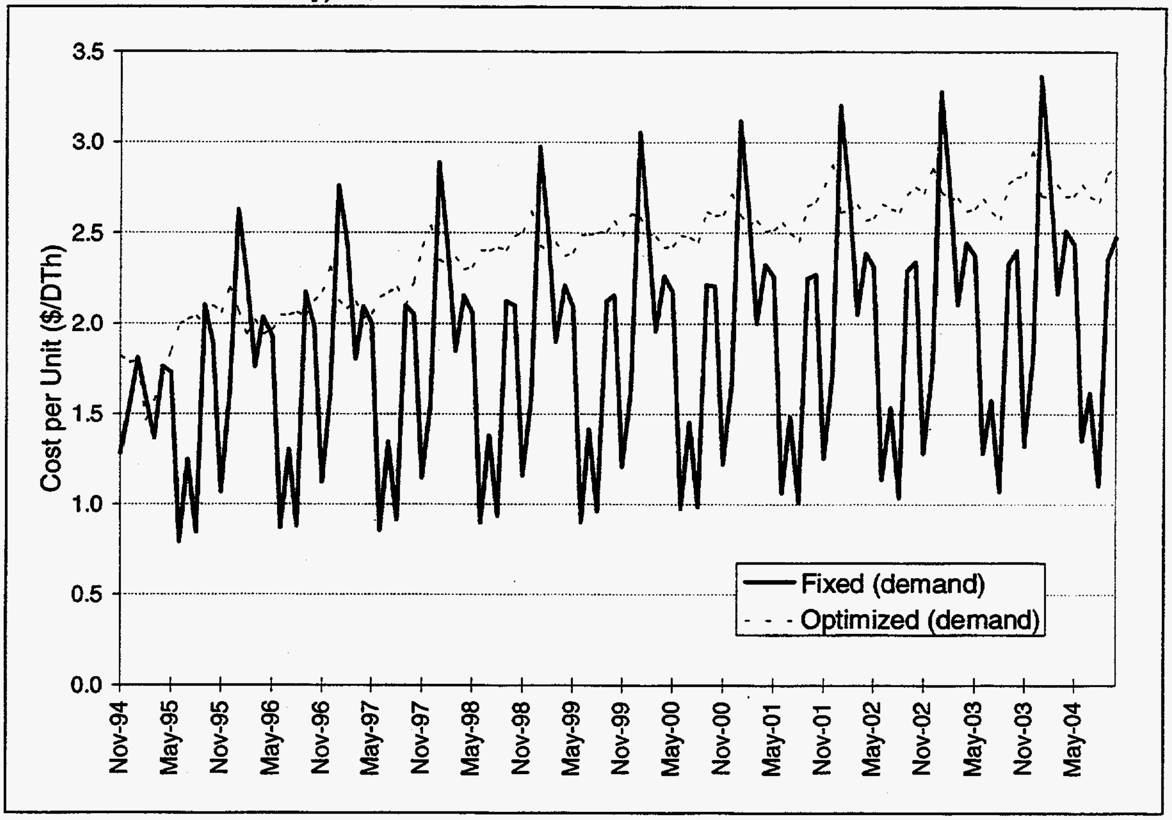
The second modeling sensitivity concerns what is in the denominator of the $/DTh avoided cost. Typically the denominator holds the difference in demand between the decrement and base cases (as we have presented above). However, due to the presence of storage which operates inter-temporally, injecting and withdrawing gas during different periods, costs incurred in one period are used to reduce costs in another, which can theoretically bias

Figure 5-12. Per Unit Demand vs. Per Unit Supply DSM In/Out Avoided Costs (baseload decrement @ 10 MDTh/day; optimized system)



avoided cost. An alternative denominator to the demand impact is the supply impact that the demand change induces, which adjusts for these inter-temporal storage effects.[19] As shown in Figure 5-13, where per unit demand and supply impact DSM in/out avoided costs are compared, the main effect is to significantly raise avoided costs in the peak month (January) when storage withdrawals are high and reduce avoided costs in the summer when storage injections are high. We have chosen to follow convention in presenting our avoided costs on a per unit demand basis, but note that if the purpose of the avoided costs is to evaluate supply alternatives, a supply-based denominator may be more appropriate.

Figure 5-13. Baseload DSM In/Out Avoided Cost: Fixed vs. Optimized System (baseload decrement @ 10 DTh/day)



19 Note that the system costs in the numerator of the avoided cost equation are already adjusted for the cost impacts of storage operation, i.e., the cost of net storage withdrawals is added to supply and capacity contract costs.

Planning for Storage

Storage plays a pivotal role in the U.S. natural gas supply system. The existence of storage allows for more efficient utilization of the gas pipeline network, given the distinctions between end-user demand profiles and producer supply profiles and the geography that separates them. Storage in the supply area enables gas production to remain relatively constant even when demand is fluctuating. When gas demand downstream is low, production can flow into storage; when gas demand downstream is high, production can flow into the pipeline. Storage in the market area provides enhanced reliability and enables a smaller commitment to pipeline capacity to meet peak demand. Furthermore, storage in either area offers gas purchasers the potential for price arbitrage, to take advantage of any gas commodity price differentials across time or space. The value of storage for price arbitrage under extreme weather conditions has been imputed in a recent analysis in the premium of spot gas prices over the futures price for gas for the same period (EIA 1995b). More recently, with the advent of market hubs, storage plays a facilitative role in the establishment of such market centers by allowing buyers and sellers to "park" gas while engaging in market transactions. While the role of storage in the context of the larger natural gas industry is interesting, our focus here (as in the rest of the report) is on the benefits of storage from the LDC perspective.

6.1 Types of Storage

Natural gas can be stored in many different ways. The most common form of gas storage is in underground depleted gas or oil reservoirs. These obviously tend to be located near production centers, although they are distributed among 23 states (albeit with five of those states holding half the depleted gas/oil reservoir capacity). The deliverability of these reservoirs depends on the porosity and permeability of the rock formation, although their characteristics tend to make them best suited for cycling (i.e., injection and withdrawal) once in the course of a year. Aquifers are the next most common form of gas storage, but less significant (by an order of magnitude) in terms of capacity. Aquifers have similar performance characteristics as depleted gas or oil reservoirs. Mined caverns in underground salt formations are another form of gas storage, and one that is viewed as especially attractive in the current gas market. The reason for this is because the cavern that is hollowed out of impermeable salt dome or salt bed formations is essentially a gas tank, without the friction of porous rock, which allows for rapid withdrawal and injection. This permits storage to be used in different ways than would be possible with either depleted reservoirs or aquifers, with cycling possible multiple times over a year.

Other types of conventional storage are liquefied or compressed natural gas plants, and gas put under high pressure in pipelines known as "linepack." More unconventional forms of gas storage include curtailment of gas field development, shut in of gas wells, and gas futures contracts (Duann et al. 1990). We confine our analysis to underground storage types.

6.2 Status of Storage Services in the U.S.

Table 6-1 shows the technical characteristics of existing natural gas underground storage reservoirs by ownership. Existing capacity is dominated by interstate pipeline and LDC ownership. Total capacity in terms of working gas[20] is approximately 38,000 Bcf. Two-thirds of this capacity is held by interstate pipelines, with LDCs holding about one-third. In terms of daily deliverability, interstate pipelines own roughly half, while LDCs own about 40 percent. This higher proportion of total deliverability owned by LDCs is reflected in the average days of service (which is simply the ratio of working gas capacity to deliverability). Storage owned by LDCs averages 44 days of service while interstate pipelines average 63 days. This distinction no doubt reflects the different needs and uses for storage between the two parties.

Table 6-1. Existing Underground Natural Gas Storage by Ownership

Ownership	Number of Sites	Working Gas Capacity (Bcf)	Deliverability (MMcf/day)	Average Days of Service
Interstate Pipelines	184	2,160	34,091	63
LDCs	158	1,123	25,274	44
Independents	24	275	4,776	58
Intrastate Pipelines	11	137	3,586	38
Total	375	3,695	67,729	55

Source: EIA, 1995b.

Table 6-2 shows the status of underground storage by type. Depleted gas or oil reservoirs dominate all other types in number, capacity, and deliverability. The high deliverability of salt caverns is evident by the low days of service (12), as compared to those for depleted gas/oil and aquifer reservoirs (60 and 70 days, respectively).

Market forces have unleashed an expansion of U.S. storage capacity. Table 6-3 shows the proposed new and expansions to existing storage sites on the drawing board expected to come online in the latter half of the 1990s. Salt caverns form the great majority of projects, capacity, and deliverability under consideration. Because of availability of sites and the desire to pool multiple buyers, most of these are being developed proximate to supply basins and market hubs rather than market centers.

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20 Working gas is the portion of gas that is available for withdrawal. The balance, known as base gas, remains underground to maintain sufficient pressure in the reservoir for withdrawal of working gas.

Table 6-2. Existing Underground Natural Gas Storage by Type

Type	Number of Sites	Working Gas Capacity (Bcf)	Deliverability (MMcf/day)	Average Days of Service
Depleted Gas/Oil Reservoir	316	3,170	53,380	60
Aquifer	38	443	7,306	70
Salt Cavern	21	82	7,041	12
Total	375	3,695	67,729	55

Source: EIA, 1995b.

Table 6-3. Proposed Storage Projects 1994-1999

	New	Expansions	Total
Depleted Gas/Oil Reservoir			
No. of Projects	24	7	31
Working Gas Capacity (Bcf)	293	28	322
Deliverability (MMcf/day)	6,028	493	6,521
Aquifer			
No. of Projects	1	2	3
Working Gas Capacity (Bcf)	3	5	9
Deliverability MMcf/day)	35	75	110
Salt Cavern			
No. of Projects	22	25	47
Working Gas Capacity (Bcf)	89	74	164
Deliverability (MMcf/day)	8,175	5,940	14,115
Total			
No. of Projects	47	34	81
Working Gas Capacity (Bcf)	387	108	495
Deliverability (MMcf/day)	14,238	6,508	20,746

Source: EIA, 1995b

6.3 Role of Storage in LDC Resource Portfolio

Storage has emerged as a key strategic asset in LDC resource portfolios. It has always been valuable as a peaking resource for LDCs, and in the early period of the spot gas market, it provided a means for LDCs to obtain cheap gas during the off-season for use during the winter period. With the change in pipeline tariff structures contained in FERC Order 636, where more of the costs were shifted to the demand charge, there is greater incentive for LDCs to more closely manage pipeline holdings and usage to reduce those costs. This is the case because LDCs with large residential and commercial customer bases typically have low load factors and pipeline capacity under the new tariffs appears more expensive than previously. Additionally, with the shift in responsibilities in the deregulated environment, LDCs must assume more responsibility for managing flows into their system. Storage can play a valuable role for balancing these flows to meet contractual obligations and physical requirements.

6.4 Analysis

6.4.1 *LDC Storage Resource Optimization*

In light of the unbundling of storage services from transportation, the expansion of storage capability in the near term, and the motivation of LDCs to review their storage and transportation capacity holdings, we examine the effect of different levels and types storage on system cost for our prototypical LDC. Figure 6-1 shows system cost as a function of the withdrawal capacity for storage with 45-day service.[21] As withdrawal capacity is increased above 100 MDTh/day, the present value system cost falls as storage replaces transportation capacity and associated gas supply. Beyond the optimum of 565 MDTh/day, increasing withdrawal capacity is not economically beneficial because there is insufficient excess summer transportation to supply gas for injecting into storage to support the utilization of that incremental storage withdrawal capacity. Another way of thinking about this that storage is used to flatten the load duration curve (an example of which is shown in Figure 5-2). At a certain point, the load is flattened sufficiently that doing so further is not economically desirable.

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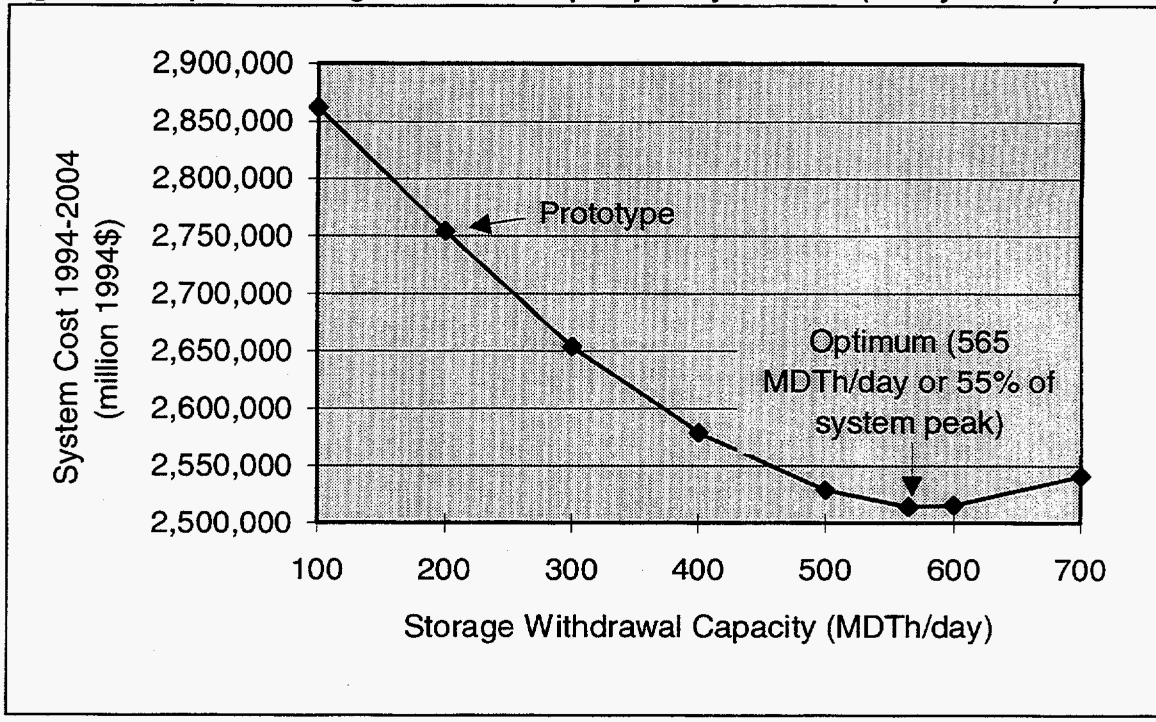
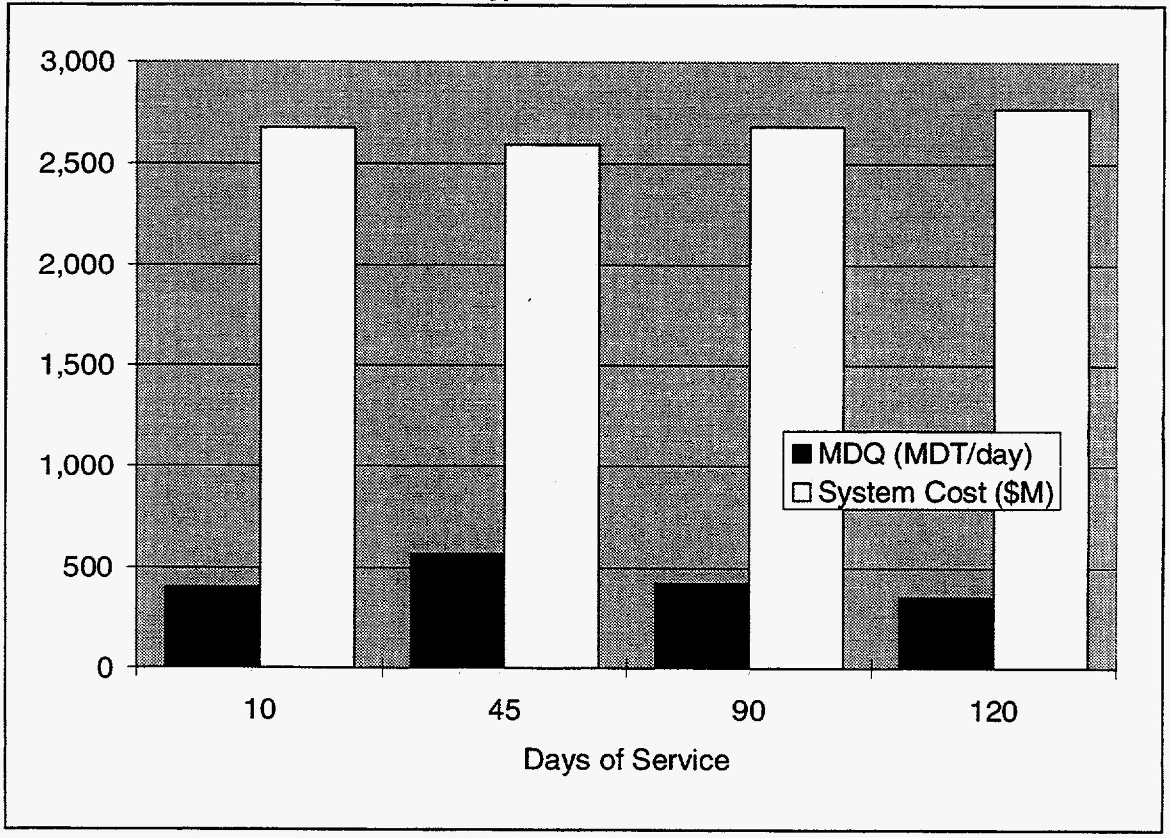
21 Recall that the prototypical LDC storage was arbitrarily defined with a withdrawal capability of 20% of the peak demand day (e.g. a maximum daily quantity of 200 MDTh) and the reservoir capacity was set to provide 45 days of service at that MDQ, a level which matches the average for U.S. LDCs (see above).

Figure 6-1. Impact of Storage Withdrawal Capacity on System Cost (45-day service)



Next, we optimized storage for a range of deliverability/capacity ratios, expressed in days of service. High deliverability storage is often packaged as ten-day service, whereas seasonal storage is packaged in the range of 30- to 120-day service or more, depending on storage customer needs. For the three types of seasonal storage, we used the same tariff structure except for high deliverability storage, where we used a different tariff structure based on a project in New York State (Rosenkranz 1995). A different tariff for high deliverability storage is appropriate because its costs differ greatly from seasonal storage costs. Figure 6-2 shows the optimum storage withdrawal level and the resultant system cost over the ten-year planning horizon. For our prototype LDC, the least cost storage service level is 45 days and a correspondingly high level of withdrawal capability was chosen by the model. However, when sized optimally, total cost varies only seven percent for this system over the range of storage days of service levels shown in the figure.

Figure 6-2. Optimal Storage for Prototypical LDC



6.4.2 The Storage and Pipeline Tradeoff

Market area storage serves as a substitute for transportation, but is also dependent on it for moving gas for injection into the storage reservoir. The economic tradeoff between storage and transportation hinges largely on the fixed demand charges of the two resources. In our prototypical LDC, specific tariffs are used for each of these. However, there is a range of demand charges in the U.S. for storage and pipelines depending on vintage, location, distance from load, and technology, and more recently, regulatory treatment with market-based rates becoming more common. We examine the sensitivity of storage sizing and system cost to variations in demand charges for transportation and storage, where each resource's demand charge is increased and decreased by 50 percent, respectively, over the prototype levels. Figures 6-3 and 6-4 display this calculation for 45- and ten-day storage service, respectively. The bars in the figures show the percentage change from the case where storage was optimized for the days of service level. What is immediately apparent is the asymmetric impact on optimal storage sizing from increasing versus decreasing demand charges by a fixed percentage. For instance, with 45-day storage service, a 50 percent increase in the transportation demand charge results in an increase of just over five percent of the optimal storage withdrawal capacity, whereas a 50 percent decrease in transportation demand charge

Figure 6-3. Sensitivity of Storage Sizing and System Cost to Demand Charges (45-day service)

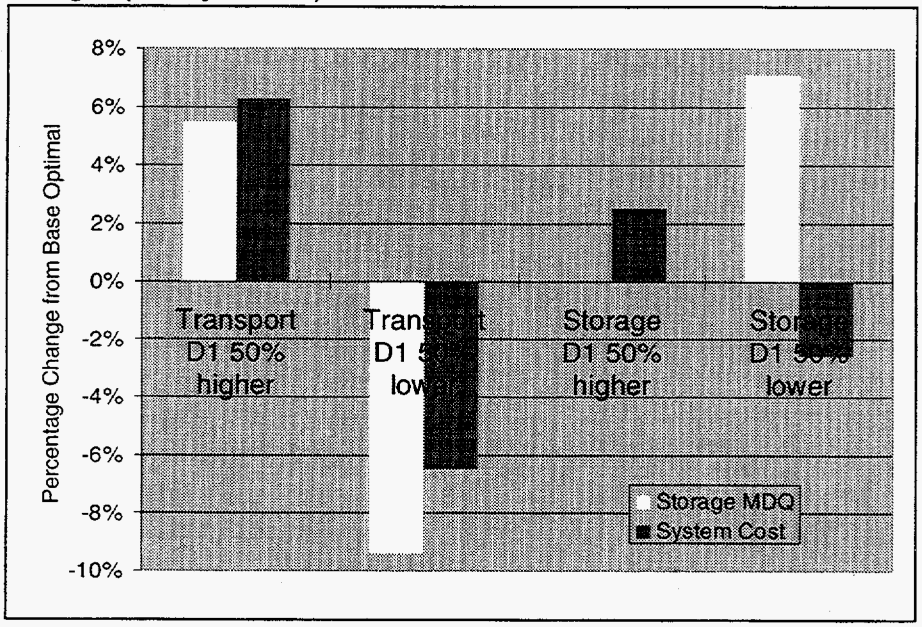
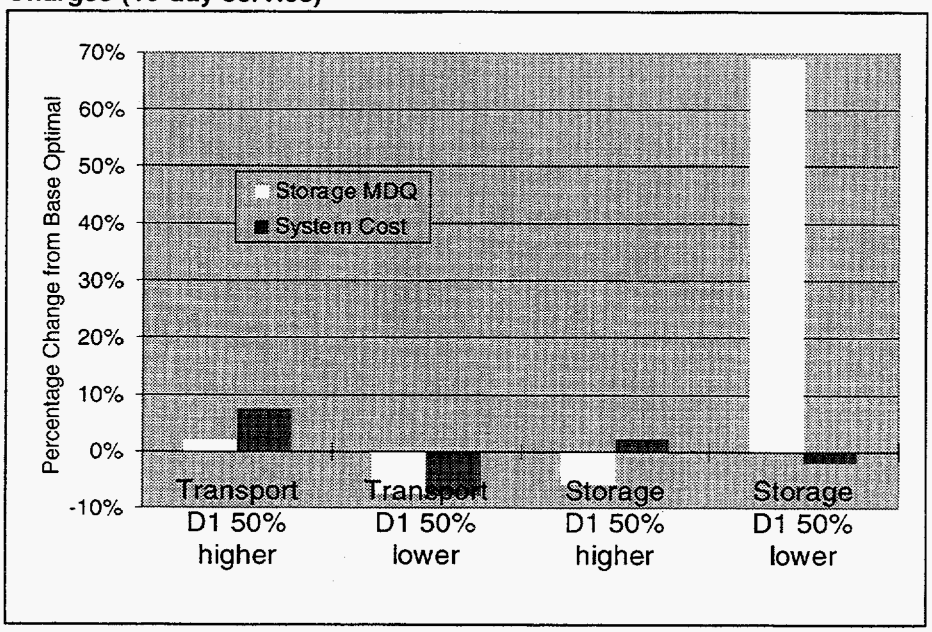


Figure 6-4. Sensitivity of Storage Sizing and System Cost to Demand Charges (10-day service)



results in a nine percent decrease. Similarly, 50 percent increase in the storage demand charge induces no reduction in the optimal storage withdrawal capacity, whereas a 50 percent decrease in the storage demand charge causes the optimal storage withdrawal capacity to increase by seven percent. Indeed, these asymmetric patterns are similar for the ten-day storage service case, but with an even more dramatic distinction when the storage demand charge is reduced by 50 percent and the optimal storage sizing increase nearly 70 percent. The reason is that storage that cheap fully displaces the 300 MDTh/day propane/air plant operation during peaking periods.

6.4.3 Pipeline Capacity Release Effect on Optimal Storage

The existence of a market for excess capacity holdings on the part of LDCs could influence the optimal amount of storage they would want in their resource portfolio. Releasing pipeline capacity makes it unavailable both to serve demand and fill storage. Specifically, the tradeoff is between the marginal revenues from capacity release and the marginal savings from using that capacity to meet demand and facilitate the use of storage.

We performed a joint optimization of 45-day storage service and capacity release under the scenario that the LDC transportation capacity commitment extends through the planning horizon at the base year level (i.e., 623 MDTh level). In these runs, the model is set to release 100 percent of releasable transportation capacity should it be economically desirable to do so. Initially the capacity release decision is for a long-term release (i.e., 10 years) with no recall. Figure 6-5 shows the effect of expected capacity release revenues (expressed as a percentage of the full pipeline demand charge) on optimal storage sizing and amount of transportation capacity released. At the lowest level of expected revenues (i.e., 25% of pipeline demand charge), no capacity is released. Since no capacity is released, the optimal amount of storage withdrawal capability is relatively small because less is needed to meet peak demands. At the highest level of expected capacity release revenues (i.e., 100% of pipeline demand charge), more transportation capacity is released and, therefore, more storage withdrawal capacity is needed to meet peak demands. Because storage was sized concurrently with the capacity release decision, changing the capacity release arrangement to allow for recall does not alter these results.

Next, the capacity release decisions are made annually instead of once at the beginning of the ten-year planning period. Figure 6-6 shows the same analyses for the case of annual capacity releases. The capacity release quantities shown are averages over the planning period. Going to the capacity market every year allows the LDC to tailor their releases more closely to their needs at the time, which in turn allows for both higher releases and lower storage withdrawal capacity requirements. This apparent advantage to short-term over long-term releases in terms of the amount of long-term storage to contract for must be traded off against the risks of price volatility in the release market that could diminish the value of short-term releases. In other words, if an LDC pursues a short-term capacity release strategy and market prices are lower than expected, then the risk to the LDC is that it might find itself with too little storage withdrawal capacity and the higher net costs associated with that outcome. Note that this analysis does not account for any inherent price differentials between short- and. long-term capacity releases. Also, although all the scenarios shown in Figures 6-5 and 6-6 are optimal, they suppress some risk allocation issues. If expected capacity release revenues leads an LDC to hold more capacity, a regulator may want to put the LDC at risk for this capacity, even though the holding is expected to be economic. This is because the holding is strictly to enhance revenues and not to provide core service.

Figure 6-5. Impact of Pipeline Capacity Release Revenues on Release Amount and Optimal Storage Sizing (long-term release)

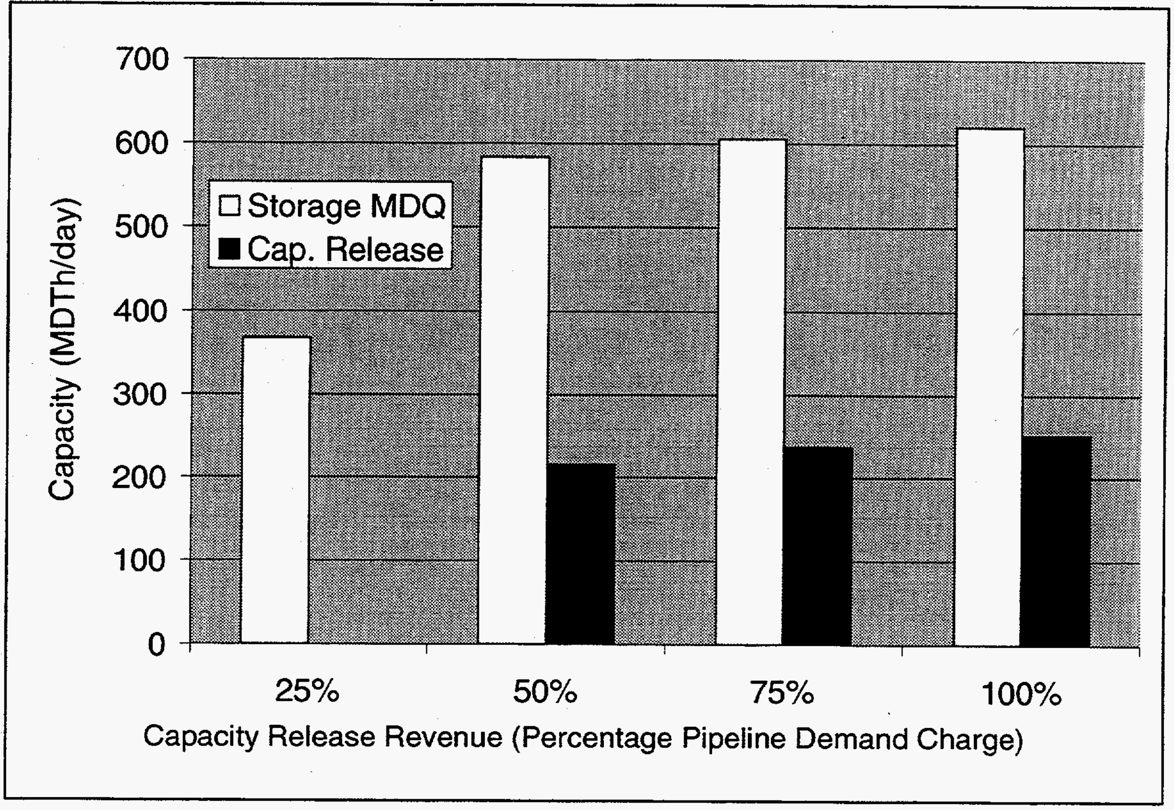
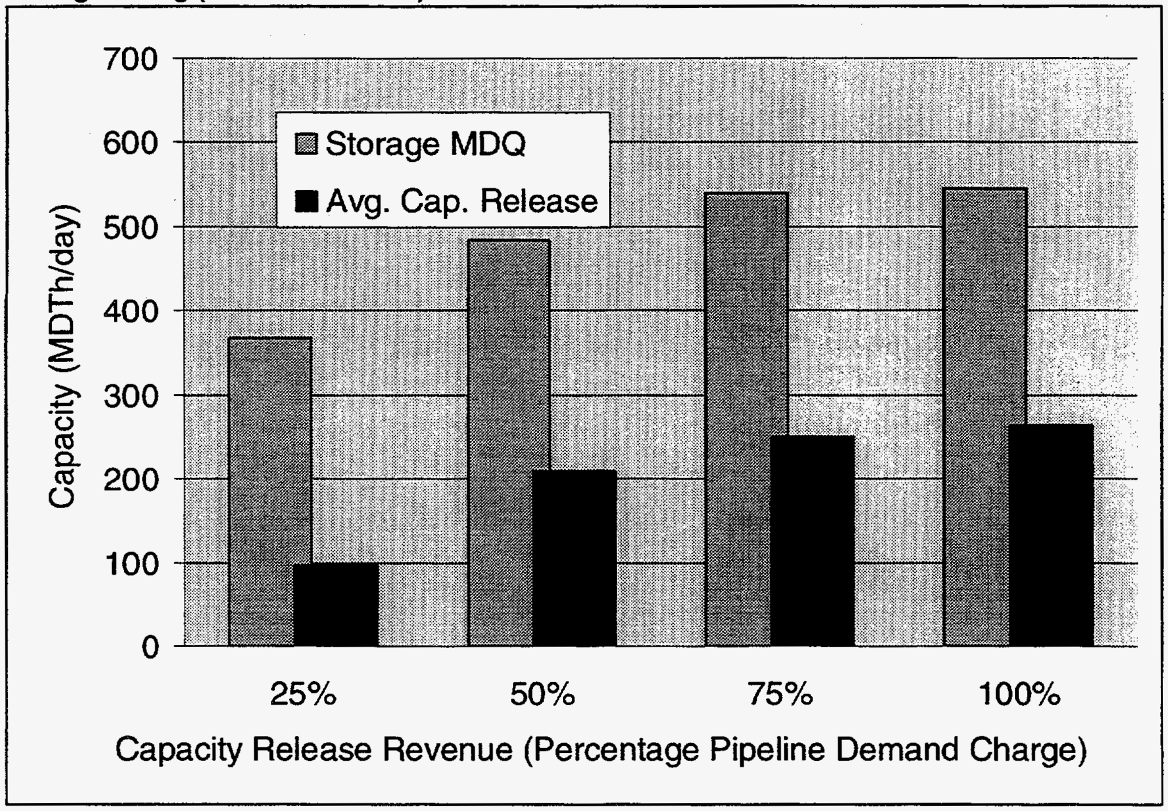


Figure 6-6. Impact of Pipeline Capacity Release Revenues on Release Amount and Optimal Storage Sizing (Annual Releases)



6.4.4 Dependence on Modeling Conventions

The characterization of demand can have an important influence on storage resource modeling. Without adequate time resolution, storage operation cannot be accurately represented, particularly for high deliverability storage. In all the foregoing runs, demand was modeled using the high demand day method, which selects a user-specified number of the highest demand days in each month for daily dispatch and dispatches the remainder of days as one day with averaged demand. Our analysis used five high demand days during the winter months, three high demand days during the swing months of October and April, and a single average day for the rest of the months of the year.

We analyzed the effect of increasing the number of high demand days to be used in simulating salt bed storage with ten-day service. Increasing the number of winter month daily dispatches up to half the days of the month had an insignificant influence on the optimum size of high-deliverability storage chosen by the model. Increasing the number of daily dispatches to ten in every month of the year also had no effect. This is not necessarily a generalizable result. The particular characterization of our prototypical LDC very likely makes a higher resolution of demand unnecessary. For example, using storage to trade off supply cost differences among different basins and transportation routes—an option available to many LDCs—is not captured in our prototypical LDC characterization.

The Economics of Buyback Contracts

7.1 Introduction

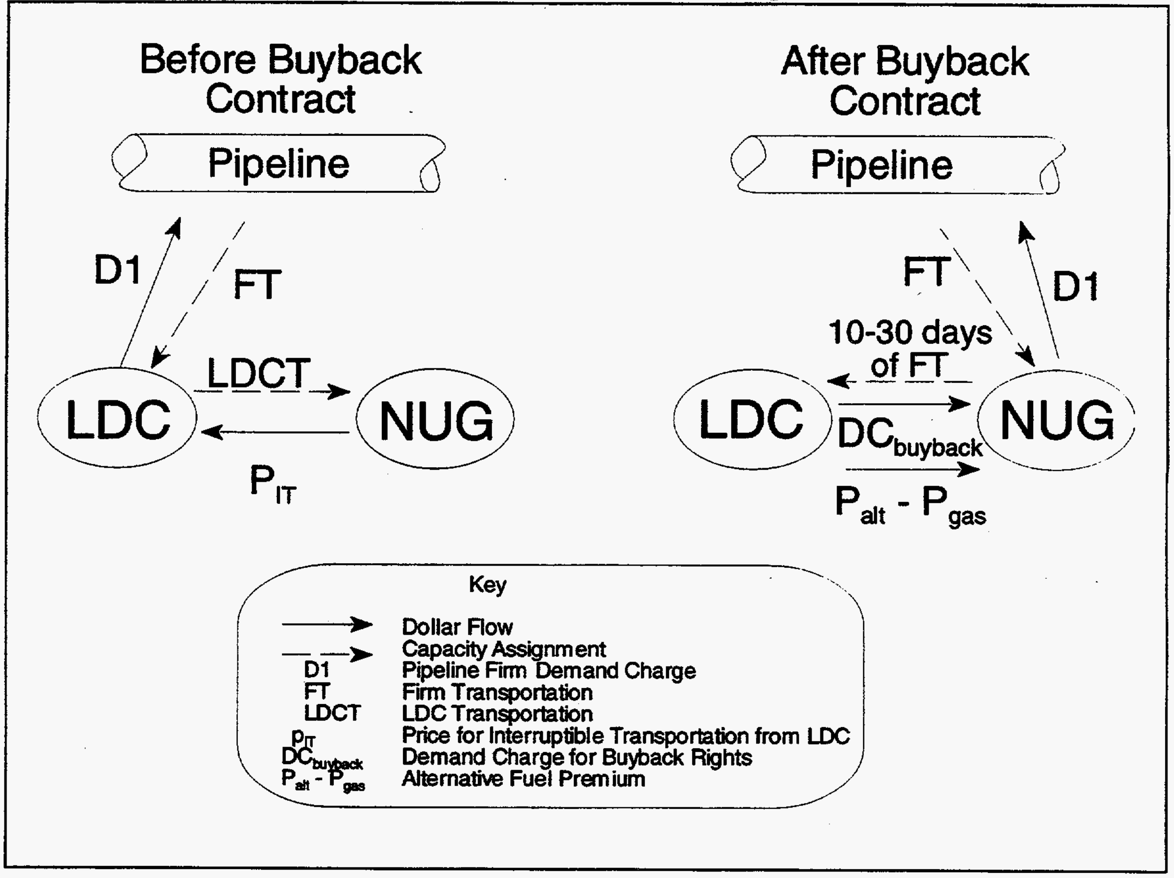
FERC Order 636 led to a significant recontracting of gas supplies in the U.S. The activity led to innovations in the natural gas marketplace. One of these innovations is the buyback contract. In buyback contracts, a gas LDC sells capacity or supply with limited rights of recall. The buyer of such capacity gets near-firm capacity at a discount, and the LDC gets peak supply, which is quite valuable in light of core loads. Particularly fruitful are buyback arrangements between gas LDCs and electric generators. Gas LDCs typically have sharp peaks driven by winter heating loads. Electric generators tend to either be run year-round (if they are base loaded) or have peaks in the summer because retail electric peak demands are typically driven by cooling loads. Further, to receive financing, lenders typically require nonutility generators (NUGs), which include IPPs and QFs, to obtain firm, year-round fuel supplies and transportation capacity. Thus, it is no surprise that NUGs are motivated to pursue ways offset the cost of their required pipeline capacity holdings. One way to do this is to buy firm capacity released by the LDC and then, in turn, enter into a buyback contract wherein the buyer agrees to sell capacity back to the LDC for a limited number of days per year.

7.2 Description of Buyback Contracts and a Simplified Example

A typical arrangement for a buyback is shown schematically in Figure 7-1. Before the buyback, it is typical for the LDC to contract for interstate pipeline capacity and the NUG buys transportation service from the LDC. Because the NUG is likely to buy transportation capacity on a generic transportation tariff (labeled "LDCT" in Figure 7-1), it is unlikely to get any guarantees with respect to reliability. As a result, NUGs needing firm capacity have been known to bypass the LDC altogether.[22] Under a buyback contract, the LDC releases firm transportation (FT) capacity that it holds on a pipeline to a NUG. The NUG becomes obligated to pay all FT demand charges to the pipeline. However, the LDC retains the right to buy the capacity back from the NUG for a certain number of days per year--ten to 30 days is typical. In return for this right of recall, the LDC may pay the NUG a percentage of the

[22] The inability of NUGs and enhanced oil recovery customers in California to receive firm or near-firm capacity from the LDC was one reason why three bypass pipelines were constructed in California in the late 1980s and early 1990s.

Figure 7-1. Schematic of a Typical NUG-LDC Buyback Arrangement



pipeline demand charge, pay for the incremental cost of alternative fuels during recall periods, or both.[23] Under buyback contracts, the LDC fills the pipe with whatever gas it wishes to purchase when it exercises the contract. The LDC may, but is not required, to buy the NUG's gas supply as it is likely that the NUG will have already purchased gas for the buyback period. It is not unusual for buyback contracts to have terms of ten years (WWP/Willamette 1994).

An LDC should be willing to enter into a buyback arrangement on infrequently-used capacity as long as the penalty costs of alternative fuel payments are less than the savings the LDC makes on demand charges. Equation 7-1 shows the maximum buyback demand charge the LDC would be willing to pay a NUG for 30 days of buyback capacity:

23 LDCs may also pay for the installation of alternative fuel facilities. This is sometimes done for industrial buyback contracts. Most NUGs, however, already have some sort of alternative fuel capability.

$$DC_{buyback} \leq D1 - (P_{alt} - P_{gas}) \times Pr_{curtail} \times 30 \qquad (7\text{-}1)$$

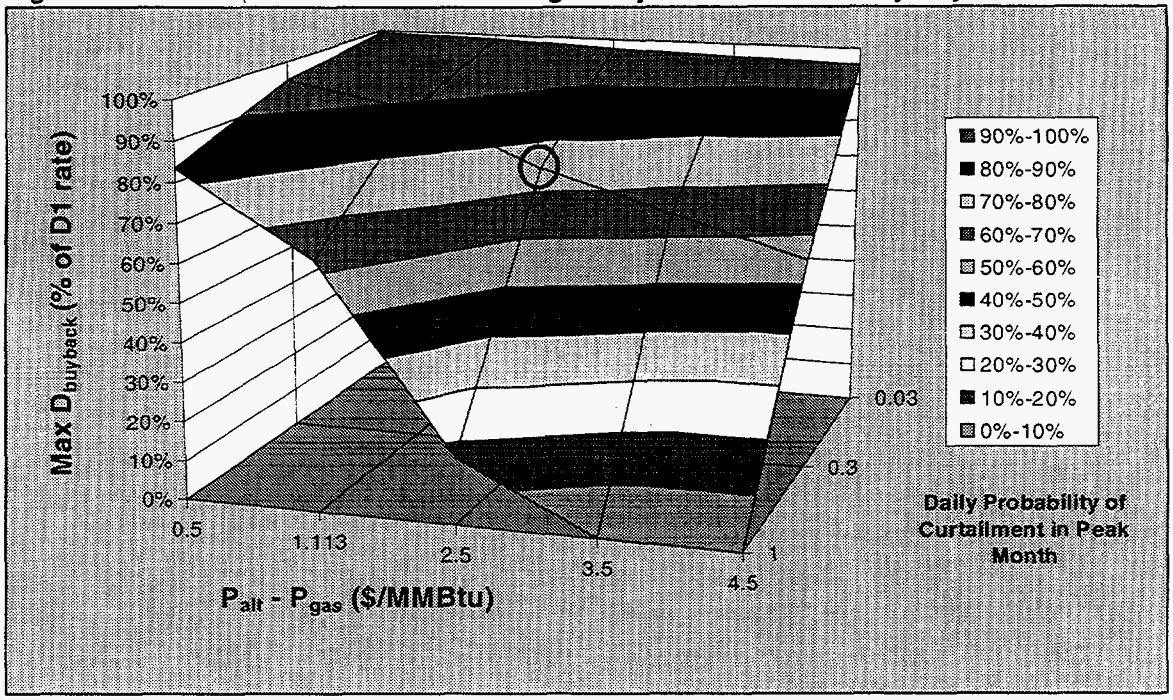
where,

$DC_{buyback}$	=	*annual* demand charge paid by LDC to NUG for buyback capacity ($/year per mcf/d)
D1	=	as-billed rate pipeline demand charge ($/year per mcf/d)
P_{alt}	=	price of alternative fuel
P_{gas}	=	price of gas
$Pr_{curtail}$	=	daily probability of exercising contract in peak month
30	=	average days per month

Recall that the NUG is already obligated to pay the full D1 charge to the pipeline because the pipeline has acquired the released capacity from the LDC. Equation 7-1 simply considers whether the annual buyback demand charge, $DC_{buyback}$ plus the expected cost of alternative fuel, is more economical than the annual cost of regular pipeline capacity, D1. The second term on the right-hand side equals the expected value of the payment made by the LDC to the NUG for the incremental cost of the fuel. Figure 7-2 shows the maximum buyback rate an LDC should be willing to pay at various values of $Pr_{curtail}$ and alternative fuel premiums (P_{alt} - P_{gas}). For example, if there is a 30 percent daily probability of using the contract, a $2.50/MMBtu premium for alternative fuel in the peak month,[24] and a D1 rate of $8/mo/Mcf/day of capacity, the maximum buyback demand charge is 77 percent of the D1 rate or $6/mo/Mcf/day. This point is circled on the surface in Figure 7-2. In fact, NUGs appear willing to enter into buyback contracts for low percentages of the D1 rate. For example, Washington Water Power has acquired buyback capacity for less than ten percent of the applicable D1 charge (WWP/Willamette 1994). It appears that buyback arrangements are fruitful in the post-636 world.

24 Using EIA data for the top 10 net consuming states (NJ, NY, PA, IL, IN, OH, WI, FL, GA, CA) for three recent Januaries (1992, 1993, 1994) the average premium paid by electric utilities for distillate fuel oil over natural gas was $1.06/MMBtu (EIA 1992, 1993, 1994). It is reasonable to assume that any alternative fuel premium would include an administrative surcharge which we estimate to be 5%. On a peak day, utilities often face higher premiums for alternative fuels. Premiums of $4-$6/MMBtu have been reported.

Figure 7-2. Maximum Rate an LDC is Willing to Pay to NUG for a 30-Day Buyback Contract



7.3 Detailed Analysis for Prototypical LDC

To make the basic economic tradeoff of buybacks easy to understand, we simplified and suppressed some of the actual complexity of a buyback arrangement in the previous example. For example, the probability of curtailment is difficult to estimate without detailed demand data. Also, the avoided cost of the deferred supply resource may not simply be the D1 rate as was estimated above. In particular, the avoided supply cost may vary by year because the LDC's base case resource plan may contain periods of excess capacity. Greater precision may be achieved by using a resource planning model, however. To this end, we analyze a NUG-LDC buyback contract for our prototypical utility using the Sendout model. Our goal is to find, at a given amount of buyback capacity, the maximum economic buyback demand charge. We consider the situation where the LDC faces the following resource choices at the margin: (1) pipeline capacity that is available year-round at the full D1 rate and (2) buyback capacity that is available for up to 30 days per year.[25] Table 7-1 summarizes the assumptions we made for the buyback case.

[25] Instead of modeling the NUG as part of the LDC's system, we exclude it from both the base and policy case. We do not lose any accuracy by doing this because the LDC faces the choice of buying firm, year-round capacity or buyback capacity to meet its core loads, and NUG demands do not affect this decision.

Table 7-1. Assumptions for Buyback Case Sendout Run

Contract Size:	0 to 100 MDTh/d (equivalent to 0 to 600 MW of combined-cycle capacity)[26]
Contract Start Date:	Year 1, 1994 (cannot be moved forward or back in time)
Contract Term:	10 years
Alternative Fuel Premium:	$1 to $4 above the price of the premium spot

We used the optimization module of Sendout to decide whether the buyback contract was economic to add to the resource mix. For a given alternative fuel premium, we found the maximum economic rate for buyback capacity (Figure 7-3). Our prototypical utility is willing to pay at least 54 percent of the full D1 rate for buyback capacity. For example, at an alternative fuel premium of $2.50/MMBtu, buyback capacity is economic at prices in the range of 58 to 63 percent. As we expected, the buyback contract's value per unit of capacity drops as more capacity is made available and the probability of exercising the contract increases. Further, as predicted in Equation 7-1, the buyback contract's value drops as the alternative fuel premium rises.

Although at high capacities the buyback contract drops in value significantly, its value at quantities up to 50 MDTH/day stays in a relatively narrow range: 59.5 to 65 percent of D1. This is true even though we vary the alternative fuel premium estimate fourfold, from $1 to $4/MMBtu. We believe this relatively narrow range is because the contract is in fact rarely exercised by our LDC prototype. As described in Section 4.2.2, the prototypical LDC's peak day is based on design (extreme) weather conditions and is grafted onto typical January daily loads. It is considerably higher in load than any of the other winter daily loads. The buyback contract has a dispatch cost that exceeds the dispatch cost of most other resources, including pipeline-commodity and storage gas. Thus, the buyback contract is always either the first- or second- (to propane/air) most expensive resource from a variable cost perspective. Resource that are relatively expensive, while needed for capacity purposes, are not dispatched very much given the relative magnitude of the peak-day load.

26 600 MW is equivalent to 100 MDTh/day, assuming a heat rate of 7,000 Btu/hour.

Analysis of Core Reliability Criterion

8.1 Introduction

By definition, public utilities, including LDCs, provide essential services. Demand for these services is uncertain, so utilities must build reliable systems in the face of demand uncertainty. As a result of FERC Order 636, gas LDCs generally have more supply options than in the past, and the traditional means of meeting peak core demands--pipeline capacity--has become more expensive because of straight-fixed-variable rate design. There has been a considerable amount written on the growth of supply options (EIA 1994b). In addition to pipeline capacity, LDCs may now choose from released capacity, buyback contracts, no notice service,[27] and storage services. An associated fundamental question has not been adequately addressed, however: What is the *value* of peak-day supply to the core customer? In this chapter, we attempt to improve the level of understanding of this value question. We examine the LDC peak-day planning problem using a method that trades off the marginal value of core service with its marginal cost. We illustrate the method using a range of assumptions that are representative for U.S. LDCs.

8.2 Background

Reliability planning involves the tradeoff of investments in facilities against the value those facilities provide. Although facilities' investments are relatively certain, value is not because of the unpredictable nature of core loads.

Reliability planning has been most thoroughly explored in the electric industry. In that industry the planning dilemma comes more from the unpredictable outages of thermal units than from the unpredictability of demand although both factors are uncertain (Kahn 1991). Various methods have been developed to measure reliability for a given electric supply system and demand profile (Stoll 1989).

Gas utility reliability planning methods are necessarily different than those for electric utilities because of the different circumstances faced by LDCs.[28] First, most gas utilities arguably serve a more disparate range of customer reliability needs. For example, customers without alternative fuel capability that use the fuel for high-value needs like heating or cooking value a unit of service many times more than industrial customers with alternative fuel capabilities.

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27 No-notice service is a peaking service that some pipelines are required to provide certain to LDCs under FERC Order 636.

28 For a more extensive discussion of gas utility reliability planning, see Goldman et al., 1993, Section 4.4.

As a result, LDC customers are typically grouped into core and noncore categories, and the reliability targets of the two are very different. A second reason for the difference in reliability planning for gas and electric utilities is that core customer demands are typically highly variable because of the temperature sensitivity of their heating loads. Third, storage plays an important role in providing reliability.

Methods for reliability planning in the natural gas industry appear more ad hoc than in the electricity industry. Some utilities face supply uncertainty but mitigate such contingencies only implicitly by choosing to plan for extreme weather. As a result, many gas utilities plan for a repeat of worst-observed historical weather with little justification for the appropriateness of this standard. Other gas utilities add reserve margins for potential supply outages but, again, provide little justification.

8.3 Reliability Planning Using the Value-of-Service Approach

For every LDC customer, investments in facilities and contract commitments should only be made when the marginal value of service (VOS) to the customer exceeds the marginal cost of service by the utility. If, for a given level of reliability, marginal LDC costs exceed marginal value, the LDC should not serve the customer at that level of reliability. Below, we describe a method for balancing marginal cost with VOS for core customers. This method is the most economically sound method of reliability planning and is now being used by some electric and gas utilities.[29] We then analyze the costs and benefits of changing reliability using a range of supply cost and VOS's typical for U.S. LDCs. For one of our scenarios, we use avoided costs, modeled using Sendout, for our prototypical LDC.

As described above, noncore customers are usually defined as customers with alternative fuel capability. Thus, for these customers, value of service (VOS) is relatively easy to estimate: it is the cost of the customer's alternative fuel plus some small premium for the inconvenience caused by fuel switching. More difficult and more interesting, however, is estimating VOS for core customers. Reliability is valued, but because core customers often have a significant temperature-sensitive component to their load, estimating the planning demand is uncertain. The value standard requires that for any reliability criterion considered, the improbable cost of firm customer curtailments must be weighed against the relatively certain costs of LDC facilities.

Most LDCs have an existing system that is built to some reliability standard. As a result, the reliability planning problem is a process of estimating the costs and benefits of increasing or decreasing reliability relative to the initial standard. Although uncertain, curtailment costs are roughly proportional to frequency of curtailment. Facility costs, on the other hand, are

29 See, for example, PG&E (1994) and Penny and Smith (1987).

roughly proportional to peak-day loads. For most LDCs in northern climates, peak-day loads are, in turn, proportional to heating degree-days (HDDs).[30] The probability of peak-day HDDs may be estimated using historical weather data; however, because weather is highly variable, it is necessary to look at long periods of time, typically 30 years or more, to determine with confidence the probability of a particular HDD.

An LDC can evaluate a change in reliability by defining a finite change in its reliability standard. It can then compute the expected change in facility costs and expected change in demand-side costs. The facility cost equation may be represented as follows:

$$FC = (HDD_1 - HDD_0) \times \beta \times N \times AC \tag{8-1}$$

where,

FC	=	incremental annual facility costs
HDD_1	=	heating degree days at new curtailment probability
HDD_0	=	heating degree days at base probability
β	=	estimated demand per customer per HDD on a peak weekday (DTh/customer/HDD)
N	=	number of firm, temperature-sensitive customers
AC	=	LDC avoided cost ($/DTh on a peak day)

On the demand side, the incremental change in reliability will result in a change to the expected customer VOS and restoration cost:

$$DC = (VOS \times D + R) \times (P(HDD \geq HDD_1) - P(HDD \geq HDD_0)) \times N \times \%curtailed \tag{8-2}$$

30 A heating degree-day (HDD) is the average daily temperature minus a base temperature. HDDs may be aggregated for a month or year, giving a convenient measure of heating load. Base temperatures are typically 55 or 65 degF. Data shown herein use a base of 65 degF.

where units are defined above or as:

DC	=	incremental expected demand costs
VOS	=	customer value of service ($/day/customer)
D	=	expected curtailment duration (days)
R	=	service restoration (relight pilots) costs
$P(HDD>=HDD_1)$	=	annual probability that actual heating degree-days will meet or exceed HDD_1
$P(HDD>=HDD_0)$	=	annual probability that actual heating degree-days will meet or exceed HDD_0
HDD_0	=	initial standard
HDD_1	=	new standard
%curtailed	=	percentage of customers curtailed

Thus, for example, if a higher reliability standard is chosen ($HDD_1 > HDD_0$), the probability of curtailment will decrease and DC will be a negative number, representing a benefit to customers. Another demand-related cost is the LDC's liability incurred as a result of curtailment. We do not consider this cost explicitly but instead treat it as part of the VOS estimate. If, through litigation, a utility is required to compensate a customer for lost VOS due to curtailments, this payment is really a transfer between the utility and customer and does not truly represent a separate cost.

The net benefit (cost) of the change in reliability is:

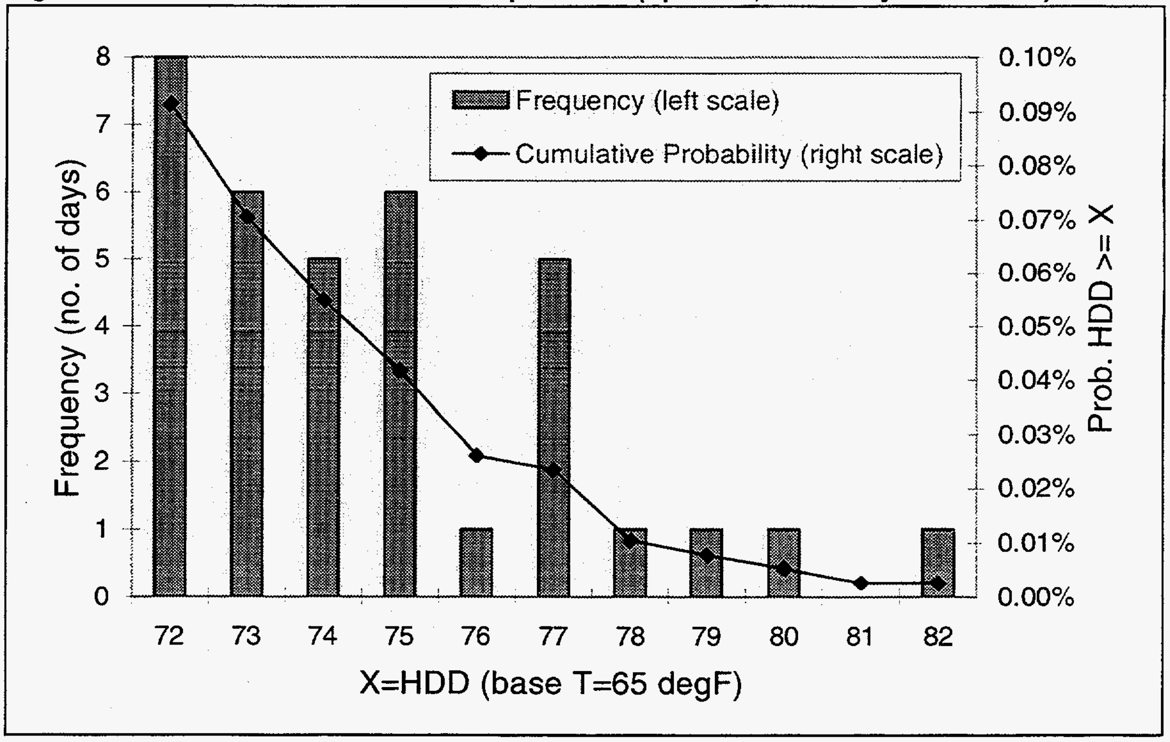
$$NB = -(DC + FC) \quad \textbf{(8-3)}$$

Having laid out the formulae for costs and benefits, we discuss some of the most important variables that have large uncertainties associated with them.

8.4 Probability of Extreme Weather P(HDD>=X)

It is very difficult to estimate extreme day temperatures, which drive the peak loads of most LDCs. The extreme day represents the tail of a distribution of HDDs. What is an outlier to one commonly-used statistic (mean or median HDDs) becomes the target statistic in a reliability study (Limaye and Whitmore 1984). Ideally, we should consider issues of sample bias and estimate a separate distribution just for the extreme value. However, the literature provides little guidance on how to do this even when considerable data exist, as in our example. For simplicity, we compute probabilities for the extreme day based on the entire daily sample of HDDs. We base our illustrative analysis on 105 years of daily temperature data for the Spokane area (Figure 8-1). Because we are using actual daily data, we make no

Figure 8-1. Distribution of Extreme Temperatures (Spokane, WA: 105 years of data)



assumption about the underlying distribution of temperature.[31] Spokane has a total winter HDD of 6,873, colder than the national average of 4,694 (AGA 1993, pp. 130). Further, Figure 8-1 shows that the cumulative probability of daily HDDs exceeding a design HDD increases rapidly as the design HDD is decreased.

Many utilities either explicitly or implicitly use this empirical approach to estimating the distribution of HDDs. Daily historical temperatures are available for many locations for long periods of time. Thus, it is possible, with some degree of precision, to ascribe probabilities to extreme HDDs observed in a particular LDC service territory.

Other approaches for estimating extreme-day weather are used as well. Historical data may be used as the basis for estimating an extreme temperature *function*. PG&E (1994) takes the coldest *daily* system average temperature in every year for which data are available and fits those data to a Gumbel distribution (Gumbel 1951). A Gumbel is one of several extreme-value distributions available in the literature. Interestingly, the Gumbel uses only the highest value in each year; thus, many data are excluded in estimating its shape.

31 No attempt was made to assure that the data set is stationary; i.e., that average temperatures do not rise or fall over time.

8.5 Beta, β

Beta, β, is the coefficient taken from a regression of per-customer demand and HDD and is used as the marginal response of demand to changes in temperature. Beta is typically estimated using daily winter season weather data (Goldman et al. 1993, Section 3.4). Regression techniques are used to estimate demand per customer as a function of heating degree days, a constant, and dummy variables, such as weekday/weekend dummies. Frequently, lagged HDDs and wind speed are also found to be significant. Demand response to weather is influenced by appliance efficiencies, and some LDCs have adjusted for them (Carillo 1992; WWP 1993). We make no such adjustment here. Ideally, the uncertainty associated with the β coefficient should be accounted for in the reliability study. However, we suppress the uncertainty of the coefficient for our simplified analysis.

8.6 Value of Service (VOS) and Avoided Costs (AC)

For core customers, value of service on a peak day is high but uncertain. Typical units of measurement are dollars per customer (household) per day curtailed. Two recent studies conducted by or for utilities have estimated firm customer VOS (RJRA 1993; PG&E 1994). In addition, an earlier study conducted by EPRI (1979) also estimated values based on natural gas curtailments from the 1970s. A range of VOS values are shown in Table 8-1. The range of median values from the three studies is very large, from $16 to $1,820 per customer per day.

Table 8-1. Range of Assumptions Regarding Value of Service and Avoided Cost

	Low		Medium		High	
	Value	Source	Value	Source	Value	Source
a. Demand-Side Value of Service (VOS) ($/day/customer)						
Avg. Core VOS	16	Implied value from EPRI (1979), adjusted for inflation (reproduced in Penny & Smith 1987)	62	PG&E, 1994 adjusted for inflation	1,820	RJRA 1993; estimate of median value; range of values goes from 1,000 to 4,000
b. Supply Side Avoided Costs (AC) ($/peak-day-DTh)						
Distribution	0				125	Median value in CA PUC marginal cost decision: $62-130 is range for different methods and assumptions
Local Transmission	0		24	PG&E marginal cost study, adjusted to peak day	24	Same as medium case
Subtotal: Downstream of City Gate	0	Assume no avoidable costs downstream of city gate	24		149	
Storage			20	Midpoint of SoCal/PG&E		
Pipeline			43	El Paso, adjusted for winter season demand		
Supply			2			
Subtotal: Upstream of City Gate	47	Propane/Air, RJRA 1993	65		162	Average peak-day annual value for the prototypical LDC (see Chapter 5) plus a 5% reserve margin.
Total AC	47		89		311	

The most recent study of VOS was conducted by PG&E; we use PG&E's values in our "medium" case. PG&E's estimates of VOS are the first to be based on customer surveys. PG&E asked customers how much a gas curtailment would cost them. The survey was conducted by mail with telephone follow-up. Although the climate in PG&E's service territory is relatively mild compared to other parts of the U.S. (extreme average daily temperatures are in the upper 20s °F), its results are in the same order of magnitude as EPRI's (1979). The VOS numbers for the "high" are based on a study for Indiana Gas and Electric, which faces considerably colder weather and uses a different methodology.

For avoided costs there are two separable issues. First, there is the issue of what portions of the system are affected by changes in reliability standards. Are all parts of the system, from the meter to the wellhead, avoidable, or are upstream supply costs the only avoidable ones? There is no easy answer to this question. Each LDC must evaluate how it plans its system and ask whether peak-day per customer demand is a significant design factor. For service lines and portions of the distribution system, such peak-day values may not be that relevant. As one goes further upstream, however,coincident peak-day values are more likely to be drivers of system costs. Second, there is the issue of estimating the marginal cost for each portion of the system. We take avoided cost estimates from various studies sponsored by LDCs or as estimated in our own Sendout runs. A complete avoided cost includes the avoided cost of facilities and supplies both upstream and downstream of the city gate. For a low estimate, we set avoided cost equal to the cost of building a propane/air plant, and we assumed that there are no avoided costs downstream of the city gate. We also based our middle estimate on the assumption that only system-wide LDC capacity and supply costs are avoidable but that distribution marginal costs are not. In the middle case, however, marginal transmission and supply costs were based on recent studies for long-run marginal costs for three California LDCs (Comnes 1992). Our "high" avoided cost estimate assumes that all aspect of LDC operations have avoidable costs with respect to the peak-day: distribution, on-system transmission, upstream transmission and storage, and supply. The values for the high case come from the California marginal cost studies for on-system costs and, for upstream costs, from our prototypical LDC. Our prototypical LDC's peak-day avoided cost is generally based on incremental interstate pipeline capacity and supply. The capacities of storage and propane/air facilities are fixed in size and, thus, are unlikely to be marginal resources on the LDC's peak day. For a more detailed description of our estimate of the peak-day avoided cost, see Chapter 5.

8.7 Percentage of Customers Curtailed and Duration of Curtailment

Curtailment of firm gas customers is a serious event. In cold climates, an extreme cold day can create life threatening situations if proper contingency actions are not taken. Pilot lights must be manually relit; this can take days and there is some risk of explosion during the relighting process. We assume an average curtailment duration of five days and a service restoration cost of $50 per customer. It is important to note, however, that a gas supply or capacity shortage is unlikely to cause all customers to be curtailed. Under most alternative scenarios, demand exceeds supply by only a few percent. It is impossible to perfectly coordinate curtailments of customers with the quantity of the supply or capacity shortfall, so we conservatively assume that demand is curtailed ten times the amount of the supply or capacity shortfall. We use a large multiplier because some reliability analyses appear to assume 100 percent customer curtailment whenever there is a supply shortfall and because we had no data on typical distribution system configurations.[32] Even using this large multiplier, only 10 to 30 percent of all customers are curtailed in our hypothetical analysis.

32 RJRA (1993) appears to assume 100% curtailment in its estimate of appropriate LDC reliability standards.

8.8 Additional Assumptions

Additional study assumptions are given in Table 8-2:

Table 8-2. Other Assumptions for Core Reliability Analysis

Assumption	Variable	Value	Notes
Outage Duration (Days)	D	5.0	
Relight Cost ($/Customer)	R	50	Median of RJRA 1993 and PG&E 1994
Number of Customers (thousands)	N	564	
Per Customer Temperature Response (Mcf/Day per HDD per Customer)	β	0.02	WWP '93 plan, pp. A-21
Per Customer Peak-Day Use (DTh/Day/Customer)		1.76	WWP '93 plan, pp. A-21 for 80 HDD
Curtailment Multiplier (actual curtailment/minimum curtailment)	M	10	Or 100% of all customers, whichever is lower
Study Period (Years)		10	
Real Discount Rate	r	6%/yr	

8.9 Benefit-Cost Calculation Examples

Table 8-3 shows the costs and benefits of changing core reliability criteria for our prototypical utility. Net present value benefits are estimated relative to the base case under six alternative reliability standards. The base case assumes that the utility is currently building to meet a planning standard of one curtailment every 50 years. Such a standard is commonly expressed as a *recurrence interval.* The table shows the incremental costs and benefits of going to two higher (105 and greater than 105 years)[33] and three lower (35, 26, and 12 years) recurrence intervals, assuming medium VOS and AC assumptions. The table indicates that it is cost effective to lower planning standards to a 26-year recurrence interval. Relative to the recurrence interval of 50 years, value of service is decreased by $843 thousand/year but facility cost savings provide $6,904 thousand/year in benefits. Optimal reliability estimates are, however, very sensitive to the VOS and AC assumptions. If the high VOS value is used, the optimal recurrence interval exceeds 105 years (Figure 8-2). At medium or low VOS assumptions, optimal recurrence intervals tend to be in the range of 26 to 30 years, although 12 years is found to be optimal assuming low VOS and AC.

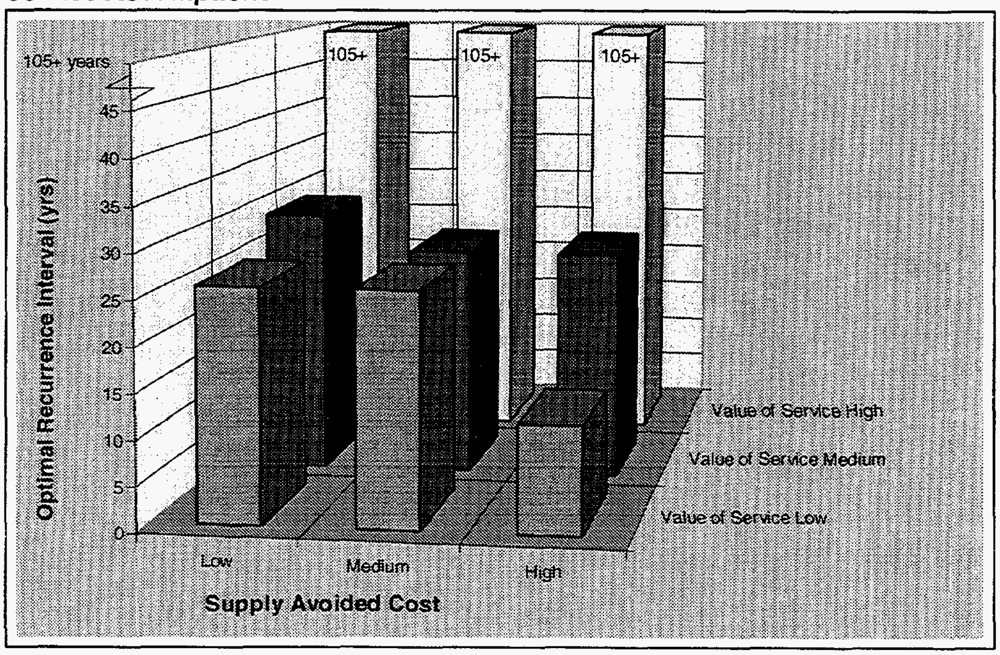
33 The probability distribution for HDDs does not extend beyond a 105-year recurrence interval. For the "105+" year standard, we plan for HDD = 83 and assume that P(X > HDD = 83) is zero.

Table 8-3. Cost-Benefit Analysis of Alternative Core Reliability Criteria for Medium VOS and AC Assumptions

Recurrence Interval (yrs)	105+	105	52 (base case)	35	26	12
Daily Curtailment Probability	0.0000%	0.0026%	0.0052%	0.0078%	0.0104%	0.0235%
Change in HDD	3	2	0	-1	-2	-3
Change in Peak-Day Load (DTh/day)	33,201	22,134	0	-11,067	-22,134	-33,201
Impact on Demand Costs (DC)						
Fraction of Core Customers Curtailed	-33%	-22%	0	11%	22%	33%
Value of Service (VOS)	($1,084)	($361)	0	$181	$723	$3,795
Relights	($180)	($60)	0	$30	$120	$630
Total Cost (Benefit)	($1,264)	($421)	0	$211	$843	$4,425
Impact on Supply Costs (FC)						
Total Cost (Benefit)	$10,355	$6,904	$0	($3,452)	($6,904)	($10,355)
Total Net Benefit						
-(DC + FC)	($9,091)	($6,482)	$0	$3,241	$6,061	$5,931

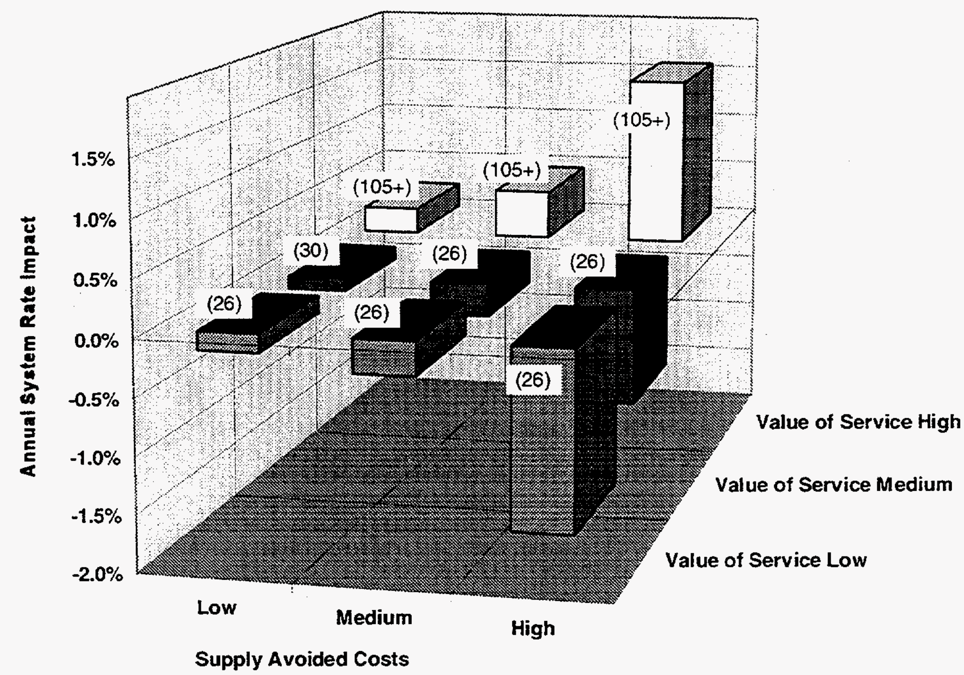
Note: All values are incremental to a recurrence interval of 52 years and are in units of $k/year unless noted otherwise.

Figure 8-2. Optimal Reliability Under Different Avoided Cost and Value of Service Assumptions



The previous analysis is from a societal point of view: both utility costs and customer costs are accounted for. What is "optimal" to society may or may not be optimal from the utility's point of view or from the point of view of an individual customer. The various scenarios show that different levels of core reliability can have very different impacts on rates (Figure 8-3). For example, at a medium VOS, the optimal recurrence interval is a relatively constant 26 to 30 years, depending on the avoided cost assumptions. However, from the low-avoided-cost to the high-avoided-cost scenario, the rate impacts of the different scenarios vary from -0.1 to -1.0 percent (Figure 8-3, medium VOS series). Although none of these rate impacts is large, they underscore the divergence that sometimes occurs between optimal planning and rate impacts.

Figure 8-3. Rate Impact of Changing to Optimal Level of Reliability (Optimal Recurrence Interval Shown in Parentheses)



Note: Rate impacts are relative to a base-case resource plan with a 50-year recurrence interval.

:.10 Final Thoughts on Core Reliability Planning

Upon initial examination of the results of our example, it may appear that reliability planning tells us nothing. Figure 8-2 shows that, depending on the assumptions made, the optimal recurrence interval can be anywhere from 12 to 105+ years. It should be emphasized, however, that we attempted to bound the ranges of assumptions relevant to a wide range of U.S. LDCs. For an individual utility, we predict that a reliability analysis would be more tractable. Although a particular utility should consider a range of values, we believe that it can reduce the degree of uncertainty exhibited in our example in light of knowledge of its own supply options and customers. Given the increased attention that LDCs are placing on providing competitive products and services, we believe that any method that improves knowledge of customer value, including the method we have presented in this chapter, should be of great importance to an LDC.

Conclusions

As gas local distribution companies assume a larger role in resource planning in response to changing market and regulatory forces, new analytical tools and methods will be marshaled to meet these responsibilities. This report characterizes some of these tools and illustrates methods that can be applied with the use of one type of model to solve representative LDC planning problems.

9.1 Avoided Cost

Choice of avoided cost method influences results. On a theoretical basis, DSM in/out is the method that most closely matches the concept of avoided cost. Practically speaking, however, DSM in/out and increment decrement methods produce very similar results for small decrement levels (larger decrements were not tested). Marginal cost methods produce similar results for baseload type DSM, but tend to be lower for heating-, cooling-, or peak-type DSM than DSM in/out or increment/decrement. Average cost methods produce highly variable results whose magnitudes and annual patterns are out of synch with the other methods and which produce counter intuitive price signals for resource selection. Our analysis is not conclusive on how generalizable these distinctions among the avoided cost methods are to other LDC systems. Nonetheless, these results are indicative of potential distinctions that should be verified by individual LDCs in doing their own avoided costing work.

It is no surprise that avoided cost results are highly sensitive to gas commodity cost escalation in a predictable way. While the capacity cost escalation rate assumption is less influential overall, the lumpiness of capacity resources can produce discrete cost shifts that are difficult to capture without the use of a sophisticated planning model. An active capacity release market raises avoided costs of DSM during those periods when LDC pipeline capacity holdings are not otherwise liquid or renegotiable.

9.2 Storage

Storage is a key strategic resource in an LDC's resource portfolio. In modeling our prototypical LDC, we found both the size of storage and the type (defined by the deliverability/capacity ratio or days of service) to significantly influence total system cost, on the order of 5 to 15 percent for the range of sensitivities we tested. Since market area storage and pipeline capacity to some extent serve as substitutes for one another, we looked at the effect of changes in the demand charges of these two resources on optimal storage sizing and total system cost. We found that raising or lowering the demand charges by the same amount produced an asymmetric response in cost and storage sizing, in some instances quite dramatic due to shifts in the loading order of capacity resources, again suggesting the value of a planning model for uncovering the complex underlying cost structure. Also because of the interdependence of pipeline capacity and storage in an LDC's resource portfolio, the existence of a pipeline capacity release market and what prices LDC sellers of capacity can expect to reap in this market influences how much storage capacity they want to have. As expected release revenues increase, so does the need for storage capacity to substitute for released pipeline capacity. Over a fairly wide range of expected release revenues, the optimal storage capacity holding is stable, but drops off fairly sharply around expected release revenues of 25 percent or less of the pipeline demand charge. In addition, short-term capacity releases tailored to the LDC's capacity needs at the time appear to allow for a lower overall storage capacity holding, which therefore lowers total system costs, *all other things being equal.*

9.3 Buyback Contracts

Buyback contracts represent a potentially beneficial arrangement between an LDC and customers that do not require firm, winter season supply. The LDC no longer acquires firm pipeline capacity for a portion of its core peak and, instead, contracts to acquire transportation and/or supply from specific noncore customers. Often the LDC is the primary capacity holder of the pipeline capacity and it releases the capacity to the customer on a long-term basis. Given the loads of our prototypical utility, we found that buyback contracts were very economic to the LDC: it was willing to pay up approximately 60 percent of the full demand charge rate just to have the right to buy back the gas for 30 days a month. The costs and benefits of a buyback arrangement for specific LDC will depend on the probability of exercising the contract and the price of alternative fuels. The probability of exercising the contract depends, in turn, on the estimated shape of normal and extreme daily winter loads and the quantity of the buyback capacity being considered. We find that resource planning models like Sendout are well suited to conduct an analysis of buyback contracts.

9.4 Core Reliability Planning

Even after restructuring, LDCs retain a solid obligation to serve core loads. Unfortunately, core loads are often temperature sensitive and the level of service provided can never be absolute; instead, service must be defined in terms of the probability of meeting load. Despite this long standing responsibility, methods in the industry for determining the appropriate core reliability standard are still ad hoc. We find that a method that compares marginal value of service (VOS) with the marginal cost of providing service to be most promising. It has already been used by at least one gas utility. Although our example of the VOS method is very sensitive to the assumptions chosen, we believe that individual LDCs will be able to estimate inputs to sufficient accuracy so that the method will make a contribution to the LDC's decision making.

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