Integrated Resource Planning at Gas Utilities: A Review of Initial Efforts

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Several local gas distribution companies (LDCs) have initiated integrated resource planning (IRP) processes in response to public utility commission (PUCs) directives. In this study, we review the initial IRP plans and planning processes of four gas utilities. These case studies illustrate the state-of-the-art in gas resource planning and identify technical and analytic issues in which additional work or improved data are needed. These areas include integration and linkage of detailed models used in various steps of the IRP analytic process, appropriateness of end-use forecasting methods, treatment of uncertainty of future loads and load growth, system reliability criteria to be used in gas resource planning, the market potential for gas DSM programs, methods used to estimate gas avoided costs, and institutional and financial barriers to gas DSM.

Introduction

Until recently, state public utility commissions (PUCs) have focused most of their attention on development of integrated resource planning processes for electric utilities. However, several PUCs are now looking closely at the planning processes of gas local distribution companies (LDCs) in part because of the increased control and responsibility that LDCs have for their purchased gas costs and because of questions surrounding the potential role for gas end-use efficiency options. A recent survey of state commissions identified 15 PUCs that are actively developing or considering IRP for gas utilities (Goldman and Hopkins 1991). By all accounts, gas IRP is still in its infancy, as gas utilities have filed initial IRP in only five states (District of Columbia, Illinois, Nevada, Oregon, Washington) in response to formal regulations. However, gas utilities in many more states believe that they will be required to develop IRP or DSM plans. For example, 41 out of 85 gas companies surveyed expect to have an IRP program within the next two years, according to the American Gas Association (1992).

In this study, we review the IRP plans prepared by four gas utilities: Washington Gas Light (District of Columbia) (DCNG 1990), People's Gas Light & Coke Company (PGLC 1991), Southwest Gas Corporation (SWG 1991a and 1991b), and Washington Water Power Company (WWP 1991). Our objectives are: (1) to assess progress among gas utilities in responding to the challenge posed by their state regulators, (2) discuss how the regulatory and market context affects plan objectives, development and emphasis, and (3) identify key technical, analytical, and institutional issues that arise in a comparative assessment of these first-generation gas IRP plans.

Approach

We reviewed the resource plans and related documents of four gas utilities. This in itself was a significant undertaking as the longest IRP plan (i.e., DCNG) consisted of 15 volumes featuring an executive summary, main report, and 22 technical appendices. In addition, we conducted telephone interviews with utility staff involved in the preparation of IRP plans. We used the general criteria and checklist developed by Hirst et al. (1990) as a starting place for our review: plan clarity, technical competence, adequacy of the short-term action plan, and fairness of the plan. However, Hirst et al. developed these guidelines based on a review of over 30 electric utility plans, many of which were second and third-generation efforts. Experience with electric utilities suggests that IRP is an iterative and evolving process, and thus expectations regarding these initial plans should take account of the relative newness of gas IRP. Thus, we view the analysis as primarily exploratory, because of limited gas industry experience and our small sample size.

State Regulatory Requirements

Differences in state regulatory or legal requirements and practices had a significant impact on the development of initial IRP plans of these four gas utilities. For example, the District of Columbia Public Service Commission's (PSC) order and subsequent regulations were quite detailed, specific, and often prescriptive. The PSC established ambitious conservation goals for natural gas utilities. These targets set 1998 goals of 25% and 35% usage reduction in residential and multifamily sectors respectively and 18-25% reductions in the commercial sector (with 70% reduction in commercial cooling). The PSC did not formally impose these targets as requirements; however, the PSC placed an implicit burden on the utility to show why certain targets were either unachievable or uneconomic. In addition, the PSC strongly encouraged DCNG to develop its IRP plan in close conjunction with "collaborative" working groups involving representatives from DCNG, the PSC staff, Office of People's Counsel, and the DC Energy Office. The collaborative created several working groups on different topics which met over 70 times during a two year period (April 1988--August 1990) to review and discuss virtually all aspects of the company's IRP activities. The working groups focused principally on the development, design, and evaluation plans for a comprehensive set of DSM pilot programs. DCNG was also required to develop end-use load forecasting models, and commence data collection and analysis efforts so that it could properly assess the DSM potential in commercial sector.

In Illinois, multiple state agencies are involved as the Public Utility Act of 1987 mandated that the Illinois Commerce Commission establish administrative rules implementing least-cost planning and that the Department of Energy and Natural Resources (DENR) prepare a statewide least-cost plan. In terms of process, the statewide gas plan was developed first and established an overall policy framework, which included 20 recommendations on various aspects of gas resource planning. Representatives from all segments of the gas industry, public interest groups, and commission staff reviewed drafts of the plan and helped shape policy recommendations through participation in a Natural Gas Plan Advisory Group. One important policy goal was to use DSM as an initial and primary source of *new* gas supplies, although its practical effect was muted because most utilities forecast no incremental supply need for the next 20 years in the face of very slow or nonexistent load growth. Utilities then developed individual plans, which were filed in January 1991 and had to be consistent with the state plan.

Washington's regulations were enacted in 1987 and required gas utilities to prepare an IRP plan in consultation with Commission staff and major stakeholders. In Washington, the commission has emphasized the planning process and mechanisms which facilitate public involvement. For example, WWP created a Technical Advisory Committee which reviewed and commented on drafts of the WWP's least-cost plan; the commission held public hearings, allowing interested parties to comment on the utility's draft plan. The utility's plan is not formally approved by the commission, although the utility's actions must be consistent with its submitted least-cost plan.

Southwest Gas (SWG) filed its first resource plan for the southern portion of its service territory in July 1990. The Nevada regulations require the Public Service Commission (PSC) to review IRP plans in formal proceedings and ultimately approve or disapprove of the utility's filed plan. The commission rejected the DSM component of SWG's plan and required SWG to refile its DSM plan in April 1991. Based on a stipulation, the commission ordered SWG to evaluate an expanded list of DSM programs using the total resource cost test as the primary criterion. In Nevada, an explicit, desired outcome of LCP regulations is an approved utility IRP plan.

LDC Responses to Industry Restructuring and Increased Competition

Each of the four utilities has been greatly affected by the restructuring of the federally-regulated segments of the gas industry, specifically, wellhead production and interstate transportation. Prior to these changes, a LDCs least-cost gas supply planning process was primarily limited to daily cost optimization decisions between a few suppliers (e.g., one or more pipelines, and storage options). The combination of comprehensive regulation of all industry segments, coupled with long-term contracts between pipelines and LDCs, meant that gas supply planning was dominated by the interstate pipelines. However, during the last decade, wellhead gas sales have been deregulated and the Federal Energy Regulatory Commission (FERC), in a series of orders, established conditions which made open access service for interstate pipeline transportation available to endusers, producers, and marketers. LDCs were then able to purchase gas supplies and firm transportation from various points as separate unbundled services.

The dramatic pace of these structural changes has led to a much less predictable business environment for LDCs. For example, within 1-2 years after the advent of open access on interstate pipelines and the availability of transportation for customer-owned gas supplies, Washington Water Power found that nearly all of its industrial customers had moved from sales to transportation customers (see Figure 1). Transportation service accounts for roughly one-third of People's Gas annual gas load. In their plans, several gas utilities emphasize the new operational and supply planning problems posed by substantial transportation volumes. These range from provision of short-term supply balancing services for end-use transporters to the longer-term planning issue of transportation customers that might ultimately want to

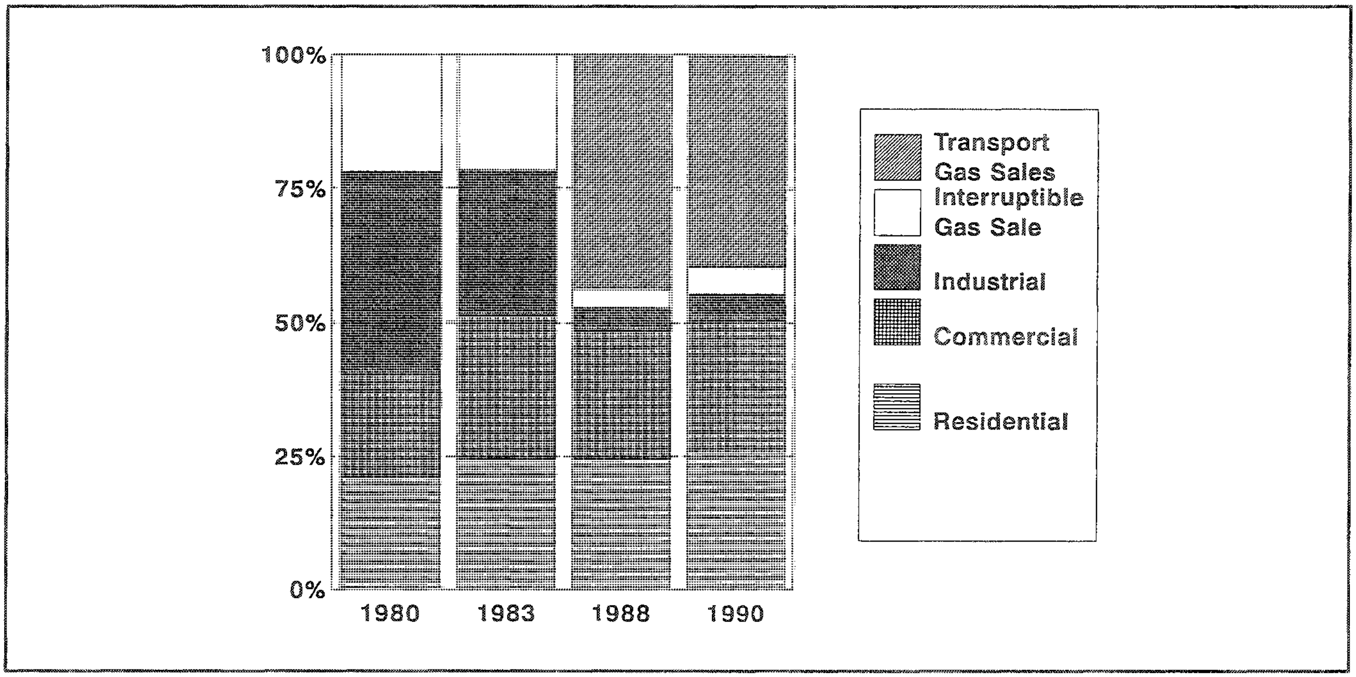

Figure 1. Washington Water Power Annual Gas Sales

shift back to LDC sales services, particularly if these customers lack alternate fuel capability (PGLC 1991).

Though all four utilities have been buffeted by industry restructuring, it is important to note important differences in their institutional and market settings, which are symptomatic of the diversity in the gas industry. For example, WWP is a combined utility, while the other three utilities are gas-only companies. WWP has proposed an aggressive natural gas conversion program which will target installation of efficient gas equipment to electric heat customers with central forced air furnaces (because they have existing duct work) and gas heat customers with electric water heating. These gas conversion programs account for a significant fraction of the projected growth in gas sales over the next decade. In contrast, the plans developed by the three gas-only utilities reflect the intense end-use competition that often occurs with the local electric utility and the difficulty that fuel substitution programs pose in this situation for many PUCs. For example, all three gas-only utilities were particularly interested in new markets for gas that would improve their load factor (e.g., increase summer gas use). However, the initial plans of DCNG and PGLC focus on gas efficiency programs, while noting the importance of fuel substitution programs. SWG proposed both gas efficiency and fuel substitution programs in its IRP plan. Of these, the commission approved two of the gas efficiency programs.

Table 1 illustrates some key differences among gas utilities in terms of firm size (as indicated by gas requirements), the underlying structure of gas demand in their service territory, the relative importance of gas transportation, and the overall supply/demand balance. Residential customers account for between 40-77% of firm sales among the four utilities. In terms of customer base, multifamily dwellings represent a significant portion of the residential gas market for PGLC and DCNG (63% and 34% of residential gas sales respectively). Commercial sales represent over 30% of total gas sales for three of the four utilities. However, comparisons across utilities in the C/I sector are more problematic because of definitional inconsistencies and opportunities for large customers to purchase their own gas and use the LDC only for transportation.

Southwest Gas' Southern Nevada service territory is situated in a very high growth region with forecasted load growth of 7.8% per year between 1990-2000. A significant fraction of its projected increase is driven by increased use of gas in electric generation. SWG and WWP, to a lesser extent, are facing significant capital investments in their pipeline and distribution system to meet projected demand over the planning horizon. In contrast, utilities such as DCNG and PGLC project that gas demand will remain flat or decline slightly over the next decade. These projections are driven by macroeconomic and demographic factors in each utility's service

Table 1. Gas Utility Requirements, Load Growth and Prices

	Washington Gas Light (DC)	People's Gas Light & Coke	Southwest Gas	Washington Water Power
1990 Total Sales (10^9 Btu)	31,163	167,595	30,768	18,078
Residential	39%	77%	40%	41%
Commercial	34%[a]	17%	31%	38%
Industrial				
Firm		6%	3%	8%
Interruptible	27%[b]	<1%	-	10%
Electric Generation	-	-	4%	<1%
Transportation Volumes	0	75,944	31,038	14,212
1990 Gas Requirement (10^9 Btu)	31,163	243,539	61,806	32,290
Forecast Load Growth Between 1990-2000 (%/yr)	-0.26%	-0.36%	7.8% (3.1%)	1.9%
Average 1990 Prices ($/Mbtu)				
Residential	7.50	5.65	5.41	3.61
Commercial	7.12	5.25	4.14	2.92
Industrial				
Firm	-	5.07	3.88	2.34
Interruptible	4.18	3.54	-	1.76
Transportation	-	1.32	0.34	0.27

(a) Commercial and industrial firm loads.
(b) Commercial and industrial interruptible loads.

territory (e.g., declining industrial base for People's Gas, flat or negative population growth in older urban areas such as Chicago and Washington D.C.) as well as decreased usage per customer, largely as a result of projected efficiency improvements in residential equipment.

Because the gas industry is not vertically integrated, it is also important to understand the historic relationships with gas producers and pipelines as they affect the strategic position and opportunities of LDCs. Access to multiple producing regions and pipelines, the relative costs of bringing gas to market from interstate pipelines, as well as the costs to serve various customer classes, account for much of the variation in end-user gas costs. For example, WWP's residential gas prices are significantly lower than the other three gas utilities, in part attributable to the fact that WWP's service territory is close to Canadian and Rocky Mountain gas producing regions and two interstate pipelines (Northwest Pipeline Corporation and Pacific Gas Transmission). SWG is located relatively near the major gas producing regions of the U.S. southwest. Illinois is particularly well-situated in terms of access to gas transportation and storage as it is served by nine interstate pipeline and ranks second in underground gas storage capacity. This facilitates competition among producing regions and pipelines on commodity costs, but also means that it is relatively easy for end-use customers to bypass the existing LDC and buy gas directly from a nearby pipeline. Other utilities, such as Washington Gas Light, have historically been served by a few major pipelines and are more remote from major producing regions.

Plan Objectives

Table 2 summarizes major objectives listed by the four gas utilities in their initial IRP plans. Several utilities framed the planning exercise in terms of the ways in which their traditional gas supply planning process had to be modified to accommodate additional regulatory requirements. Often, utilities provided specific objectives for both gas supply planning and DSM resource planning, which reflects to some extent the more limited degree of integration.

Table 2. Gas Utility Plan Objectives

	IRP	DSM
Washington Gas Light	• Meet quantitative & qualitative planning criteria • Quantitative criteria: - design day & sales requirements - operational integrity - meet PSC DSM goals - least cost (typical bills) - feasibility of implementation	• Implement pilot programs to determine if, on a full scale basis, they produce reductions in gas use equivalent to conservation targets specified by PSC
People's Gas	• Comply fully with Illinois statewide Gas Utility Plan & requirements of ICC least cost planning regulations • Provide gas supplies sufficient to meet design peak day, peak season & annual requirements of all customers, at lowest cost consistent with short & long-term reliability & safety requirements	• Increase capability to deliver viable DSM programs • Provide all customer classes with cost-effective DSM options • Increase company's understanding of DSM-related uncertainties • Pursue other DSM activities that will reduce system-wide average unit costs of gas
Southwest Gas	• Pursue best available courses of action that will balance customer service obligations with interests of shareholders, while retaining its position as a leader in energy marketplace	• Respond to Nevada resource planning regulations • Provide all customers classes with cost-effective DSM options
Washington Water Power	• Comply with commission mandate; illustrate WWP gas resource planning process	• Identify and quantify DSM resources in its territory • Develop a planning level assessment, not to develop specific DSM savings and expenditures at this time

It is clear that the turmoil in the gas industry has had its effect on the planning horizons of LDCs as several of the utilities noted that their planning environment was dominated by the need for "transition strategies" to cope with fast-paced changes brought about by industry restructuring and new regulatory requirements. Not surprisingly, the plans reflect the fact that few gas utilities believe that they can afford to focus much analytic effort on the long-term. In some cases, objectives are offered that appear to be primarily reactive rather than stated as strategic goals for the utility. For example, DCNG develops alternative scenarios which comply to different degrees with PSC DSM goals, indicative of the way in which commission directives explicitly shaped the IRP plan. Some utilities (e.g., WWP) framed their objectives in terms of getting started with an IRP process.

Public Involvement in Plan Development and Review

Adequate participation in development and review by various stakeholders is one of the major criteria used by Hirst et al. (1990) in assessing the fairness of an IRP plan. The four gas utilities employed a range of approaches in terms of the degree and stages of public involvement. As indicated previously, DCNG relied heavily on the expertise of formally constituted working groups of major stakeholders that were involved in the design of a comprehensive set of pilot DSM programs and review of its IRP plan. DCNG's approach essentially can be characterized as a collaborative process, driven to a great extent by commission policy goals and rulings, with substantial involvement of non-utility parties in both plan development and review.

In contrast, SWG did not have a formal collaborative process, but did hold three workshops which involved non-utility parties during plan development. SWG was faced with significant revisions to its DSM plan during the plan review process. This is exemplified by the stipulation that SWG reached with the other parties. In Washington, involvement of non-utility parties occurred during plan development and review, with input primarily in the form of advisory groups (rather than the formal collaboratives used by DCNG). As in Nevada, review of the initial IRP plan by commission staff and other parties resulted in WWP undertaking significant revisions (and additional analytic work) in the DSM planning portion of its filing. Public involvement took a different form in Illinois, principally because of the two-stage resource planning process. Major stakeholders were involved in review and policy consensus-building activities in the statewide gas planning framework, with much less explicit involvement in plan development for the individual utility plans.

Plan Contents: Technical and Analytic Issues

Gas Utilities Rely on Series of Linked Models for IRP Analysis

Electric utilities typically rely on one of two general analytical approaches in performing integrated resource planning: (1) linked, detailed models and/or (2) integrated planning models (Eto 1990). In the first method, utilities must link inputs and outputs of individual, detailed models for each step of the IRP process (e.g., load forecasting, generation planning, production costs, financial analysis) into an integrated process. In the second method, electric utilities use commercially-available integrated planning models which incorporate important elements necessary for comprehensive treatment of DSM and supply-side options and where the major linkages are embedded in the simulation model and are made transparent to the user.

In our small sample, gas utilities utilized the linked, model approach. This is not too surprising because the IRP analytic effort for most of these utilities involved bootstrapping models and tools that were already available within the appropriate departments into an integrated analysis procedure. Some utilities (e.g., DCNG) had to develop new models for the various steps in the IRP analytic process. The apparent lack of stand-alone integrated planning models might also be a by-product of gas industry structure (i.e., vertically disintegrated) which meant that it wasn't particularly relevant for LDCs to consider all strategic resource options from wellhead to end-user customer.

Figure 2 summarizes the analytic framework developed by People's Gas. The company notes that the most important change brought about by the LCP requirements was the complete integration of its existing approaches to demand forecasting, demand-side planning, and supply-side planning.

The major steps in PGLC's process included: (1) develop forecast of annual and design peak day loads under several alternative economic scenarios and futures; (2) using demand forecasts, develop Baseline Resource plan based on results of screening available supply-side resource options in company-developed monthly gas supply optimization model (LINDO--Linear, Interactive, and Discrete Optimizer); this produces supply-only least-cost plan; (3) identify available DSM options; develop savings and cost estimates for each option; (4) conduct economic analysis of 13 DSM program options using estimates of avoided costs developed from Baseline

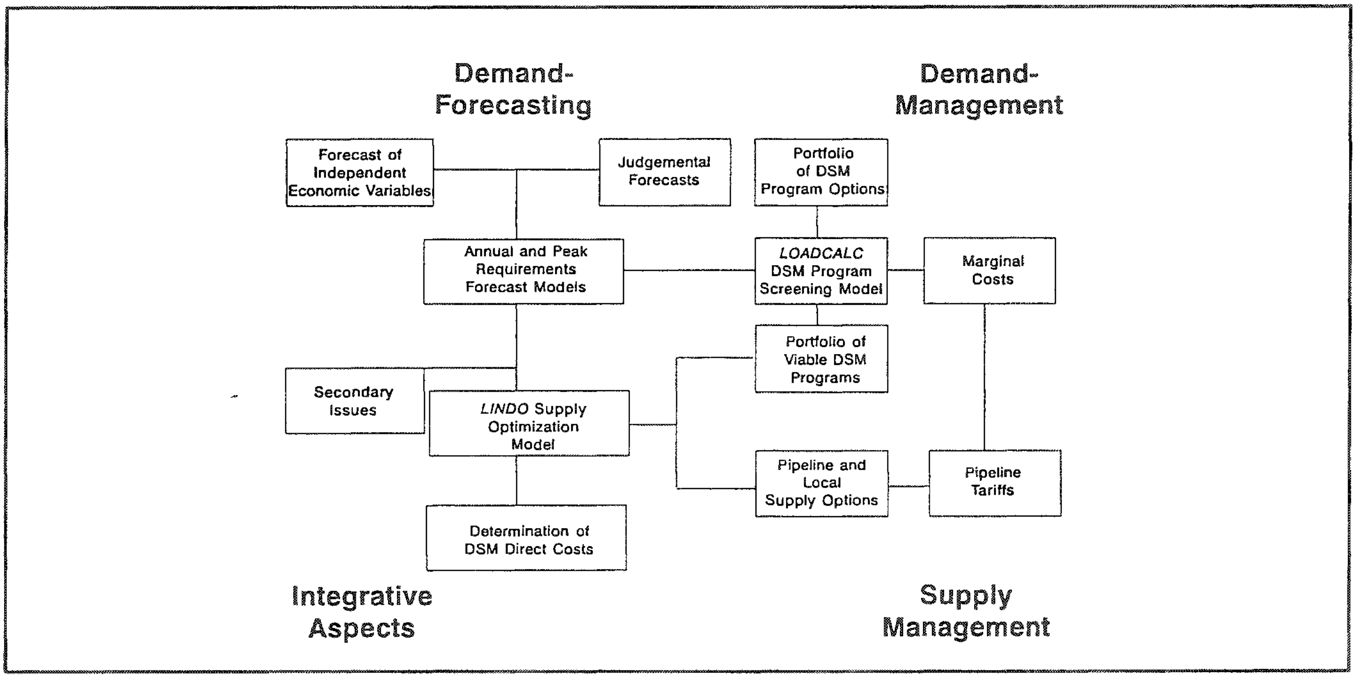

Figure 2. People's Gas IRP Analysis Framework

Resource plan; screening of DSM options conducted using LOADCALC (a DSM screening software system developed by a consulting firm); options had to provide positive net benefits using societal, participant, and utility perspectives; (5) combine viable DSM and supply-side options for further detailed analysis in LINDO model; model selects combination of supply-side and DSM resources; (6) utility considers several secondary issues (e.g., potential implementation barriers, rate design consideration) and determines financial impact on Company in terms of earnings, and rates; and (7), select Integrated Least-cost plan based on preceding analytic steps (PGLC 1991).

One clear benefit of the IRP process is that gas utilities have had to grapple with analytical and modeling techniques required to integrate DSM options into the traditional supply planning process. Prior to implementing IRP, People's Gas did not consider DSM programs as resource options in developing its least-cost supply portfolio.

The various steps in the IRP process--forecasting, optimization of the gas supply plan, and development and screening of DSM options--were performed with relative degrees of sophistication among the four utilities. The integrated planning process, and the requirements to consider DSM measures as resource options, revealed significant analytic and data gaps for each utility, which are briefly discussed in the next sections.

Limited Use of End-use Forecasting Models

Except for DCNG, gas utilities relied primarily on econometric models to develop their long-term sales forecasts for residential and commercial customers. For example, WWP's econometric model for these two sectors has 95 equations relating gas consumption (by class, rate schedule, and state jurisdiction) to weather, the economy, and price variables and is built on a historical data base beginning in 1978. The model does not include cross-price elasticities and assumes that new customers will choose gas water and space heating based on current patterns (i.e., 60% of all new customers use natural gas). Typically, gas utilities then forecast future loads for large interruptible and transport customers using customer surveys and analysis of future gas use by utility marketing account executives.

At the PSC's direction, DCNG developed end-use forecasting models for residential and commercial sectors. The residential model estimates gas usage across six primary end-uses and three customer classes and attempts to model and incorporate appliance choice decisions and changes in appliance saturations. In developing this capability, DCNG conducted detailed and statistically representative surveys of single-family, multifamily, and commercial buildings (disaggregated into 16 SIC codes). These surveys were also used to assess the level of energy efficiency in the building stock and constituted a major data collection and analysis effort involving almost 4,000 commercial and multifamily buildings and over 1,500 single-family dwellings. In addition, DCNG developed a database of gas consumption data using historic metered billing data at both the building and rate class level (e.g., commercial and apartment heating, non-heating, and central heating), which involved aggregating gas consumption on a whole building level from meter or accounting records.

These efforts illustrate the substantial baseline data collection and model development which are required in order for gas utilities to conduct an integrated and comprehensive analysis of demand-side options in an IRP plan. One advantage of end-use-based models is that DSM resource opportunities and impacts can be more readily accounted for in forecasts of future loads and factors that affect gas usage, such as thermal integrity of buildings, appliance efficiency and saturation, and gas consuming activity can be accounted for explicitly. Another side-benefit is that this information is invaluable for market research. Based on our small sample, few gas utilities have this capability at the present time. However, we expect that the data requirements of IRP, along with potential strategic benefits (and competitive pressures), will encourage more gas utilities to undertake these activities.

Gas Supply Reliability Planning Criteria Vary Among Utilities and are Driven Principally by Design Peak Day Requirements

Concern over the public health, safety and economic consequences of interruptions of gas service during severe weather for customers without short-term alternatives to gas has meant that utilities traditionally place the highest priority on system reliability in gas supply planning. Gas utilities seek to ensure that their gas supply portfolio is diversified and can meet the usage requirements of core customers under extremely adverse weather conditions.

All four utilities estimate peak day usage using recent historical data on the relationship between annual gas consumption and peak day demand. System load factors (LF) range between 30-35% and are defined as:

$$LF = \text{Avg. gas use/peak demand} \qquad (1)$$

where, average gas use equals annual gas requirements (i.e., firm sales plus transportation volumes)/365.

Peak day demand estimation methods vary in their degree of sophistication among utilities. One utility assumed a 33% load factor for the entire forecast period. Another utility conducted an econometric analysis of the relationship between daily firm sales and weather by day type (i.e., weekday vs. weekend) during five recent winter periods and then adjusted peak day demand over the forecast period to account for efficiency impacts.

Several of the gas utilities used regression parameter estimates (base-load and weather-sensitive) to calculate peak day usage under extremely adverse weather conditions ("design day"). Typically, the design day peak demand requirement was then increased upward by an additional reserve margin, which ranges between 5-15%. Rationales offered to support reserve margin levels typically rest on judgment. Initial analysis suggests that there appears to be substantial variation in "reserve margins" that are deemed appropriate among utilities. It is difficult to discern if these differences are solely attributable to unique characteristics of individual gas systems (e.g., company's gas supply mix, configuration of transmission and distribution system, availability of peaking facilities) or reflect lack of generally-accepted industry standards on supply planning reliability criteria. In an IRP context, reliability planning criteria assume increased importance because it has a direct bearing on the relative mix of firm vs. non-firm gas supplies as well as the comparative evaluation of the benefits of DSM vs. supply resource options (Jensen 1991).

Assessing DSM Technical and Market Potential: Does DSM Represent a Significant Resource Option for Gas LDCs?

Table 3 summarizes the approach and results from various stages of each utility's DSM planning process: assessment of DSM technical and market potential, proposed DSM programs, projected DSM program expenditures, savings, and relative impacts. We make the following observations: (1) Several utilities' assessment in their IRP plans of the DSM technical and market potential was somewhat narrow initially, generally confined to a limited set of residential DSM options. However, these utilities have quickly taken steps to remedy deficiencies and have conducted more comprehensive planning level assessments of DSM resource opportunities, most often at the urging of commission staff. (2) Several utilities indicated that they do not have a high degree of confidence in the key input assumptions (i.e., savings, incremental costs, and

Table 3. DSM Resource Planning

	Southwest Gas	People's Gas	Washington Water Power	DCNG
Tech/Market Potential	• 15 programs selected for detailed analysis from a list of 68	• 14 programs (10 residential; 4 C/I)	• 5 residential efficiency options • Focus on fuel substitution programs • Planning level assessment of 68 electric & 9 DSM options (April 1991)	• 74 program options • 17 programs selected
DSM Screening Criteria	• Market potential, reliability, customer acceptance, net impact of utility action, expected cost-effectiveness, balance among customer segments	• Societal, participant, utility tests	• Magnitude of load impact, expected cost effectiveness, reliability of savings, environmental impacts, consistency with corporate objectives, proven market performance	• Quantitative: all-ratepayer test was primary screening criteria followed by rate impact, participant and non-participant, test • Qualitative: customer acceptance, regulatory acceptance, flexibility, number of free riders, externalities, cream skimming
Proposed DSM Programs	• 13 programs (including 4 fuel substitution)	• 5 residential • 2 commercial\industrial		• 17 pilot programs implemented (October 1988)
DSM Proposed Program Costs	• Proposed: \$3.90M • Approved: \$0.34M (91-94)	• Proposed: \$0.36M (92) • Proposed: \$3.20M (93)	• \$2.6M (92) • \$5.2M (93)	• \$3.8M (91) • \$4.0M (92)
Relative Impact of DSM	• 0.2% of operating revenues for 2 approved programs	• 0.37% of annual requirements (1995) • 0.9% of annual requirement (2000) • 0.04% - 0.35% of revenues (in 1992, 1993 respectively)	• 2% of annual gas requirements over next 10 years • 4.8% - 9.6% of revenues (in 1992, 1993 respectively)	• Meet Commission targets • Estimate no effect on annual requirements systemwide

Sources: SWG 1991a, 1991b; PGLC 1991; WWP 1991b; DCNG 1990.

penetration rates), because they are not drawn from their own actual experience. Their own experience in fielding DSM programs is limited to energy audit services, for all but PGLC. Some utilities stated that their estimates of market potential and program design features were illustrative in providing an initial indication of the relative cost-effectiveness and contribution of DSM in a least-cost plan. In addition, utility estimates of the aggregate DSM savings potential in their service territory were often hampered by limited data on energy-using characteristics of the building and equipment stock. (3) Based on this limited sample, there are fewer gas efficiency options that provide significant resource savings at much lower costs than supply alternatives, which is a distinctive feature of DSM plans filed by many electric utilities (e.g., commercial sector lighting). Space and water heating dominate residential and commercial gas consumption and some efficiency opportunities have been and will continue to be realized through appliance efficiency standards as well as comprehensive weatherization efforts initiated by government, utilities, or customers. In addition, analysis of industrial DSM options is technically more complex (and often constrained by proprietary concerns related to processes), while analysis of the economic benefits to gas utilities are complicated by industry structural changes (e.g., customer-owned gas, end-user transportation). (4) For two utilities, estimated savings from gas DSM programs are quite small (e.g., 1-2%) relative to annual gas requirements, while the systemwide effects are minimal at the other two utilities given current DSM programs (see Table 3).

Analyzing Economics of DSM: What Test to Use, How to Estimate Benefits?

In screening DSM options, all four utilities relied primarily on the results of the total resource cost test results in the economic analysis of DSM programs, often at the commission's direction. In Nevada, SWG was ordered to obtain better utility and rate impact measure (RIM) values for one of its DSM programs prior to implementation, despite a satisfactory TRC test value. At the other utilities, DSM options were not eliminated because they failed the ratepayer impact measure (RIM) or non-participants test, although several of the gas utilities noted their serious concerns about potential rate impacts associated with gas efficiency programs.

The gas industry has also raised practical and methodological concerns with regard to estimating the long-term benefits of gas efficiency programs and utilized divergent approaches in developing gas avoided costs. These include difficulties in estimating gas commodity costs over the planning horizon, disagreements regarding the extent to which pipeline demand or capacity-related costs can be avoided by DSM, and the use of simplified proxy approaches to estimate avoided gas costs (AGA 1991).

Gas DSM Program Experience is Limited

Among the four utilities, actual experience implementing large-scale gas DSM programs is limited. PGLC had the most prior experience implementing gas efficiency programs at the time its plan was filed. Beginning in 1984, the utility offered six DSM programs, which included loan programs for single and multi-family building owners, incentives to purchase high-efficiency gas equipment, a program targeted at religious buildings, and several informational programs. PGCL completed an impact evaluation of its multi-family program, which led to modifications in program design. PGCL offered two DSM programs (i.e., multi-family and high-efficiency equipment incentive) at the time its IRP plan was filed.

As it developed its IRP plan, DCNG was required to implement a comprehensive set of DSM pilot programs, which it did beginning in late 1988. Initially, DCNG offered 17 DSM pilot programs targeted to all major customer groups: residential (9), multifamily (2), commercial (2), and multi-family/commercial (4) (see Table 3). In each sector, programs build off of an initial energy audit, which then are complemented by rebate or loan programs for high-efficiency equipment, controls, and weatherization measures. Several the pilot programs are innovative either in terms of program design (e.g., multifamily rehabilitation) as well as technologies promoted (e.g., package cogeneration, gas chillers). Comprehensive program evaluations are underway for these pilot programs and DCNG will not proceed to full-scale implementation until evaluations demonstrate benefits of programs in their own service territory.

Southwest Gas experience in DSM program implementation included the Residential Conservation Service (RCS) energy audits during the active period of the federal RCS program and residential weatherization activities. The company's revised DSM program Plan consisted of 13 DSM programs, four of which were fuel switching programs. Of the 13 programs, the PSC approved two. Objections to the other programs included RIM test values, the sensitivity of the fuel-switching issue, and the high cost of the Plan (estimated at $3.5 million). The two DSM programs, which only recently received approval, are: (1) weatherization retrofit plan, and (2) boiler retrofit with heat recovery program. Both are expected to be implemented in 1992, with estimated costs of $335,000.

Fuel Substitution and Strategic Load Building: The Gas Utility's "Golden Carrot?"

As indicated earlier, of the four utilities, only WWP and SWG proposed fuel substitution programs in their initial IRP plans. These utilities proposed that fuel substitution efforts would account for a significant portion of their overall DSM activities. This is not to suggest that fuel substitution and strategic load building were not a major concern for the other two utilities. In fact, fuel substitution and load building were extremely important to both PGLC and DCNG. It appears that differences among utilities have to do more with timing rather than substance. For example, PGLC identifies barriers to strategic load growth as one of the two potential barriers to implementation of its Least-cost plan. Specifically, PGLC is interested in pursuing compressed natural gas powered vehicles, gas-fired cogeneration, and gas air conditioning. The utility calls upon the Illinois commission to re-examine policies that provide electric utility competitors with an advantage in certain end-use markets (e.g., promotional allowances for electric heat pumps), allow PGLC to recover expenses related to promotion of these new market opportunities, and support the utility's rate design and promotional proposals where gas utilization could reduce overall consumer energy costs (PGLC 1991).

Initial evidence suggests that utility desires in the fuel substitution area have been thwarted somewhat by reluctant PUCs. For example, the Nevada commission explicitly deferred a decision on SWG's proposed fuel substitution programs and ordered that a special investigatory docket be opened to address the fuel-switching programs and other fuel substitution issues. Other commissions have also not been particularly anxious to confront this issue head-on. However, the issue is fundamental for gas only and combination utilities and appears to be driven by the underlying system economics. Annual load factors for gas utilities tend to be low (30-35%) compared to typical values in the electric utility industry (50-60%). Not surprisingly, many gas utilities seek to develop new gas loads, in off-peak periods, that have load factors greater than their average load factor. In so doing, gas utilities seek to reduce systemwide average gas costs on a per unit basis, essentially spreading fixed costs over larger volumes.

Institutional and Financial Barriers to DSM

Operation of traditional load management programs allowed electric utilities and their regulators to gain experience in developing cost recovery mechanisms for demand-side interventions that preceded large-scale DSM programs. In contrast, despite the fact that many gas utilities offered informational audit and weatherization programs to residential customers in the late 1970s and early 1980s, this experience appears *not* to have produced well-accepted and standardized procedures for cost recovery for these types of activities. Thus, in addition to industry concerns regarding "lost revenues" and potential under-recovery of fixed costs that arise from gas efficiency programs, several gas utilities mention cost recovery issues in their initial IRP plans. For example, PGLC states: "The timely recovery of prudently incurred costs associated with the implementation of DSM programs is critical if utilities are to have a strong incentive to aggressively pursue DSM resource options... To remove a potential disincentive associated with a delay or prohibition on recovery, the Company is presenting a cost recovery mechanism which illustrates the Company's proposal for recovering direct costs of DSM programs. The Company currently contemplates recovering lost revenues through rates established in general rate proceedings (PGLC 1992)."

In its plan, PGLC stressed that implementation of its two-year action plan which emphasized DSM capability building efforts, was dependent upon the commission's approval of an appropriate DSM cost recovery and margin erosion mechanisms.

Issues related to direct cost recovery may initially be somewhat more difficult for gas utilities compared to electric utilities because of more limited experience on the demand-side and because of cost allocation issues related to transportation customers. However, a variety of traditional and innovative cost recovery approaches have been suggested by the industry (AGA 1992). It is a threshold question for serious utility involvement on the demand-side. Mechanisms that seek to overcome financial disincentives for the utility to pursue gas efficiency through recovery of "net lost revenues" are more difficult to implement. They will typically involve the utility documenting gas savings and corresponding "lost revenues," which will involve a significant commitment to ongoing DSM program evaluation, an area in which few gas utilities have much experience.

Conclusion

Regulators often cite the policy goal of comparable and consistent ground rules for electric and gas utility planning as a primary motivation for initiating IRP. However, our review of first-generation gas IRP plans suggests that these processes have to be tailored to the conditions, circumstances, and structure of the gas industry. It appears that the most successful processes have occurred in working environments that are relatively "non-threatening" to the utilities: workshops, collaborative processes to design DSM programs, or joint research projects which investigate controversial or technical topics (e.g., fuel substitution or DSM potential).

Based on discussions with gas utility staff, it is apparent that IRP processes require significant staff resources, are quite time-consuming, and involve major infrastructure investments, not in pipe and compressors, but principally in human resources. Moreover, the IRP process requires a broad interdisciplinary team consisting of staff from various departments (e.g., planning, engineering, marketing, rates, regulatory affairs). In reviewing IRP plans, PUCs are insisting that a gas utility demonstrate that a serious effort has been made to analyze supply and DSM resource opportunities in a consistent and comprehensive fashion. In establishing a gas IRP process, explicit policy guidance from regulators is most needed in the following areas: (1) balancing of various economic tests, (2) ensuring comparable earnings opportunities for DSM, and (3) interfuel competition and promotional practices. Most commissions have adopted a flexible approach in terms of balancing plan contents with the actual experience base of gas utilities. However, utilities will be expected to proceed up the IRP learning curve quickly in terms of analytical sophistication and data requirements. For gas utilities, potential benefits of an IRP process include establishing a framework for utilities and regulators to address and reconcile short- and long-term resource planning objectives, ensuring fairly-structured competition among fuels in end-use markets, and creating new market opportunities for gas.

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