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NATURAL GAS SUPPLY AND INFRASTRUCTURE ASSESSMENT

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Executive Summary

This *Natural Gas Supply and Infrastructure Assessment* staff paper is the first step in a public process for analyzing natural gas trends and issues for the *Integrated Energy Policy Report* (IEPR), mandated by Chapter 568 of the Statutes of 2002 (formerly SB 1389). This paper will be discussed at a staff workshop to be held in January 2003. The workshop will solicit comments from the public and interested parties regarding the issues that should be addressed in the next *Natural Gas Market Outlook* report. That report will be published as a stand-alone document in Spring 2003 and also as an element of the IEPR in Fall 2003.

Highlights

Electric generator demand for natural gas is driving growth in natural gas demand throughout the United States. Supplies of natural gas will be sufficient but more costly. The estimates of wellhead prices for Lower 48 gas for 2002 jumped approximately 50 percent compared to the wellhead prices forecasted for 2002, published in the 1998 *Natural Gas Market Outlook* report. To accommodate growing demand in California and surrounding states, interstate pipeline infrastructure to gas supplies in the Southwest, Rocky Mountains, and Canada need to be expanded. Southern California Gas Company (SoCal Gas) has adequate pipeline capacity to receive supplies through 2012, while the staff expects that Pacific Gas and Electric Company (PG&E) will need to expand pipeline capacity in the 2007 to 2012 time period. The analyses in the paper assume average hydroelectricity and weather conditions, and well-functioning competitive markets.

Key Findings and Conclusions

Demand Trends

For this paper, the Energy Commission staff relied on the Gas Research Institute's (GRI) forecast of natural gas demand in the United States, except for California. In the United States, the GRI predicted the demand for natural gas would grow faster than its forecast published in 1999, with most of the growth occurring in the electricity generation sector. From 2002 to 2012, based on Energy Commission staff analysis, California's demand for natural gas will grow two percent per year.

Since 1997, almost all power plant developers have chosen to build gas-fired combined cycle facilities because of their thermal efficiency, expandability, and ability to obtain permits. As these more efficient facilities come on-line, gas demand in California is initially expected to decrease. Then, as electricity demand continues to grow, the new units will operate along with some older units to meet the total demand. If merchant generators abandon or delay power plant projects, however, then gas demand will escalate sooner because the older, less efficient plants will need to increase their use of natural gas to meet the increase in electricity demand.

California's future need for new power plants, and the gas supply to serve them, could decrease if power plants are constructed outside of California and electricity can be imported from these out-of-state facilities. If merchant generators delay or abandon their plans to construct power plants outside the state, then California's need for gas supplies and in-state generation will likely increase.

Supply Trends

Between 2002 and 2012, supplies of natural gas are likely to be sufficient but more costly because of several reasons. The demand for natural gas is increasing throughout North America, but supplies are not as plentiful as anticipated. The Commission staff assumed proved reserves of natural gas would not appreciate at the same rate assumed in the 1998 *Natural Gas Market Outlook* report. Further, the model results predict that gas production in the Lower 48 States will peak around 2012 and then decline.

As a consequence, the U.S. will likely become increasingly reliant on natural gas from Canadian and liquefied natural gas (LNG) imports, while developing economical "unconventional" sources of natural gas to meet growing demand. Some customers will be priced out of the natural gas market. Where possible, customers with dual-fuel capability will likely switch to another fuel, such as oil.

Through 2012, the Southwest will remain the state's major natural gas resource region; however, California will increase its gas imports from the Rocky Mountain region and Canada, because these areas offer the lowest wellhead prices.

Price Projections

Prices for natural gas will likely rise faster than inflation due to gas demand growth and the expense of developing new gas wells and pipeline capacity.

Electricity generators in the Western Electricity Coordinating Council (WECC) region will likely find the lowest-cost natural gas along the PG&E-owned Gas Transmission Northwest pipeline corridor in the Pacific Northwest which delivers Canadian supplies, and the Kern River pipeline corridor which connects California to Rocky Mountain gas supplies. Electricity generators who receive gas-delivery service from PG&E, SoCal Gas, and San Diego Gas and Electric Company (SDG&E) are expected to pay the highest prices for natural gas.

California's two largest natural gas utilities will have similar California border prices after 2007, but PG&E's prices are expected to be slightly less expensive than SoCal Gas gas prices. System-average prices for all customers of these utilities will probably range between \$4 to \$6 per thousand cubic feet of natural gas (Mcf), in constant 2002 dollars, between 2002 and 2012. Gas-fired generators that obtain gas from California gas utilities are projected to pay more than \$4 per Mcf (in constant 2002 dollars) in 2012.

Infrastructure Trends

New gas-fired power plants in the Western U.S. are increasing gas demand and necessitating investments in interstate pipeline construction projects. The basecase scenario of gas flows indicates that additional pipeline capacity will be needed to meet growing electricity generator demand in southern Nevada, Arizona, and New Mexico. The San Juan and Rocky Mountain basins are the supply basins of choice.

Within California, the staff predicts that PG&E will need additional receiving capacity in Northern California between 2007 and 2012. SoCal Gas recently completed major infrastructure projects. As a result, the staff believes that under average conditions, SoCal Gas has ensured adequate slack capacity for its service territory through 2012.

Chapter 1 Introduction

This paper presents the Energy Commission staff's natural gas projections for 2002 to 2012, including assessments of natural gas demand, supply, prices, and infrastructure needs. These projections serve as the starting point for a natural gas analysis that will be incorporated into the *Integrated Energy Policy Report*. As required by Chapter 568 of the Statutes of 2002 (formerly Senate Bill 1389), the Energy Commission will conduct natural gas forecasting and assessments of: 1) statewide and regional natural gas demand, 2) adequacy of natural gas supplies, 3) assessment of natural gas infrastructure, and 4) natural gas markets.

In addition the Commission is required to identify trends and impending or potential problems or uncertainties in the natural gas markets as well as potential options, solutions, and recommendations. A January staff workshop will be a forum for the public to provide comments on these topics.

The Energy Commission staff used the North American Regional Gas (NARG) model as its principal assessment tool. Basic inputs to the NARG model include estimates of regional demand, resource availability, production costs, pipeline capacity, and pipeline transportation costs. NARG allows modelers to increase a region's resource availability using a parameter called the reserve appreciation factor to reflect the gas industry's experience in recovering more natural gas than originally estimated. Relative to the 1998 forecast, the staff reduced the reserve appreciation factors by almost fifty percent for this assessment, because of the observed minimal response in Lower 48 States natural gas production to higher wellhead prices.

To simulate long-term market conditions, the assessment assumes average temperature and water supply conditions for hydroelectricity generation in the Western U.S. The basecase assessment does not reflect the short-term consequences of temperature extremes, droughts, abundant hydroelectricity conditions, or financial difficulties within the natural gas industry.

The NARG model was programmed to assume an inelastic demand for energy, although fuel substitution can occur. Only demand regions with LNG receiving facilities were allowed to receive LNG supplies, not California. Furthermore, the NARG does not allow natural gas supply curtailments; supply must meet demand.

Key assumptions used in this assessment included how much new electricity generation would be constructed in the Western U.S. between 2002 and 2012, and where these facilities would connect to pipelines. Furthermore, as the rates of natural gas flow on a pipeline increase to meet increasing demand, the NARG assumed that capacity on an existing pipeline will be expanded or that a new pipeline would be built, with associated costs, when it is needed. For more information on the assumptions used to produce the supply and price assessments, see the methodology descriptions in the Natural Gas Supply and Natural Gas Prices chapters and Appendix C.

The paper is organized into the following chapters:

- Chapter 1 — Introduction
- Chapter 2 — Natural Gas Demand
- Chapter 3 — Natural Gas Supply
- Chapter 4 — Natural Gas Prices
- Chapter 5 — Natural Gas Infrastructure

The organization of the paper follows the logic of the analysis. The demand forecast determines the amount of natural gas supplies needed. Probable supply sources must be known to determine prices. Finally, estimates of demand, supply, and prices are used to predict natural gas infrastructure needs.

The second chapter, Natural Gas Demand, presents trends in natural gas demand at the North American and national levels, within the WECC region and in California. The Natural Gas Supply chapter, chapter 3, discusses which gas-producing regions in North America will likely serve the Lower 48 States and California.

Based on demand and supply trends presented in chapters 2 and 3, the Natural Gas Prices chapter, chapter 4, provides assessments of wellhead prices for gas produced in Canada and in the Lower 48 States, prices for electricity generators in the WECC region and California, and prices for California consumers. The Energy Commission staff analyzed the possible effects to wellhead prices from changes in demand, supply, and other critical parameters to produce upper and lower boundaries for wellhead-price estimates.

Many electricity generators in the WECC region are expected to receive gas shipments directly from interstate pipelines. Following wellhead price assessments, the Natural Gas Prices chapter projects gas prices for electricity generators at sites along interstate pipeline corridors. As the starting point for determining consumer gas prices, the chapter next assesses gas prices at the California border for California's three largest gas utilities. The chapter also provides historical and projected prices for gas-utility customers, including electricity generators connected to California gas-utility systems.

The Natural Gas Infrastructure chapter presents a basecase scenario of interstate pipeline expansions based on the assessment of wellhead prices and a projection of pipeline flows needed to balance supply and demand. Alternatives to the basecase and regulatory impediments to interstate pipeline expansions are also presented. The chapter then discusses the status of intrastate pipeline capacity for PG&E and SoCal Gas.

This paper also provides a list of acronyms and a glossary of terms used in this paper. Appendices provide detailed supply and price projection data.

Chapter 2 Natural Gas Demand

Introduction

This chapter provides historical and projected demand trends in North America, the Western U.S., and California. California natural gas supply and prices are affected by national trends in natural gas demand. Natural gas demand is increasing in the electricity generation sector due to widespread construction of gas-fired combined-cycle power plants. Gas demand within the residential, commercial, and industrial sectors is growing too, but at a much slower pace. Growth in electricity demand by these other sectors, however, is creating the need for new electricity generating facilities.

The Commission staff used the following sources of natural gas demand data:

- United States — GRI
- Canada — Canadian Energy Research Institute (CERI)
- Electricity generators in the WECC — Energy Commission
- California — Energy Commission

Demand Growth in North America

United States

The United States is the biggest consumer of natural gas in the world.[1] In 1997, the reference year for this paper, the U.S. consumed 20.2[2] trillion cubic feet (Tcf) of natural gas, which represented approximately one quarter of total world demand.

The GRI, a research, development, and training organization representing the natural gas industry, predicted that U.S. consumption could reach 30 Tcf by 2015.[3] If this happens, then U.S. demand growth will be nine years ahead of schedule because it had not been expected to reach 30 Tcf until 2024.[4] (The GRI and the Institute of Gas Technology merged to become the Gas Technology Institute (GTI). The forecasts referenced in this staff paper were GRI publications.)

The GRI expects all end-use sectors to increase their natural gas demand approximately 28 percent between 2002 and 2012, from 23 Tcf to 29.5 Tcf. While residential, commercial, and industrial demand will have an annual growth rate of 1.8 percent, demand by electricity generators is expected to increase 4.6 percent per year. Nearly half of projected demand growth, therefore, will likely come from the electricity-generation sector.[5] Electricity-demand growth will necessitate more power plants; these plants generally will be fueled by natural gas. Appendix A provides data on actual North American gas demand in 1997 and projected demand data by region for 2002, 2007, and 2012.

Although the total demand for energy is anticipated to reach 29.5 Tcf by 2012, natural gas use will account for 27.9 Tcf or 95 percent of total energy demand. Alternative fuels to natural gas such as oil will satisfy the remaining five percent of total energy demand.

Residential Demand

According to the American Gas Association, more than half of all heated homes in the U.S. – approximately 49 million households – used natural gas for space and water heating in 2000, and 70 percent of new single-family homes built in 2001 were heated with natural gas. Residential natural gas demand, however, is expected to increase less than one percent per year between 2002 and 2012, due to the energy efficiency of modern gas appliances.

Figure 1 illustrates growth in natural gas demand for all end-use sectors, as forecasted by GRI.

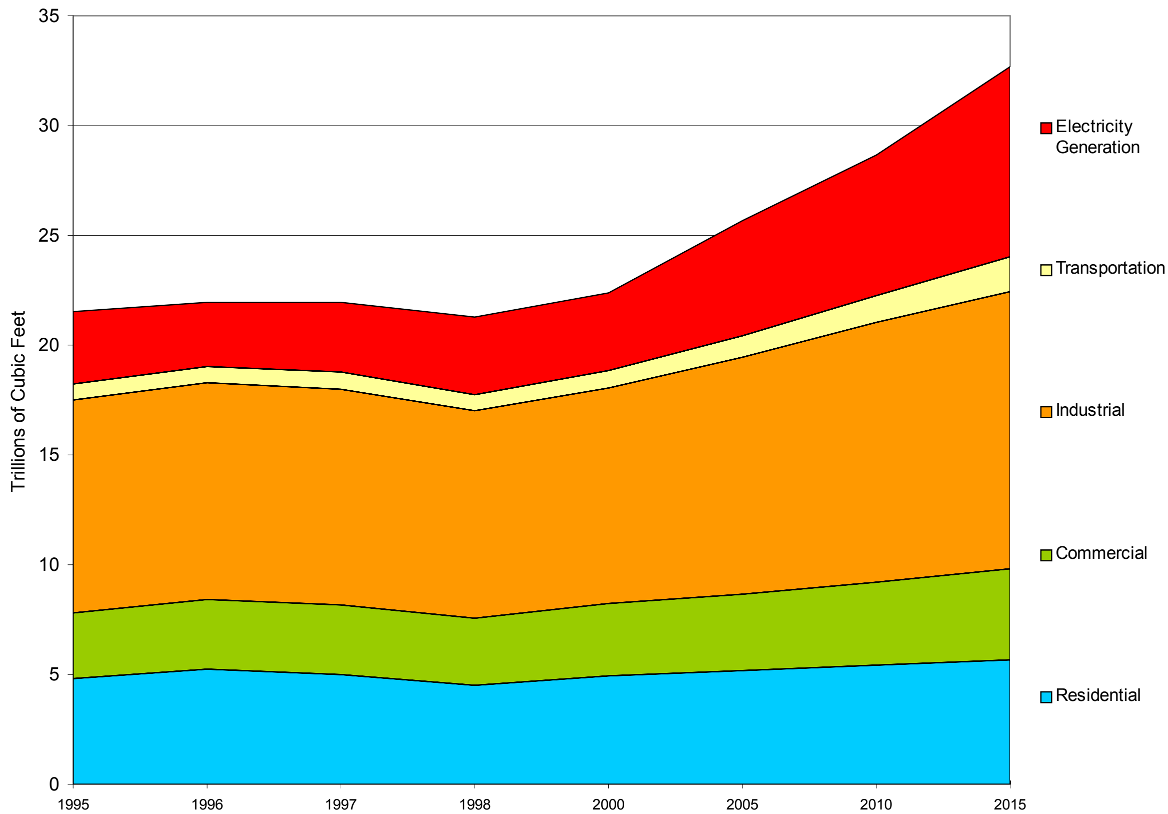

Figure 1: Historical and Forecasted Natural Gas Consumption in the U.S. by End-Use Sector
Source: GRI, *2000 Baseline Projection,* Summary Table 2

Commercial Demand

In 1999, the U.S. had approximately 4.7 million commercial buildings, comprising more than 60 billion square feet of floor space.[6] Four commercial activities account for half of these buildings: office, warehouse and storage, mercantile, and education.

Natural gas serves 57 percent of all commercial buildings. Where available, natural gas provides space heat (in 51 percent of buildings with space heating), hot water (in 47 percent of buildings with water heating) and cooking fuel (in 59 percent of buildings with cooking activities). Although the number and average size of commercial buildings has been increasing steadily since 1979, natural gas consumption has remained relatively flat.

Natural gas demand in the commercial sector is expected to grow 1.5 percent per year between 2002 and 2012.[7] Growth is expected to occur primarily due to increased use of natural gas for space cooling (e.g., absorption cooling) and on-site electricity generation.[8] On-site electricity generators provide back-up power in the event of a power interruption or supplemental power to augment grid supplies such as during peak-demand periods. While both renewable energy and diesel fuel can power these units, natural gas is a common fuel because it is burns cleaner relative to diesel fuel, and the natural gas-delivery infrastructure is extensive in urban areas. Gas-fired technologies include reciprocating engines, gas turbines, microturbines, and fuel cells.

Industrial Demand

The industrial sector is the largest natural-gas user in the U.S. The industrial sector will remain the largest user of natural gas through 2012, but growth in natural gas demand is expected to be relatively slow — 1.7 percent between 2002 and 2012.[9] In 2000, industrial consumption, including cogeneration, was 9.5 Tcf, which represented nearly half (47 percent) of total U.S. demand. A relatively small number of industries account for 84 percent of industrial natural-gas use — the chemical; petroleum refining; metals; pulp and paper; stone, clay, and glass; plastic; and food processing industries. In 1998, the chemical industry used more natural gas than any other industry (36 percent), while the next largest users, the petroleum refining and metals industries, consumed approximately 13 percent each.[10]

Natural gas has a multitude of industrial uses, including as a raw ingredient for plastic, fertilizer, anti-freeze, and fabrics. Its primary use, however, is as a fuel source for process heating and steam generation.

Natural gas is the preferred fuel for industrial cogeneration with a 65 percent market share.[11] The penetration of cogeneration technology in the industrial sector is due in large part to federal Public Utilities Regulatory Policy Act (PURPA) incentives, which provided a guaranteed buyer — the local electric utility — for co-generated electricity not used by the manufacturing plant. New industrial cogeneration facilities are expected to be sized smaller than PURPA-era facilities and will primarily meet process-steam requirements rather than produce surplus electricity for off-site sales.

Electricity Generation

The GRI projects natural gas for electricity generation to increase from 3.5 Tcf in 2000 to 6.4 Tcf in 2012.[12] In the 1970s and 1980s, most utility-owned electricity generators were large coal or nuclear-powered plants. Currently, coal and nuclear plants produce 54 and 22 percent of the electricity in the U.S., respectively. Both coal and nuclear power plants are expected to remain dominant power suppliers between 2000 and 2010.[13] By 2015, however, natural gas could become the number-two ranking fuel source (20 percent) for electricity power generation.[14]

Coal is the cheapest fossil fuel for generating electricity, but it also releases the highest levels of pollutants into the air. Air pollution regulations, therefore, are a major reason natural gas has become the preferred fuel for new power plants. In addition, the lead time for constructing a natural gas-fired combined-cycle power plant is shorter than that of a new coal-fired plant. Further, a gas-fired power plant can be constructed in a modular fashion. Rather than constructing one large coal or nuclear unit and assuming the risk that forecasted demand for electricity will be realized, smaller gas units can be constructed as warranted without the economic penalties associated with building "small" coal or nuclear plants.

In 2000, 23,453 megawatts (MW) of new electricity capacity were added in the U.S. Of this new capacity, gas-fired additions represented almost 95 percent. The most common type of new central station power plant will be the combined-cycle facility, which partners gas turbines with waste-heat-recovery steam generators.

Canada and Mexico

Canada consumes more energy per capita than most other countries in the world.[15] Its energy use can be explained partially by the temperature extremes of its climate and its relatively dispersed population. Natural gas currently supplies approximately 44 percent of total energy use in Canada, second only to electricity (45.7 percent).

In 1997, Canadian gas consumption was 2,776 billion cubic feet (Bcf).[16] The Canadian industrial sector used approximately 40 percent (1,080 Bcf), residents consumed 23 percent (627 Bcf), and commercial businesses used 15 percent (413 Bcf). Electricity generation represented approximately seven percent of total gas demand (184 Bcf), while pipeline fuel and other uses consumed the remaining 17 percent (472 Bcf).

Regionally, the largest Canadian markets for natural gas in 1997 were Ontario – 35 percent (965 Bcf), Alberta – 30 percent (824 Bcf) and British Columbia – 11 percent (306 Bcf). Minor amounts of U.S. natural gas are purchased by eastern Canadian consumers. In 1997, Canadian imports of U.S. gas totaled 45 Bcf, or only two percent of total Canadian demand. The CERI forecasted that the annual growth rate for Canadian gas demand will be 1.1 percent, from 2.8 Tcf in 2002 to 3.1 Tcf in 2012.

In Mexico, the *Comision Federal de Electricidad* (CFE), the state utility that currently serves 99 percent of the Mexican power market anticipates strong growth for natural gas consumption for power generation. Natural gas demand for power generation grew by more than five percent per year for several years, and the CFE hopes to install 13 gigawatts of new capacity — predominantly gas-fired combined-cycle power plants — over the next five years. The CFE has indicated that it plans to have 47 gigawatts of installed capacity by 2006. By 2006, overall CFE gas consumption is expected to quintuple from the current rate of 500 million cubic feet (MMcf) per day.[17]

Only that portion of total Mexican gas demand connected to the U.S. natural gas grid is included in the Commission's NARG model. This portion is projected to grow at 7.6 percent per year, from 0.179 Tcf in 2002 to 0.373 Tcf in 2012. During this time frame, the Baja Mexico Demand region will nearly quadruple its gas demand, from 0.035 Tcf in 2002 to 0.136 Tcf in 2012.

Demand Growth in the Western U.S.

Within the Western U.S., total population grew 20 percent between 1990 and 2000[18] and is now more than 61 million people (approximately 22 percent of the total U.S. population). California's population — 33.8 million in 2000 — represents more than half of this total. While California's population increased 13.6 percent between 1990 and 2000, the populations in other western states grew faster, including the following: Nevada, 66 percent; Arizona, 40 percent; and Colorado, Utah, and Idaho, approximately 30 percent each.

In 1997, the residential, commercial, and industrial sectors comprised approximately 80 percent of total natural gas demand in the Western U.S. The electricity generation sector represented the remaining 20 percent (.66 Tcf). By 2012, however, the electricity generation sector will increase its share of total gas demand to nearly 40 percent of the total (2.1 Tcf).

California used approximately 60 percent (2.0 Tcf) of total gas demand in the Western U.S. in 1997. The Pacific Northwest region (Oregon and Washington) consumed 13 percent, the Southwest Desert region (Arizona, Nevada, New Mexico) consumed 12; and the Rocky Mountain region (Colorado, Idaho, Montana, Utah, and Wyoming) consumed 17 percent of the total. By 2012, California will continue to be the largest user of natural gas in the West, but its share of total gas demand will likely decline to 50 percent (2.8 Tcf). The Southwest Desert is expected to become the second largest gas-using region (18 percent, 1.0 Tcf).

In the Western U.S in 2000, total electricity consumption was more than 615,000 gigawatt-hours (GWh), which represents a 22 percent increase from 1990. California's electricity consumption was 40 percent of total electricity consumption in the West. The other two states that consumed large proportions of the region's electricity were Washington (15 percent) and Arizona (10 percent). In Washington, because its hydroelectricity sites have all been developed, future electricity demand growth will be met with new gas-fired generation and wind resources. Gas demand is anticipated to grow in western Arizona due to new electricity generators locating along the El Paso Southern pipeline system (EPS).

Demand from New Gas-Fired Electricity Generation

Gas demand is expected to grow quickly in the West due to new gas-fired electricity generators being constructed to serve increased electrical demand.[19] The Energy Commission staff expects the electricity generation sector to almost double its natural gas demand between 2002 and 2012.

Table 1 provides the projected gas demand growth in the West by region. The percentage increases for electricity sector demand growth are dramatic in the regions other than California, because these regions have historically used coal, nuclear energy, and hydroelectricity and are only now starting to generate electricity using natural gas. As a result of these increases, California's portion of western states' gas demand for electricity generation slips from nearly 60 percent of the total in 2002 to less than 40 percent in 2012.

Table 1: Projected Western United States Gas Demand (in Tcf/year)

Demand Regions	1997 (actual)	2002	2007	2012	Volume Change 1997-2012	Percent Change 1997-2012
California						
Electric generation	0.525	0.647	0.716	0.818	0.293	56%
All other sectors	1.426	1.575	1.751	1.930	0.504	35%
Subtotal	1.951	2.222	2.467	2.748	0.797	41%
Pacific Northwest						
Electric generation	0.038	0.158	0.233	0.414	0.376	989%
All other sectors	0.395	0.452	0.501	0.492	0.097	25%
Subtotal	0.433	0.610	0.733	0.906	0.473	109%
Southwest Desert						
Electric generation	0.085	0.269	0.526	0.649	0.564	664%
All other sectors	0.316	0.286	0.336	0.390	0.074	23%
Subtotal	0.401	0.555	0.862	1.039	0.638	159%
Rocky Mountain						
Electric generation	0.010	0.065	0.127	0.225	0.215	2150%
All other sectors	0.575	0.593	0.684	0.770	0.195	34%
Subtotal	0.585	0.658	0.812	0.995	0.410	70%
Western United States						
Electric generation	0.658	1.139	1.602	**2.106**	1.448	**220%**
All other sectors	2.712	2.906	3.272	3.582	0.870	32%
TOTAL	3.370	4.045	4.874	5.688	2.318	69%

Source: California Energy Commission

The Commission staff projected electrical output from both new and existing gas-fired generators between 2002 and 2012, assuming average weather conditions and average hydroelectricity resource availability. The assessment of electrical output was prepared before a new state law was enacted in September 2002, requiring that California generate 20 percent of its electricity from renewable energy no later than 2017.

The output estimates are provided below in Figure 2: Projected Electrical Output by Generation Type for WECC Region. Output from natural gas-fired facilities is expected to exceed the output of other types of generation starting in 2006. This graph illustrates that gas-fired facilities are expected to serve most of the new electricity load growth in the region.

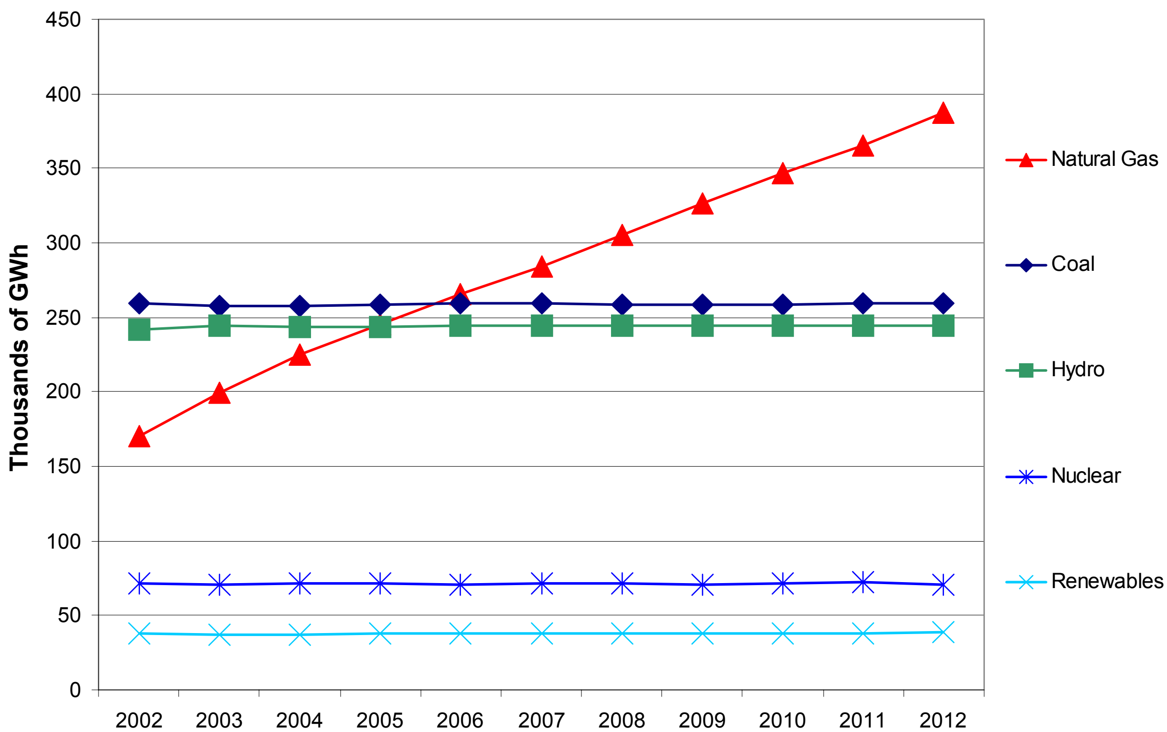

Figure 2: Projected Electrical Output for WECC Region by Generation Type
Source: California Energy Commission

The Commission staff assumed 46,182 MW of new gas-fired electricity generation would be constructed from 2002 through to 2012 in the WECC region, including Canada and northern Mexico. These assumptions are presented below in Table 2. The largest growth was assumed to occur in the California-Mexico region. Also, the southwestern states were assumed to have more than 13,000 MW of new electricity generating capacity built during the next ten years, with most of the new generation located in western Arizona and southern Nevada.

Table 2: Proposed Electricity Generation in the Western U.S. (in MW)

Region	Delayed	Total Possible June 2002	Assumed Added 2002-12	Fraction
Northwest	(6,660)	28,519	9,667	34%
Southwest	(8,112)	29,492	13,268	45%
Rocky Mountains	(857)	7,600	5,041	66%
California-Mexico	(9,880)	25,794	18,206	71%
Total	(25,509)	91,405	46,182	50%

Source: California Energy Commission, http://www.energy.ca.gov/electricity/wscc_proposed_generation.html (updated July 9, 2002)

Because much of the new generation would be sited to accept supply directly from interstate pipelines, the Commission staff configured the NARG model to recognize electricity generation along these pipeline corridors. Specifically, the staff assigned electricity generator demand to specific pipeline corridors according to the locations of the proposed projects. The staff used the results of this analysis to project pipeline infrastructure needs, which are presented in Chapter 5.

Table 2 indicates that new power plant sponsors are considering either canceling or postponing some proposed plants. In fact, as this pipe-flow modeling was conducted, additional projects in the WECC have been postponed or canceled. It is unclear what the impact on natural gas demand would be if actual new power plant construction were lower than estimated in this analysis. Several outcomes are possible, depending on the power plant construction schedules assumed in the analysis.

One possible outcome may be that new and efficient power plants that are built would operate at higher capacity factors and support all load that would have been served by new units that were assumed, but postponed or canceled. This outcome may not affect gas demand projections. On the other hand, if the new plants that are built do not have enough combined capacity to meet electricity demand, then the older and less efficient units would be expected to fill the need. This outcome would increase the demand for natural gas and raise the need for new pipeline infrastructure.

The timing for any new natural gas pipeline capacity would depend on how much electricity generation capacity is deferred and for how long. Furthermore, the regional needs for pipeline capacity expansion will depend on the location of the canceled or delayed power plants. The Commission staff intends to update its assumptions and issue a new assessment of pipeline flows in 2003.

Demand Growth in California

California has seven gas utilities, including PG&E, SoCal Gas, and SDG&E. Together, California's seven gas utilities have approximately 10 million customers and serve 83 percent of total state gas demand. Non-utility or bypass customers — who receive gas directly from producers within California or from the Kern River or Mojave interstate pipeline systems —

comprise the remaining 17 percent of total load. It should be noted that 12 counties in California do not have gas service: Alpine, Del Norte, Inyo, Lake, Lassen, Modoc, Mariposa, Mono, Plumas, Sierra, Siskiyou, and Tuolumne.

Gas utility deliveries in California increased at an annual average rate of four percent between 1995 and 2000.[20] Between 1999 and 2000, gas consumption increased by 8.1 percent.[21] This unusually large increase was caused by increased gas-fired electricity generator demand in response to reduced hydroelectricity generation caused by drought. In 2000, California set a record for natural gas demand by consuming, on average, more than 6,500 million cubic feet per day. The industrial and electricity generation sectors each used approximately 35 percent of this total. Residential and commercial customers used 21 and seven percent, respectively.

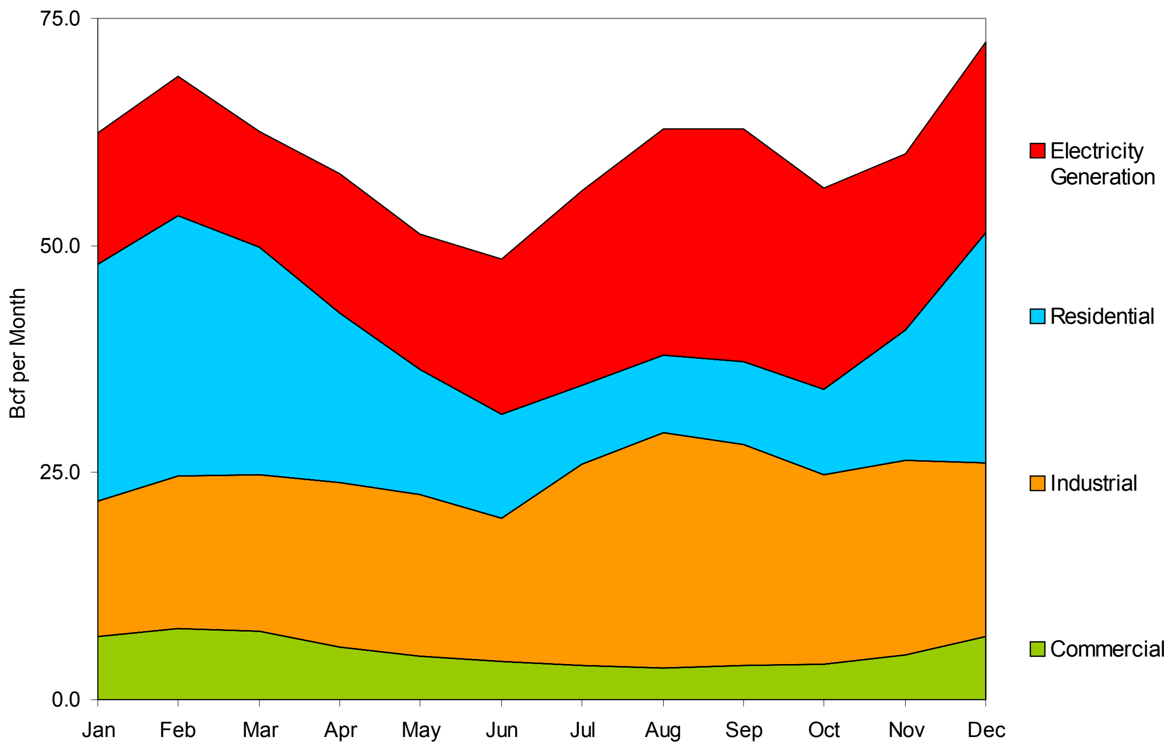

Figure 3: PG&E's Average Monthly Natural Gas Demand
Source: PG&E filings to the California Energy Commission

As shown in Figure 3, natural gas demand on the PG&E system changes with the heating and air conditioning seasons. Residential heating loads raise gas demand in winter, while air conditioning raises peak electricity demand in summer. PG&E's monthly gas demand pattern is also influenced by the availability of hydroelectricity generation in spring and industrial food-processing operations in fall. The SoCal Gas system shows similar, but less pronounced, seasonal variations in demand.

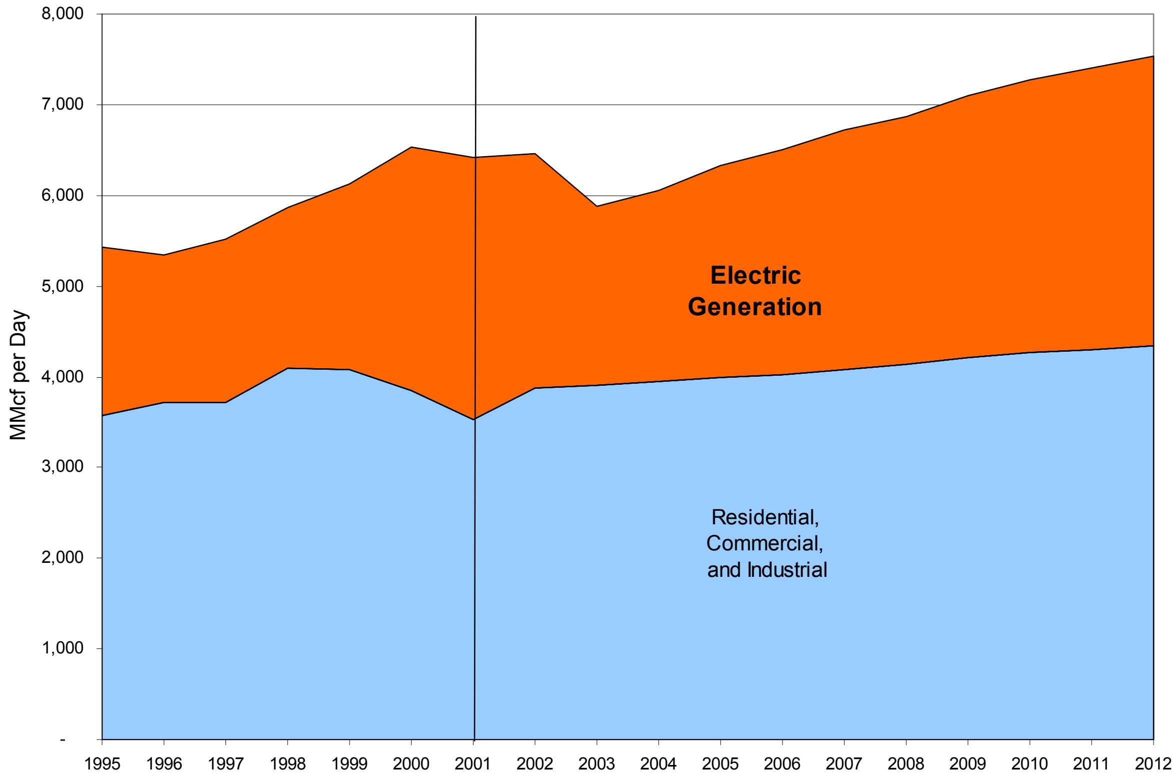

Figure 4: Historical and Projected Natural Gas Demand in California
Source: California Energy Commission

Figure 4 shows the historical and projected natural gas demand for California. As the figure shows, the greatest growth occurs in the electricity generation sector.

By 2012, California's annual-average natural gas demand is estimated to reach 7.5 Bcf per day, which is approximately 1 Bcf per day above its historical demand level in 2000.

Residential demand will grow less than one percent per year between 2002 and 2012. Per person, gas use has decreased over the past 20 years. The California building energy efficiency standards are contributing to this slow-growth trend. They help reduce gas demand by preventing heat losses through better insulation, windows, and ductwork. The appliance efficiency standards also contribute to the reduced usage.

Commercial gas demand is expected to grow between 2002 and 2012 at twice the rate of residential demand growth — 1.7 percent per year versus 0.8 percent. For the same time period, statewide industrial demand will grow 1.1 percent per year.

Gas demand by the electricity generation sector is expected to grow 2.1 percent per year between 2002 and 2012.

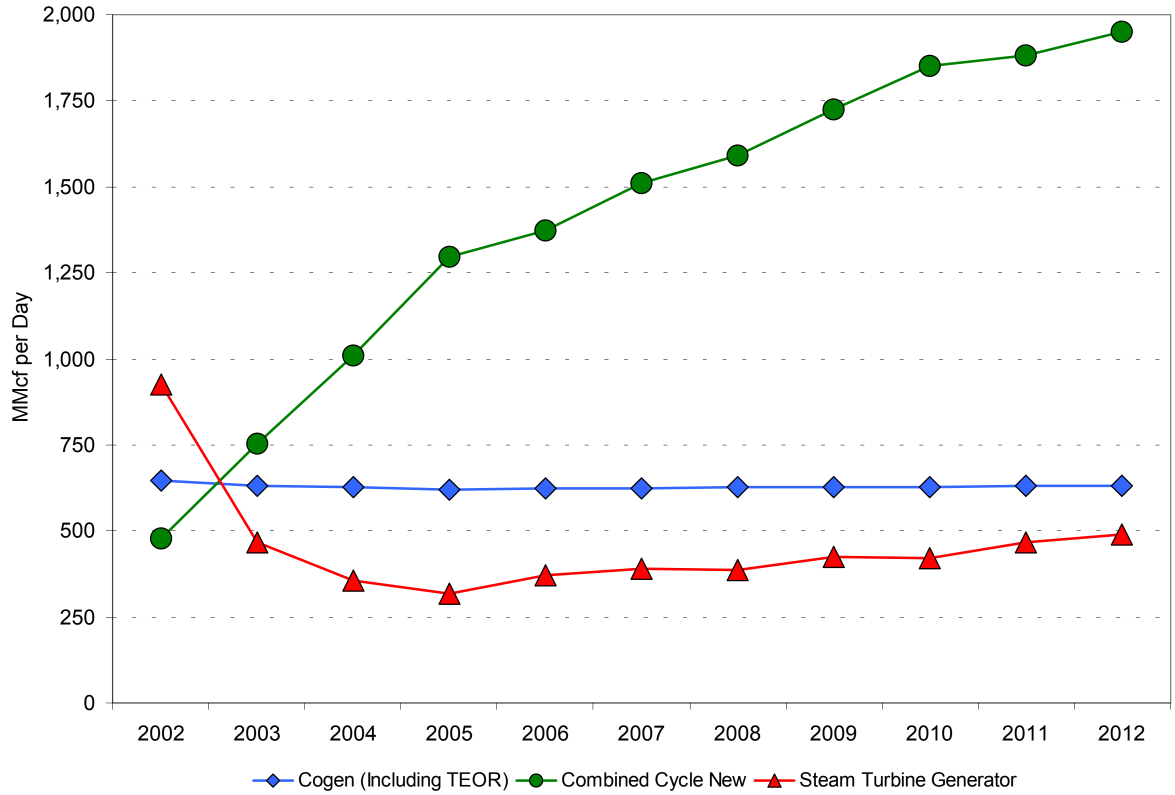

Figure 5: Projected California Natural Gas Demand for Electricity Generation
Source: California Energy Commission

In California, new combined cycle power plants are expected to come on-line between 2001 and 2004 and displace approximately two-thirds of the natural gas used by the old steam-turbine power plants as well as meeting growth in electricity demand, as illustrated in Figure 5.

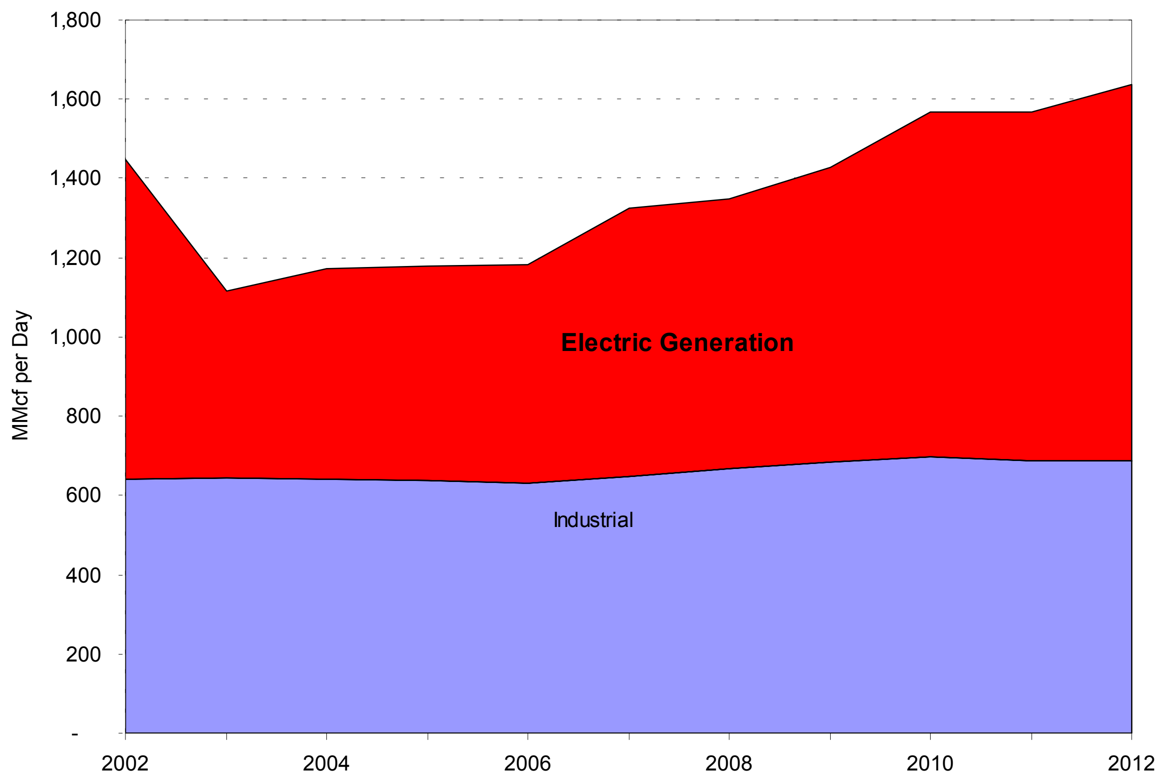

Figure 6: Projected California Non-utility Natural Gas Demand
Source: California Energy Commission

Projected growth in non-utility gas demand is also due to the electricity generation sector, as illustrated in Figure 6.

A number of new combined-cycle facilities will be located in the lower San Joaquin Valley. Several of the new power plants will rely on California natural gas production to meet their fuel needs. Most, however, will draw natural gas from the Kern River/Mojave pipeline system. Industrial demand, mainly steam generation for thermally enhanced oil recovery (TEOR), is expected to remain constant during the next ten years. In these operations, waste heat from electricity generation is used to produce hot water or steam for injection into heavy oil production formations. The fuel portion for the TEOR cogeneration is included in the electricity generation portion of the area graph shown in Figure 6.

Chapter 3 Natural Gas Supply

Introduction

This chapter covers the assessment of natural gas supply, including methodology and the sources and quantities of supply to serve North America, the U.S., and California. In the 1998 *Natural Gas Market Outlook* report, the staff predicted that natural gas supplies would remain plentiful for the next several decades. North America continues to have sufficient natural gas supplies to meet its predicted demand, but the costs to develop new supplies is increasing faster than previously anticipated.

Supply Assessment Methodology

Since 1989, the Commission staff has used the NARG model as its principal assessment tool. This general equilibrium model determines the quantities and prices of natural gas needed to balance supply and demand throughout North America during a 45-year time horizon. The NARG estimates natural gas quantities and prices every five years for each designated region. In addition to 20 demand regions, the NARG designates 18 North American supply regions and LNG import facility locations. Pipeline corridors connect the supply and demand regions. The supply and demand regions are shown on Figure 7 below as well as the projected 2002 gas flows along pipeline corridors.

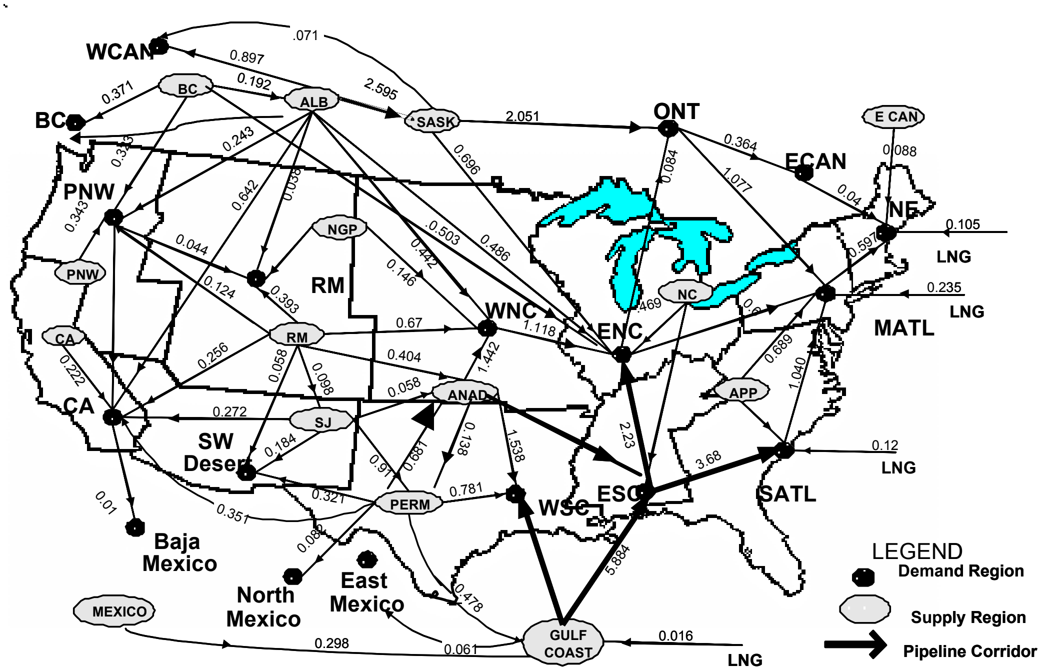

Figure 7: Projected 2002 Send-Out Gas Flows (in Tcf)
Source: California Energy Commission

Each supply region contains multiple natural gas resources, reflecting different types of conventional and unconventional geological formations. The demand regions largely correspond to census regions defined by the U.S. Department of Energy. Each demand region contains three end-use consumer classes: core, noncore, and power generation. Core customers rely solely on natural gas, whereas noncore customers, usually industrial, can switch to another type of fuel. Similarly, power generation customers outside of California can use natural gas or another fuel.

The Commission staff models California in greater detail within NARG than other states by adding structure for the three largest gas utilities and for in-state gas production in northern and southern California. For the pipelines, transport capacity and costs are defined. Rules are also applied for pipelines running over or under capacity.

Basic inputs to the NARG model include United States Geological Survey (USGS) estimates of resource availability and production costs. Other inputs include pipeline capacity and transportation costs, regional demand projections, and other parameters, which simulate long-term market conditions.

In the NARG model, the resource base consists of two categories of reserves, proved and potential. The production of proved reserves requires only the outlay of operation and maintenance (O&M) cost, whereas potential reserves require both capital and O&M costs.

As the model determines the quantity of natural gas needed to meet demand, reserves move from the potential to the proved category. Curves representing the capital cost structure provide the model with potential reserves and their associated cost of development. Technology enhancement parameters lower the cost at which potential reserves become proved. As a result, the model determines which reserves will likely serve demand, based on their lower cost.

To account for the observed increase in estimates of proved reserves, the model includes a reserve appreciation factor. Experience has shown that known producing areas recover more natural gas than originally anticipated, thus expanding proved reserves. Several factors account for this phenomenon, including the following:

- Technology improvements in recovery and production methods, and
- Increased drilling sites (i.e., in-fill drilling) tapping into remaining pockets of natural gas.

In the 1998 *Natural Gas Market Outlook* report, the staff introduced the reserve appreciation factor to increase reserves above those estimated by USGS. Each resource in the model utilizes a unique reserve appreciation factor. Using this factor, proved reserves can grow during the assessment horizon to a level greater than originally estimated by USGS. For this paper, the Commission staff is reducing the reserve appreciation factors used in the 1998 *Natural Gas Outlook* report by almost fifty percent. The decrease reflects the fact that Lower 48 proved reserves have not increased as much as the staff estimated in 1998. The reduction in the reserve appreciation factor contributes to the higher observed price level in this assessment.

Table 3 shows some of the data that the Commission staff tracks in determining the reasonableness of the reserve appreciation factor used in the NARG model. The table shows natural gas production, gas wells drilled, and wellhead prices in the U. S. from 1990 through 2001. From 1990 to 1999, wellhead prices fluctuated around $2.00 per Mcf and the rate of gas wells drilled averaged around 10,000 wells per year. (All of the wellhead prices shown in Table 3 are in current-year dollars.)

In 2000, the price increased to $3.69 per Mcf, wells drilled increased to 15,837, and production barely changed from 18,832 Bcf in 1999 to 18,987 in 2000. In 2001, the wellhead price increased to $4.12 per Mcf, wells drilled increased to 22,083, and production increased marginally to 19,434 Bcf. The small increase in production at these price levels suggests that the approximately 2.25 percent average reserve appreciation factor used in the 1998 *Natural Gas Market Outlook* report exceeds observed growth in reserves.

Even though the 2000 and 2001 data suggest that eliminating the reserve appreciation factor might be justified, the staff does not believe that only two years of data provides sufficient basis for this change. Instead, for this paper, the staff reduced the average reserve appreciation factor by roughly half – to approximately 1.25 percent on average.

Based on the reserve appreciation factors used in the 1998 *Natural Gas Market Outlook* report, the staff expected higher levels of production given the number of wells drilled and the level of wellhead prices. To reconcile the assumptions used in the NARG model to the observed levels of production, wells drilled, and wellhead prices, the Commission staff reduced the reserve appreciation factor used in this paper.

Table 3: Natural Gas Production and Wells Drilled 1990 - 2001

Year	Natural Gas Production (Bcf)	Gas Wells Drilled	Wellhead Price ($/Mcf)
1990	17,810	11,044	1.71
1991	17,698	9,526	1.64
1992	17,840	8,209	1.74
1993	18,095	10,017	2.04
1994	18,821	9,538	1.85
1995	18,599	8,354	1.55
1996	18,854	9,302	2.17
1997	18,902	11,327	2.32
1998	19,024	11,308	1.96
1999	18,832	10,411	2.19
2000	18,987	15,837	3.69
2001	19,434	22,083	4.12

Source: DOE/Energy Information Administration

The Canadian National Energy Board published *Canadian Natural Gas Market -- Dynamics and Pricing: An Update/Energy Market Assessment* in October 2002.[22] While it was not available when the staff performed its analysis, the staff believes the findings in the Canadian report contribute to the analysis of this issue. In part, the Canadian document reports the following:

> …[P]roducers across North America responded to a period of high gas prices from late 2000 to mid-2001 by stepping up drilling activity. In Canada, a record 11,200 gas wells were completed. Despite this level of drilling, Canadian gas production increased modestly: by less than two percent. This result is consistent with a trend that seemed to develop during the mid-1990s. A doubling in drilling, from 2,000 to 4,000 wells earlier in the decade increased supply by 30 percent. The recent doubling in drilling from 4,000 to 8,000 wells has increased supply by only 10 percent. This ever-diminishing supply response to increased drilling or, the "treadmill effect," causes many to speculate that the Western Canadian Sedimentary basin is reaching maturity.

The Commission staff will continue to monitor natural gas production, drilling, and wellhead price information to further refine the reserve appreciation factor assumption as facts warrant.

NARG Model Structure and Assumptions

The Commission staff updated both data inputs and model structure to generate this assessment. The data updates include the following: natural gas demand projections, reduced reserve appreciation parameters, all prices converted to 2000 dollars, LNG costs, and oil prices. The staff also updated the model structure to better reflect demand-and-supply fundamentals observed in the natural gas market.

Model Structure Updates

To better simulate actual natural gas market conditions and behavior, the staff added the following updates to the NARG model:

- Added the North Baja pipeline, which takes gas at Blythe and delivers it to the North Baja California, Mexico;
- Added the Kern River delivery point to SoCal Gas at its Adelanto compressor station;
- Added demand nodes to represent gas consumption by power generators located along specific pipeline corridors within the WECC region; and
- Modified the delivery and receipt points on the El Paso and Transwestern lines to allow separate demand nodes in the Southwest region.

After entering all necessary parameter and assumption data, the NARG model solves for equilibrium prices and gas flows in all regions in all time periods.

Model Assumptions

The level of detail in the model has evolved over time. As new information becomes available, the Commission staff updates various parameters within the model, such as the resource base, pipeline expansions and additions, and disaggregation of demand sectors throughout the continent.

The model's flexibility allows the staff to add or delete pipelines, supply regions, and demand regions. The user can adjust the capacity of any pipeline at a specific time in the future, or alternatively the model can adjust capacity as additions become economically viable. Transportation rates and the amount of fuel used for pipeline compressors can also be modified by time period.

Demand assumptions for each customer class — core, noncore, and power generation — can also be modified to make demand elastic or inelastic to price. While the core customer class relies solely on natural gas, the noncore and power-generation classes outside of California can switch to an alternate fuel depending on the price differentials. For this analysis, the staff did not incorporate any decrease or increase in natural gas demand due to changes in natural gas prices. The staff did allow noncore customers to substitute oil for natural gas when the natural gas price exceeds preset targets.

Supply for North America

Table 4 shows the North American natural gas supplies that the Commission staff estimates will be used to meet the predicted demand. The first column, labeled Source, identifies the major geographical areas of supply. The source labeled "Other" contains other than conventional sources.

Table 4: Projected Natural Gas Supplies for North America (in Tcf/yr)

Supply Sources	1997 (actual)	2002	2007	2012	Projected Increase 1997-2012	Percent Change 1997-2012
Lower 48	18.343	18.974	22.052	24.391	6.048	33%
Canada	5.430	7.094	7.718	7.997	2.567	47%
Other	1.504	1.204	1.474	2.837	1.333	89%
TOTAL	25.277	27.272	31.244	35.225	9.948	39%

Source: California Energy Commission

"Other" includes fuel switching, receiving LNG at existing U.S. import facilities, and developing new natural gas resources that were not identified in NARG. The model recognizes that certain customers are capable of switching between natural gas and an alternative source of energy to meet their needs. As the price of natural gas increases, competition for markets occurs between natural gas and alternative sources of energy, such as fuel oil. The model, therefore, substitutes an alternative fuel for some of the natural gas these customers would have otherwise used, when the price of natural gas increases above the alternative fuel's cost.

The U.S. has four LNG import facilities, three along the Atlantic seaboard and one on the Gulf Coast. While no new LNG facilities were assumed in this analysis, the NARG model allows existing LNG facilities to expand, if required to reach supply-demand equilibrium.

Examples of new natural gas resources that were not identified in the NARG include LNG imported at new U.S. receiving facilities, developing coal bed methane and tight sands, and producing gas from Prudhoe Bay in Alaska and the Mackenzie Delta in Canada.

Supply for the United States

Table 5 shows production in each North American supply basin. The sources labeled Lower 48 are all geographical designations and can be identified on the previously shown Figure 7 by their initials.

Production from the Lower 48 States is likely to continue growing through the end of the assessment period in 2012. Also noticeable is the increased reliance on imports from Canada. Compared to 1997, imports from Canada are projected to be 2.3 Tcf per year higher by 2012. The United States will increase its use of Canadian natural gas from 53 percent in 1997 to 64 percent in 2012.

**Table 5: Projected Natural Gas Supplies for the U. S.
(in Tcf/yr)**

Supply Sources	1997 (actual)	2002	2007	2012	Projected Increase 1997-2012	Percent Change 1997-2012
LOWER 48						
Anadarko	2.308	2.298	2.347	2.160	-0.148	-6%
Appalachia	0.529	1.126	1.489	1.819	1.290	244%
California	0.297	0.388	0.330	0.380	0.083	28%
Gulf Coast	10.449	8.919	10.262	10.961	0.512	5%
North Central	0.258	0.584	0.762	0.829	0.571	221%
Northern Great Plains	0.200	0.319	0.376	0.439	0.239	120%
Permian	1.668	1.582	1.636	1.586	-0.082	-5%
Rocky Mountains	1.230	1.968	2.835	3.994	2.764	225%
San Juan	1.404	1.790	2.015	2.223	0.819	58%
Total: Lower 48	18.343	18.974	22.052	24.391	6.048	33%
CANADA	2.891	4.230	4.733	5.104	2.213	77%
OTHER	1.504	1.204	1.474	2.837	1.333	89%
TOTAL	22.738	24.408	28.259	32.332	9.594	42%

Source: California Energy Commission

Table 5 also points to the increased reliance on "Other" sources. Increased dependence on "Other" sources generally signals upward pressure on natural gas prices. Developing unidentified supply sources could also mean switching to alternative fuels.

While still representing a significant share of Lower 48 production, Southwest production is projected to flatten out and start to decline during the next ten years. It appears that both the Permian and Anadarko basins' production will start to decline after 2007. Additionally, Gulf production will be flat for the next ten years. Although not shown on Table 5, production from the Lower 48 is expected to decline after 2012.

The Southwest supply basins are old and past maturity, having been in production for nearly a century. Supplies from the developing Rocky Mountain and Canadian production regions are expected to replace them.

Supply for California

Table 6 shows the portion of North American sources of natural gas used to meet projected California demand. The table indicates that the Rocky Mountains represent a significant source of new supply for California. Supplies from the Rocky Mountains are expected to more than double from 1997 levels, representing 62 percent of the increase in supplies to California from 1997 to 2012.

Table 6: Projected Natural Gas Supplies for California (in Tcf/yr)

Supply Sources	1997 (actual)	2002	2007	2012	Projected Increase 1997-2012	Percent Change 1997-2012
Lower 48						
California	0.297	0.388	0.330	0.380	0.083	28%
Rocky Mtns.	0.341	0.320	0.601	0.734	0.393	115%
San Juan/Permian	0.885	0.933	0.889	0.943	0.058	7%
Total: Lower 48	1.523	1.641	1.820	2.057	0.534	35%
CANADA	0.599	0.647	0.681	0.704	0.105	18%
TOTAL	2.122	2.288	2.501	2.761	0.639	30%

Source: California Energy Commission

California natural gas production is projected to remain nearly constant from 2002 through 2012.

Chapter 4 Natural Gas Prices

Introduction

This chapter covers the assessment of natural gas prices, including the methodology, wellhead gas prices in North America, gas prices for electricity generators in the WECC region, and gas prices for customers of California's largest gas utilities. Natural gas prices are projected to rise faster than the inflation rate between 2002 and 2012. The major reasons for these increases are the costs of finding the gas to meet the growing natural gas demand and for bringing gas supplies to customers.

The gas prices in this chapter represent the long-term annual average prices for each demand region. These prices smooth volatility that is expected in the gas market. The basecase assessment[23] represents the best estimate of how the gas market will behave over the assessment horizon, using assumptions and data about demand, natural gas resources, transportation rates, and pipeline capacities. The assessments assume average temperature and water supply conditions for hydroelectricity generation in the Western U.S. They do not reflect the short-term consequences of temperature extremes, droughts, abundant hydroelectricity conditions, or financial difficulties within the natural gas industry. All prices have been adjusted for inflation and are expressed as year 2000 dollars. (See Appendix B: Gross Domestic Product Implicit Price Deflator Series.)

Price Projection Methodology

Natural gas price projection requires three sequential analyses. First, natural gas production, transportation, and demand are analyzed throughout the North American continent from a long-term perspective. The geographic scope of the analysis includes the U.S., Canada, and the northern regions of Mexico along the U.S. border. A continent-wide study is needed because of the integrated nature of the natural gas pipeline grid. Changes in price or supply influence contiguous regions and create a ripple effect across the continent.   For each demand region, the model identifies the likely sources of supply, their wellhead prices, and their border prices.

The second analysis evaluates impacts of uncertainty in the natural gas market on prices. The staff analyzes two scenarios, a high-price and a low-price scenario, to determine plausible high and low price boundaries relative to the basecase assessment. This integrated price and supply outlook (IPSO) estimates how different natural gas market conditions might influence both wellhead prices and supply availability. Unlike sensitivity analyses, which assess impacts on price due to variations in a single variable, IPSO analyses broadly examine the influence of a combination of market changes occurring at the same time. In developing the IPSO, the Commission staff modifies the following five critical parameters: technological advances, resource availability, efficiency improvements affecting demand projections, oil prices, and oil use constraints. (See Appendix C: Integrated Price and Supply Outlook Assumptions for a complete list of the specific parameters and assumptions.)

IPSO analyses indicate plausible upper and lower limits but not the actual volatility in prices normally observed in the marketplace. The price deviations derived in the IPSO analyses are reachable but are not sustained because markets tend to correct themselves under volatile conditions when prices either rise or fall. After a brief price spike or sag, the general, long-term trend returns. The probability that price extremes could occur was not determined in this analysis.

The third analysis develops the price assessments for the following classes of gas-utility customer: residential, commercial, industrial, and power generation. In addition, the staff produces a price projection for non-utility customers receiving gas deliveries via the Kern and Mojave interstate pipelines. The Commission's assessment for gas-utility customers is limited to California's three major gas utilities: PG&E, SoCal Gas, and SDG&E.

The supply and California border price projections from the first analysis provide the initial inputs for the third analysis. The staff matches supply and demand for each customer class, then allocates gas transportation and distribution pipelines costs to these customer classes. Sources of gas-delivery cost information include firm and interruptible transportation agreements between the gas utilities and customers or between suppliers and non-utility customers, utility revenue projections, and other utility costs that have been approved for pass-through to customers by the California Public Utilities Commission (CPUC). This phase results in price projections for end-use customers.

It is well understood that the long-term perspective provides an annual average price projection and does not provide insight into the volatility of the day-to-day or the seasonal market aberrations. The four factors contributing to volatility weather changes, hydroelectricity conditions, demand swings due to seasonality, and changes in economic parameters are not exactly quantifiable. For example, during peak periods, price spikes will be observed if all the pipelines serving a region are full, with premium prices being charged to account for the transportation congestion. The increase in price will be moderated by the quantity of natural gas that is available from storage. Weather changes such as repeated droughts or lack of adequate rainfall could reduce the amount of hydroelectricity generated, causing seasonal increases in natural gas demand. This can result in higher prices lasting over longer period of times than the spiking volatility observed under former peak conditions. Quantifying these factors requires a comprehensive analysis of short-term market fundamentals. The staff will be developing a short-term analysis of the natural gas market in its next cycle of price analysis in 2003.

Figure 8 illustrates how natural prices increase from the wellhead to the California border and on to the ultimate gas consumer. These data are an illustration of a spot market transaction on October 4, 2002. The wellhead price represents the price of gas sold at the San Juan basin, according to *Natural Gas Intelligence*. The gathering and conditioning charge is an estimate based on EIA publications. The price represented by the caption "Beginning of Interstate Pipeline" denotes the sum of these two previous components.

For this transaction, the transportation charge is the price of transporting natural gas from the San Juan basin to the California border at Topock, Arizona. The circle captioned "End of Interstate Pipeline, CA Border" represents the price for gas at the Topock, Arizona hub as published in *Natural Gas Intelligence* on October 4, 2002. The remainder of the figure illustrates the computed charges for gas distribution within the SoCal Gas service area for each customer class. The end-use prices show that the wellhead price comprises about one-half of the price for industrial and electricity-generation customers and about one-third for core customers. Interstate-pipeline transportation and utility-handling costs make up the rest of the end-use prices.

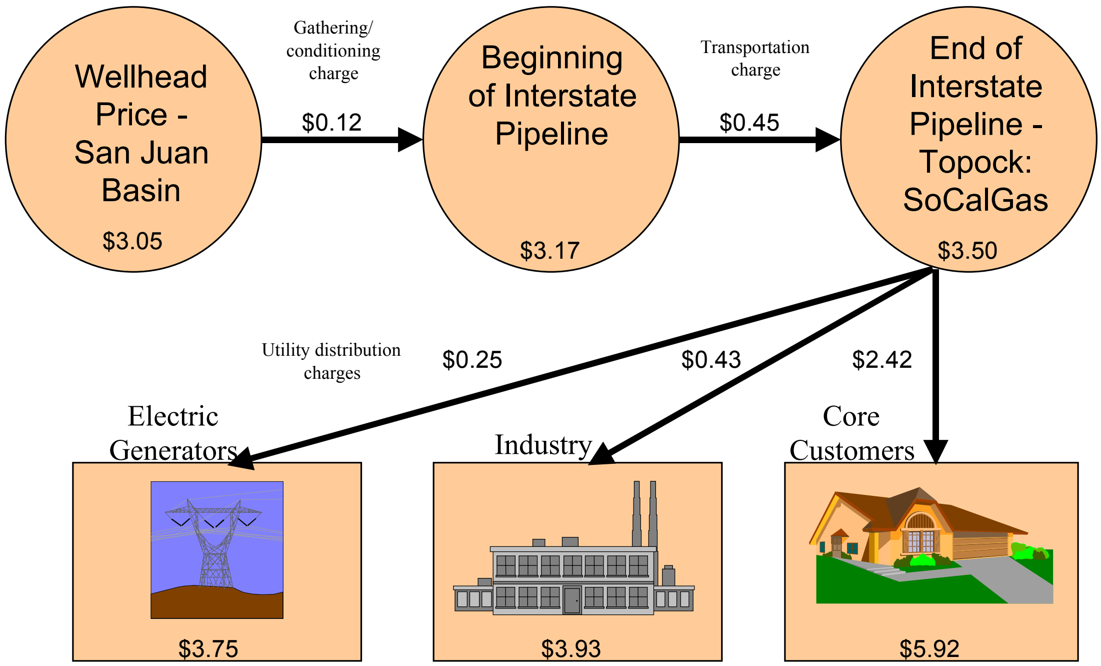

Figure 8: Natural Gas Price Components
(Note: Data from October 4, 2002, expressed in dollars per decatherm)

Wellhead Gas Prices in North America

Wellhead prices motivate gas producers to explore, drill, develop, and produce the gas needed to satisfy consumer demand. Wellhead prices reflect the capital and production costs and the willingness of buyers to pay for natural gas.

Because of reductions in regulatory controls at the wellhead in the U.S. and Canada, gas supplies increased, surpassing demand from the mid–1980s to the late 1990s, putting downward pressure on prices. These low prices encouraged growth in natural gas demand. In response to rising demand, gas prices went up starting in 1999.

The stage for wellhead price spikes was set in Summer 2000, when gas supplies were used for electricity generation rather than placed in storage for the coming winter. When winter arrived, storage levels across the nation were below standard levels. During 2000-2001, prices increased dramatically because of a cold November and December 2000, resulting in robust demand, inadequate supply deliverability to meet demand, low hydroelectricity resources, and alleged price manipulation in the gas and electricity markets. Gas prices dropped again when demand weakened in mid-2001. In October 2002, wellhead prices ranged between $3.50 and $4.00 per Mcf. Figure 9 shows these historical trends in wellhead prices.

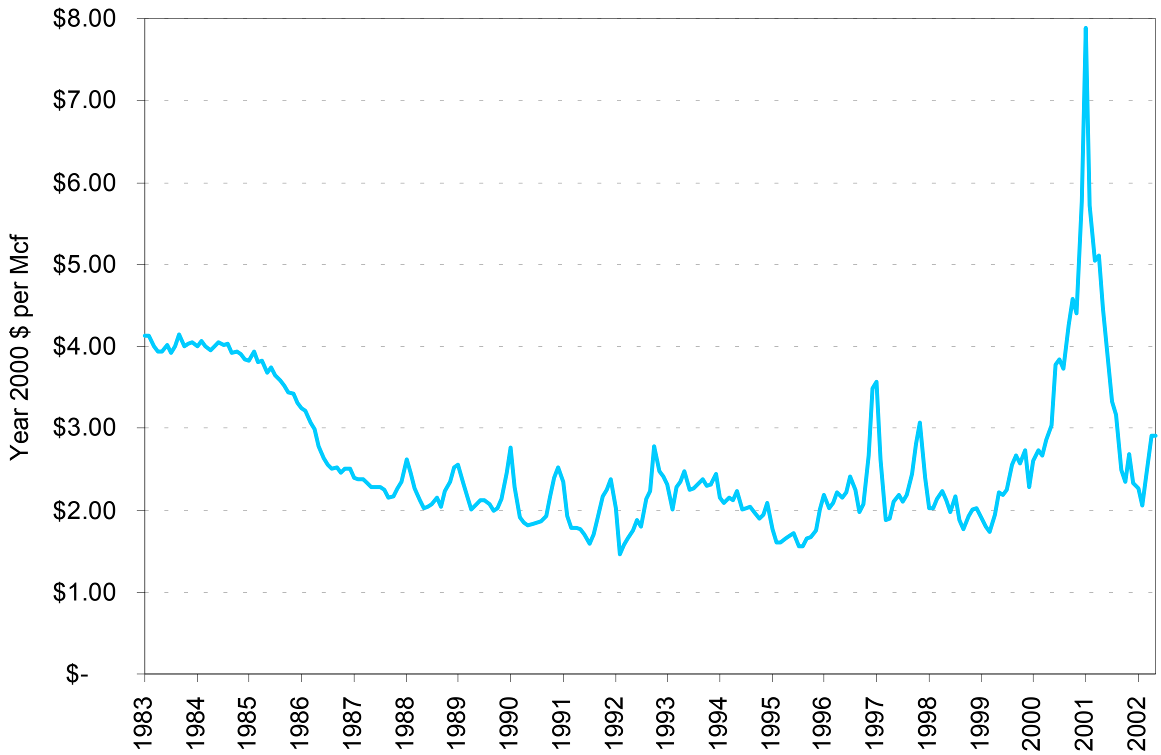

Figure 9: Historical Wellhead Prices in the Lower 48 – Monthly Averages
Source: DOE/Energy Information Administration

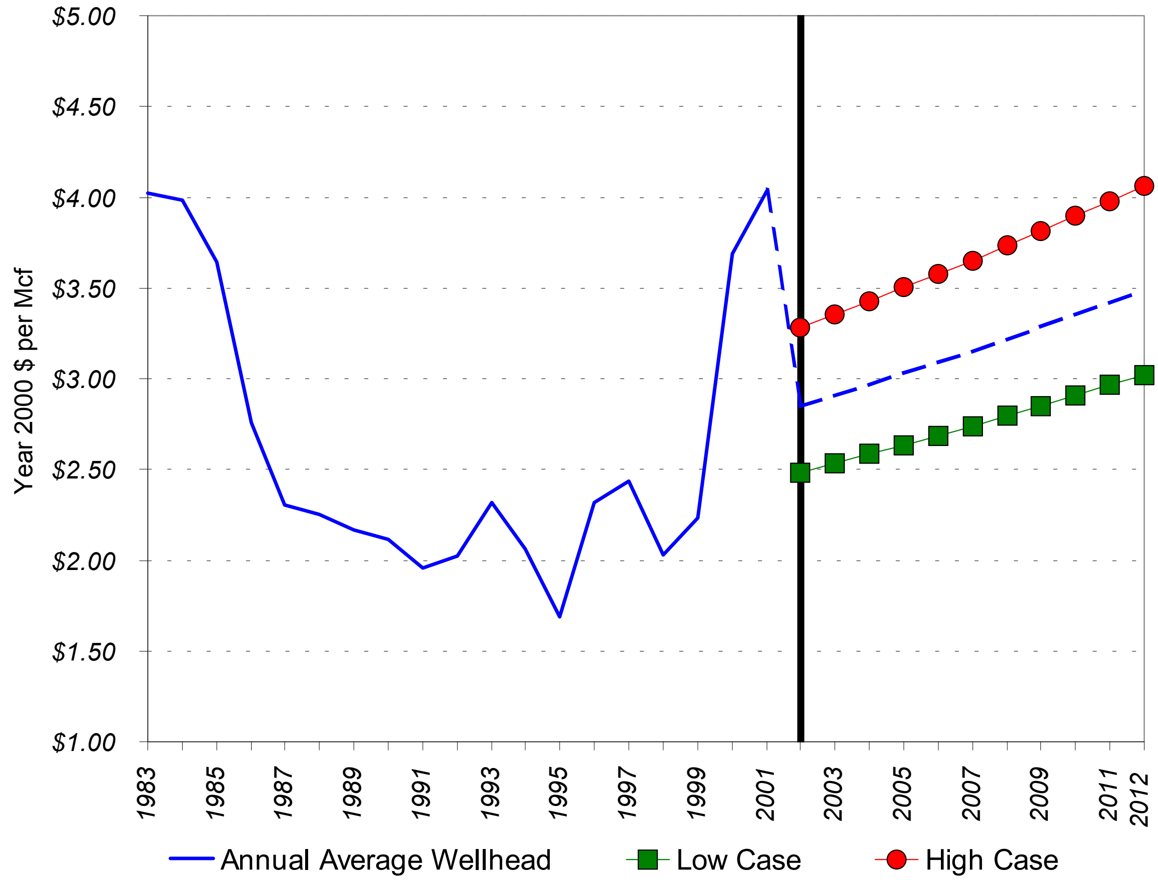

Figure 10: Historical and Projected Wellhead Prices in the Lower 48 States with High and Low Boundaries – Annual Averages

Source: California Energy Commission

Figure 10 illustrates the historical price path of annual average Lower 48 States wellhead prices with the basecase price assessment provided after 2001. As shown on Figure 10, between 2002 and 2012, the following ranges are plausible deviations in wellhead prices for the Lower 48 States:

- On the high side, the band widens from $0.43 per Mcf to $0.57 per Mcf and
- On the low side, from $0.37 per Mcf to $0.47 per Mcf.

Table 7: Projected Wellhead Prices for Lower 48 and Canadian Producing Regions – Annual Averages

Producing Region	2002	2007	2012
LOWER 48			
Anadarko	2.95	3.36	3.79
Appalachia	3.40	3.72	3.98
California	3.03	3.40	3.80
Gulf Coast	2.84	3.17	3.56
North Central	2.98	3.22	3.48
Northern Great Plains	2.45	2.59	2.79
Permian	2.86	3.21	3.63
Rocky Mountains	2.62	2.78	3.01
San Juan	2.63	2.93	3.28
Weighted Average: Lower 48	2.83	3.09	3.37
CANADA			
Alberta	2.27	2.53	2.82
British Columbia	2.48	2.84	3.20
Eastern Canada	3.65	3.45	3.68
Saskatchewan	3.05	3.60	4.00
Weighted Average: Canada	2.35	2.62	2.91

Source: California Energy Commission

Table 7 gives the projected prices, in year 2000 dollars per Mcf, for major gas-producing regions throughout North America.

The assessment of wellhead prices shows different prices between regions. These results stem from dissimilar regional demand growth, varying resource costs, differences in access to production basins, and available pipeline capacity. The following regions' wellhead prices are of interest to California because they are expected to provide supply:

- Anadarko
- California
- Permian
- Rocky Mountain
- San Juan, and
- Alberta

Wellhead prices for Canadian gas supplies will likely be less expensive than gas from the Lower 48 States, but prices from both sources are expected to increase approximately two percent annually. The 2012 weighted-average price for Canadian wellhead gas is projected to be $2.91 per thousand cubic feet (Mcf), compared to $2.35 in 2002. By 2012, the lowest-cost natural gas in the Lower 48 States are likely to come from the Rocky Mountains, the San Juan basin in the Four Corners region and the Northern Great Plains in Montana. In 2012, all three sources will have wellhead prices below the weighted-average price for the Lower 48 States of $3.37 per Mcf. In 2002, the weighted-average price is $2.83.

The rank order of five Lower 48 States regions, from least to most expensive, does not change between 2002 and 2012. The Rocky Mountain and San Juan regions will continue to have the lowest wellhead prices, and the California and Anadarko regions will have the most expensive gas. Canadian supplies, however, will be lower cost on average than any Lower 48 supply. Gas from the Rocky Mountain region, however, will be cheaper than British Columbia gas by 2012.

The assessment of wellhead gas prices in the Lower 48 and Canada, indicated in Table 7, includes the following:

- Prices for gas produced in the Lower 48 States are expected to grow 1.8 percent per year, climbing from $2.83 per Mcf in 2002 to $3.37 in 2012.

- Canadian production prices will likely increase 2.2 percent per year, from $2.35 per Mcf in 2002 to $2.91 in 2012.

The wellhead prices in Table 7 are more than 50 percent higher than the Energy Commission's 1998 price forecast for the 2002-2012 time period. As mentioned in the supply chapter, the staff reduced the reserve appreciation factor by half, compared to the factor used in the 1998 forecast. This is the primary reason for the increase in projected wellhead prices. In addition, natural gas demand in the Lower 48 States and Canada is expected to be higher than forecasted in the 1998 report. These factors principally caused the increase in average wellhead prices.

Gas Prices for Electricity Generators in the WECC Region

Low wellhead prices can attract gas-fired electricity power generators into a region as can direct access to wellhead gas via interstate pipelines. Figure 11 shows the price projections for electricity generators located within the WECC region[24] receiving direct gas deliveries from interstate pipelines, thereby avoiding gas-utility distribution costs, associated taxes, and surcharges. Other costs or constraints, however, may be incurred by locating on an interstate pipeline. Saving on gas costs is particularly important to merchant generators who must compete for market share based on their electricity prices. Power plant developers must consider other factors as well, when choosing where to locate a facility, including proximity to the electricity transmission system and costs to connect to it.

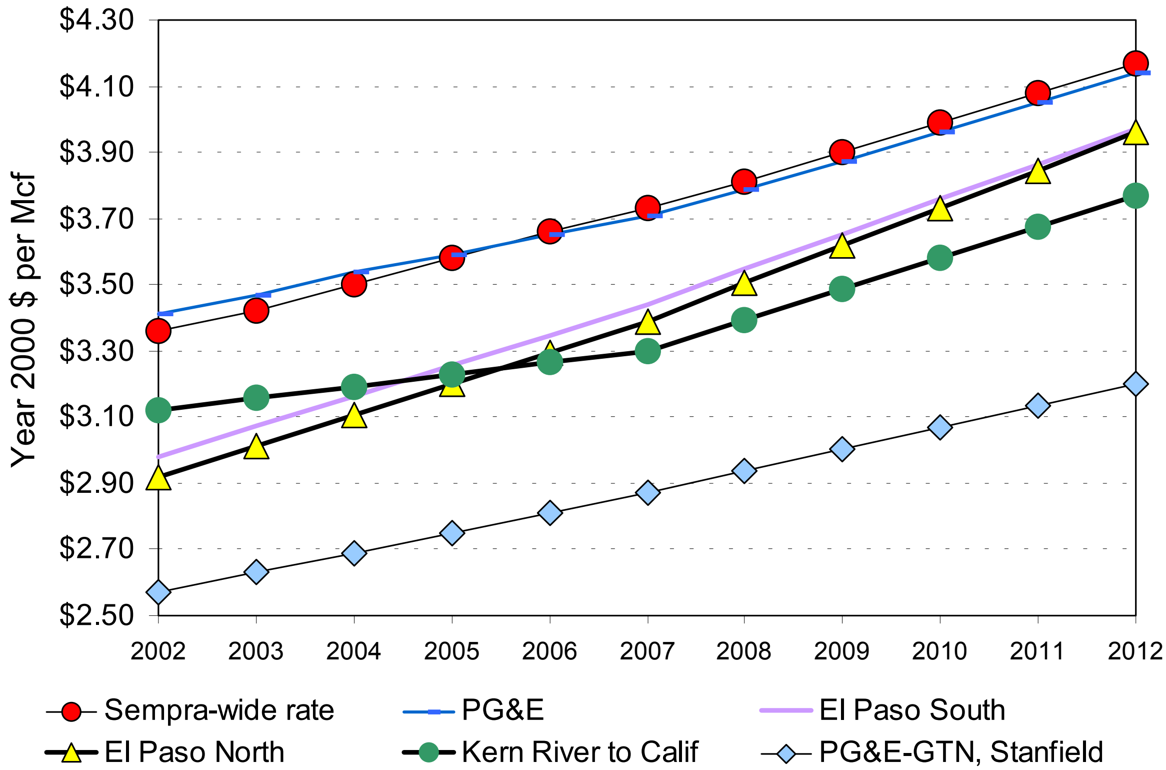

Figure 11: Projected Natural Gas Prices for Electricity Generators within the WECC Region
Source: California Energy Commission

Electricity generators who receive their gas shipments over utility-owned gas lines are classified as noncore customers of PG&E, SoCal Gas, or SDG&E. They must purchase gas supplies from third parties. The prices that electricity generators will pay to receive gas from gas utilities are projected to increase approximately two percent above inflation annually. As noncore customers, these electricity generators will be paying higher prices for gas compared to electricity generators taking gas directly from interstate pipelines through 2012. Electricity generators located near California demand centers, however, may be offsetting these higher gas prices by reducing other expenses, such as transmission line loses and transmission costs.

Electricity generators receiving gas from PG&E will pay approximately the same prices as electricity generators in Southern California. Commodity prices will be lower in PG&E's service area, but these are partially offset by higher instate transportation costs. Even so, PG&E is likely to maintain a slight price advantage over Southern California after 2006.

The lowest-cost region is, and will continue to be, Alberta, Canada via the PG&E-Gas Transmission Northwest (GTN) interstate pipeline at the Washington-Oregon border in Stanfield, Oregon.

In Arizona, electricity generators will probably see a slight price advantage for gas delivered using the El Paso North corridor[25] rather than the EPS corridor through 2012.

In the short term, Rocky Mountain gas supplies delivered by the Kern River pipeline are expected to be more expensive than gas supplies from the San Juan, Anadarko, or Permian regions that are delivered over either El Paso North or South pipeline corridors. The price for Rocky Mountain gas, however, is expected to be lower after 2006.

Gas prices in these six regions are expected to escalate between 1.5 to 3 percent above inflation per year. The factors contributing to these growth rates include differences in regional demand growth, access to production regions, production costs, and pipeline utilization.

See Appendix D: Natural Gas Prices for Electricity Generators in the WECC Region for "burner tip" price projections in the following WECC subregions: California, Pacific Northwest, and Southwest Desert-Mountain.

California Border Prices

This section provides assessments of California border prices for both Northern California (PG&E service area) and Southern California (SoCal Gas and SDG&E). These prices represent what utility customers are expected to pay for gas to be delivered to the utility service system, but do not include other costs, such as local distribution and regulatory charges. These border prices represent all natural gas delivered to the gas utility from production regions including Canada, Rocky Mountains, the Southwest, and California production.

In 2002, the Southern California price is about 18 cents higher than the Northern California price. Northern California prices will likely grow at 2.2 percent annual rate, whereas Southern California prices at a 2.4 percent rate. The major driver behind this price difference is that northern California has access to lower priced Canadian supply while southern California relies to a greater extent on higher-priced southwest supply. Figure 12 shows that the average price for gas at the California border for California's major gas utilities are expected to be on either side of $4.00 per Mcf in 2012.

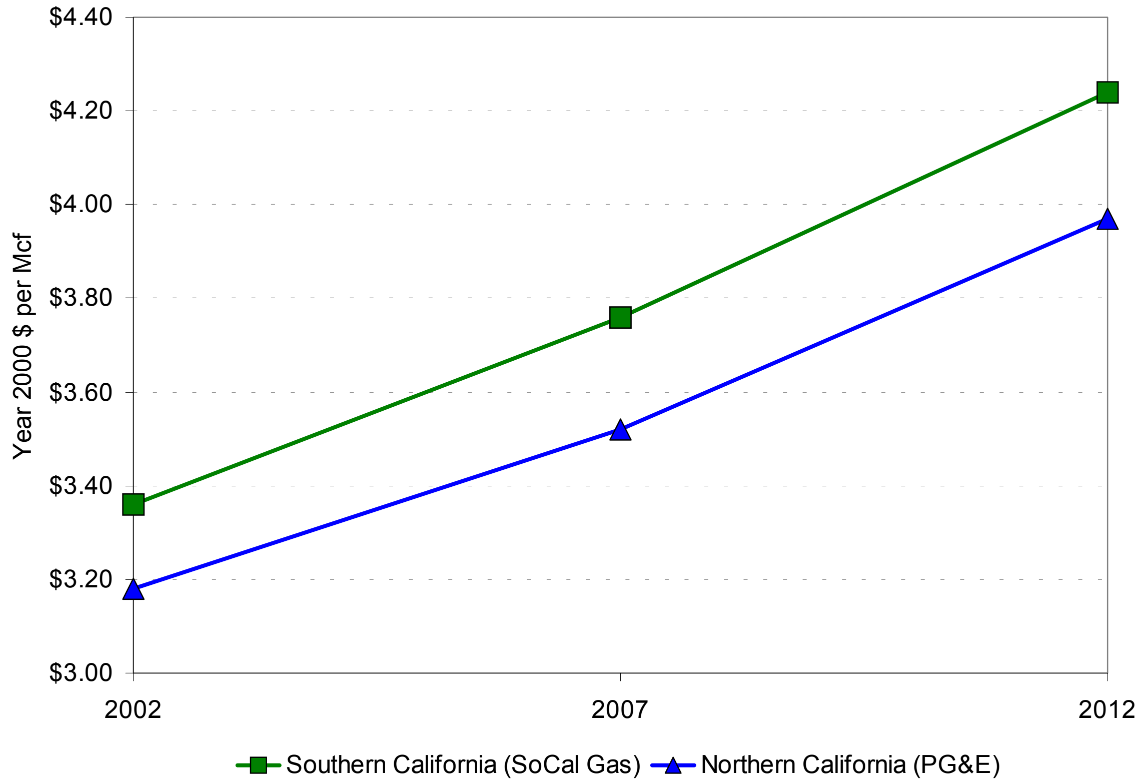

Figure 12: Projected California Border Prices – Annual Averages
Source: California Energy Commission

Gas Prices for California Gas Utility Customers

Based on projected California border prices, the Commission staff predicted prices for each major gas utility's core and noncore customers. Appendix E has tables that contain end-use prices for each class of the gas utility's core and noncore customers.

Figure 13 shows volume-weighted annual-average prices for all customers in the PG&E, SoCal Gas, and SDG&E service areas, expressed in year 2000 dollars per Mcf. These system-average prices are expected to settle between $4 to $6 per Mcf. During the next ten years, gas prices are likely to fluctuate above or below this basecase assessment due to short-term shifts in supply availability, seasonal and demand fluctuations, regulatory changes, and other factors affecting short-term market trends.

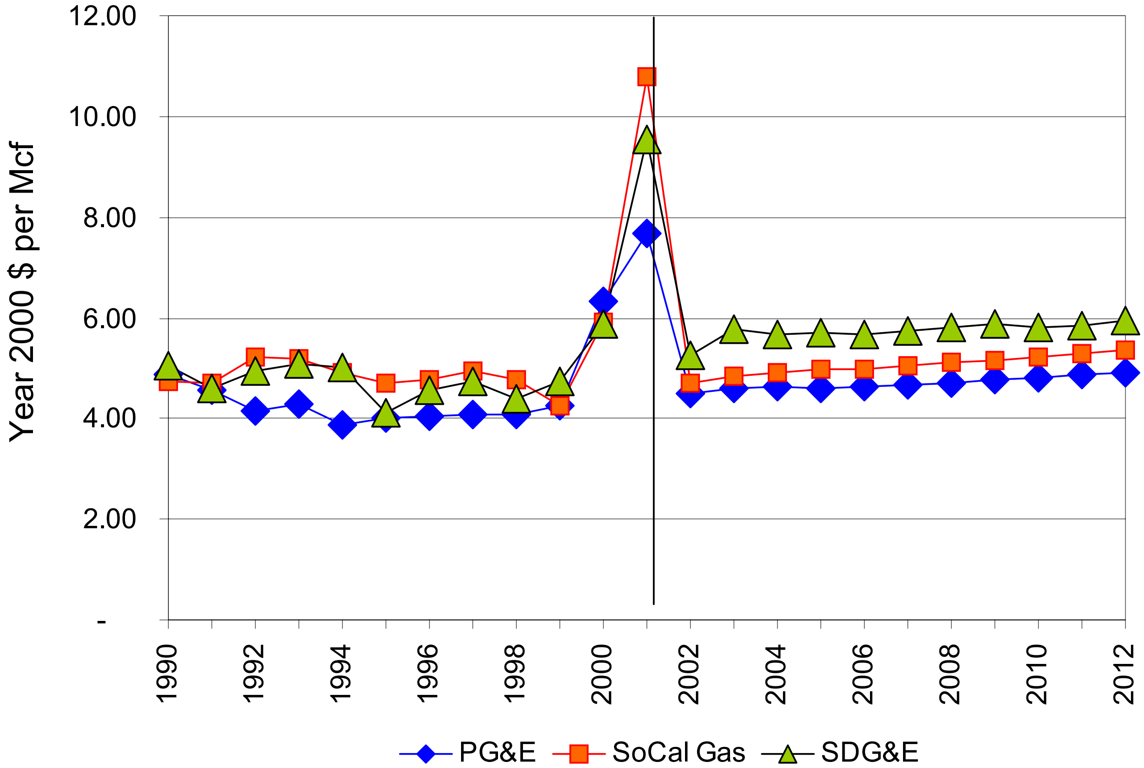

Figure 13: Historical and Projected Utility End-Use Prices in California – Annual Averages
Source: California Energy Commission

Figure 13 also shows the price spike of 2000-2001, when prices reached $11 per MMBtu in some instances. The spike occurred when demand was strong, and supply deliverability was tight.

When prices increased, producers increased drilling and gas-pipeline owners expanded pipeline capacity and storage facilities. At the same time, gas consumers conserved energy to decrease their demand and utility bills. A slowdown of the national and California economies also contributed to lower demand. As a consequence, prices returned to the $4 to $6 per Mcf range after 2001. The long-term assessment calls for gas prices to remain between $4 to $6 per Mcf.

Chapter 5 Natural Gas Infrastructure

Introduction

This chapter covers the interstate and intrastate pipelines serving California. The need for natural gas infrastructure is driven by natural gas demand. The geographical location of the natural gas demand is critical in determining how much pipeline capacity is needed and where.

Interstate Pipelines Serving California

Interstate pipelines transport natural gas from the Southwest, Rocky Mountains, and Canada to California. Figure 14 is a map, which shows the locations for the natural gas supply areas and major pipelines serving the western states. The map also shows that California is at the end of the interstate pipelines, and that natural gas must travel large distances to reach California.

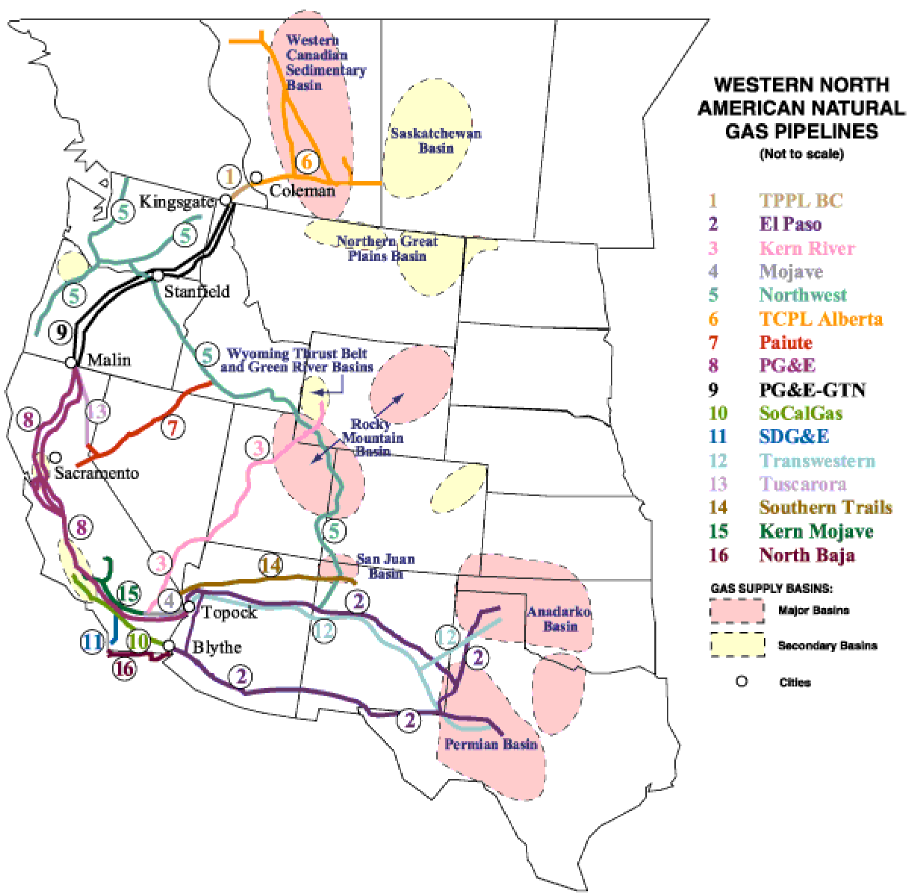

Figure 14: Western North American Natural Gas Pipelines
Source: California Energy Commission

California receives its southwest supply principally from the San Juan and Permian basins, but the Anadarko basin also supplies California with limited quantities. In addition, three companies bring southwest supply to California: the El Paso Natural Gas Company, the Transwestern Pipeline Company, and the Southern Trails Company. El Paso has a Northern System that transports mainly San Juan gas and a Southern System that moves Permian gas. Both El Paso and the Transwestern systems can transport natural gas produced in the Permian and Anadarko basins. Rocky Mountain production is mainly transported to California through the Kern River pipeline system. The PG&E – GTN pipeline receives natural gas produced in Alberta, Canada at Kingsgate, British Columbia for delivery to California at Malin, Oregon.

In the last few years, rapid population and economic growth have driven electricity demand and caused a number of gas-fired power plants to be built in the states surrounding California. Most of the new combined cycle gas-fired plants are about 500 MW, but some are 1,000 MW. Each plant uses a significant amount of natural gas, with most ranging between 90 to 200 MMcf per day when operating at full capacity. The large number of proposed gas-fired power plants in the west is increasing the expected demand for natural gas, thereby increasing the need for more pipeline capacity.

Southwest Pipeline Corridor

In March 2001, El Paso held an open season to test the need for new pipeline capacity to serve its California and East-of-California customers. Responses totaled 9,700 MMcf per day. To date, El Paso has not announced any plans for expanding its Northern System, mainly due to a lack of commitment from prospective shippers. El Paso is in the process of converting its All-American crude oil pipeline to carry natural gas. This conversion would become part of the EPS.

Other pipeline owners are stepping out to meet the expected capacity requirement. For example, Transwestern recently completed its Redrock pipeline expansion, allowing more gas to flow into California at North Needles. The Southern Trails pipeline, which once transported crude oil, now carries natural gas between the San Juan basin and Topock. Combined, these projects added 242 MMcf per day in new capacity or approximately 15 percent of the projected need for expansions. Kinder Morgan's open season on its proposed Sonoran Pipeline project, which would run from the San Juan basin in New Mexico to Needles and Topock near the California border, failed to garner the necessary support. Subsequently, that project has been dropped.

Figure 15 provides an estimate of how much additional capacity will be needed along interstate pipeline corridors in the Southwestern region to deliver natural gas to California and customers east of California.

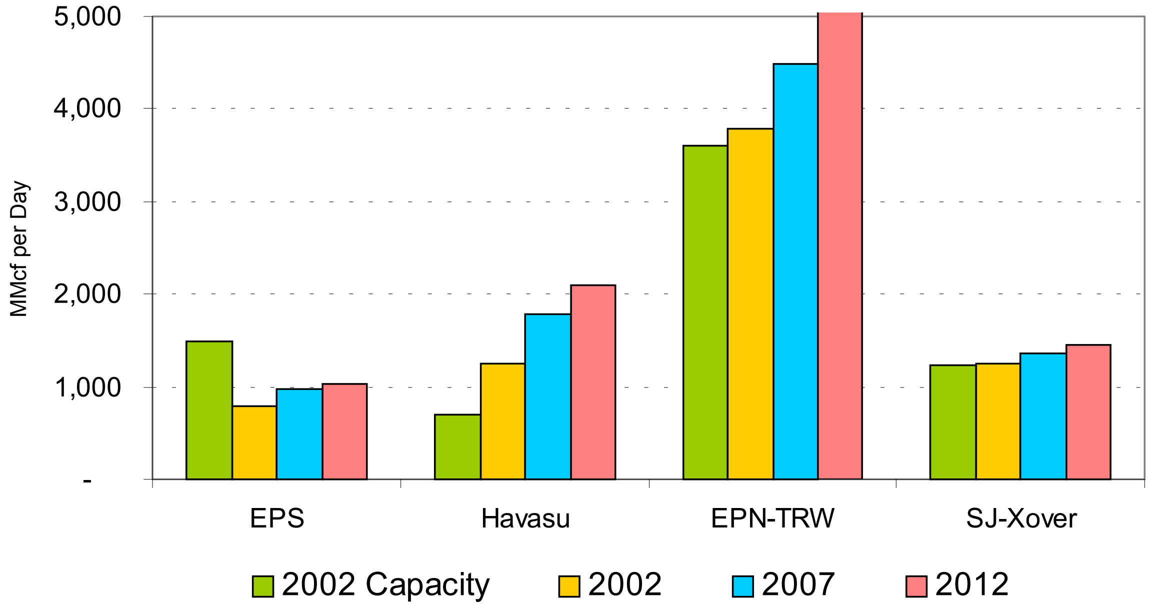

Figure 15: Projected Utilization Factors for Pipeline Corridors in the Southwest
Source: California Energy Commission

In the figure, pipeline capacity in the year 2002 is contrasted with the growth in gas flows to meet the projected demands for 2002, 2007, and 2012.

Demand at the western end of the EPS is anticipated to grow substantially, but not to meet California's needs. According to the model's analysis, California gas demand served by southwest supply is projected to remain relatively stable for the next ten years (See Table 6: Projected Natural Gas Supplies for California.)

Significant growth, however, is anticipated in power plant demand in western Arizona and along the North Baja Pipeline. The North Baja pipeline, which receives gas from El Paso at Blythe, became partially operational on September 1, 2002, and by the end of 2002, it will be capable of operating at its certificated capacity of 500 MMcf per day. This gas will be delivered to three large power plants in Mexico. El Paso is in the process of converting its recently purchased All-American crude oil line to carry 230 MMcf per day of natural gas, adding more capacity to the Southern System. Given the new demand sources, the NARG model analysis indicates that the EPS will operate at most up to 83 percent of its present capacity, when measured at the eastern end of the system near the Permian basin. (See EPS on Figure 15.)

According to the basecase analysis, the North Baja Pipeline and the southwest power generators prefer the cheaper San Juan basin and Rocky Mountain supply sources to meet their needs. (See Table 7: Projected Wellhead Prices for Lower 48 and Canadian Producing Regions for comparisons of projected basin wellhead prices.) These generators prefer to pay for new or incremental pipeline capacity to the cheaper sources in the San Juan and Rocky Mountain regions rather than use the comparatively more expensive gas in the Permian region.

As a result, instead of using the EPS to deliver Permian supply, natural gas deliveries to meet this growing demand will flow west from the San Juan basin through the El Paso North - Transwestern (EPN-TRW) pipeline corridor (See EPN-TRW on Figure 15). Just east of Topock, the gas will then flow south on the El Paso Havasu Crossover (See Havasu in Figure 15), then either east on the EPS or to Mexico at Blythe on the North Baja Pipeline.

Under the basecase assumptions, expanding the El Paso Havasu Crossover and the EPN-TRW corridors is an option to meet this demand and could be needed in the next five to ten years. Analysis indicates that in the basecase flows will exceed the present Havasu Crossover capacity by nearly 300 percent over the next ten years.

For the Havasu Crossover project to succeed in relieving gas-transmission congestion, two other interstate pipelines in northern Arizona would have to be expanded as well. The combined carrying capacities of the EPN-TRW pipelines, which connect the San Juan basin to the California border at Topock, must increase 30 percent by 2007 and more than 50 percent by 2012. These expansions will enable more gas to flow through the Havasu Crossover into the North Baja Pipeline, which will deliver gas to new power plants in southwestern Arizona.

Several other pipeline project proposals could also help to satisfy this anticipated need. One option would be to flow the San Juan gas east on either the El Paso or Transwestern pipelines in the San Juan Crossover (See SJ-Xover in Figure 15), then west on El Paso's Southern System. This option would allow El Paso to take advantage of the slack capacity on the EPS and also the conversion of the All-American crude oil pipeline to natural gas service. This option would require capacity expansion on each of the transport legs.

Two other likely candidates stand out as they would both lie directly in the Havasu corridor. First, while El Paso has not proposed to do this, the company could increase its current Havasu Crossover capacity to meet all of the increased demand. Second, in a separate proposal, Sempra could build its 800 MMcf per day Desert Crossing. The Sempra project would extend from an inter-tie with Kern River in southern Nevada to the EPS pipeline system in western Arizona. The Sempra proposal would also include storage facilities.

Alternately, two projects within California may be indirectly able to fill part or all of the projected need. One would be the El Paso conversion of the All-American Pipeline between Blythe and Daggett, California. This project in turn would allow El Paso to receive Rocky Mountain gas at Daggett flowing to Blythe and into the EPS system. El Paso has currently filed its application for this project with the California State Lands Commission and the U.S. Bureau of Land Management. A second project would be the Southern Trails conversion of the Four Corners pipeline between Topock, Arizona, and a point on SoCal Gas's southern system.

There is yet another option that could contribute to meeting growing gas demand from power plants east of California. LNG landed and regasified in Baja California, Mexico could flow to Blythe on the North Baja Pipeline. The limit on the quantity of gasified LNG that could flow east would be the current 500 MMcf per day capacity of the North Baja pipeline.[26]

From there, it could be transported on the EPS to meet the east of California needs. Secondly, this would divert up to the 500 MMcf per day of southwest gas that would have otherwise been used in Mexico and instead would be used in Arizona and California. The staff intends to model each of these options in the next *Natural Gas Market Outlook* report.

Pacific Gas and Electric - Gas Transmission North Corridor

Based on the assumptions in the basecase**,** Figure 16 shows projected gas flows on the PG&E Gas Transmission North (GTN) pipeline corridor between Canada and the California border. During the next ten years, PG&E-GTN is anticipated to expand its pipeline capacity by 20 percent. Principally, this expansion is to meet:

- The growing generation demand located in the Pacific Northwest region to receive direct service along the pipeline;
- Demand on the Tuscarora Pipeline that receives natural gas at Malin, Oregon for delivery to Reno, Nevada; and
- Demand in the PG&E service area.

PG&E-GTN has already taken steps to add this capacity. By summer 2002, the company added about 210 MMcf per day. Additional increments are planned.

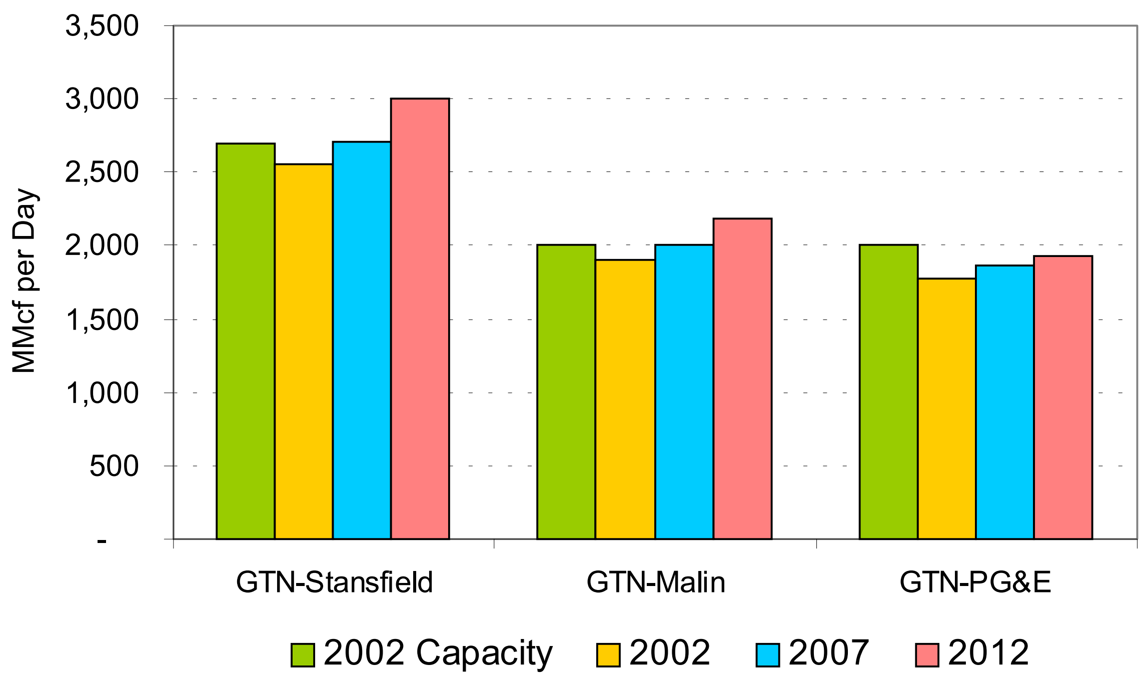

Figure 16: Projected Utilization Factors at Locations along the PG&E-GTN Pipeline Corridor
Source: California Energy Commission

Kern River Corridor

Natural gas from the Rocky Mountain region comes to California, mainly through the Kern River pipeline system. In addition, new gas-fired power plants will be built along the pipeline corridor, placing increasing demand on its 700 MMcf per day carrying capacity. Figure 17 illustrates the staff assessment indicating that the Kern River pipeline must triple its capacity by 2012 to meet California's growing demand for Rocky Mountain gas supply. Much of this needed capacity is already under construction and expected to be operational in 2003, reaching a capacity of 1,750 MMcf per day.

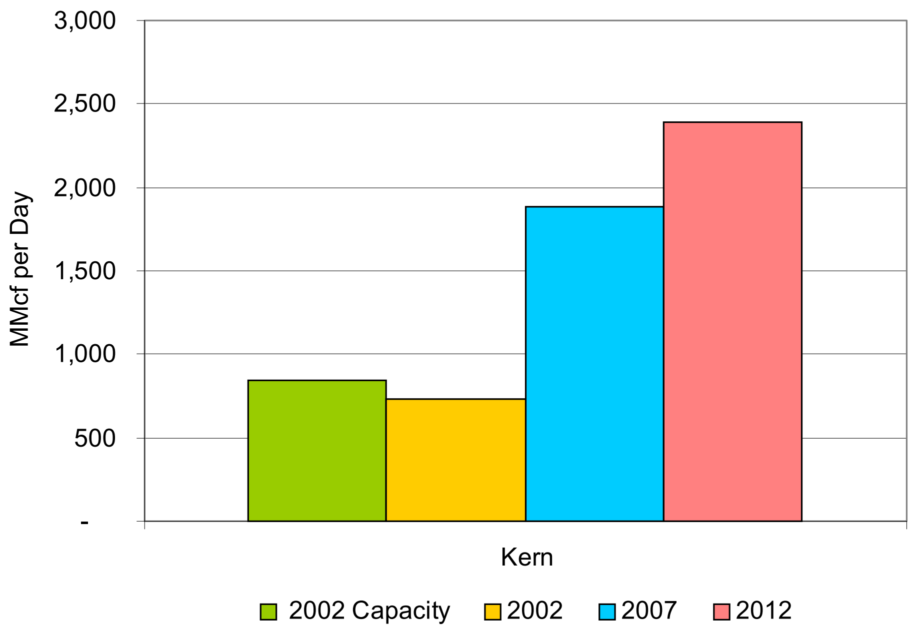

Figure 17: Projected Utilization Factors for the Kern River Pipeline Corridor
Source: California Energy Commission

All of the interstate pipeline flow and capacity analysis assumes average hydroelectricity and temperature conditions. The Federal Energy Regulatory Commission (FERC) regulates interstate pipelines, but does not set guidelines or requirements for reliability of service by interstate pipelines. There is no rule that the natural gas demands of California must be met with sufficient capacity to meet expected demand plus reserves. The FERC relies on market incentives to produce sufficient interstate pipeline capacity. There is a question as to whether market incentives will produce enough interstate pipeline capacity to serve the needs of California during droughts and adverse temperature conditions. The staff is currently analyzing the impact of increased demand due to adverse weather conditions on the need for additional interstate pipeline capacity and will publish its findings in 2003.

Concerns Regarding Upstream Demand

California is in a dispute with upstream customers on the El Paso system regarding the firm rights to use El Paso pipeline capacity. The upstream customers claim to have rights, which would constrain California's use of the El Paso system. The FERC has agreed to settle the dispute between the parties, and proceedings are ongoing. Until the FERC settles this matter, customers will be unable to determine how much capacity will be available for reliable service. Thus, customers are reluctant to commit to paying for new capacity and will be reluctant to support any new capacity that is needed.

California Pipeline Infrastructure

Both PG&E and SoCal Gas have increased their capacity to receive natural gas supply into their respective service areas. PG&E has added 200 MMcf per day in 2002, and SoCal Gas has successfully completed the addition of 375 MMcf per day. Provided below is the Commission staff's assessment of the adequacy of these expansion projects, assuming that average hydroelectricity and temperature conditions prevail each year of the projection period.

In a drought or an extremely cold winter, the receiving capacity in conjunction with storage may not be adequate to meet peak day requirements. The staff has not analyzed the adequacy of the receiving capacity in California under adverse conditions. To provide the flexibility to meet seasonal changes in demand and adverse year conditions, the CPUC typically requires utilities to maintain some excess receiving capacity. The criterion set by the CPUC is to maintain receiving capacity about 20 percent above the average annual daily demand in a year with average hydroelectricity and temperature conditions. Many refer to this extra capacity as slack capacity.

PG&E Receiving Capacity

Figure 18 presents the Energy Commission's average daily natural gas demand assessment by sector for the PG&E service area, assuming average weather and hydroelectricity conditions. The assessment included the quantity of natural gas delivered to SoCal Gas from PG&E via the Wheeler Ridge inter-tie.

SoCal Gas would receive supplies from the southwest via Line 300, from Canada via Line 401 (by displacement), or both. The heavy horizontal line at 3,400 MMcf per day represents PG&E's receiving capacity after the 200 MMcf per day has been added to its Redwood Path (Line 400/401). California production delivered to the PG&E system is included in the receiving capacity.

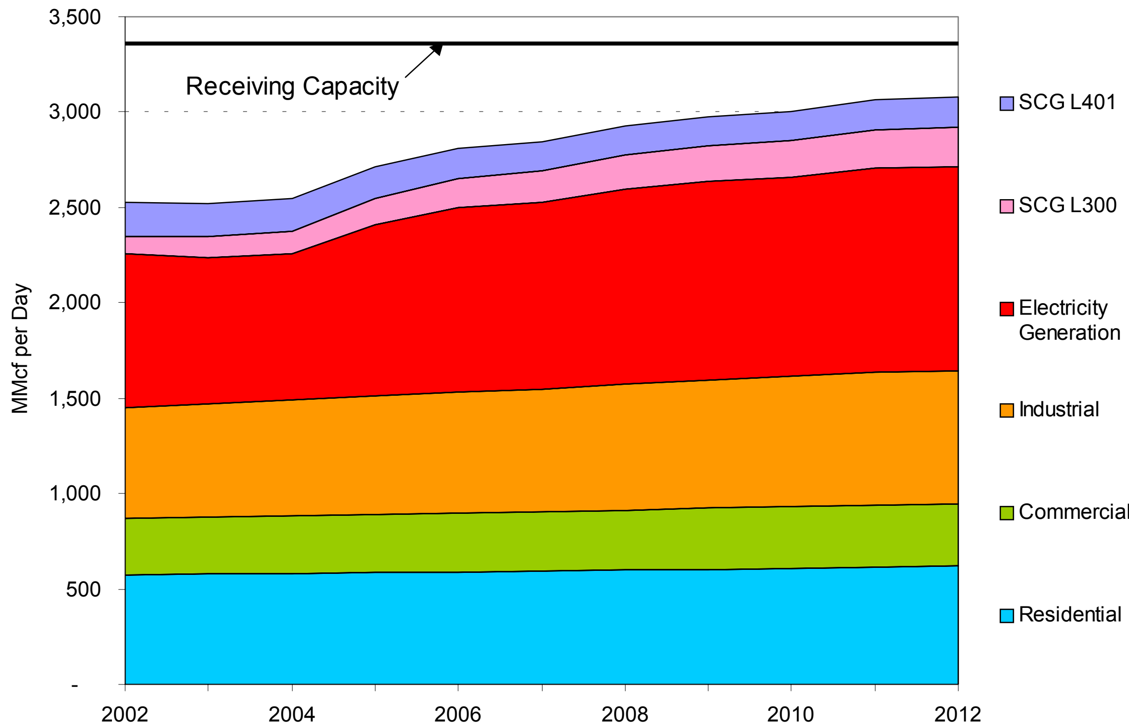

Figure 18: Projected Natural Gas Demand by End-Use Sector Compared to PG&E's Supply Receiving Capacity
Source: California Energy Commission

Projections for residential, commercial, and industrial demand indicate only a slight growth throughout the horizon. Deliveries by PG&E to SoCal Gas are expected to grow slightly. However, during the next ten years, the natural gas demand to meet electricity generation requirements have the potential to cause constrained pipeline capacity on the PG&E system. Up until 2006, apparently PG&E will have about 20 percent in slack capacity. By 2012, the slack capacity drops to 10 percent.

Several alternatives exist to meet PG&E's need for increased receiving capacity. For example, the capacity of the Redwood Path (Line 400 and 401) has been expanded, increasing PG&E's ability to receive additional natural gas supply from Canada. More additions to this path are possible. Additionally, the Baja Path (Line 300) could also be expanded to receive supply from the Rocky Mountain production area and southwestern supply regions.

Other options under consideration would not require substantial upgrades by PG&E. El Paso Energy Group is proposing to build the Ruby Pipeline that would extend from the Rocky Mountains to Reno, Nevada, and then to the Yuba City, California, area. Pipeline capacity to California would be 500 MMcf per day with availability in 2005 or later. Shell and Bechtel have proposed to build a LNG receiving terminal and gasification plant on Mare Island in Vallejo, California. As proposed, the facility would have the capability of providing 1,370

MMcf per day in natural gas supply to both fuel a 1,500 MW power plant and supply natural gas into the PG&E service area. The project developers believe that the project could be in service by 2006.

The third option is to expand and augment storage facilities. An increase in storage capacity at Wild Goose storage facility and the ability to cycle natural gas more frequently can significantly improve system flexibility in the PG&E region. Wild Goose has obtained the required permits to expand its facilities by the end of 2003. Also, the Lodi storage facility is now operating and providing additional storage capacity and balancing operations in Northern California. These new supply and storage enhancements would be sufficient to meet PG&E's needs for the next decade.

SoCal Gas Receiving Capacity

Figure 19 provides the Energy Commission's projections of sectoral average daily natural gas demand for the SoCal Gas service area, assuming average weather and hydroelectricity conditions. This assessment includes deliveries from the interstate pipeline into the SDG&E service area using SoCal Gas receiving capacity. As in the PG&E service area, electricity generation is the major driver behind rising natural gas demand in Southern California.

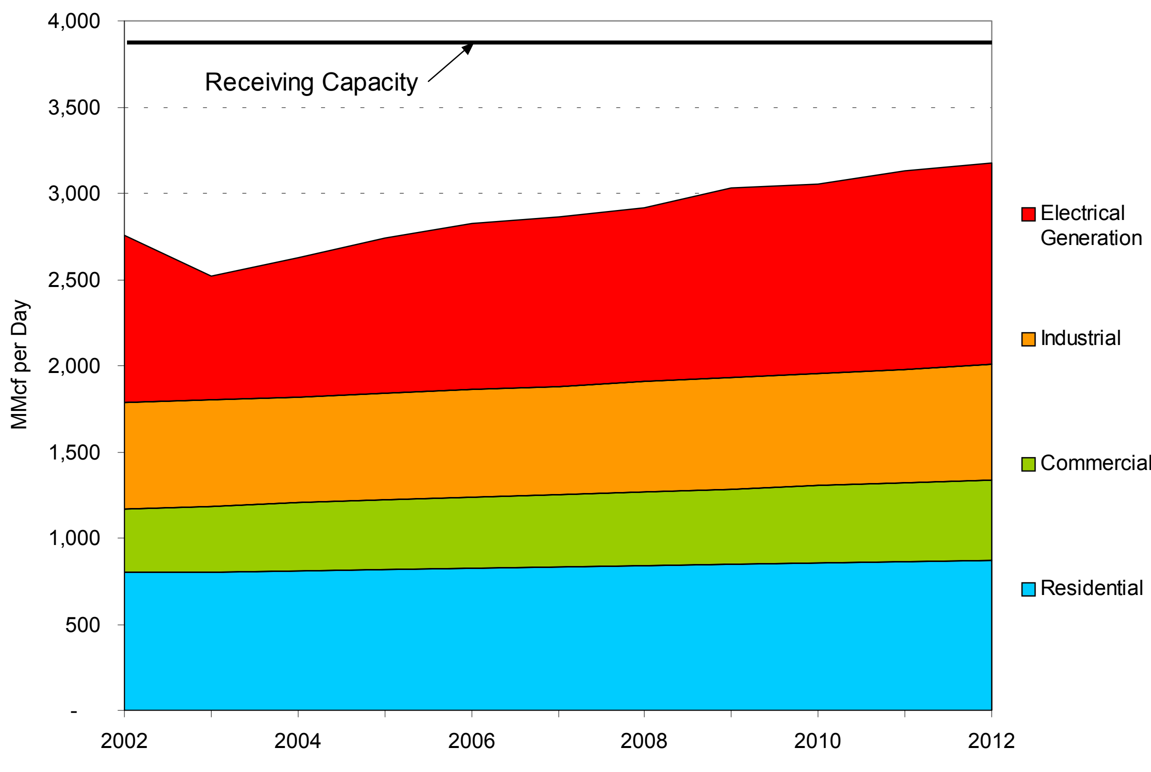

Figure 19: Projected Natural Gas Demand by End-Use Sector Compared to SoCal Gas's Supply Receiving Capacity
Source: California Energy Commission

Since the energy crisis, SoCal Gas has started an extensive program to increase its natural gas receiving capacity. SoCal Gas's firm receiving capacity has increased from 3,500 MMcf per day to 3,875 MMcf per day. The heavy dark line at the top of the figure shows the new total. This number includes deliveries of California production into the utility pipeline system. As shown in Figure 19, SoCal Gas's slack capacity will be greatly enhanced, relative to the annual average daily natural gas demand projected for the next ten years. Slack capacity will range from 41 percent in 2002 to 22 percent in 2012. Without the additions, SoCal Gas's slack capacity would have been lower by about 10 percent per year. SoCal Gas's ability to meet peak day requirements has been augmented by using a greater portion of its storage capacity at the Aliso Canyon and La Goleta storage facilities.

Acronyms

Bcf — Billions of cubic feet
Btu — British thermal unit
CERI — Canadian Energy Research Institute
CFE — *Comision Federal de Electricidad*
CPUC — California Public Utilities Commission
EPN-TRW — El Paso North – Transwestern pipeline
EPS — El Paso Southern pipeline system
FERC — Federal Energy Regulatory Commission
GRI — Gas Research Institute
GTI — Gas Technology Institute
GTN — (PG&E) Gas Transmission Northwest
GWh — Gigawatt-hours
IERP — Integrated Energy Policy Report
IOU — Investor Owned Utility
IPSO — Integrated Price and Supply Outlook
LNG — Liquefied natural gas
Mcf — Thousand Cubic Feet
MMcf — Million cubic feet
MW — Megawatt or megawatts
NARG — North American Regional Gas model
PG&E — Pacific Gas and Electric Company
PURPA — Public Utility Regulatory Policy Act
SCG L 300 — Southern California Gas Company's Line 300
SCG L 401 — Southern California Gas Company's Line 401
SDG&E — San Diego Gas and Electric Company
SJ-Xover — San Juan Crossover pipeline
SoCal Gas — Southern California Gas Company
Tcf — Trillion cubic feet
Tcf/yr — Trillion cubic feet per year
TEOR — Thermally enhanced oil recovery
WECC — Western Electricity Coordinating Council

Glossary

Capacity Factor — *See pipeline capacity factor*.
Cogeneration — The production of electrical energy and another form of useful energy (such as heat or steam) through the sequential use of energy.
Combined Cycle Power Plant — An electricity generating station that uses waste heat from its gas turbines to produce steam for conventional steam turbines.
Commodity Cost — The cost of just the natural gas product, itself.
Core customer (gas utility definition) — A customer who depends on the local distribution company for gas supply and all associated services. Core customers include all residential, regardless of load size, commercial customers with annual loads below 250,000 therms per year (annual monthly average usage level of 20,800 therms), and those commercial customers with annual loads above 250,000 therms electing to receive core service. In the event of a shortage, the gas utility may curtail deliveries to noncore customers, but will not curtail deliveries to its core customers except in extreme conditions.
Core customer (NARG definition) — One of three end-use customer classes within each demand region. Core customers rely solely on natural gas; they can not switch to an alternative fuel.
Cubic Feet — The most common unit of measure of gas volume. One cubic foot roughly equals 1,000 Btu's.
Fuel Cell — An electrochemical engine (no moving parts) that converts the chemical energy of a fuel, such as hydrogen, and an oxidant, such as oxygen, directly to electricity. The principal components of a fuel cell are catalytically activated electrodes for the fuel (anode) and the oxidant (cathode) and an electrolyte to conduct ions between the two electrodes.
Inelastic Demand for Energy — Demand does not increase or decrease despite changes in prices. Demand can be met by natural gas or by an alternative fuel.
Interstate Pipeline — A federally regulated company engaged in the business of transporting natural gas across state lines from producing regions to end-use markets.
Merchant Generator — Any generating unit not owned by a traditional load-servicing utility.
Noncore Customer (gas utility definition) — A customer who must make commercial arrangements with a gas service provider, other than the local distribution company, for gas supply and distribution services. Noncore customers include all cogeneration, regardless of load size, and those commercial, industrial, and electricity-generation customers with annual loads above 250,000 therms (annual monthly average usage level of 20,800 therms).
Noncore Customer (NARG definition) — One of three end-use customer classes in a demand region that can switch from natural gas to an alternate fuel once the price of conventionally produced natural gas exceeds a pre-determined cost. Power generation is not included in the noncore customer class.
Pipeline Capacity — A measure of the maximum amount of natural gas that can flow through a pipeline based on the pipeline's maximum allowable design pressure.
Pipeline Capacity Factor — The ratio of the amount of pipeline capacity used during average operations compared to its maximum capacity rating (expressed as a percent).
Proved Reserves — Natural gas resources which have been discovered and which can be extracted economically with current technology.

Proved Reserve Revisions — Changes in the estimates of proved reserves resulting from advances in recovery techniques or technologies, but not from extensions of known gas fields.
Reserve appreciation factor — A parameter used in NARG to take into account proved reserve revisions.
Reserves — The portion of discovered natural gas resources, which has not already been produced. Includes both proved reserves and other reserves.
Resource Base — An estimate of the amount of natural gas available, based on the combination of proved resources and those additional volumes that have not yet been discovered, but are estimated to be 'discoverable' given current technology and economics.
Sensitivity analysis — Investigation into how projected performance varies along with changes in the key assumptions on which the projections are based.
Spot Market — A method of contract purchasing whereby commitments by the buyer and seller are of a short duration at a single volume price. The duration of these contracts is typically less than a month, and the complexity of the contracts is significantly less than their traditional market counterparts.
Therm — A metric unit denoting the heating value of natural gas. Equal to 100,000 Btus. Ten therms is a decatherm, which roughly equals 1,000 cubic feet of natural gas or one million Btus.
WECC — The Western Electricity Coordinating Council was formed on April 18, 2002, by the merger of the Western Systems Coordinating Council and the two regional transmission associations in western North America. It is one of the ten electric reliability councils in North America, encompassing a geographic area equivalent to over half the United States. The members, representing all segments of the electricity industry, provide electricity to 71 million people in the following 14 Western states, two Canadian provinces, and portions of one Mexican State, respectively: Arizona, California, Colorado, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming; Alberta and British Columbia; and Baja California.
Wellhead — The point at which a well (whether or not cased) reaches the surface of the land.

End Notes

[1] [http://www.ngsa.org/facts_studies/gasfacts.asp]
[2] *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply*, U.S. Energy Information Administration, Page 2, December 2001.
[3] "World Resources and Various Perspectives on Natural Gas," *Summary of Minerals Management Services Natural Gas Symposium*, held April 25, 2000, [http://www.mms.gov/revaldiv/ngsSUM.htm].
[4] Combination of Lower 48 (except California) and California demand estimates of "Total Demand by NARG Region – Tcf per Year" from "Appendix C: Demand Projections," *Natural Gas Market Outlook*, California Energy Commission, June 1998.
[5] The definition of electric generation here does not include on-site generation of electricity in the industrial and commercial sectors.
[6] Data from *Commercial Buildings Energy Consumption Survey (CBECS)*, U.S. Department of Energy, Energy Information Administration, [http://www.eia.doe.gov/emeu/cbecs/contents.html].
[7] "Commercial Energy Consumption by Type of Service" Table, *GRI 2000 Baseline Projection*, Page COM 2.
[8] Ibid.
[9] "Summary Table 2: Fuel Consumption by Sector," *Baseline Projection Data Book*, Volume 1, 2000 Edition, Gas Research Institute, January 2000.
[10] "Consumption of Natural Gas in the U.S. Manufacturing Sector, 1998" Table F4.1 from the *Manufacturing Energy Consumption Survey*, U.S. Department of Energy, Energy Information Administration [http://www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html].
[11] *Summary of the 1999 Industrial Cogeneration Projection*, Gas Research Institute Topical Report No. GRI-99/0155, July 1999.
[12] "Fuel Consumption by Sector" Table from *Baseline Projection Data Book*, Volume I, Gas Research Institute, 2000 Edition.
[13] Summary Table entitled, "Fuel Consumption by Sector," from *Baseline Projection Data Book*, Volume 1, 2000 Edition, January, 2000.
[14] Ibid.
[15] http://energy.accc.ca/issues/natural_gas.htm
[16] *Energy in Canada 2000*, Chapter 3 Canada's Energy Markets – Sources, Transformation and Infrastructure, Natural Resource Canada. [http/www.nrcan.gc.ca/es/ener2000/online/html/chapter3b_e.htm]
[17] http://energy.accc.ca/issues/natural_gas.htm.
[18] "Western Infrastructure Assessment," a Power Point presentation prepared by the Division of Market Development of the Federal Energy Regulatory Commission, dated October 24, 2001. [http://www.ferc.gov/electric/infrastructure.htm#western]
[19] The Energy Commission's gas demand projections includes cogeneration within the electric generation sector rather than the industrial sector.

[20] "Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply," Chapter 6 - Natural Gas, U.S. Department of Energy, Energy Information Administration. June 2001. [http://www.eia.doe.gov/emue/steo/pub/special/california/june01article/canatgas.html].
[21] Ibid.
[22] *Canadian Natural Gas Market Dynamics and Pricing: An Update An Energy Market Assessment*. National Energy Board. October 2002. [http://www.neb.gc.ca/energy/ema02gasdyn_e.pdf].
[23] Appendix F provides the deflator series for converting real dollars into nominal dollars. The source of the deflator is the California Energy Commission, dated July 16, 2001.
[24] The WECC region includes nine Western states, portions of Montana, South Dakota, New Mexico and Texas, Northern Baja California in Mexico, and British Columbia and Alberta in Canada.
[25] El Paso North is a NARG interstate pipeline corridor that includes El Paso North, Transwestern and Southern Trails pipeline systems. EPS includes only the El Paso Southern pipeline system.
[26] By adding compression, the North Baja Pipeline's capacity could be increased by another 500 MMcf per day.

Appendix A: North American Gas Demand by Region

(in Tcf/year)

Regions	(Actual) 1997	2002	2007	2012	Change TCF/Year 1997-2012	Percent Change 1997-2012
California						
Core gas	0.618	0.966	1.016	1.062	0.444	72%
Non-core gas	0.808	0.609	0.735	0.868	0.06	7%
Electric generation gas	0.525	0.647	0.716	0.818	0.293	56%
Total California gas	**1.951**	**2.222**	**2.467**	**2.748**	**0.797**	**41%**
Pacific Northwest						
All other sectors	0.395	0.452	0.501	0.492	0.097	25%
Electric generation gas	0.038	0.158	0.233	0.414	0.376	989%
Total Pacific Northwest gas	**0.433**	**0.61**	**0.733**	**0.906**	**0.473**	**109%**
West North Central						
All other sectors	1.258	1.387	1.526	1.643	0.385	31%
Electric generation gas	0.048	0.133	0.303	0.532	0.484	1008%
Total West North Central gas	**1.306**	**1.519**	**1.829**	**2.175**	**0.869**	**67%**
Southwest Desert						
All other sectors	0.316	0.286	0.336	0.39	0.074	23%
Electric generation gas	0.085	0.269	0.526	0.649	0.564	664%
Total Southwest Desert gas	**0.401**	**0.555**	**0.862**	**1.039**	**0.638**	**159%**
Rocky Mountain						
All other sectors	0.575	0.593	0.684	0.77	0.195	34%
Electric generation gas	0.01	0.065	0.127	0.225	0.215	2150%
Total Rocky Mountain gas	**0.585**	**0.658**	**0.812**	**0.995**	**0.41**	**70%**
West South Central						
All other sectors	4.323	4.082	4.524	4.696	0.373	9%
Electric generation gas	1.488	1.613	1.496	1.709	0.221	15%
Total West South Central gas	**5.811**	**5.695**	**6.02**	**6.405**	**0.594**	**10%**
East North Central						
All other sectors	3.724	3.899	4.243	4.551	0.827	22%
Electric generation gas	0.103	0.337	0.816	1.003	0.9	874%
Total East North Central gas	**3.827**	**4.236**	**5.059**	**5.554**	**1.727**	**45%**
East South Central						
All other sectors	0.874	0.933	1.009	0.958	0.084	10%
Electric generation gas	0.087	0.114	0.176	0.182	0.095	109%
Total East South Central gas	**0.961**	**1.047**	**1.184**	**1.14**	**0.179**	**19%**
South Atlantic						
All other sectors	1.445	1.692	1.99	2.19	0.745	52%
Electric generation gas	0.354	0.548	0.931	1.259	0.905	256%
Total South Atlantic gas	**1.799**	**2.24**	**2.921**	**3.449**	**1.65**	**92%**
Mid Atlantic						
All other sectors	2.235	2.286	2.391	2.505	0.27	12%
Electric generation gas	0.259	0.672	0.853	0.785	0.526	203%
Total Mid Atlantic gas	**2.494**	**2.958**	**3.244**	**3.29**	**0.796**	**32%**

Appendix A: North American Gas Demand by Region

(in Tcf/year)

Regions	(Actual) 1997	2002	2007	2012	Change TCF/Year 1997-2012	Percent Change 1997-2012
New England						
Core gas	0.444	0.451	0.483	0.522	0.078	18%
Non-core gas	0.089	0.116	0.134	0.13	0.041	46%
All other sectors	0.533	0.567	0.617	0.652	0.119	22%
Electric generation gas	0.098	0.243	0.289	0.291	0.193	197%
Total New England gas	**0.631**	**0.81**	**0.907**	**0.943**	**0.312**	**49%**
Alaska Export to Asia	**0.191**	**0.308**	**0.589**	**0.774**	**0.583**	**305%**
United States						
All other sectors	17.104	17.751	19.572	20.775	3.671	21%
Electric generation gas	3.095	4.549	5.955	7.162	4.067	131%
Total United States gas	**20.199**	**22.3**	**25.526**	**27.937**	**7.738**	**38%**
Canada						
Core Gas	1.524	1.72	1.763	1.807	0.283	19%
Non Core Gas	0.875	1.04	1.16	1.281	0.406	46%
Total Canadian Gas Demand	**2.399**	**2.76**	**2.923**	**3.088**	**0.689**	**29%**
Mexico (Northern only)						
Total Mexican Demand	**0.038**	**0.179**	**0.327**	**0.373**	**0.335**	**882%**
Total North America	**22.636**	**25.239**	**28.776**	**31.398**	**8.762**	**39%**

Appendix B: Gross Domestic Product Implicit Price Deflator Series

Year	Current Index	Annual Growth Rate
1970	26.62	
1971	27.96	5.0%
1972	29.14	4.2%
1973	30.78	5.6%
1974	33.54	9.0%
1975	36.67	9.3%
1976	38.75	5.7%
1977	41.24	6.4%
1978	44.17	7.1%
1979	47.85	8.3%
1980	52.25	9.2%
1981	57.12	9.3%
1982	60.68	6.2%
1983	63.09	4.0%
1984	65.43	3.7%
1985	67.50	3.2%
1986	68.98	2.2%
1987	71.06	3.0%
1988	73.47	3.4%
1989	76.27	3.8%
1990	79.24	3.9%
1991	82.13	3.6%
1992	84.12	2.4%
1993	86.16	2.4%
1994	87.92	2.0%
1995	89.90	2.3%
1996	91.58	1.9%
1997	93.38	2.0%
1998	94.55	1.2%
1999	95.97	1.5%
2000	97.95	2.1%
2001	**100.00**	**2.1%**
2002	101.64	1.6%
2003	103.20	1.5%
2004	104.94	1.7%
2005	106.97	1.9%
2006	109.39	2.3%
2007	112.12	2.5%
2008	115.07	2.6%
2009	118.25	2.8%
2010	121.71	2.9%
2011	125.50	3.1%
2012	129.65	3.3%

Source: 1970 – 2012 DRI Trend 25 Year 0201 Forecast

Appendix C: Integrated Price and Supply Assessment Assumptions

Parameters	High Price Outlook	Basecase Projection	Low Price Outlook
Natural Gas Resources			
Reserve Appreciation	Lowered by 25%.	Appreciation range: 0.03% to 2.2 %.	Raised by 33%.
Gas Resources	Same as basecase.	Lower 48: 975 Tcf Canada: 417 Tcf	Same as basecase.
Natural Gas Demand			
Gas Demand	Low efficiency improvements. Step increase in gas demand, up 10% by 2017.	Total consumption by 2007: 25.5 Tcf.	High efficiency improvements. Net demand falls 5%.
Competing Fuel Sources			
Oil Price	World oil prices rise to $30 per barrel by 2007.	World oil prices rise to $26 per barrel by 2007, then remained constant through 2012.	Same as basecase.
Oil Burn	All states are constrained from switching to oil.	Only California is constrained from switching to oil.	Same as basecase.

Appendix D: Natural Gas Price Projections for Electricity Generation in Western Electricity Coordinating Council Subregions

Table D-1
Natural Gas Prices for Electricity Generation in the California Region
(in year 2000 dollars per Mcf)

Year	PG&E	SoCalGas	SDG&E	Southern California Production	TEOR	Coolwater	Rosarito	Otay Mesa	Kern River	Mojave
2002	3.41	3.36	3.36	3.12	3.17	3.17	3.24	3.26	3.12	3.27
2003	3.47	3.42	3.42	3.20	3.22	3.22	3.32	3.33	3.16	3.35
2004	3.54	3.50	3.50	3.28	3.27	3.27	3.39	3.39	3.19	3.42
2005	3.59	3.58	3.58	3.37	3.31	3.31	3.47	3.46	3.23	3.50
2006	3.65	3.66	3.66	3.45	3.36	3.36	3.54	3.53	3.26	3.57
2007	3.71	3.73	3.73	3.53	3.41	3.41	3.62	3.60	3.30	3.65
2008	3.79	3.81	3.81	3.62	3.50	3.50	3.70	3.68	3.39	3.74
2009	3.87	3.90	3.90	3.71	3.59	3.59	3.79	3.77	3.49	3.83
2010	3.96	3.99	3.99	3.79	3.69	3.69	3.87	3.86	3.58	3.92
2011	4.05	4.08	4.08	3.88	3.78	3.78	3.96	3.94	3.68	4.01
2012	4.14	4.17	4.17	3.97	3.87	3.87	4.04	4.03	3.77	4.10

The following legend defines each price heading.

Legend:
- PG&E – Natural gas deliver by PG&E for the electricity generation.
- SoCalGas and SDG&E – These prices represent the Sempra-wide electric generation rate.
- Southern California Production – Gas prices for California natural gas produced in the Lower San Joaquin Valley or Coastal oil and used for electric generation.
- TEOR – Thermal Enhance Oil Recovery represents the weighted average gas price, mainly for cogeneration in oil and gas production area in Southern California. Supply sources include SoCal Gas, PG&E, Mojave and Kern River pipelines, and California production.
- Coolwater – Weighted average gas price for the Coolwater power plant. Supply would be from Kern River and Mojave pipelines.
- Rosarito – Represents gas price for power generation in northern Baja California, Mexico.
- Kern River – Gas delivered to electric generators on the Kern River Pipeline in California.
- Otay Mesa – Gas delivered to the proposed Otay Mesa Power Plant located in San Diego County.
- Mojave – Gas prices delivered to electric generators off the Mojave pipeline in California.

Table D-2
Natural Gas Prices for Electricity Generation in the Pacific Northwest Region
(in year 2000 dollars per Mcf)

Year	Alberta	British Columbia	Montana	North Nevada	PG&E-GTN, Kingsgate	PG&E-GTN, Malin	PG&E-GTN, Stanfield	PNW	PNW-Coastal
2002	2.61	2.81	3.05	3.53	2.40	2.83	2.57	3.47	2.89
2003	2.66	2.88	3.10	3.61	2.45	2.89	2.63	3.55	2.97
2004	2.71	2.94	3.15	3.69	2.50	2.96	2.69	3.64	3.06
2005	2.75	3.01	3.21	3.77	2.55	3.02	2.75	3.72	3.14
2006	2.80	3.07	3.26	3.85	2.60	3.09	2.81	3.81	3.23
2007	2.85	3.14	3.31	3.93	2.65	3.15	2.87	3.89	3.31
2008	2.90	3.21	3.36	4.00	2.71	3.22	2.94	3.97	3.39
2009	2.95	3.28	3.41	4.08	2.77	3.30	3.00	4.05	3.46
2010	3.01	3.34	3.47	4.16	2.84	3.37	3.07	4.12	3.54
2011	3.06	3.41	3.52	4.24	2.90	3.45	3.13	4.20	3.61
2012	3.11	3.48	3.57	4.32	2.96	3.52	3.20	4.28	3.69

The following legend defines each price heading.

Legend:
- Alberta – Gas prices for electric generation in Alberta, Canada.
- British Columbia – Gas prices for electric generation in British Columbia, Canada.
- Montana – Gas delivered for electric generation in the Montana.
- North Nevada – Weighted average price for gas delivered for electric generation in the Reno area. Supply sources would be the Paiute or Tuscarora pipelines.
- PG&E-GTN, Kingsgate – Gas priced on PG&E-GTN at the Idaho-Canada border.
- PG&E-GTN, Malin – Gas priced on PG&E-GTN at Malin, Oregon.
- PG&E-GTN, Stanfield – Gas priced on PG&E-GTN at Stansfield, Oregon
- PNW – Gas delivered to power generators located on local utility distribution systems in the Pacific Northwest (Washington and Oregon).
- PNW Coastal– Gas delivered directly to electric generators located on the Northwest Pipeline system (Washington and Oregon).

Table D-3
Natural Gas Prices for Electricity Generation in the Southwest Desert - Mountain Region
(in year 2000 dollars per Mcf)

Year	Colorado	North Arizona	North New Mexico	South Arizona	South New Mexico	South Nevada	Utah
2002	3.12	2.92	2.92	2.98	2.98	3.41	3.11
2003	3.16	3.01	3.01	3.07	3.07	3.46	3.15
2004	3.20	3.11	3.11	3.16	3.16	3.51	3.19
2005	3.24	3.20	3.20	3.26	3.26	3.55	3.23
2006	3.28	3.30	3.30	3.35	3.35	3.60	3.27
2007	3.32	3.39	3.39	3.44	3.44	3.65	3.31
2008	3.37	3.50	3.50	3.55	3.55	3.74	3.36
2009	3.42	3.62	3.62	3.65	3.65	3.83	3.41
2010	3.46	3.73	3.73	3.76	3.76	3.93	3.46
2011	3.51	3.85	3.85	3.86	3.86	4.02	3.51
2012	3.56	3.96	3.96	3.97	3.97	4.11	3.56

The following legend defines each price heading.

Legend:
- Colorado – Gas prices for electric generation in Colorado.
- North Arizona – Gas delivered directly to electric generators from the El Paso North or Transwestern pipeline systems.
- North New Mexico – Gas delivered directly to electric generators from the El Paso North or Transwestern pipeline systems.
- South Arizona – Gas delivered directly to electric generators from the El Paso South pipeline system..
- South New Mexico – Gas delivered directly to electric generators from the El Paso South pipeline system delivery.
- South Nevada – Weighted average gas prices for electric generation in the Las Vegas, Nevada area. Supply sources would include Rocky Mountain production delivered by the Kern River pipeline and southwest produced gas delivered Southwest Gas Corp and received from either the El Paso North or Transwestern pipelines.
- Utah – Gas delivered to electric generators in Utah.

Appendix E: Natural Gas Price Projections for End-Use Customers in California Investor-Owned Utility Service Areas

Table E-1
PG&E Service Area
(in year 2000 dollars per Mcf)

	Core			Noncore					System
Year	**Res**	**Comm**	**Indust**	**Comm**	**Indust**	**TEOR**	**Cogen**	**EG**	**Average**
1990	6.73	6.64	5.87	3.80	4.13	3.08	3.82	3.82	4.89
1991	6.76	6.75	5.91	3.14	3.29	3.64	3.30	3.30	4.58
1992	6.50	7.10	5.29	3.04	2.43	2.86	3.01	3.01	4.14
1993	6.15	6.58	5.21	3.26	2.41	2.56	3.25	3.25	4.29
1994	6.40	6.62	5.10	3.16	2.15	2.14	2.43	2.43	3.87
1995	6.67	6.73	4.90	2.65	1.94	1.60	2.36	2.36	4.00
1996	6.02	6.01	4.94	3.41	2.42	2.10	2.48	2.48	4.04
1997	6.21	6.22	5.31	2.89	2.83	3.12	2.81	2.81	4.08
1998	6.09	7.36	4.26	3.21	2.56	2.37	2.63	2.63	4.08
1999	7.54	7.51	4.28	3.78	2.76	2.66	2.71	2.71	4.25
2000	8.88	8.88	6.45	6.00	5.22	5.07	5.16	5.15	6.32
2001	9.75	9.69	7.60	7.54	6.77	6.74	6.75	6.75	7.68
2002	6.75	6.69	4.59	4.16	3.43	3.39	3.41	3.41	4.51
2003	6.80	6.74	4.65	4.20	3.49	3.45	3.47	3.47	4.61
2004	6.85	6.79	4.71	4.28	3.55	3.52	3.54	3.54	4.62
2005	6.78	6.72	4.73	4.32	3.61	3.58	3.59	3.59	4.59
2006	6.83	6.77	4.79	4.38	3.67	3.65	3.65	3.65	4.63
2007	6.94	6.88	4.87	4.46	3.73	3.72	3.71	3.71	4.68
2008	6.92	6.86	4.92	4.52	3.81	3.80	3.79	3.79	4.71
2009	6.97	6.91	4.99	4.60	3.89	3.88	3.87	3.87	4.76
2010	7.03	6.98	5.06	4.69	3.97	3.98	3.96	3.96	4.82
2011	7.03	6.97	5.11	4.76	4.06	4.06	4.05	4.05	4.87
2012	7.04	6.99	5.16	4.83	4.15	4.15	4.14	4.14	4.92
2013	7.12	7.06	5.24	4.92	4.23	4.23	4.22	4.22	5.00
2014	7.10	7.04	5.28	4.97	4.31	4.30	4.29	4.29	5.04
2015	7.13	7.08	5.34	5.04	4.39	4.38	4.37	4.37	5.10
2016	7.18	7.13	5.41	5.11	4.47	4.45	4.45	4.45	5.17
2017	7.21	7.16	5.47	5.18	4.54	4.53	4.53	4.53	5.23
2018	7.25	7.20	5.54	5.26	4.63	4.61	4.61	4.61	5.30
2019	7.31	7.26	5.61	5.34	4.71	4.69	4.69	4.69	5.37
2020	7.37	7.32	5.68	5.42	4.79	4.78	4.78	4.78	5.44
2021	7.43	7.38	5.76	5.50	4.88	4.86	4.86	4.86	5.52
2022	7.48	7.44	5.83	5.58	4.96	4.94	4.95	4.95	5.59

Note: Prices from 1990 to 2001 are historical prices.

Table E-2
SoCal Gas Service Area
(in year 2000 dollars per Mcf)

	Core			Noncore					System
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	EG	Average
1990	6.71	7.10	6.28	4.48	3.98	3.54	3.85	3.85	4.75
1991	7.33	7.70	7.70	4.10	3.82	3.00	3.38	3.38	4.72
1992	7.56	8.00	7.21	5.64	4.23	3.18	3.29	3.29	5.21
1993	7.36	7.84	7.14	5.22	3.91	3.31	3.30	3.30	5.18
1994	7.25	7.54	7.01	3.48	3.08	2.60	2.77	2.77	4.90
1995	7.52	7.42	6.56	2.51	2.40	2.10	2.37	2.37	4.71
1996	7.08	6.46	5.54	2.95	2.80	2.56	3.09	3.09	4.78
1997	7.38	6.70	5.63	3.11	3.45	3.01	3.36	3.36	4.93
1998	7.34	6.00	5.05	2.95	3.06	2.92	2.96	2.96	4.78
1999	6.34	4.81	3.75	3.33	3.33	3.21	2.77	2.77	4.25
2000	8.39	6.84	5.10	4.94	4.94	4.88	4.79	4.79	5.92
2001	13.69	12.08	10.40	8.75	8.75	8.70	8.58	8.58	10.78
2002	6.94	5.39	3.78	3.59	3.59	3.54	3.36	3.36	4.70
2003	7.07	5.50	3.86	3.65	3.65	3.61	3.42	3.42	4.85
2004	7.06	5.52	3.92	3.72	3.72	3.69	3.50	3.50	4.90
2005	7.17	5.62	4.01	3.81	3.81	3.78	3.58	3.58	4.97
2006	7.13	5.63	4.07	3.86	3.86	3.83	3.66	3.66	4.98
2007	7.21	5.71	4.15	3.93	3.93	3.90	3.73	3.73	5.05
2008	7.24	5.76	4.22	4.02	4.02	3.98	3.81	3.81	5.11
2009	7.31	5.84	4.31	4.10	4.10	4.07	3.90	3.90	5.16
2010	7.35	5.91	4.40	4.19	4.19	4.16	3.99	3.99	5.23
2011	7.41	5.98	4.49	4.27	4.27	4.24	4.08	4.08	5.30
2012	7.50	6.07	4.58	4.36	4.36	4.33	4.17	4.17	5.37
2013	7.57	6.15	4.68	4.45	4.45	4.42	4.25	4.25	5.45
2014	7.67	6.25	4.78	4.54	4.54	4.51	4.34	4.34	5.54
2015	7.73	6.33	4.87	4.62	4.62	4.59	4.43	4.43	5.61
2016	7.79	6.40	4.96	4.71	4.71	4.68	4.51	4.51	5.68
2017	7.87	6.49	5.05	4.79	4.79	4.76	4.60	4.60	5.76
2018	7.93	6.56	5.13	4.87	4.87	4.84	4.68	4.68	5.83
2019	7.98	6.63	5.21	4.95	4.95	4.92	4.76	4.76	5.89
2020	8.03	6.69	5.29	5.02	5.02	4.99	4.83	4.83	5.95
2021	8.08	6.75	5.37	5.10	5.10	5.07	4.91	4.91	6.02
2022	8.13	6.81	5.44	5.17	5.17	5.14	4.98	4.98	6.08

Note: Prices from 1990 to 2001 are historical prices.

Table E-3

SDG&E Service Area
(in year 2000 dollars per Mcf)

	Core			Noncore					System
Year	Res	Comm	Indust	Comm	Indust	TEOR	Cogen	EG	Average
1990	6.74	6.71	6.39	4.63	4.63	-	3.89	3.89	5.06
1991	6.35	6.44	6.41	4.07	4.07	-	3.41	3.41	4.61
1992	6.77	6.99	7.08	4.22	4.22	-	3.36	3.36	4.94
1993	7.18	6.76	7.05	2.70	2.61	-	3.49	3.49	5.10
1994	7.22	5.79	6.33	3.77	4.08	-	3.19	3.19	5.00
1995	6.76	5.58	6.26	2.84	2.87	-	2.28	2.28	4.13
1996	6.83	5.91	6.70	3.29	2.94	-	2.66	2.66	4.56
1997	7.53	6.93	7.84	3.40	3.40	-	3.07	3.07	4.74
1998	7.37	6.28	7.28	2.79	2.79	-	2.78	2.78	4.39
1999	7.52	6.84	5.40	3.55	3.55	-	3.21	3.21	4.74
2000	8.09	7.56	5.96	5.29	5.29	-	4.77	4.77	5.89
2001	11.19	10.54	8.92	9.05	9.05	-	8.58	8.58	9.55
2002	7.28	6.64	5.05	3.80	3.80	-	3.36	3.36	5.26
2003	7.31	6.68	5.10	3.78	3.78	-	3.42	3.42	5.77
2004	7.14	6.55	5.07	3.83	3.83	-	3.50	3.50	5.67
2005	7.21	6.62	5.13	3.92	3.92	-	3.58	3.58	5.71
2006	7.14	6.56	5.14	3.97	3.97	-	3.66	3.66	5.67
2007	7.25	6.67	5.22	4.05	4.05	-	3.73	3.73	5.74
2008	7.38	6.79	5.32	4.15	4.15	-	3.81	3.81	5.82
2009	7.46	6.87	5.40	4.24	4.24	-	3.90	3.90	5.87
2010	7.37	6.81	5.41	4.31	4.31	-	3.99	3.99	5.80
2011	7.45	6.86	5.48	4.40	4.40	-	4.08	4.08	5.83
2012	7.59	6.99	5.59	4.50	4.50	-	4.17	4.17	5.96
2013	7.64	7.05	5.66	4.59	4.58	-	4.25	4.25	6.04
2014	7.75	7.16	5.76	4.67	4.67	-	4.34	4.34	6.16
2015	7.84	7.25	5.85	4.76	4.76	-	4.43	4.43	6.26
2016	7.88	7.30	5.91	4.84	4.84	-	4.51	4.51	6.34
2017	7.97	7.39	6.00	4.92	4.92	-	4.60	4.60	6.44
2018	8.05	7.47	6.08	5.00	5.00	-	4.68	4.68	6.53
2019	8.13	7.55	6.16	5.07	5.07	-	4.76	4.76	6.62
2020	8.17	7.59	6.22	5.14	5.14	-	4.83	4.83	6.69
2021	8.21	7.65	6.29	5.22	5.21	-	4.91	4.91	6.76
2022	8.26	7.70	6.36	5.29	5.29	-	4.98	4.98	6.83

Note: Prices from 1990 to 2001 are historical prices.