CALIFORNIA
ENERGY
COMMISSION

REVISED REFERENCE CASE IN SUPPORT OF THE 2005 NATURAL GAS MARKET ASSESSMENT

In Support of the
2005 Integrated Energy Policy Report

STAFF REPORT

September 2005
CEC-600-2005-026-REV

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Jairam Gopal
Principal Author

Leon Brathwaite
Jim Fore
Mark DiGiovanna
David Maul
Suzanne Phinney (Consultant)
Ken Medlock (Consultant)
Mike Purcell. P.G.
Bill Wood
Contributing Authors

Jairam Gopal
Project Manager

Sandra Fromm
Assistant Program Manager
2005 Energy Report

Kevin Kennedy
Program Manager
2005 Energy Report

David Maul
Manager
Natural Gas and
Special Projects Office

Rosella Shapiro
Deputy Director
Transportation Fuels Division

B.B. Blevins
Executive Director

DISCLAIMER

Abstract

This report presents the revised results of the California Energy Commission staff's most recent assessment of California's natural gas markets. It covers natural gas demand, supply, infrastructure, price, and policy issues. While this report examines these issues from a California perspective, the assessment considers all this information within a North American context since California is closely tied to this larger natural gas system. This report is based upon the staff's preliminary forecast, issued in June of 2005, the comments received at the July 2005 public hearing on that report, and additional updated information. This forecast was prepared without considering the long-term effects of hurricane Katrina. At this time, adequate information does not exist to determine what, if any, long-term impacts will occur.

California currently has adequate infrastructure (pipelines and storage facilities) to ensure a reliable delivery of natural gas supplies on an average annual basis, although the staff is concerned about the availability to California of these supplies at all times to meet demand. However, the dominant issue that California and the rest of the nation now face is price – the natural gas commodity that consumers buy is considerably more expensive now than it was just a few years ago. Further, the staff expects the price to remain high, assuming average annual conditions. This report concludes with a list of policy questions that address how California might manage this price level and the risks of higher prices in the future, to help consumers spend less for natural gas.

Acknowledgements

This report documents the results of the many staff members who worked on the underlying model and wrote the report. The staff has benefited from the insights and contributions of other agencies and the comments received at the July 14, 2005, public hearing on the preliminary reference case. Staff hopes that the collaborative effort reflected in this report will effectively serve California consumers.

The modeling team draws upon the work of staff in the Natural Gas and Special Projects Office (NGO), the Electricity Analysis Office (EAO), the Demand Analysis Office (DAO), and its consultants. These staff include: Leon Brathwaite, Mark Di Giovanna, and Jairam Gopal, with data analysis assistance from Jim Fore and Mike Purcell and data collection support by the offices' able student assistants Taijinder Grewal and Sarah Bounauro (NGO); Angela Tanghetti (EAO); Lynn Marshall, Tom Gorin, and David Vidaver (DAO); and NGO's consultants Dr. Ken Medlock with the James Baker Institute at Rice University and Dr. Dale Nesbit with Altos Management.

The report writing team included Leon Brathwaite, Mark Di Giovanna, Jim Fore, Jairam Gopal, David Maul, Ken Medlock, Suzanne Phinney of Aspen Environmental Group, Mike Purcell, and Bill Wood. Graphics support was provided by Mary Dyas, Jacque Gilbreath, and Terry Rose. Editorial support was provided by Suzanne Phinney, Dora Gomez, and Carolyn Walker. Technical review was provided by Mike Smith, Scott Tomashefsky, Melissa Jones, Gary Klein, and Karen Griffin.

This report also benefited greatly from the Energy Commission staff's frequent collaboration with other state agencies involved in the Natural Gas Working Group, including California Air Resources Board, California Public Utilities Commission (CPUC), Department of General Services, and Division of Oil, Gas, and Geothermal Resources. The staff expresses its additional appreciation for the close working relationship with the CPUC on natural gas issues and for the information derived from CPUC proceedings on natural gas.

The assessment presented in this report is being conducted in parallel with a similar effort on behalf of the Western Governor's Association and its energy policy arm, the Western Interstate Energy Board (WIEB). Energy Commission staff is providing technical support to WIEB to analyze the adequacy of the western natural gas supplies and infrastructure. In order to conduct this work, the Energy Commission staff formed a team representing the 15 western states and Canadian provinces. The staff has benefited from the advice of this group and wishes to acknowledge its contributions, along with the leadership provided by Doug Larson, the executive director of WIEB.

Table of Contents

List of Figures and Tables

Appendices

Executive Summary

Introduction

California is currently facing a natural gas price challenge. While wholesale prices California consumers pay for this fuel are lower than prices in most other areas in the nation, they are still significantly higher than they were a few years ago. These higher prices are having a direct negative impact on all California natural gas consumers and on the State's economy, and an indirect negative impact on all California electricity consumers since this fuel is used for a large portion of the State's power supply. California gas consumers will spend over $10 billion for natural gas this year. California must act more aggressively to develop short-term, mid-term, and long-term solutions to help bring prices down. Even a ten percent reduction in natural gas prices will keep an extra $1 billion in the State and in consumers' pockets.

In the natural gas arena, California is tied closely to the North American market through its connections with the intercontinental pipeline network. Demand, supply, and infrastructure throughout the entire continent establish prices in North America. As a result, California often has little direct control over market prices. For example, California natural gas wholesale prices spiked in February 2003 due to extreme weather conditions in the Northeast at a time when California's own demand was moderate. However, that is not the situation today. The increasing national hunt for a limited supply of natural gas is driving prices higher. Therefore, California needs to focus on those actions within its control that can help California consumers.

This report presents the California Energy Commission (Energy Commission) staff assessment of long-term natural gas demand, supply, infrastructure, and prices during the 2006 to 2016 forecast period, and a discussion of policy issues to help reduce prices to consumers. The revised forecast in this report differs from the earlier preliminary forecast in three areas. First, staff lifted the artificial cap that constrained the expansion of liquefied natural gas (LNG) terminal operations. The revised forecast now allows all economically competitive LNG supplies to flow. Second, staff delayed the on-line date of both the MacKenzie Delta pipeline and the Alaska pipeline, based on more recently available project development information. Third, staff included several minor technical refinements that allowed the model to operate more efficiently.

Hurricane Katrina

Natural gas price challenges faced by California and the nation were worsened in late August 2005 by Hurricane Katrina. While the human suffering from the hurricane eclipses all other issues, we need to note that the hurricane has negatively impacted natural gas consumers. The hurricane caused natural gas operators to evacuate many of their production rigs in the Gulf of Mexico, resulting in an 83 percent reduction in production at the peak. The hurricane also damaged some of the infrastructure needed to process and deliver natural gas to the nation's pipeline network. Three weeks after the hurricane, 34 percent of total production was still unavailable due to damage that has not been repaired, and experts are unable to precisely determine when full production will resume.

The natural gas that would have been produced during this time would have been put into storage for this winter. As a result, natural gas storage levels are lower than they would have been and less stored gas will be available to meet winter peak needs. This has caused natural gas prices bid for future delivery to be higher. Again, experts cannot determine how long the restricted supply/higher price situation will last.

California is a little more fortunate than most states since its stored natural gas supplies were at historically high levels before Hurricane Katrina stuck the Gulf of Mexico. As a result, natural gas prices at the California border have not risen as much as elsewhere in the U.S.

Another issue raised by Hurricane Katrina is the need to diversify locations where natural gas is imported. LNG terminals should be located on both east and west coasts in order to avoid the supply interruptions that could occur from weather events such as Hurricane Katrina. This will become even more important should the number of Gulf Coast LNG terminals increase.

Natural Gas Demand

Over the forecast period, the Energy Commission staff expects natural gas demand growth in California to be less than that seen in the nation as a whole. According to the U.S. Department of Energy, Energy Information Administration, natural gas customers in the contiguous United States consumed 56 billion cubic feet of natural gas per day during 2004. Total natural gas consumption in the lower 48 states of the U.S. will climb to 70 billion cubic feet per day or 1.7 percent per year from 2006 to 2016, with most of that demand growth occurring in the power generation sector in regions east of the Rocky Mountains. Throughout Canada, natural gas consumption will grow at an annual rate of 1.3 percent per year over the next decade, reaching 10.1 billion cubic feet per day in 2016. Meanwhile, natural gas demand in Mexico will grow 2.9 percent per year, increasing from 6.7 to 9 billion cubic feet per day.
Total demand is based on use within four sectors: residential, commercial, chemical and non-chemical manufacturing, and power generation. Over the coming decade, demand for natural gas by electricity generators will account for the bulk of the demand growth in the lower 48 United States. Gas consumption for power generation will increase at an annual rate of 4.3 percent between 2006 and 2016, growing from 15.3 to 23.4 billion cubic feet per day.

Total natural gas demand in California is projected to grow at a rate of 0.7 percent per year, from 6.2 billion cubic feet per day in 2006 to 6.6 billion cubic feet per day in 2016. Strong growth in the residential and commercial sectors will be offset by declining industrial gas demand and slower growth in gas consumption by power generators than has been observed in recent years.

Natural Gas Supply

Natural gas production from the lower 48 states is expected to increase by about 1.6 percent per year for the period 2006 to 2016. Unfortunately, this increase in supplies will not keep pace with the greater increase in national demand. Imports of Canadian supplies are expected to decrease over the same period at an annual average rate of 2.3 percent. While the MacKenzie Delta supplies show significant potential and could provide 0.3 to 0.8 trillion cubic feet per year to Canadian markets as early as 2013 if regulatory approval is obtained, the initial potential increase is not expected to offset the increased need for natural gas in Canada used in tar sands production. As a result, the net available for export to the U.S. will decrease.

Alaskan production, mainly from the Beaufort Sea region, could be available by 2016, assuming a new, major pipeline is approved and built to move these remote supplies to the Canadian and lower 48 states markets. This new supply could provide between 1.5 to 2.0 trillion cubic feet per year by the end of the forecast period.

Gas supplies from LNG import facilities in North America that have been approved and are under construction are expected to grow from 2006 to 2016 by 8.7 percent per year. While additional LNG import terminals are likely to be built in the U.S. during the forecast period, staff has not predicted which specific ones will be approved and built in the future.

Natural Gas Infrastructure Needs

While existing interstate pipeline capacity can meet the annual average demand, California will not necessarily always have sufficient capacity to meet daily peak needs. Natural gas supplies needed to meet the requirements of all consumers vary significantly on a month-to-month and day-to-day basis. The State lacks the interstate pipeline capacity to meet the needs of all consumers on the coldest days in winter as well as on occasions when there are disruptions in an interstate pipeline. Fortunately, the State has significant in-state storage facilities that can supply additional natural gas to meet these peak needs. Historically, curtailments in supply deliveries to customers have been very limited.

California has significant pipeline capacity to access the four major natural gas supply basins: the San Juan, Permian, Rocky Mountain, and the Western Canadian Sedimentary basins. Pipelines constructed over the last 50 years connect these basins to California. While this capacity will ensure that available supplies can be physically transported to California, it does not prevent other U.S. markets from outbidding California for its natural gas and causing the supplies to flow away from California.

Given the pipeline expansions completed over the past four years since the energy crisis and the potential modification of pipelines connecting to LNG facilities in Baja California, California is well situated to access both conventional supply basins and potential new LNG supplies. Pipeline capacity should be sufficient to meet the annual average quantity of gas that consumers in the State need. An LNG facility on the West Coast will provide a new and competitive source of natural gas to California, assuming that the TGN pipeline and the Baja Norte pipeline that currently deliver gas in Baja California will reverse flows and supply natural gas from LNG supplies in the Baja California region to the State. Although this report models LNG delivered from Baja California, it is understood that there may be other LNG terminals on the West Coast in the future.

On an annual average basis, receipt capacity — the ability of the major backbone pipelines within the state borders to transport natural gas from the border points to utilities and consumers in the State — appears to be adequate in both northern and southern California over the next decade.

Natural Gas Price Outlook

From 2006 to 2016, the Energy Commission staff expects a general increase in natural gas wellhead prices in the basins supplying California, reflecting the increasing marginal costs to produce gas in those regions to keep pace with growing demand. During several years over the forecast horizon, however, that upward price trend in those basins is altered by market influences such as the introduction of large, new supplies into the market such as LNG, or changes in natural gas demand.

As a result of pipeline expansions completed during 2002 and 2003, which afforded California unconstrained access to regional supplies, California natural gas prices no longer tend to be out of step with the rest of the North American natural gas market. Consequently, from 2006 to 2016 California's end-use natural gas prices mirror the trends of the overall market.

Natural Gas Policy Options

The State of California's long-term policy goal for natural gas is succinctly stated as follows: to ensure a reliable supply of natural gas, sufficient to meet California's demand, at reasonable and stable prices and with acceptable environmental impacts and market risk.

The State's natural gas policy goal addresses the needs of natural gas consumers (reliable supplies at reasonable prices), the natural gas industry (stable prices with acceptable market risk), and the State of California (environmental protection and a healthy economy).

The staff has interpreted the natural gas policy goal to mean that reliability of supply is the top priority, followed by reasonable and stable prices. These goals must be achieved in a manner consistent with environmental and public health and safety protection requirements. Market risk analysis and risk mitigation are important strategies that consumers and providers use to achieve their individual goals and can complement the actions the State might take. For example, when balancing reliability, price, and market risk, consumers (or their regulated natural gas providers) may be willing to pay a slightly higher price than the minimum achievable in order to substantially reduce the risk of future price spikes or increase the reliability of future supplies. Since the State's infrastructure and access to supplies are currently adequate due to several recent and expected pipeline and storage facility additions, the Energy Commission staff does not have an immediate concern regarding reliability. Although the State needs to take additional action to ensure its long-term supply reliability, it does not have to take these actions now.

Staff is concerned, however, about the availability of natural gas supplies at reasonable prices. Therefore, the issues discussed focus on natural gas price reduction and the actions the State can take to reduce prices (and bills) for consumers.

Consumers can help reduce their bills for natural gas by investing in energy efficiency measures which reduce their total consumption. The State can also pursue additional supplies that come directly to California and are not tied to national pricing benchmarks. California as a whole can benefit from:

- Continued strong efforts on gas and electric conservation and energy efficiency to reduce natural gas and electricity demand.
- Increases in domestic natural gas production.
- Development of supplemental natural gas supplies.
- Development of alternative energy sources that reduce overall energy (electricity and natural gas) demand.
- Attention to timely infrastructure additions to ensure supplies continue to be reliably delivered without causing localized congestion.

Energy Commission staff has identified the challenges the State must face to meet this goal, including concerns broadly categorized as:

- Demand
- Supply
- Infrastructure
- Price position relative to national markets
- Natural gas and electricity interfaces

The overarching theme for the policy issues can be summarized as follows:

> Are there additional, cost-effective actions California could take to reduce consumers' prices below the expected levels and to manage the risk of

potentially higher natural gas prices, while maintaining adequate reliability and meeting environmental and public health and safety requirements?

The Energy Commission staff proposes this theme to direct the development of effective solutions to these issues.

Input from various stakeholders, particularly the staff of the CPUC, has contributed to the identification of issues and potential solutions as discussed in Chapter 6. The Energy Commission staff now seeks additional input on potential policy choices.

Chapter 1: Introduction

California is currently facing a natural gas price challenge. While wholesale prices paid by California consumers for fuel are lower than most other areas in the nation, they are still significantly higher than a few years ago. Current prices are having a direct negative impact on all California natural gas consumers and on the State's economy and an indirect negative impact on all California electricity consumers, since this fuel is used for a large portion of our power supply. California gas consumers will spend over $10 billion for their natural gas this year. California must act more aggressively to develop short-term, mid-term, and long-term solutions to help bring prices down. Even a ten percent reduction in natural gas prices will keep an extra $1 billion in the state and in consumers' pockets.

Fortunately, California currently has adequate infrastructure to bring traditional supplies of natural gas into the State since California must import about 87 percent each year to meet its demand. This level of imports means that California competes with all major North American markets for natural gas. California must continue to evaluate its infrastructure needs and approve needed import and storage facilities to ensure that it avoids regional congestion or capacity constraints that could jeopardize the reliable delivery of this important fuel or contribute to market distortions. California must now diversify its traditional supply sources and explore importing alternative supplies of natural gas since national demand for natural gas continues to outstrip national supply; this increased demand, coupled with limited supply, is forcing prices higher).Therefore, California must pursue all cost-effective actions on both the demand side and the supply side to help reduce prices to consumers and help manage the risk of potentially higher prices.

This report discusses the California Energy Commission (Energy Commission) staff's revised market assessment of California's natural gas demand, supply, infrastructure, and prices for the forecast period 2006 - 2016. This report also discusses the natural gas market overview and identifies a list of policy questions that need to be addressed. These policy questions are organized in the same fashion. This revised market assessment reflects public comments from a July 14 workshop on the preliminary market assessment report, published in June 2005.

Energy Commission staff conducted this assessment using a variety of analytical techniques. The staff routinely gathers data from many sources, monitors market behavior to identify trends, investigates specific issues, and conducts analyses using spreadsheets and computer models. For several years, Energy Commission staff used the North American Regional Gas (NARG) model for long-term outlooks. This past year, staff upgraded its modeling capabilities and now uses the NARG-MarketBuilder (NARG-MB) model. The results for natural gas demand levels, supply, infrastructure needs, and price outlooks are products of the latter model and are documented in this report.

In order to assess these outlooks, a preliminary reference case was constructed. This reference case contains many assumptions about future conditions that affect natural gas. Energy Commission staff defined the reference case to include those infrastructure projects (pipelines, storage, and liquefied natural gas (LNG) import terminals) that either existed as of June 2005 or had received regulatory approvals and had started construction. Energy Commission staff did not include natural gas infrastructure projects that might be approved and constructed in the future, with the exception of the Alaskan natural gas pipeline and the Canadian MacKenzie Delta natural gas pipeline. These two projects were included because they are so significant, are being debated in the international energy policy arena, could impact the nation's natural gas future greatly, and are likely to be built at some time in the future. Without these projects, natural gas supply would be much more restricted and the resulting prices would be much higher. Also, Energy Commission staff did not speculate as to whether additional energy efficiency measures or renewable energy projects beyond those reasonably expected would be implemented. Therefore, staff's reference case reflects an extension of currently known conditions rather than a forecast of future events.

The Energy Commission natural gas forecast is a long-run estimate of the costs of new gas supply to serve California. The forecast is a 'fundamental' forecast because it is built up from the sum of costs of each function in the supply chain and is not based upon a regression or trend from historical and current natural gas prices. The costs include both fixed costs of new capacity (e.g., pipeline, storage, LNG terminal) and operating costs (e.g., variable costs of production, lost-and-unaccounted for (LUAF) gas, compression). As a long-run marginal cost forecast, the Energy Commission forecast is an estimate of the total costs through the natural gas supply chain to provide new natural gas resources for California. Depending upon market conditions, the price of natural gas may be either higher (during supply shortages) or lower (during supply surpluses) in any given year, but are expected to fluctuate around the fundamental gas price estimate.

Alternative assumptions for future demand, supply, and infrastructure conditions can have a dramatic impact on prices. Weather has a dramatic impact on natural gas prices. Energy Commission staff assumed average weather conditions in this assessment, an assumption that will be wrong most of the time since weather on any given day in the future will rarely be "average." Given these caveats, the price outlook in this report should not be viewed as a prediction of future natural gas market prices and should not be used by anyone to make financial commitments in the natural gas market—considerably more information is needed than just this price outlook. However, this assessment can be used to define the outcomes of various policy choices.

This report is one of several products and events being conducted in the natural gas area in support of the Energy Commission's *2005 Integrated Energy Policy Report* (*Energy Report*). In December 2004, the Energy Commission conducted a workshop on different modeling approaches that can be used to assess California's natural gas markets. In February 2005 the Energy Commission, in cooperation with the California Public Utilities Commission (CPUC), the California Air Resources Board

(CARB), and the Division of Oil, Gas, and Geothermal Resources, conducted a two-day technical workshop on natural gas quality issues. Following issuance of the June 30 preliminary market assessment report, the Energy Commission conducted a public hearing in July 2005, to seek advice and insight from all of California's natural gas stakeholders. This revised forecast and report reflect those comments. The Energy Commission staff also expects to issue reports in the future examining alternative future views of the world as they might affect California's natural gas markets, using sensitivities and scenarios to develop alternative assumptions for the staff's analytical efforts. Again, the Energy Commission staff will be seeking public input on these products.

Chapter 2: Natural Gas Demand

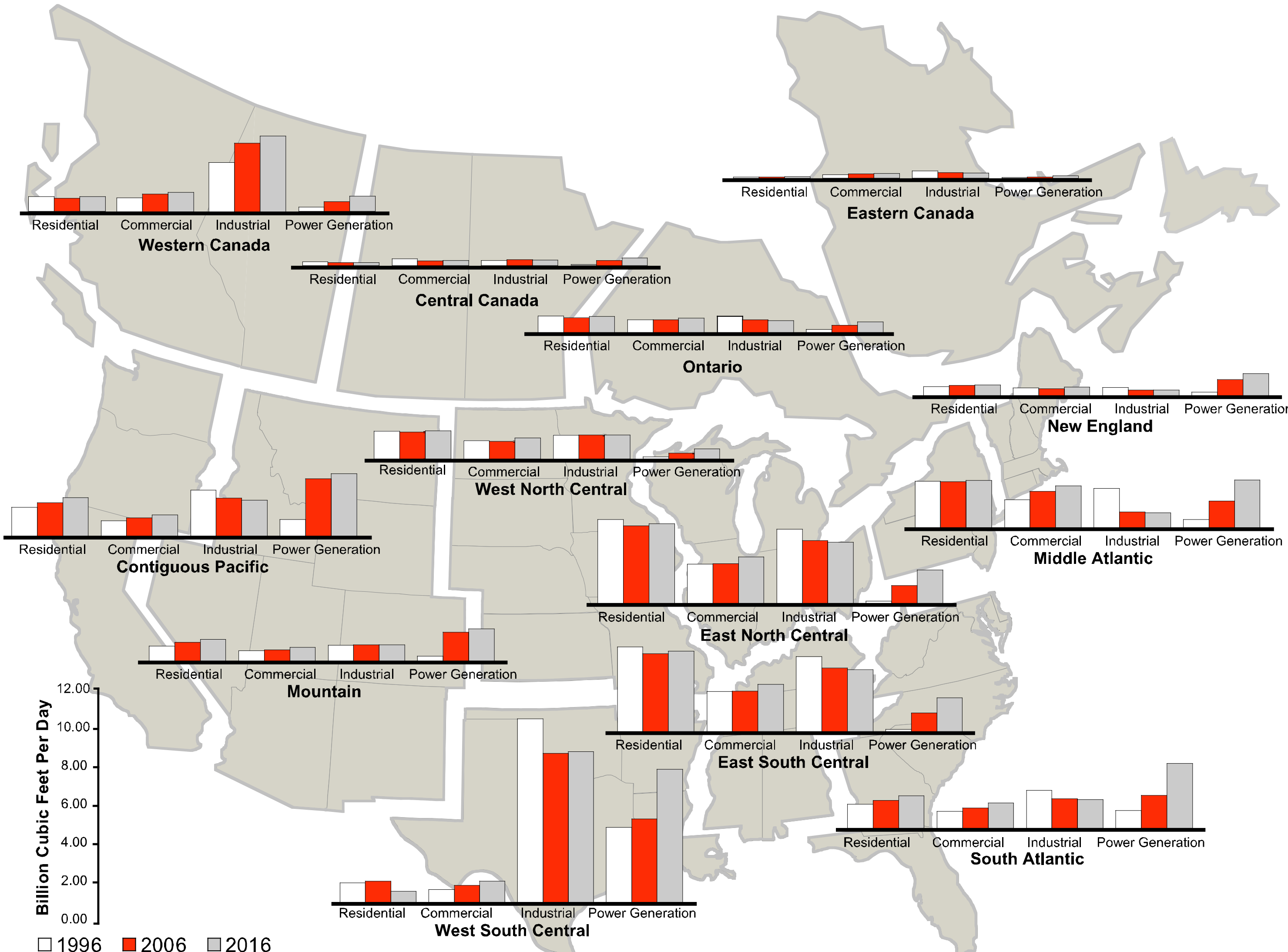
Introduction

This chapter discusses how California's demand for natural gas will change for the forecast period of 2006 to 2016. Projected natural gas consumption by end use is compared to changes expected in the Western United States. The following five end-use sectors are examined for Pacific Gas and Electric (PG&E), Southern California Gas (SoCalGas), and San Diego Gas and Electric (SDG&E) demand regions: residential, commercial, industrial gas demand for chemical manufacturing, industrial gas demand for non-chemical manufacturing, and power generation. Information on overall changes in demand for the U.S. and California is provided as background. The assessment of natural gas demand in this study includes the effect of natural gas efficiency standards and programs implemented and adopted prior to the forecast horizon.

U.S. and California Natural Gas Demand

According to the U.S. Department of Energy and the Energy Information Administration (EIA), natural gas customers in the contiguous United States consumed 56 billion cubic feet (Bcf) of natural gas per day during 2004.[i] By 2016, total natural gas consumption in the lower 48 states (lower 48) will climb to 70 Bcf per day, or 1.7 percent per year, with most of that demand growth occurring in the power generation sector in regions east of the Rocky Mountains. Throughout Canada, natural gas consumption will grow at an annual rate of 1.3 percent per year over the next decade, reaching 10.1 Bcf per day in 2016. Meanwhile, natural gas demand in Mexico will grow 2.9 percent per year, increasing from 6.7 Bcf per day to 9 Bcf per day. Figure 2-1 compares the natural gas consumption in various parts of the United States and Canada with both the decade prior to and the decade following 2006, the beginning of this study's forecast period.

Figure 2-1—Natural Gas Demand in the United States and Canada

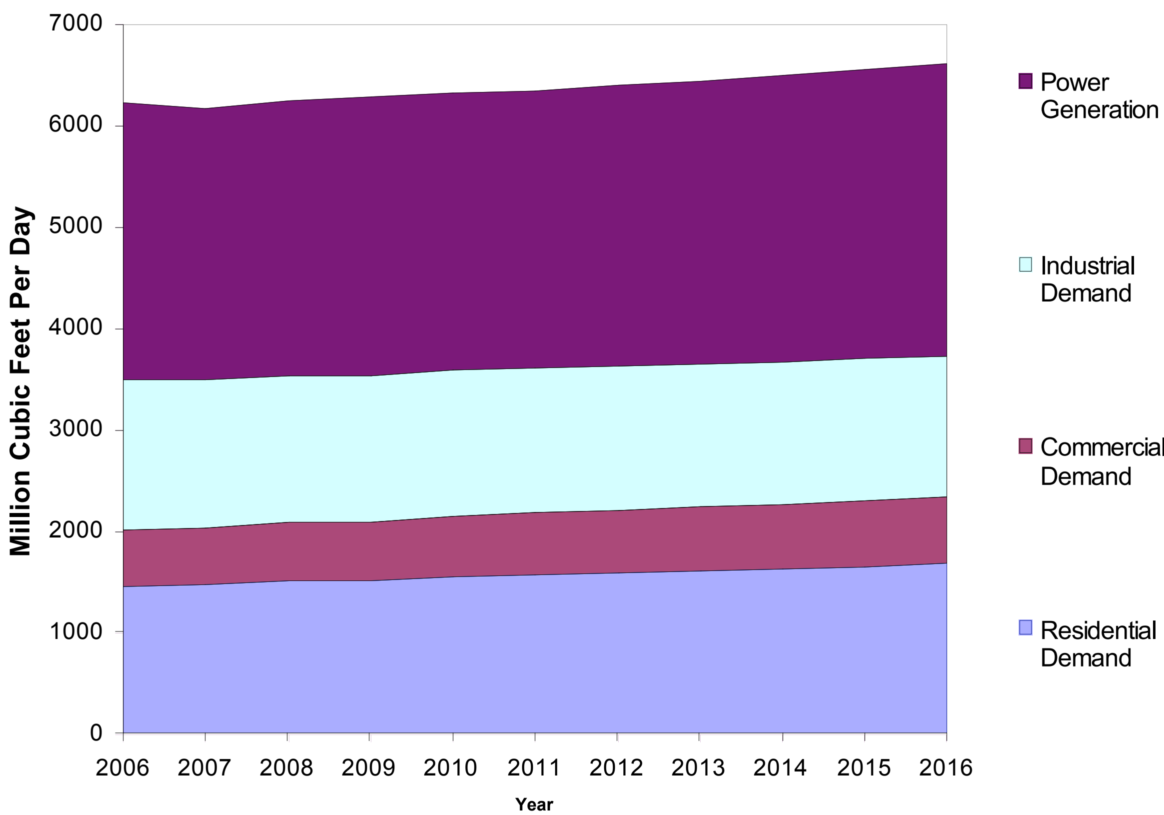


Source: California Energy Commission, Natural Gas and Special Projects Office; Energy Information Administration[ii]

Nationally, residential natural gas demand will grow at an annual rate of 0.8 percent over the coming decade, from 14.6 Bcf per day in 2006 to 15.8 Bcf per day in 2016. Over the same period, natural gas demand by commercial gas customers nationwide will increase from 9.6 Bcf per day to 11.4 Bcf per day, or 1.8 percent per year. U.S. industrial gas demand for chemical and non-chemical manufacturing will actually shrink very slightly, decreasing from 19.6 Bcf per day to 19.4 Bcf per day by the end of the forecast period. As mentioned above, over the coming decade demand for natural gas by electricity generators will account for the bulk of the demand growth in the contiguous United States. Gas consumption for power generation will increase at an annual rate of 4.3 percent between 2006 and 2016, growing from 15.3 Bcf per day to 23.4 Bcf per day. The net change of 8.1 Bcf per day will account for 74 percent of the total demand growth in the U.S. over the next decade.

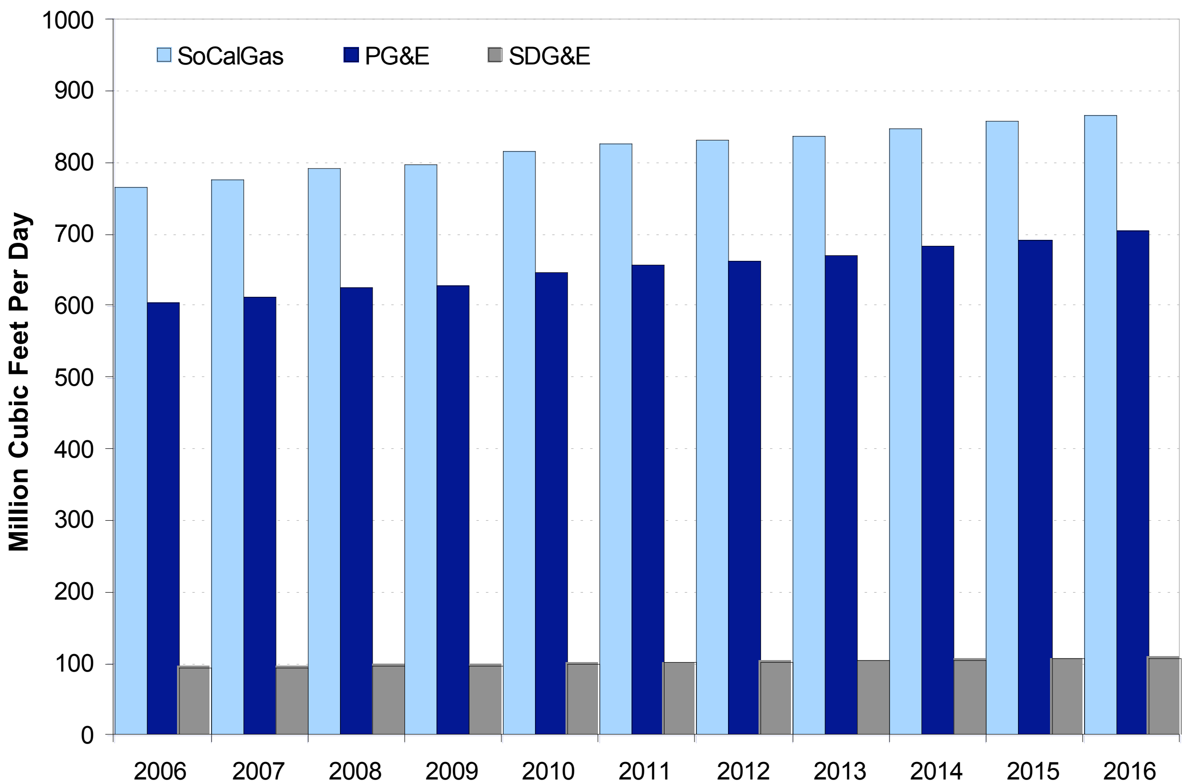
Over the forecast period, natural gas demand growth in California will be less than in the nation as a whole. As shown in Figure 2-2, total natural gas demand in California is projected to grow at a rate of 0.7 percent per year, from 6.2 Bcf per day in 2006 to about 6.6 Bcf per day in 2016. Strong growth in the residential and commercial sectors will be offset by declining industrial gas demand and slower growth in gas consumption by power generators than has been observed in recent years.

Figure 2-2—Natural Gas Demand in California



California's residential natural gas consumption, comprised mostly of space and water heating, will grow at an annual average rate of 1.4 percent in the coming decade, from 1,448 to 1,669 million cubic feet (MMcf) per day, driven primarily by population growth. The strongest growth in residential gas demand will occur in PG&E's service territory, where the California Department of Finance projects that population will grow at a pace of close to 1.5 percent per year through 2016. During that time, residential gas demand in PG&E's territory will increase from 606 MMcf per day in 2006 to 706 MMcf per day by 2016, resulting in a growth rate of 1.5 percent per year. By comparison, residential gas demand in the SoCalGas and SDG&E service territories will grow at a slightly lower pace as population growth slows down in the second half of the forecast horizon.[iii] Residential demand for gas in the SoCalGas service territory will increase from 767 MMcf per day to 867 MMcf per day over the next decade, or 1.2 percent per year, while residential gas demand will grow from 95 to 109 MMcf per day in SDG&E's service territory, or 1.4 percent per year. Figure 2-3 illustrates the growth in residential gas demand over the next ten years in California's three major gas utility service territories.

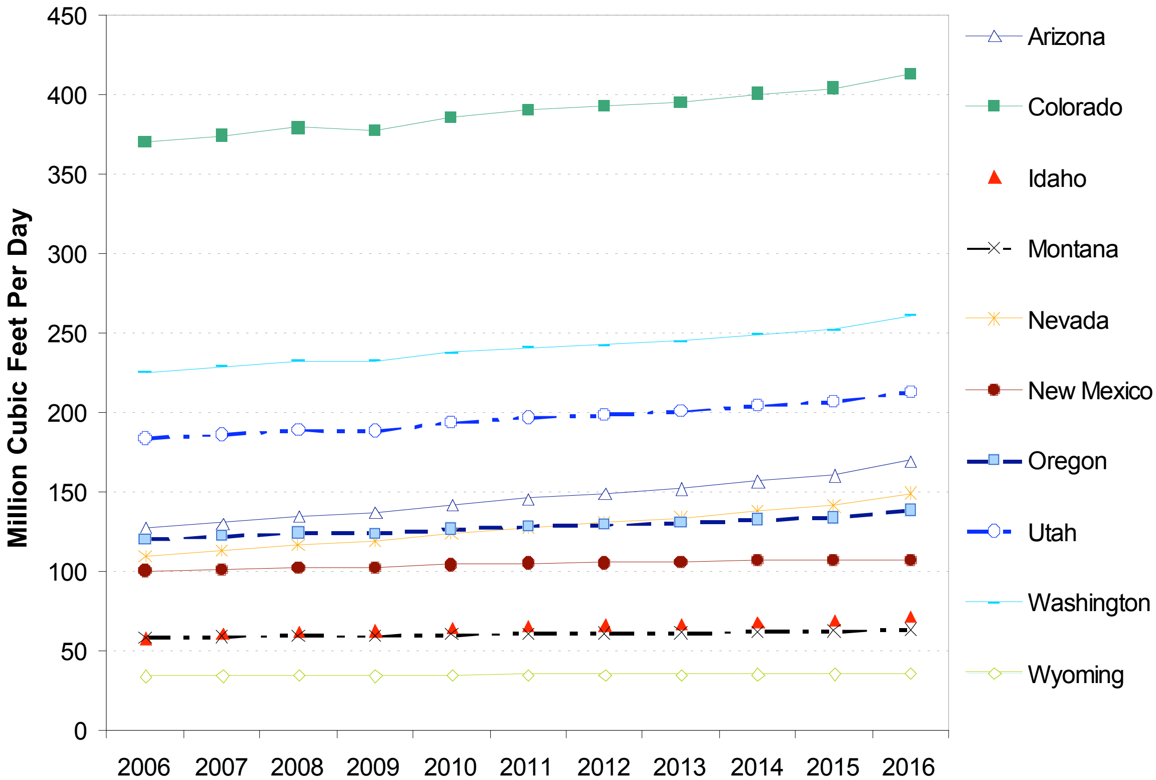
Figure 2-3—Projected Natural Gas Consumption by Residential Customers in California, by Utility Service Territory



Source: California Energy Commission, Natural Gas and Special Projects Office

In the states outside of California, residential gas demand will grow steadily at a pace of 1.7 percent per year from 2006-2016. Leading the growth in residential gas demand in the western states are Arizona and Nevada, both of which will see their respective populations grow by almost 30 percent over the forecast horizon, increasing at annual rates of 3.3 and 3.5 percent, respectively.[iv] The lowest growth will occur in Wyoming. In total, residential gas demand in the western states outside of California will climb from 1,392 MMcf per day in 2006 to 1,626 MMcf per day in 2016. To put this in perspective, in 2003, residential customers in California consumed 1,347 MMcf per day.[v] Figure 2-4 shows the residential natural gas demand in each of the western states.

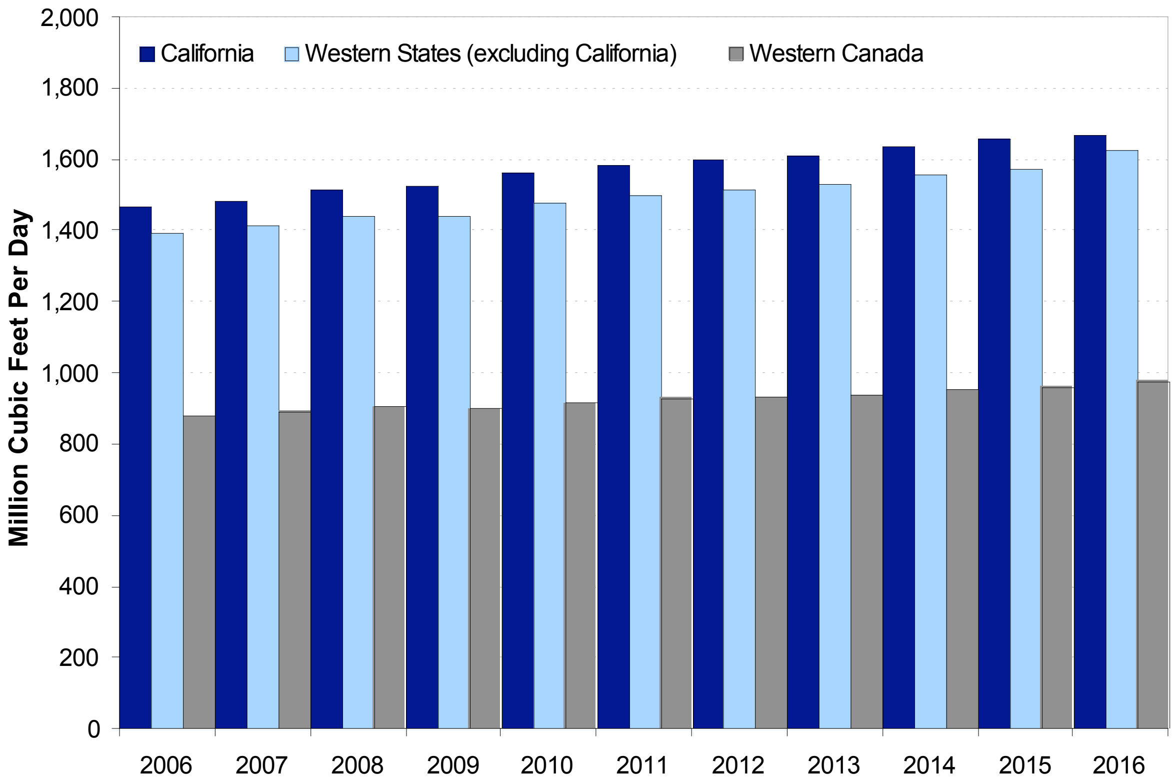
Figure 2-4—Projected Residential Gas Consumption in the Western United States (Excluding California)



Source: California Energy Commission, Natural Gas and Special Projects Office

Residential natural gas consumption in western Canada will grow at a slower pace over the next decade, compared with the western United States. From 2006 to 2016, residential natural gas consumption in British Columbia will grow from 280 MMcf to 323 MMcf per day, an annual increase of 1.5 percent. During the same period, residential gas consumption in Alberta will grow 1.1 percent per year, from 502 MMcf to 559 MMcf per day. The slower growth in residential natural gas consumption reflects lower population growth rates, compared with the western U.S., and less income growth. The population of British Columbia and Alberta is projected to grow at 1.2 and 0.7 percent per year, respectively, and Canadian gross domestic product (GDP) is assumed to grow at 2.5 percent per year over the forecast horizon.[vi] By comparison, over the same period, population in the western U.S. is projected to grow at a pace of 1.4 percent per year[vii] while income growth is projected to be 3.1 percent annually. Projected gas consumption by residential customers in the West is compared in Figure 2-4.

Figure 2-5—Comparison of Projected Residential Natural Gas Consumption in the West

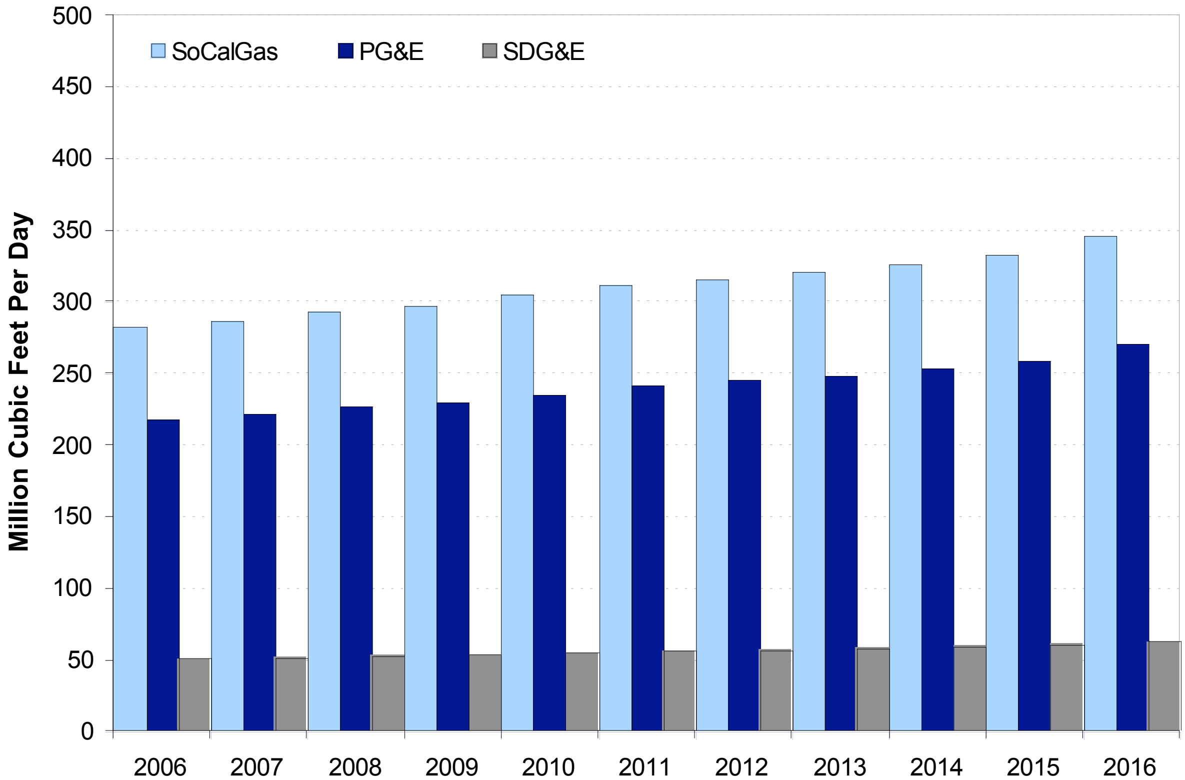


Source: California Energy Commission, Natural Gas and Special Projects Office

Commercial Natural Gas Demand

Commercial customers consume gas primarily for space heating and a variety of natural gas appliances. Natural gas consumption as a transportation fuel is included in the commercial sector because natural gas is used most commonly in fleet vehicles. Natural gas demand for transportation represents about 1 percent of commercial gas consumption in California and an even smaller portion of commercial demand in the other western states. Over the next decade, natural gas demand by commercial customers in California will grow at an annual rate of 2.3 percent, causing statewide commercial gas demand to increase from 552 MMcf per day in 2006 to 679 MMcf per day in 2016. While population growth will certainly play a role in the increase in commercial gas consumption, income growth, as measured by GDP, will have a strong influence. Over the forecast horizon, GDP is assumed to grow at a steady, moderately strong rate of 3.1 percent per year, which is consistent with the assumptions used by EIA in its *2005 Annual Energy Outlook*.[viii] While the majority of commercial gas consumption stems from space heating, water heating, and the use of other natural gas appliances, this sector also includes gas used for natural gas-powered vehicles. Figure 2-6 shows the projected natural gas consumption by commercial customers in each of California's major natural gas utility service areas.

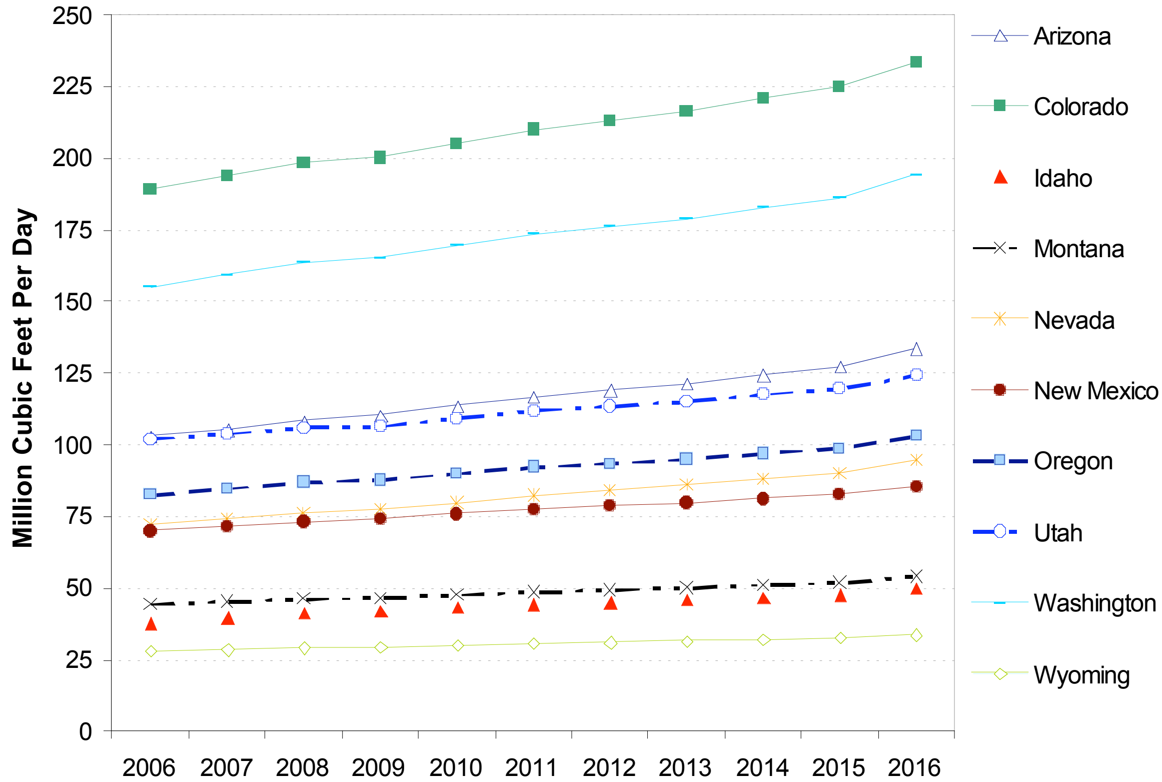
Figure 2-6—Projected Natural Gas Consumption by Commercial Customers in California, by Utility Service Territory



Source: California Energy Commission, Natural Gas and Special Projects Office

Through 2016, the other western states will see commercial gas demand growth similar to that in California, as a whole growing at about 2 percent per year. The growth rates vary by state because of differences in population growth, with Wyoming showing the lowest rate of growth in commercial gas demand at 1.7 percent per year, and Idaho at the top of the list with annual growth rates of 2.6 percent per year. Combined, commercial gas demand in the western states will grow from 884 MMcf per day in 2006 to 1,084 MMcf per day in 2016. Figure 2-7 illustrates the projected natural gas consumption in the West, excluding California.

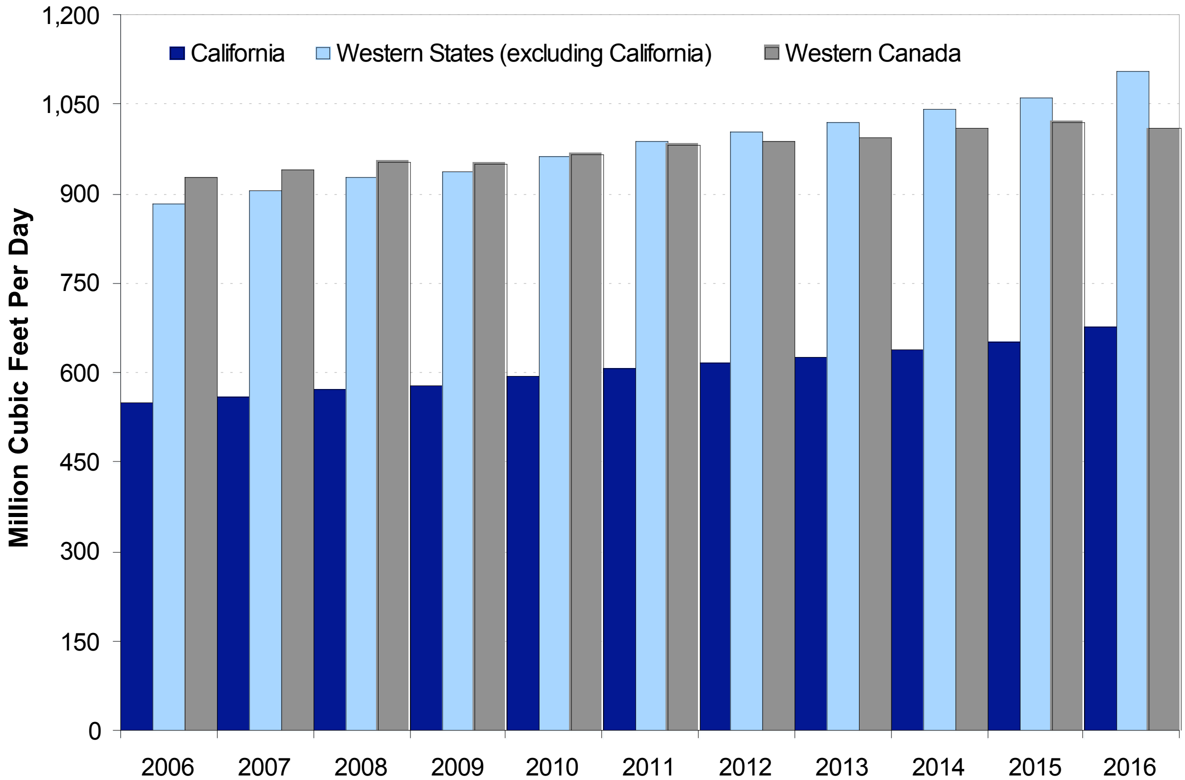
Figure 2-7—Projected Commercial Gas Consumption in the Western United States (Excluding California)



Source: California Energy Commission, Natural Gas and Special Projects Office

Commercial gas demand in the western Canadian provinces of British Columbia and Alberta will grow at a slower rate than the western U.S., owing mainly to slower economic growth. Demand for natural gas by commercial customers in British Columbia will grow at an annual rate of 1.3 percent from 2006 to 2016, increasing from 269 MMcf to 309 MMcf per day. Meanwhile, natural gas demand in Alberta's commercial sector will grow at a slower rate of 0.7 percent, reaching 524 MMcf per day in 2016. Projected gas consumption by commercial customers in the West is compared in Figure 2-8.

Figure 2-8—Comparison of Commercial Natural Gas Consumption in the West



Source: California Energy Commission, Natural Gas and Special Projects Office

Industrial Natural Gas Demand

Of all the end-use sectors, industrial customers are the most sensitive to rising natural gas prices. As a result, industrial natural gas demand is flat or declining in nearly all of the western states, including California, over the forecast horizon, despite increasing economic growth. For the purposes of this study, industrial demand was split into two categories: gas demand for chemical manufacturing and gas demand for all other manufacturing processes. Gas demand for thermally enhanced oil recovery in California and bitumen extraction and processing in Alberta are included in the discussion of non-chemical industrial processes.

Natural Gas Demand for Chemical Manufacturing

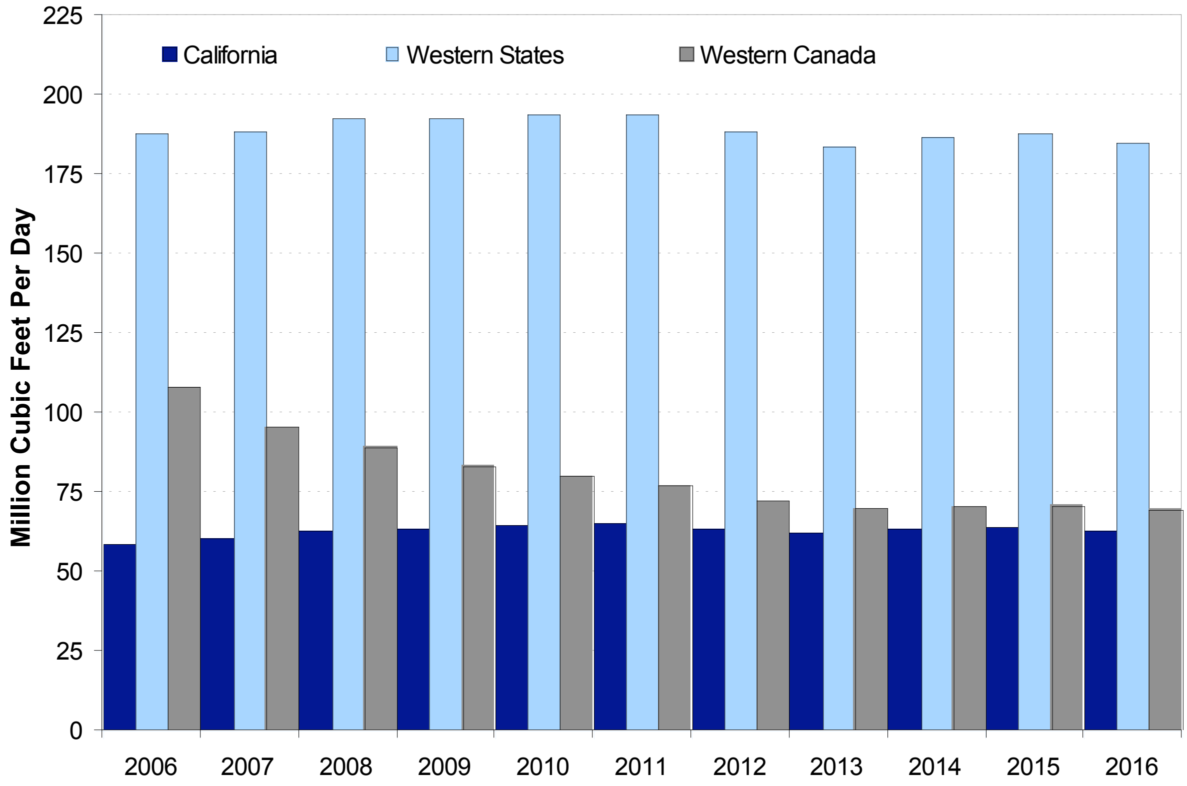
Of the two industrial classes assessed in this study, chemical manufactures are the most sensitive to changes in natural gas prices. That is to say, if all factors, other than price, were held constant, gas demand for chemical manufacturing would change more in response to price than would gas demand for other industrial processes. Chemical manufacturers are also, however, much more responsive to the growth in industrial production and the cost of alternative energy sources than industrial customers manufacturing goods other than chemicals. In many instances, demand for natural gas by customers producing chemical products is actually growing in areas where gas demand by non-chemical industrial customers is flat or declining. In these instances, the influence of growth in industrial production and high oil prices has outweighed the effect of natural gas prices. Please see Appendix A for an explanation of the methodology used to forecast the demand for each end-use sector.

Chemical manufacturing is not a large contributor to gas consumption in California, accounting for only about 6 to 7 percent of California's total industrial natural gas demand over the forecast horizon. Despite rising gas prices over the forecast horizon, gas consumption by these customers will slightly increase in all three of California's major gas utility service territories. By 2016, natural gas consumption by chemical manufactures in the State will increase from 59 MMcf per day in 2006 to 63 MMcf per day, an annual rate of growth of 0.7 percent.

In the other western states, gas demand for chemical manufacturing will slightly decrease, from 188 MMcf per day in 2006 to 185 MMcf per day in 2016. Colorado and Nevada have the greatest demand for chemical manufacturing of all of the western states, at 84 and 85 MMcf per day, respectively. Figure 2-9 compares gas demand for chemical manufacturing in the west.

More dramatic decreases are seen in Western Canada, where gas demand for chemical manufacturing will drop from 108 MMcf per day in 2006 to 70 MMcf per day in 2016, an annual rate of decline of 4.3 percent. This decline is primarily due to a decrease in Alberta's chemical manufacturing gas demand, where gas consumption will drop from 101 MMcf per day in 2006 to 64 MMcf per day in 2016.

Figure 2-9—Comparison of Industrial Natural Gas Consumption for Chemical Manufacturing in the West



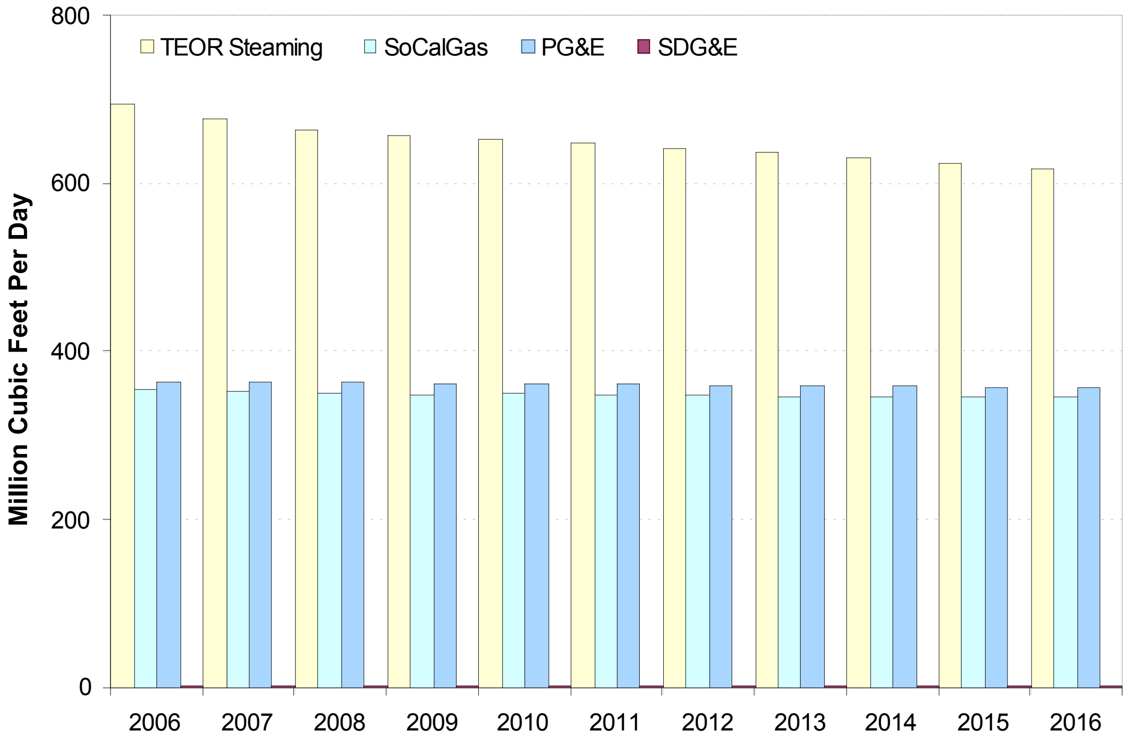
Source: California Energy Commission, Natural Gas and Special Projects Office

Natural Gas Demand for Non-Chemical Industrial Processes

In California, the industrial process that accounts for the largest gas consumption is thermally enhanced oil recovery (TEOR), a process where steam is used to decrease the viscosity of heavy underground oil deposits to facilitate their production. In 2003, TEOR customers consumed 753 MMcf per day of natural gas for process heat, in addition to the gas consumed for on-site electricity cogeneration. By comparison, that same year, natural gas consumption by all sectors in Arizona was about 700 MMcf per day.[ix] Over the next decade, however, gas consumption for TEOR will drop considerably, declining to 611 MMcf per day by 2016. A combination of higher gas prices and declining oil production in the San Joaquin Valley contributes to this decline.

Similar to the decline in TEOR natural gas consumption, customers in the SoCalGas territory will see gas demand for non-chemical industrial processing decrease from 356 MMcf to 346 MMcf per day by 2016, an annual decline of 0.3 percent. Similarly, demand in the PG&E service territory will decline at an annual rate of 0.2 percent, from 363 MMcf per day in 2006 to 358 MMcf per day in 2016. By the end of the forecast horizon, industrial natural gas demand for non-chemical manufacturing in the SDG&E area will have decreased at a rate of 0.8 percent per year, from 2.3 to 2.1 MMcf per day. Decline rates are due to rising gas prices. The projection for natural gas demand for non-chemical manufacturing processes is shown in Figure 2-10.

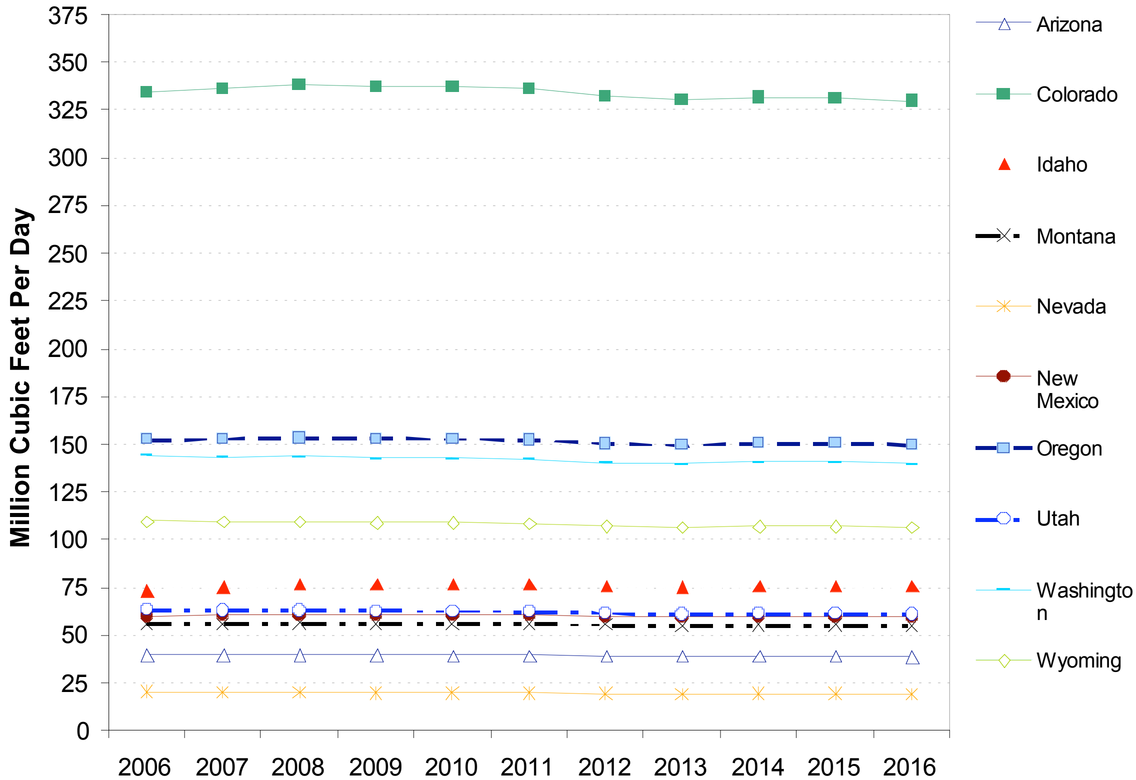
Figure 2-10—Projected Natural Gas Consumption by Non-Chemical Manufacturing Industrial Customers in California, by Utility Service Territory



Source: California Energy Commission, Natural Gas and Special Projects Office

Similar to California, from 2006 to 2016, natural gas demand for non-chemical manufacturing will decrease by 0.2 percent in the western states.. This is a reflection of higher natural gas prices over the forecast period. Idaho is the only state in the West that shows positive demand growth over the next decade, albeit at a low rate of 0.1 percent per year. The remaining western states will see gas demand for non-chemical manufacturing decline at rates of 0.1 to 0.6 percent per year. As a result, overall gas consumption for non-chemical manufacturing in the West will drop from 1,085 MMcf to 1,066 MMcf per day over the next decade. Figure 2-11 illustrates the natural gas consumption for non-chemical industrial customers in the western states, excluding California.

Figure 2-11—Projected Gas Consumption by Non-Chemical Manufacturing Industrial Customers in the Western United States (Excluding California)



Source: California Energy Commission, Natural Gas and Special Projects Office

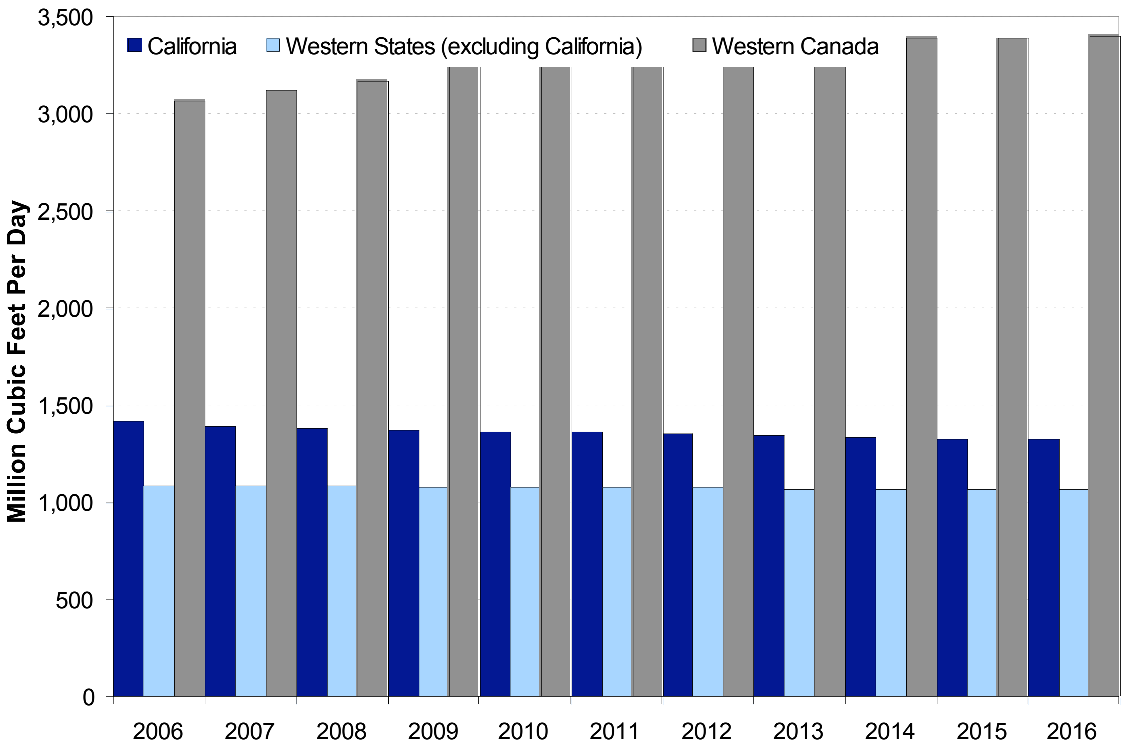
Non-chemical manufacturing industries in British Columbia and Alberta will behave the same as similar industries in the western U.S. and the rest of Canada, with gas consumption in non-chemical manufacturing sector dwindling at annual rates of 0.3 and 0.4 percent, respectively. As in other regions, higher natural gas prices are the reason for the decline. During the next ten years, gas demand by non-chemical manufacturers in British Columbia will decrease from 459 MMcf per day in 2006 to 445 MMcf per day in 2016. Over that time, gas demand by the same sector in Alberta will drop from 1,538 MMcf to 1,480 MMcf per day.

Western Canada's industrial consumption includes gas consumed in the oil sands sector, where a significant quantity of natural gas is used in the process of producing bitumen (heavy crude oil) from oil sands deposits. Bitumen is a tar-like mixture of hydrocarbons too heavy and viscous to recover conventionally through a well. Deposits close to the surface are mined and separated in a water-based slurry to remove the bitumen from the oil sands. With this method, natural gas is used to heat water for the extraction process. Deeper deposits are recovered using one of two processes: Cyclic Steam Stimulation (CSS) or Steam Assisted Gravity Drainage (SAGD). Both methods use natural gas to generate steam to reduce the viscosity of the bitumen and enable its recovery. The more common of the two processes, CSS, is more energy intensive and requires more natural gas per barrel produced. The SAGD method is a relatively new recovery process, first used commercially in 2001. Additionally, bitumen is low in hydrogen, compared with crude oil; therefore, it must be upgraded prior to delivery to conventional refineries. Natural gas is used as a feedstock for this process.[x]

Because of its bitumen deposits, Canada possesses one of the largest oil reserves in the world, second only to Saudi Arabia. Virtually all of Canada's oil sand deposits are in Alberta. Within Alberta, the bulk of the bitumen deposits are found in the Athabasca, Peace River, and Cold Lake regions.[xi] Canada's National Energy Board's (NEB) forecast for natural gas demand for bitumen extraction and processing was used in this study. According to the NEB, natural gas demand for Alberta's bitumen extraction and upgrading will increase at an annual rate of 4.2 percent between 2006 and 2016, growing from 834 MMcf to 1,253 MMcf per day.[xii]

This sector accounts for nearly one-third of the total natural gas consumed in the industrial sector As a result, the total demand for natural gas consumed by non-chemical manufacturing industrial customers in Western Canada actually grows at a rate of 1.1 percent per year over the forecast period, from 3071 MMcf per day to 3,406 MMcf per day in 2016. Figure 2-12 provides a comparison of non-chemical industrial gas demand in different parts of the West.

Figure 2-12—Comparison of Natural Gas Consumption by Non-Chemical Manufacturing Industrial Customers in the West



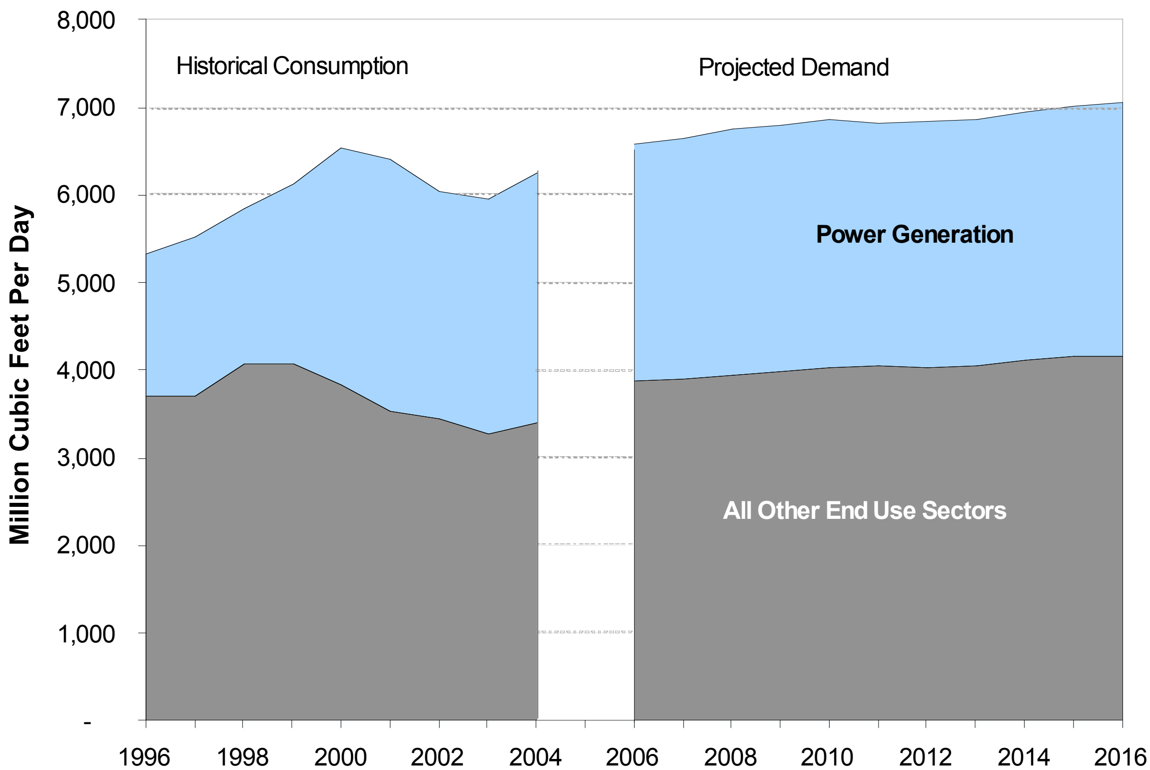
Source: California Energy Commission, Natural Gas and Special Projects Office

Natural Gas Demand for Electricity Generation

According to the California Energy Commission's (Energy Commission) power plant database, California's first natural gas-fired power plant went into service in 1901.[xiii] By the end of the 20th century, natural gas was not just the fuel of choice for electricity generation; it was the dominant choice for new large thermal power plants. The last large non-gas-fired generating station built in California was Unit 2 of the Diablo Canyon Nuclear Power Plant, which went on line in 1985.[xiv] In contrast, since 1998, 27 natural gas-fired generating stations have come on line in California, with a combined capacity of 9,308 MW, and another 11 power plants, with a cumulative capacity of 4,352 MW, are currently under construction.[xv]

Given the large build out of natural gas-fired power plants in California over the past decade, it is not surprising that power generation now accounts for more than one-third of the gas consumed in the State. Over the past few years, electricity generation has been the fastest growing end-use sector in California and, until recently, growth in gas consumption for power generation was projected to continue to out pace all other end-use sectors.[xvi] In the new forecast, however, the demand for gas by the electricity sector will grow at a relatively modest rate of 1 percent per year through 2016. Several factors might explain the slow down in power generators' demand for natural gas in California. First, demand for electricity in California is projected to grow at a slightly lower rate than in the past (around 1.15 percent per year, as opposed to the 1.4 percent per year growth rate that was observed from 1990-2000). Secondly, the influx of new, more efficient power plants is reducing the State's dependence on aging, less energy efficient facilities with higher heat rates. While total electricity demand is increasing, the newer, more efficient power plants can produce this electricity with less fuel input. Finally, California's renewable portfolio standard (RPS) requires by law that by 2017, 20 percent of the State's electricity must come from renewable energy facilities, thus reducing some of the electricity generating load from gas-fired facilities. California is pursuing a more aggressive goal of 20 percent by 2010. Figure 2-13 shows the historical and projected relationship between California's gas consumption for electricity generation, compared to all other end-use sectors.

Figure 2-13—Historical and Projected Natural Gas Consumption for Electricity Generation in California, Compared with all Other End Uses

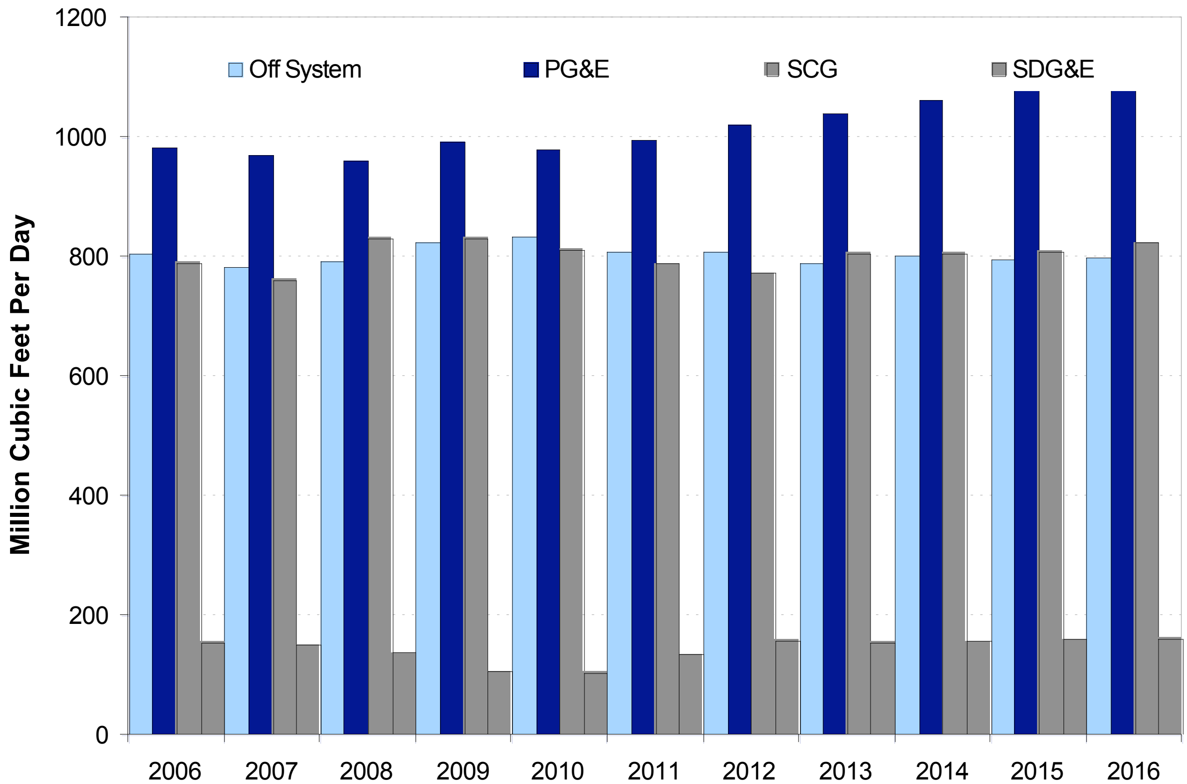


Source: California Energy Commission, Natural Gas and Special Projects Office

Over the forecast horizon, growth in natural gas demand for power generation is strongest in the PG&E and SMUD area, which will grow from 981 MMcf to 1100

MMcf per day, an annual rate of 1.1 percent per year. Most of this growth is attributable to increased use of natural gas in the SMUD region growing at nearly 5.1 percent. SDG&E region consisting of utility served powered plants do not show any significant growth, increasing from 156 MMcf per day to 162 MMcf per day by 2016. Otay Mesa, which is slated to be in operation by 2007, adds to gas consumption in the SDG&E area. Because this is a relatively large facility operating in a smaller service territory, it has a greater influence on the cumulative fuel consumption by electricity generators in the SDG&E territory (The gas demand from Otay Mesa is included in the off-system totals). Gas consumption at the remaining power plants in the SDG&E service territory will grow at a slower rate of 0.7 percent per year. The power generation sector in the SoCalGas area will grow from 789 MMcf per day in 2006 to 809 MMcf per day by 2016, or 0.4 percent per year. One group that does not experience any gas demand growth over the forecast horizon is power plants taking fuel directly from interstate pipelines and not through utility gas distribution systems. Between 2006 and 2016, new power plant additions within utility service territories take market share away from off-system generators, causing natural gas consumption at those stations to be almost flat throughout the horizon. Figure 2-14 illustrates the projected gas demand for electricity generation in California.

Figure 2-14—Projected Natural Gas Consumption by Electricity Generation Customers in California

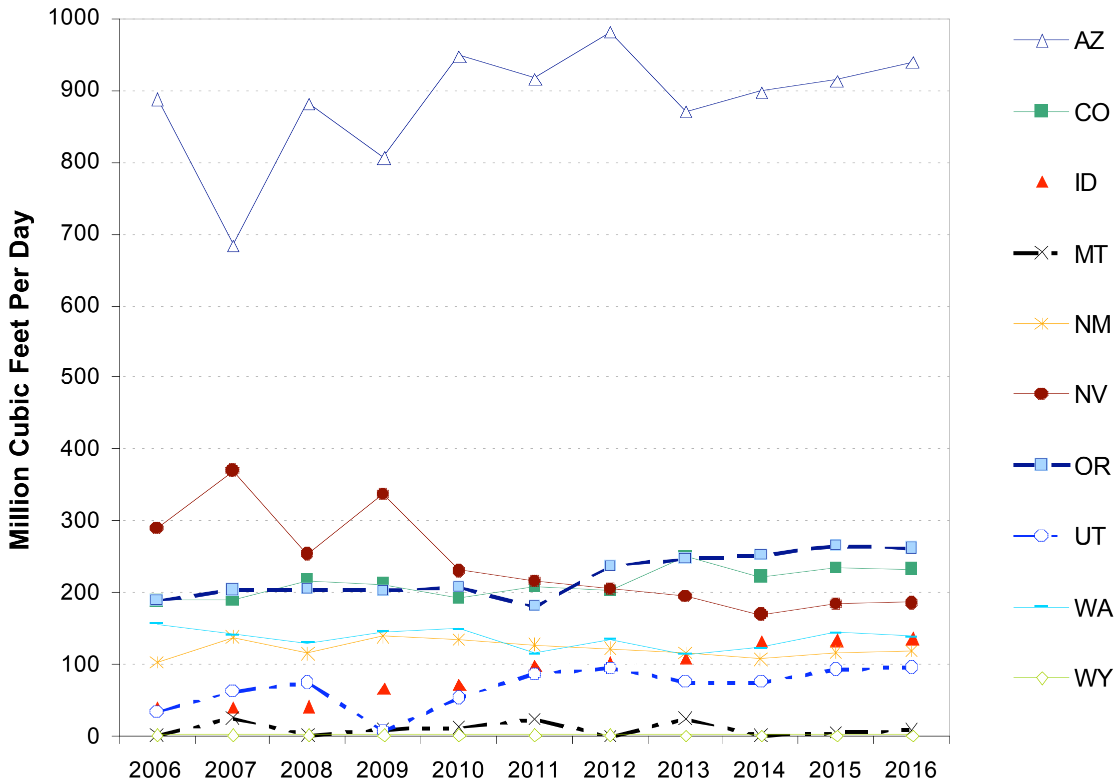


Source: California Energy Commission, Natural Gas and Special Projects Office

The overall increase in gas prices over the past several years has sparked a renewed interest in coal-fired electricity generation. While it is unlikely under existing energy policies that any coal facilities will be constructed within California's borders, new coal facilities have been included in the resource plans for several western states, thus causing gas demand for electricity generation in some states to decrease over the forecast period. Additionally, there has been a greater interest in renewable generation in other western states, which will help keep gas demand for power generation in check.

Natural gas demand in the states surrounding California will grow at a similar rate to California, increasing about 0.9 percent per year. The most significant non-gas-fired addition during the forecast horizon is Intermountain 3, a 1,000 MW, coal-fired power plant that is projected to begin operating around 2011. Gas demand in Nevada, particularly, will be most affected by new coal generators, with the state's gas demand for electricity generation declining at an annual rate of 5 percent. Other states, such as Idaho and Montana, will see a large increase in overall gas demand for power generation. Together, gas demand for power generation in the western states surrounding California will grow from 1,898 MMcf per day in 2006 to 2,125 MMcf per day in 2016. The projected gas demand for power generation in the western states, excluding California, is shown in Figure 2-15.

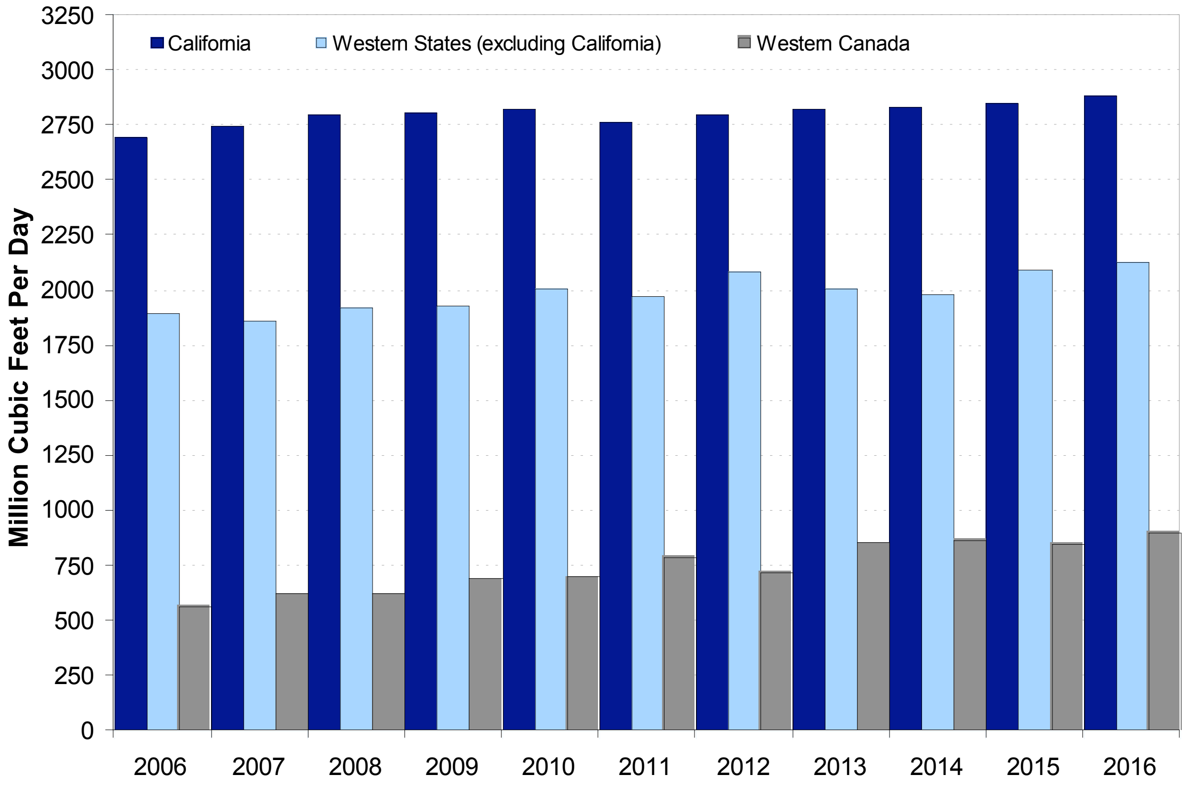
Figure 2-15—Projected Natural Gas Consumption by Electricity Generation Customers in the Western United States (Excluding California)



Source: California Energy Commission, Natural Gas and Special Projects Office

Natural gas demand for power generation across Canada is projected to grow at a rapid pace over the next decade, and western Canada is no exception. By 2016, natural gas consumption for electricity generation in British Columbia will nearly triple, growing from 60 MMcf per day in 2006 to 171 MMcf per day in 2016. Given the fact that British Columbia relies primarily on hydroelectric power, the addition of six new gas-fired combined-cycle units, with a dependable capacity of 1,637 megawatts, over the next ten years is enough to cause gas demand to grow at an annual rate of 11.1 percent. Meanwhile, gas demand for electricity generation in Alberta will grow at an annual rate of 3.5 percent per year, increasing from 354 MMcf to 500 MMcf per day. As in British Columbia, the bulk of the gas demand increase stems from new combined-cycle facilities beginning operation during or after 2010. Figure 2-16 compares natural gas demand for power generation in the West.

Figure 2-16—Comparison of Natural Gas Consumption by Electricity Generation Customers in the West

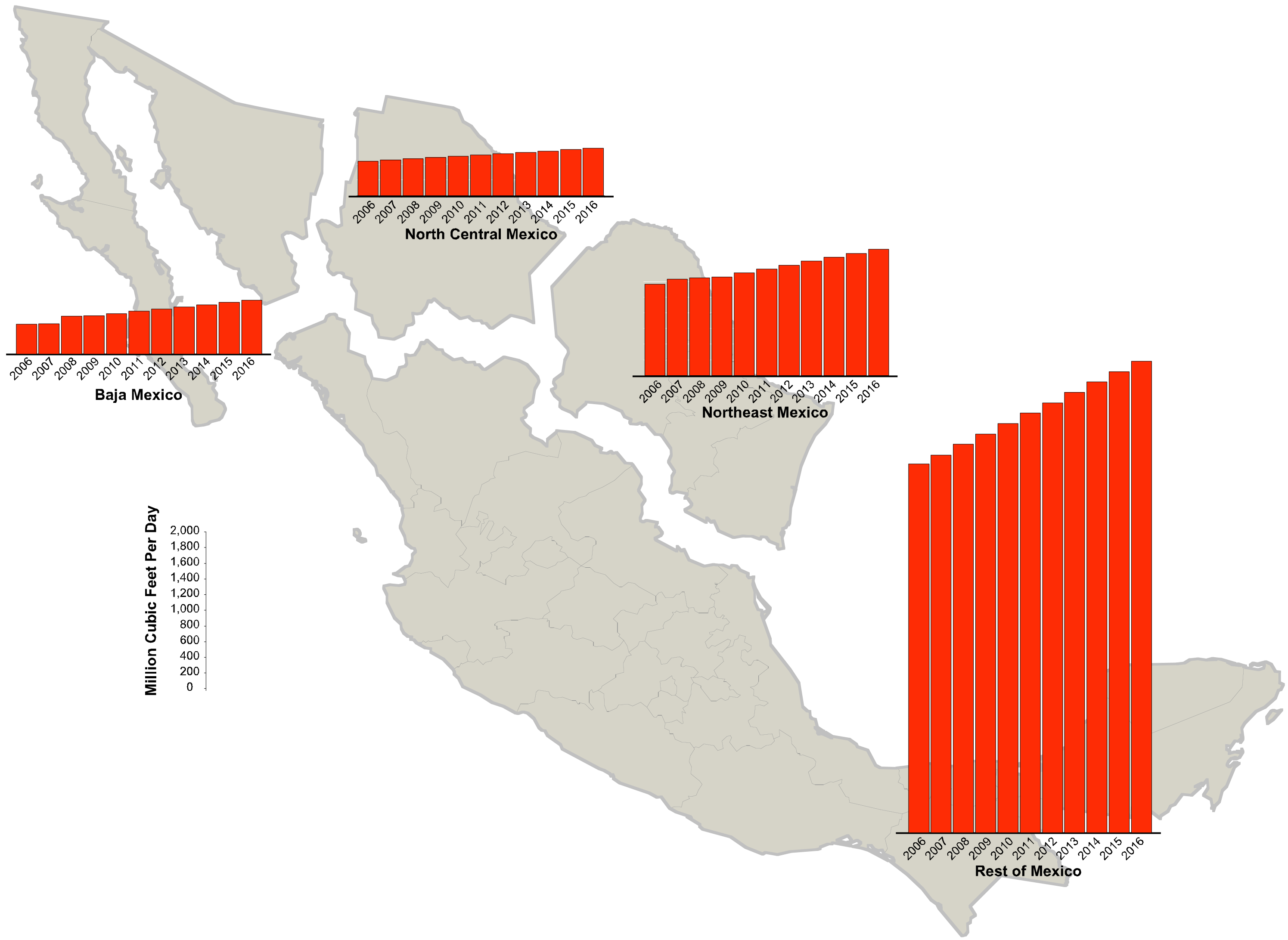


Source: California Energy Commission, Natural Gas and Special Projects Office

Natural Gas Demand in Mexico

To assess natural gas demand in Mexico, the Energy Commission staff used the natural gas demand projection developed by the National Petroleum Council (NPC) and used in its 2003 report, *Balancing Natural Gas Policy: Fueling the Demands of a Growing Economy*. In its forecast for Mexico, NPC did not distinguish between end-use sectors. According to the NPC study, natural gas demand in Mexico will grow from 6.7 Bcf per day in 2006 to 9 Bcf per day in 2016. Natural gas demand in the Mexican regions bordering the United States is projected to grow faster than in the rest of the country, with gas consumption North Central Mexico, and North East Mexico projected to grow at annual rates of 3.2 percent, and 3.3 percent, respectively. Gas demand in Baja California grows at a significantly higher rate of about 6.1 percent over the next decade. By comparison, natural gas demand in the rest of Mexico will grow at 2.5 percent per year. (Please note that the graph is not to scale between regions). Baja California, which has a greater influence on the California gas market than the other regions, will see natural gas demand for all end uses increase from 0.380 Bcf per day in 2006 to 0.688 Bcf per day in 2016. Figure 2-17 shows the projected natural gas demand in various parts of Mexico.

Figure 2-17—Projected Natural Gas Demand in Mexico (Graphs in the map are not on the same scale)



Source: California Energy Commission, Natural Gas and Special Projects Office

Chapter 3: Natural Gas Supply

Introduction

This chapter discusses natural gas resources in California, the United States, and North America. The adequacy of supply of natural gas is assessed as well as the sources of gas supply for California. In addition, California's natural gas-producing areas and the variability in gas quality within the State are described.

Much of the information presented in this report is based on recent evaluations of the North American gas market by the National Petroleum Council (NPC). The natural gas resources described in both reports consist of proven and potential reserves that exist in various supply sub-regions in North America.

Supply Assessment

The NPC study was comprehensive and incorporated the best publicly available data, including data from the United States Geological Survey, the Minerals Management Service, Canadian Gas Potential Committee, IHS Energy Group, states, provinces, and local producers. The study consisted of an in-depth review of the North American resource base (both conventional and non-conventional), based upon the history and geologic potential of hundreds of natural gas-producing areas. It also included an evaluation of drilling and production costs for probable future discoveries, based upon previous NPC assessments as well as other similar studies. The NPC study was reviewed by an experienced team of geoscientists and engineers from both industry and government, and was also reviewed in public meetings. As a result, Energy Commission staff has considerable confidence in the information.

Projected Natural Gas Supply to the United States

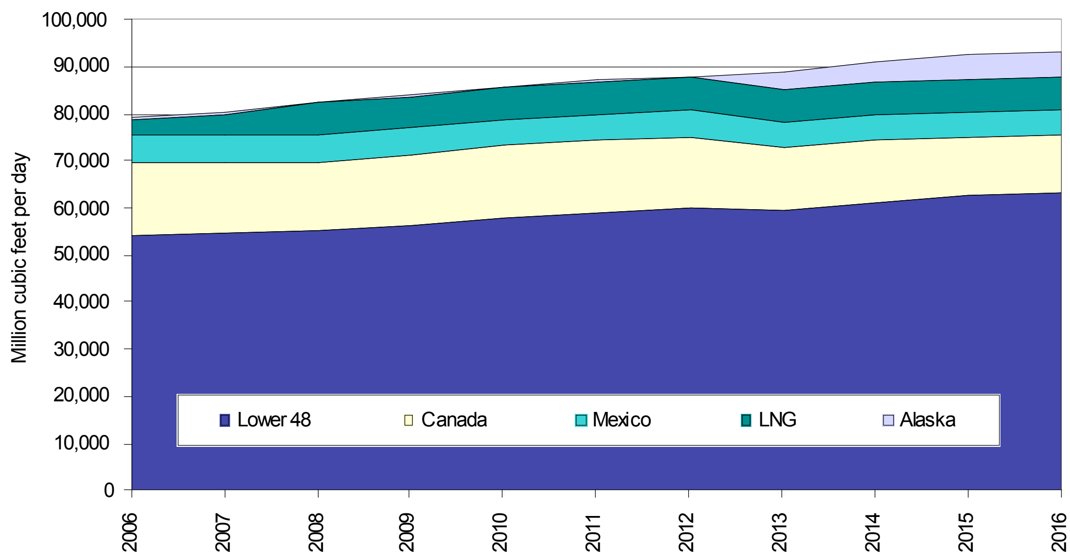
Several sources of natural gas supplies are available to the United States, including supplies from wells in the lower 48 states, supplies imported via pipeline from Canada, supplies imported via pipeline from Alaska, and supplies imported via liquefied natural gas (LNG) import terminals. Projected quantities of natural gas from these supply sources for the years 2006 – 2016 are shown in Figure 3-1. Changes to these supplies over the next decade are briefly discussed below.

Natural gas production from the Lower 48 is expected to increase by about 1.6 percent per year. Imports of Canadian supplies are expected to decrease over the same period at an annual average rate of 2.3 percent even though the MacKenzie Delta supplies show significant potential and could provide about 0.8 trillion cubic feet (Tcf) per year[xvii] to Canadian markets if regulatory approval is obtained.

Alaskan production, mainly from the Beaufort Sea region, could be available by 2016. Assuming the major pipeline is approved and built to move these supplies to Canadian and Lower 48 markets, Canada and Lower 48 states could realize about 2.0 Tcf per year at the end of the forecast period.

Gas supplies from LNG import facilities that have been approved and are under construction are also considered. Imported supplies of LNG are expected to grow from 2006 to 2016 by 8.7 percent per year. While additional LNG import terminals are likely to be built in the U.S. during the forecast period, staff has not predicted which specific ones will be approved and built.

Figure 3-1—Gas Supplies Available to North America



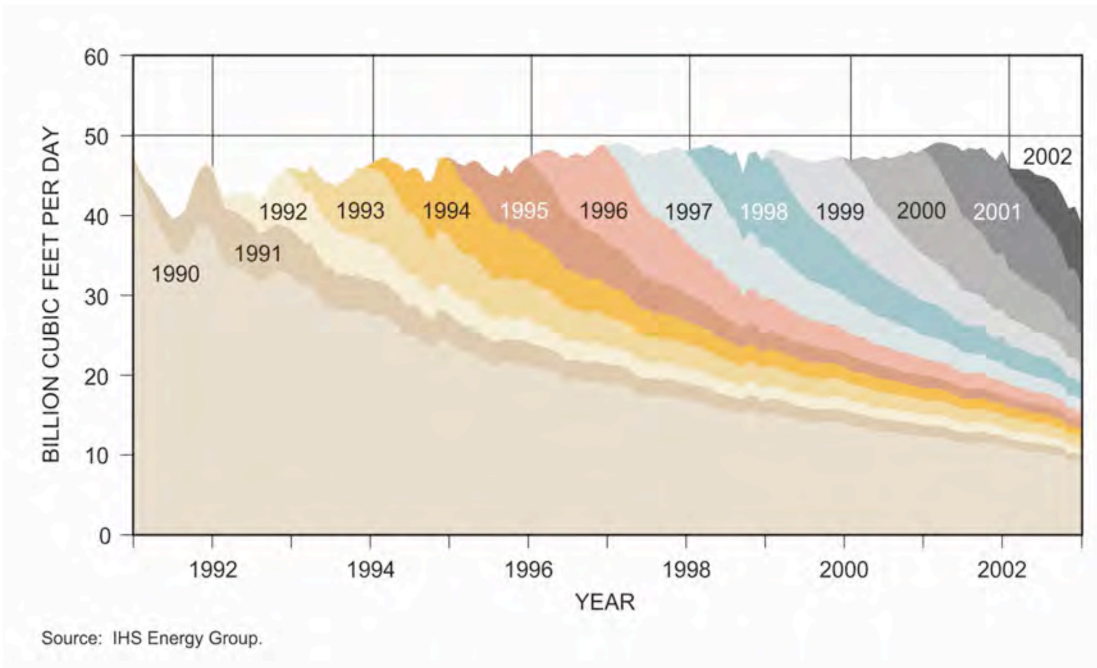
Source: California Energy Commission, Natural Gas and Special Projects Office

Changes in North American Production

Conventional production from most of the mature supply basins in North America has declined or has only increased modestly since 1990 even though the number of wells drilled in the U. S. and Canada has been at an all-time high. In the U.S, between 1990 and 1996, the average daily gas well drilling rig count was 400 and the number of wells completed per year was 9,700. In contrast, between 2000 and 2002, the average daily rig count was 780 and 19,300 wells were completed.

Additionally, the amount of gas produced per well has been declining and the average estimated ultimate recovery per well (excluding non-conventional and deep water Gulf of Mexico supplies) fell about 15 percent between 1990 and 1999. Figure 3-2 shows the production decline rate per year for wells drilled from 1990 through 2002. As this illustration shows, the initial decline rate has increased during this period. Average production from gas wells drilled in the early 2000s has declined at a far more rapid rate than gas wells drilled in the early 1990s.

Figure 3-2—Decline of Production over Time for Gas Wells Drilled from 1990 through 2002



Source: National Petroleum Council

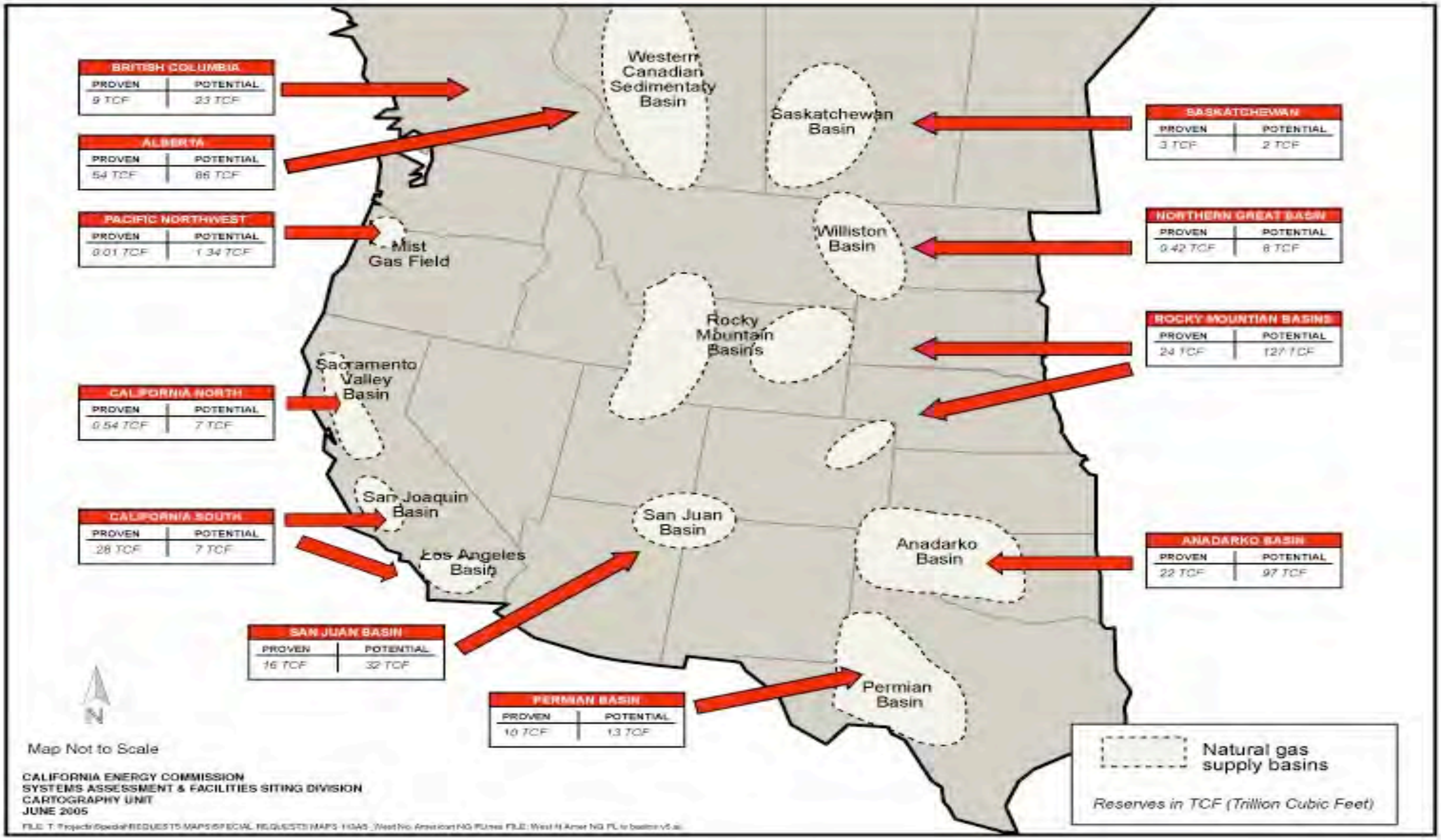
The decline in production per well is, in part, the result of increased drilling within existing fields, increased drilling for smaller prospects with less gas that could not be accessed successfully before, and increased prices that now make drilling for these previously uneconomic, smaller prospects, profitable.

In contrast, production from some newer supply basins in the Rocky Mountains, East Texas, and deep waters in the Gulf of Mexico has increased. These production gains, with the exception of deep water Gulf production, are primarily due to production from unconventional resources such as coal bed methane, tight gas, and shale gas. These unconventional resources, as well as deep water production, can have considerably higher completion and production costs. Consequently, not only are new supplies of natural gas more difficult to produce in large quantities, they are also becoming more expensive to produce. The increase in drilling costs has a significant impact on the increasing market price of natural gas.

Projected Natural Gas Supplies to California

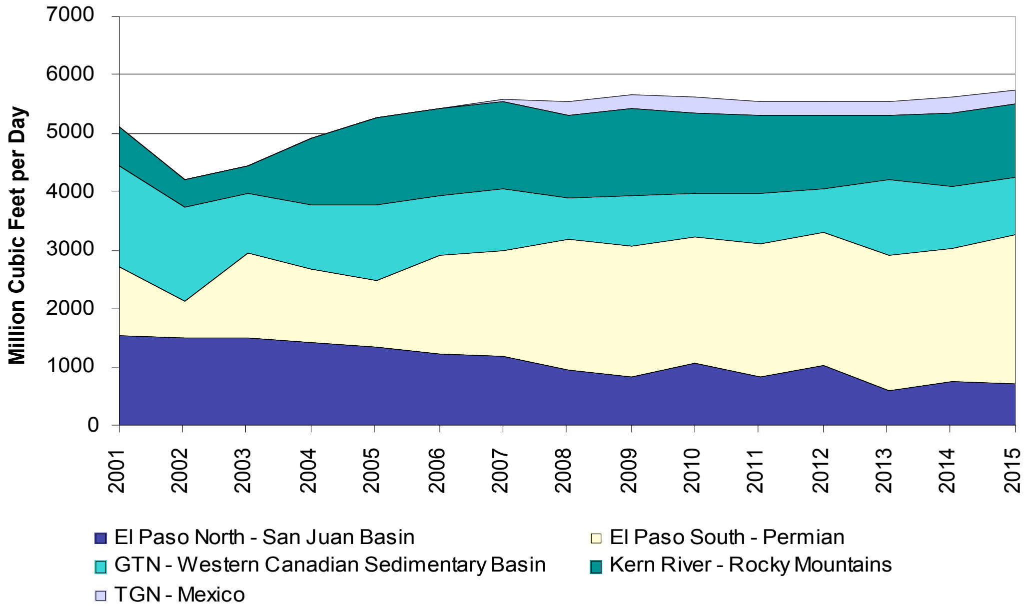
California produces about 15 percent of its natural gas needs but must import the majority of its supply from basins in the western United States and Canada. The out-of-state supply basins providing gas to California include the Rocky Mountain Region, the San Juan Basin, the Permian Basin, the Anadarko Basin, the Williston Basin, and the Western Canadian Sedimentary Basin. Figure 3-3 shows the location and proven and potential reserves for the various basins supplying gas to California.

Figure 3-3—Reserves of Major Western North American Natural Gas Supply Basins



The southwest basins, including the San Juan, Permian, and Anadarko basins, supply 35 percent of California's natural gas, and the Rocky Mountains supply about 25 percent. The Western Canadian Sedimentary Basin, located in eastern British Columbia, Alberta, and Saskatchewan, supplies about 25 percent of California's natural gas. Figure 3-4 shows the volumes of gas flowing from these various supply basins into California in the recent past and during the forecast period.

Figure 3-4—Gas Flows by Pipeline from Various Supply Basins to California



Source: California Energy Commission, Natural Gas and Special Projects Office

As previously mentioned, the Rocky Mountain basin is one of three areas in the United States where production is increasing. Production from the other basins supplying gas to California is projected to remain at current production levels through 2016.

In-state gas production began in the mid-1800s. Dry gas production — that is, gas not associated with oil production — occurs primarily in northern California in the Sacramento Valley and in the Tompkins Hill Field in Humboldt County. Wet gas production — that is, gas associated with oil production — occurs mainly in the San Joaquin Valley, the Central Coast, and in southern California, both onshore and offshore.

In the Sacramento Valley, Rio Vista is the largest dry gas field in California, with production to date in excess of 3.5 Tcf. In southern California, the largest gas field is Elk Hills, in Kern County, which has produced over 1.7 Tcf of wet gas. In 2003, gas fields in California produced 0.255 Tcf of associated gas (wet) and approximately 0.091 Tcf of non-associated gas (dry).

Natural Gas Quality

Expansion of gas field production in California will depend upon the quality of the natural gas. All natural gas is not the same. Natural gas is actually a mixture of different gases, the predominant being methane. Wells from different areas have different gas compositions. As mentioned earlier, gas produced in southern California is associated with oil production. Consequently, it contains a higher proportion of heavier hydrocarbon gas molecules such as ethane, propane, and butane. These gaseous components can vary and will affect the total energy content (the major component of gas quality of concern) of the gas stream. This energy content is measured in its simplest form by calculating the British Thermal Unit (Btu) value, a measure of a substances' heating value. Energy content is important since most end-use appliances (everything from water heaters to power plants) are designed to operate within a relatively narrow range of natural gas heating value. When the heating value is outside the design range, end-use appliances do not operate properly. While the Btu content of dry gas in the Pacific Gas and Electric (PG&E) system in northern California averages approximately 1,010 Btu /standard cubic foot (scf), the average in southern California in the Southern California Gas (SoCalGas) and San Diego Gas and Electric (SDG&E) systems is 1,020 Btu/scf. Individual wells in southern California that also produce gas associated with oil can have Btu contents as high as 1,150 Btu/scf. Depending upon the Btu content and geographic location, the heavier hydrocarbon molecules may be able to be blended with lower Btu gas before distribution to end-use customers.

In contrast, gas from certain areas in northern California has a much lower Btu content. Low Btu content gas is present on the east and west margins of the Sacramento Valley, north of Sacramento. Low Btu gas has historically been blended with higher Btu gas prior to sale. Another method to make different gas compositions acceptable is to use a gas processing unit (typically a cryogenic separation process where ultra-cold temperatures are used to remove unwanted gas fractions). This type of gas processing has been applied to the low Btu gas in the Robbins Gas Field in Sutter County since the mid-1980s.

Gas quality is an issue not only for in-state production but also for imported supplies of liquefied natural gas (LNG). The chemical composition of potential imported LNG may be significantly different than traditional supplies. The gas quality issue is potentially resolvable using known technologies and setting requirements for imported LNG supplies.

Chapter 4: Natural Gas Infrastructure Needs

Introduction

This chapter discusses current and future natural gas infrastructure. Infrastructure has typically meant the pipelines which transport supplies from remote basins and the storage facilities developed to hold natural gas supplies. The potential importation of liquefied natural gas (LNG) requires its own infrastructure, particularly onshore or offshore regasification terminals. However, this section deals primarily with pipeline transport of natural gas. Both interstate and intrastate pipeline capacities are addressed. Pricing of gas on interstate pipelines is also presented. This assessment considers annual average needs over a long-term basis; therefore, storage facility additions are not discussed in detail since they primarily meet short-term daily and seasonal needs.

Access to Interstate Pipeline Capacity and Adequacy

California has significant pipeline capacity to access the four major natural gas supply basins: the San Juan, Permian, Rocky Mountain, and Western Canadian Sedimentary basins. Pipelines constructed over the last 50 years connect these basins to California. These pipelines are described below for each supply basin area.

Canadian Basin

Western Canadian gas supplies are imported to California via the GTN pipeline. This pipeline interconnects with TransCanada's system at Kingsgate, British Columbia, at the U.S.-Canadian border. The pipeline intersects with the Williams Northwest Pipeline at Stanfield, Oregon to access supplies from the British Columbia or Rocky Mountain basins. Eventually, the GTN pipeline connects to California at Malin, Oregon, directly providing natural gas supplies to the Pacific Gas and Electric (PG&E) mainline, or backbone, pipeline system.

Rocky Mountain Basin

The Kern River pipeline connects the Rocky Mountain supply basin to California markets at Kern River Station, where it connects to the PG&E system, the Southern California Gas (SoCalGas) system, and various merchant power plants and industrial facilities in the Kern County area. The Kern River Pipeline initially started in 1993 with a capacity of 700 MMcf per day. In 2001, in response to the energy crisis, the pipeline was expanded by 135 MMcf per day. An additional expansion in 2003 added 900 MMcf per day, bringing the total capacity from the Rocky Mountain basin to 1735 MMcf per day.

Southwest Basins

The El Paso southern and northern pipeline systems, the Transwestern Pipeline, and the Questar pipelines connect natural gas basins in the Southwest to California.

These pipelines access California markets at Topock, Needles, and Ehrenberg. The El Paso southern corridor system capacity increased significantly with the conversion of the All American Pipeline, allowing transport of natural gas from the Permian basin to California in place of oil that was originally transported in the pipeline system.

Interstate pipeline expansions over the past four years since the energy crisis are summarized in Table 4-1. Both pipelines delivering gas to California and those pipelines passing through the State while delivering little to no gas for consumption are identified. As shown in Table 4-1, delivery capacity to California increased by 25 percent from 2001 to 2004. Capacity for those pipelines passing through the State increased by 15 percent during the same period. California's receipt capacity for each of the four years is also provided. A comparison of interstate pipeline capacity and State receipt capacity indicate that receipt capacity fell short of delivery capacity in all four years, despite the fact that receipt capacity grew over the four-year period.

Table 4-1—Interstate Pipeline Delivery Capacity to California

	MMcf per Day			
Pipelines Delivering Gas to California	**2001**	**2002**	**2003**	**2004**
Gas Transmission North	1,921	2,090	2,090	2,090
El Paso North	2,000	2,000	2,000	2,000
El Paso South	1,227	1,457	1,457	1,777
Kern River	835	835	1,735	1,735
Southern Trails	0	80	80	80
Transwestern	1,065	1,185	1,185	1,185
TGN	174	174	174	174
Sum of Delivery Capacity	**7,222**	**7,821**	**8,721**	**9,041**
California Receiving Capacity	**6,901**	**7,188**	**7,970**	**7,970**
Pipelines Passing Through California*				
Tuscarora	98	98	185	185
North Baja	500	500	500	500
Sum of Pass Through Capacity	**598**	**598**	**685**	**685**

* Pipelines passing through California deliver little or no gas for California consumption.

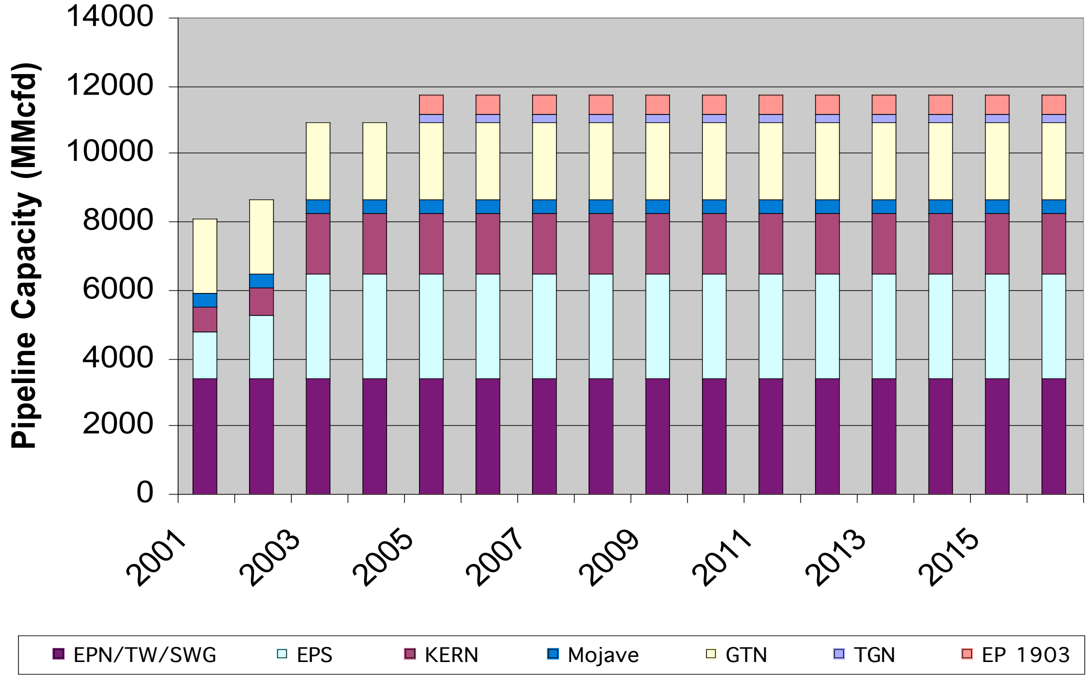
Note: 1. Upstream demand could draw on the interstate capacity, effectively reducing delivery capacity to California.
2. California also receives about 890 MMcf per day from in-state production.

Given expansions made over the past four years since the energy crisis, and the potential modification of pipelines accessing natural gas from LNG facilities in Baja California (see discussion below), California is well situated to access both conventional supply basins and potential new LNG supplies. Pipeline capacity should be sufficient to meet the annual average quantity of gas needed by consumers in the State. This assessment assumes that an LNG facility on the West Coast will be built and provide a new and competitive source of natural gas to California, and that the TGN pipeline and Baja Norte pipelines currently delivering gas in Baja California will reverse flows and supply natural gas from LNG supplies in the Baja California region to the State.[xviii]

Natural gas supplies needed to meet the requirements of all consumers vary significantly on month-to-month and day-to-day bases. The fact that existing capacity meets the current annual average demand does not necessarily mean that California will always have sufficient capacity to meet daily peak needs. The State lacks the pipeline capacity to meet the needs of all consumers on the coldest days in winter as well as when there are disruptions in an interstate pipeline. Fortunately, the State has significant in-state storage facilities that can supply additional natural gas to meet these peak needs. Historically, curtailments in supply deliveries to customers have been very limited.

Figure 4-1 shows pipeline capacity prior to 2001 and projected additions over the next decade. Pipeline capacities represent the maximum capacity on the southwest market pipeline corridor and not capacity coming into the State. Capacities of pipelines reaching the California border are noted on a graph later in this section. Some interstate pipelines both into and wholly outside California, such as Mojave and the El Paso Line 1903, provide flexibility in service and operations by providing an alternative path when some of the border crossing points are congested.

Figure 4-1—Interstate Pipeline Capacity Serving the Western Markets (MMcf per day)



Source: California Energy Commission, Natural Gas and Special Projects Office

The reliable delivery of natural gas supplies from the Southwest to southern California regional markets is of major concern to market participants. Despite the availability of excess southwest physical interstate pipeline capacity to California, year-round reliable deliveries of natural cannot be assured on those pipelines unless firm interstate pipeline capacity rights to California delivery points are obtained by consumers. During peak winter months or when the electricity generation sector demand in the Arizona markets increases dramatically, it is possible that so much natural gas will be consumed in the southwestern states that California will not receive adequate supplies. Such a scenario would significantly affect California unless an alternative supply source of natural gas or stored gas is available.

Therefore, infrastructure and its capacity (including pipeline and storage capacity) to deliver natural gas to consumers should be sufficiently large to provide both the required supplies to meet average peak demand and a margin of excess capacity. Physical capacity that allows consumers their choice of suppliers is the critical foundation needed to support a competitive market and stabilize short-term pricing trends.

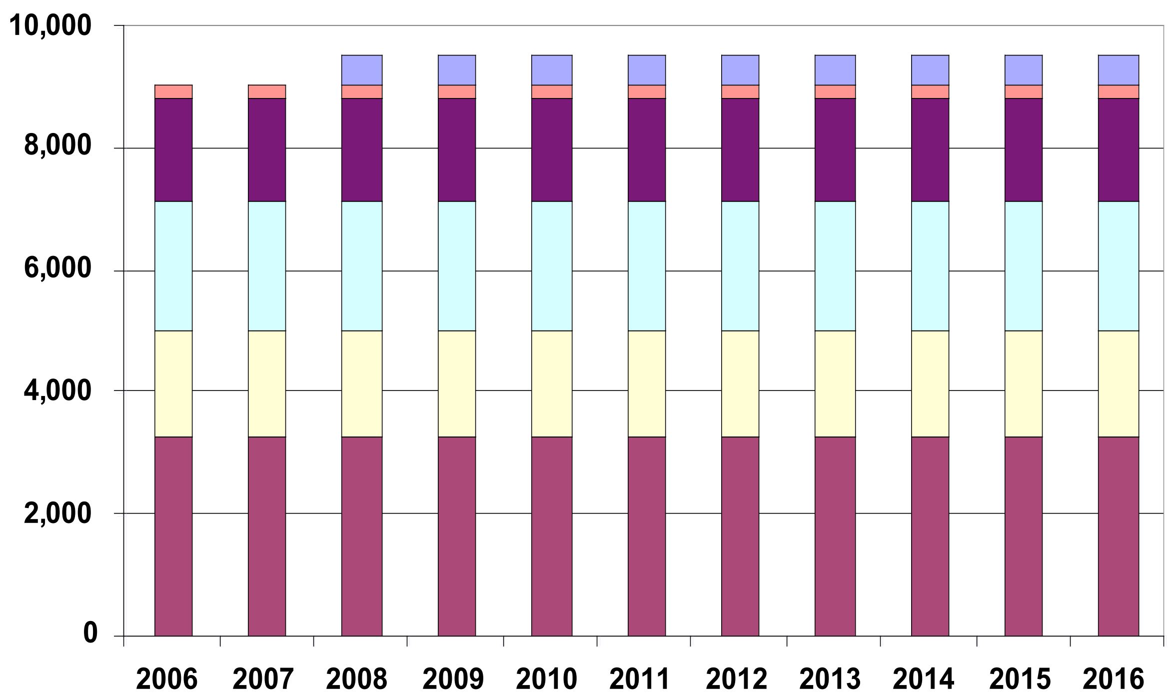
Projected Changes to Interstate Pipeline Capacity and Flows

California will benefit from anticipated modifications to the TGN pipeline linking future natural gas supplies from proposed LNG facilities in Baja California, Mexico to

San Diego, as well as a reversal of the Baja Norte Pipeline, which currently transports natural gas from Ehrenberg, Arizona to the Baja California market. A reversal of the pipeline will also transport natural gas from the LNG facilities in Baja California to the Ehrenberg junction, from which gas can flow in multiple directions to serve the northern and southern California and Arizona markets. Another important pipeline that will influence the gas market in California is El Paso's recently approved Line 1903 lateral between Ehrenberg, Arizona and Kern River Station, California. This pipeline will increase flexibility by providing an interconnection between the Kern River, Mojave, PG&E, SoCalGas, and the Baja Norte pipelines.

Figure 4-2 shows additions to interstate pipeline delivery capacity to California. These capacities represent the amount of natural gas that can be delivered into interstate or utility pipelines inside the State. With the addition of pipeline capacities since 2001, and the assumption that the TGN pipeline will be modified to supply natural gas from Baja California into San Diego, adequate capacity will be available to serve California's needs over the next decade. This case also assumes that when LNG is available at Baja California, anticipated to be available by 2008 and beyond, the Baja Norte pipeline will be reversed.

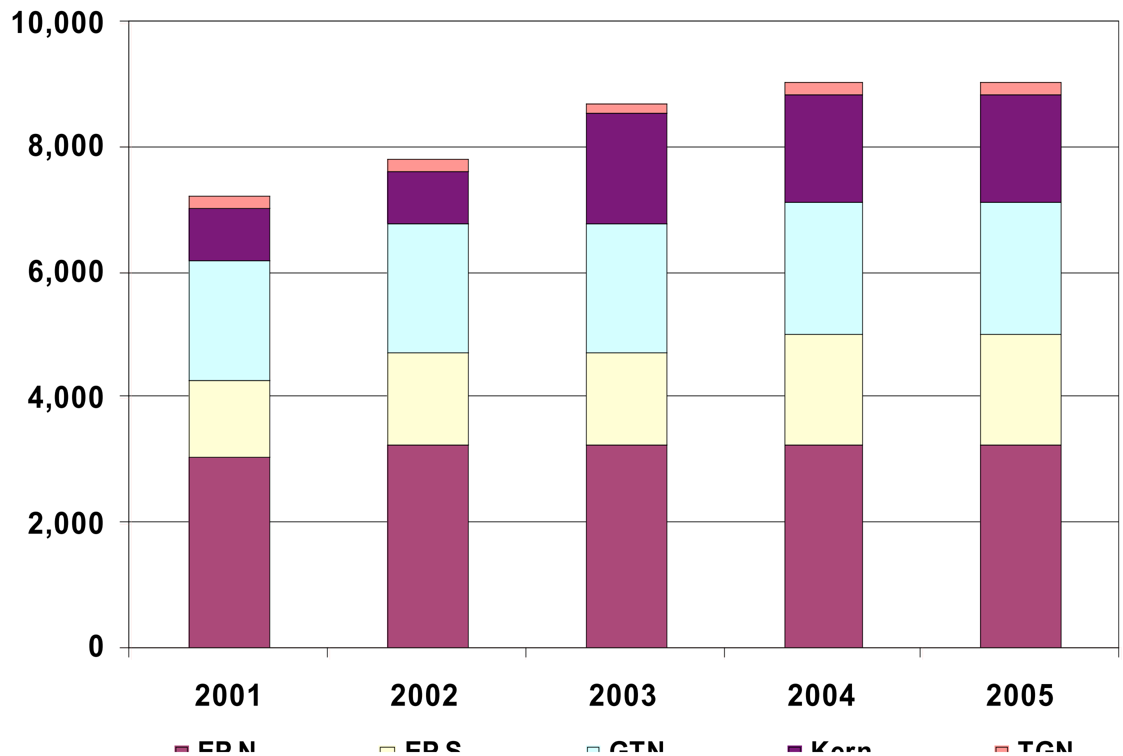
Figure 4-2—Interstate Pipeline Delivery Capacity at California Border (MMcf per day)



Source: California Energy Commission, Natural Gas and Special Projects Office

Figure 4-2 above shows the maximum amount of gas that could be delivered to California by interstate pipelines. Figure 4-3 below shows additions to interstate capacity between 2001 and 2005. As observed, there has been a significant addition to the overall delivery capacity over the past 5 years. The ability to transport natural gas from Baja California back into the U.S. – San Diego region by the TGN pipeline provides the necessary flexibility and additional capacity to serve the San Diego region that was not possible during previous years (prior to building of the Baja Norte pipeline). On an annual basis, these expansions will provide the much needed capacity to California, the gas-on-gas competition between supply basins to California, and finally the ability to bring in natural gas from LNG supplies from a terminal built in Baja California.

Figure 4-3—Interstate Pipeline Delivery Capacity Additions at California Border from 2001 to 2005 (MMcf per day)

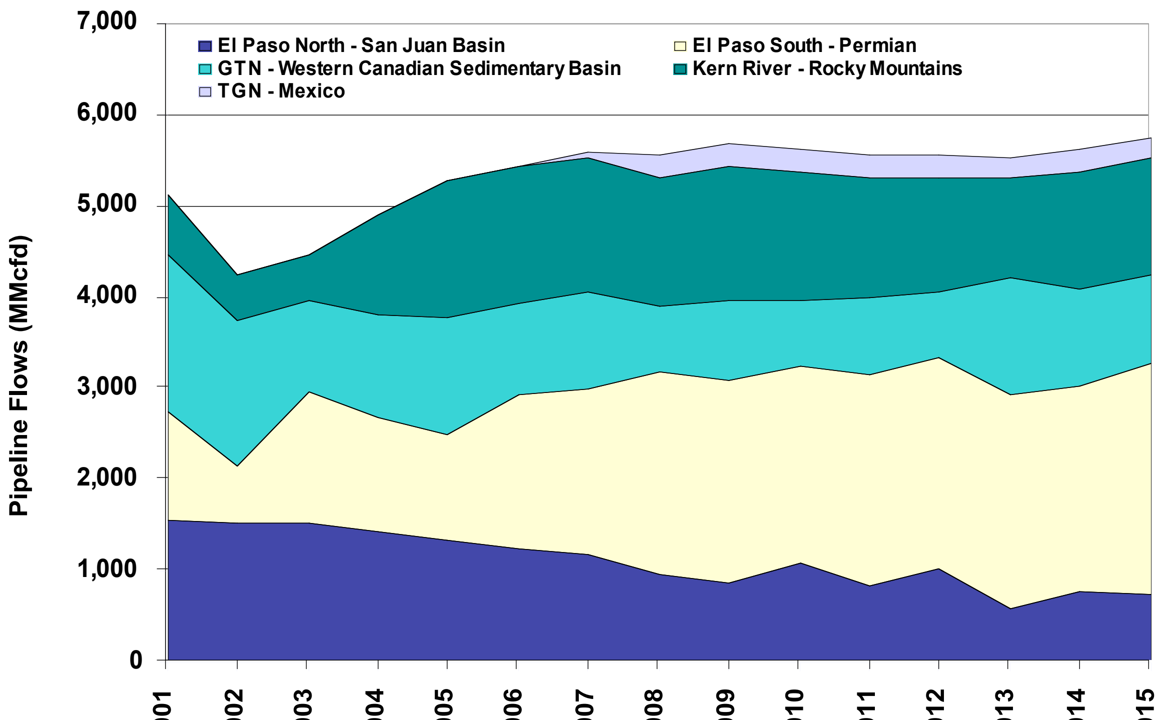


Source: California Energy Commission, Natural Gas and Special Projects Office

Figure 4-4 below shows how the actual flows in interstate pipelines are projected to change during the forecast period. While total southwest supply basins maintain their market share, El Paso's southern system will gain increasing shares with gas flowing west. New LNG supplies in the Gulf, and potential resources in the Permian Basin that can be competitive with higher prices in the future, drive the increase in westward flows. The flows on the El Paso northern system to California drop significantly over time with system capacity dropping to 45 percent at the end of the forecast horizon. This pipeline is at full capacity, starting from the supply basin and serving the southwestern market demand centers, with capacity utilization consistently running in excess of 90 percent. This drop in utilization is caused by the introduction of new LNG supplies in Baja Mexico and an increase in flows from the Rocky Mountain basins.

Supplies from Rocky Mountain basins (transported on the Kern River system) are very competitive, gain a significant market share until 2008, and slightly drop off in the following years. LNG supplies from Baja can satisfy the San Diego markets and almost meet the TGN Pipeline's full capacity of about 200 to 250 MMcf per day. Again, this assumes that the TGN Pipeline will be modified to flow gas in the northerly direction at its rated capacity.

Figure 4-4—Natural Gas Supply Projections (MMcf per day)



Source: California Energy Commission, Natural Gas and Special Projects Office

Figure 4-5 shows how much capacity could be utilized for each interstate pipeline serving the State. Capacities over 100 percent indicate that additional flows on the pipeline would be attainable through investments in infrastructure. Such modeling results can then be used to make expansion decisions. Natural gas from Baja is a very competitive supply source and gains significant market share throughout the forecast period. Current capacity of the TGN Pipeline connecting Baja California to the San Diego region is about 175 MMcf per day.

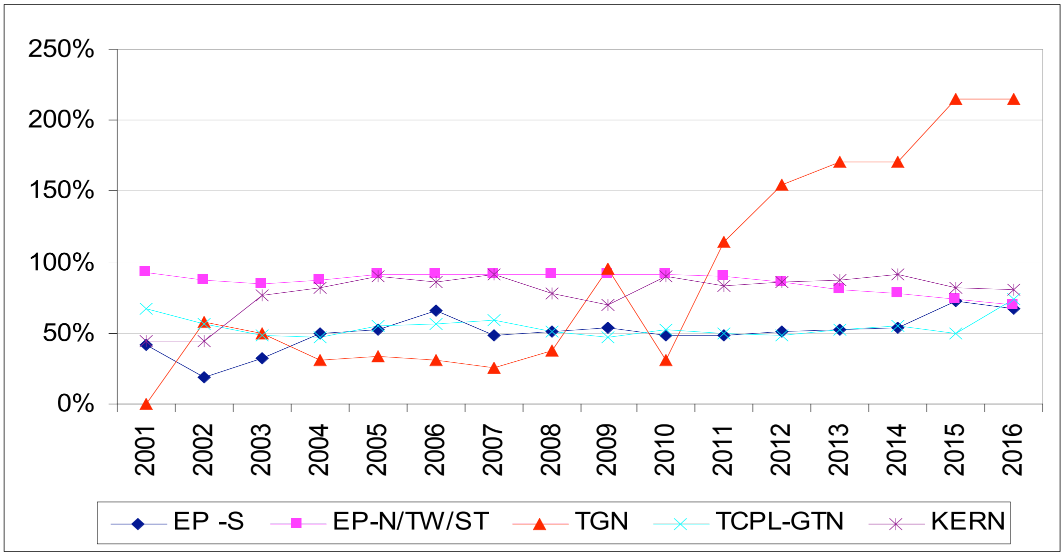
The Kern River Pipeline, with its recent expansion that almost doubled its previous capacity, continues to provide gas to California at a high utilization rate. Supply growth in the Rockies benefits California and neighboring southwestern markets. Competitive supplies from both the Rockies and Baja California tend to put downward pressure on supplies from southwestern basins. Although utilization of the El Paso and Transwestern pipelines serving the State does not reach full capacity, prices continue to be at higher levels as these pipelines run at full capacity from the San Juan and Permian basins to the southwestern markets in Arizona and southern Nevada. The high utilization factor at the upstream end of pipeline keeps the upward pressure on prices at Topock and Ehrenberg, at the southern California border.

With increasing prices in the Canadian supply basins combined with the increased need for natural gas to satisfy the bitumen extraction processes in Alberta and lucrative mid-western and northeastern markets, Canadian supplies to California remain below current levels. Therefore, Canadian gas flows on the GTN Pipeline to California maintain about 50 percent utilization over the time period analyzed in this study. The combination of El Paso's Northern System, the Transwestern and the Questar pipelines continue to provide natural gas to the state at relatively high utilization rates. El Paso's Southern system on the other hand continues to maintain about 50 percent utilization at the California border. The pipeline segment serving the Southwestern markets in Arizona and New Mexico, however, continues to be utilized fully over the next decade.

The Kern River pipeline, even after its expansion, when it doubled its previous capacity has continued to maintain a high rate of utilization, This is observed to continue well into the next decade. The new supply sources in the Rocky Mountain will continue to provide increasing quantities of natural gas to markets on the west and East of the Rocky Mountains.

The only pipeline that will possibly need an expansion is the TGN pipeline that provides natural gas from LNG deliveries in the Baja California region. Natural gas from LNG terminals in Baja will be a very competitive source of natural gas for San Diego markets and it is economical to expand the TGN pipeline beyond its existing capacity to bring in additional gas from Baja. Model results indicate that the TGN pipeline can economically expanded by as much as 200 percent of its current capacity of 175 MMcf per day, to serve the needs in San Diego. The analysis assumes that the TGN supplies gas to the San Diego market and does not make any determinations of expansion of natural gas pipelines inside the state to carry the TGN supplies into the Los Angeles area.

Figure 4-5—Interstate Pipeline Capacity Utilization



Source: California Energy Commission, Natural Gas and Special Projects Office

Intrastate Capacity Requirements

This section discusses intrastate capacity, or the actual ability of the California utility companies and other private transport companies to deliver gas to all California consumers under normal and peaking conditions.

Receipt capacity on an annual average basis in both northern and southern California appears to be adequate over the next decade. Receipt capacity represents the ability of the major backbone pipelines within the State's borders to transport natural gas from the border points to utilities and consumers in the State.

Over the past five years, both PG&E and SoCalGas have expanded their backbone pipelines. The storage capacity in the State has also increased due to expansions of the Wild Goose and Lodi storage facilities, as well as additions to PG&E and SoCalGas storage fields. When increases in storage capacity, in withdrawal capacity from these storage facilities, and intrastate pipeline capacity are considered together, staff projects sufficient total capacity to meet the annual average demand projections for the State over the next decade. However, Energy Commission staff has not yet made a determination of any additional pipeline or storage capacity needed for extreme peak periods. It is entirely possible that combinations of weather and generation capacity-related events could cause a disruption in the State's ability to obtain sufficient supplies to meet peak demand.

Chapter 5: Natural Gas Price Outlook

Introduction

The following section contains the Energy Commission staff's outlook for natural gas prices coming into California, as well as those paid by end users. For the price outlook in this report, the study methodology yields only *one* price and *one* quantity for every model node in each time period. If a comparison is made with actual natural gas price data, the price information contained here is most similar to the annual average producer and end-use price data provided by the Energy Information Administration (EIA). Other sources of natural gas prices such as the New York Mercantile Exchange (NYMEX), bidweek, and daily spot price surveys reflect seasonal and short-term market dynamics that are not captured in an annual, long-term model, making any inferences drawn between those sources and this report specious, at best.

Wellhead Price Outlook

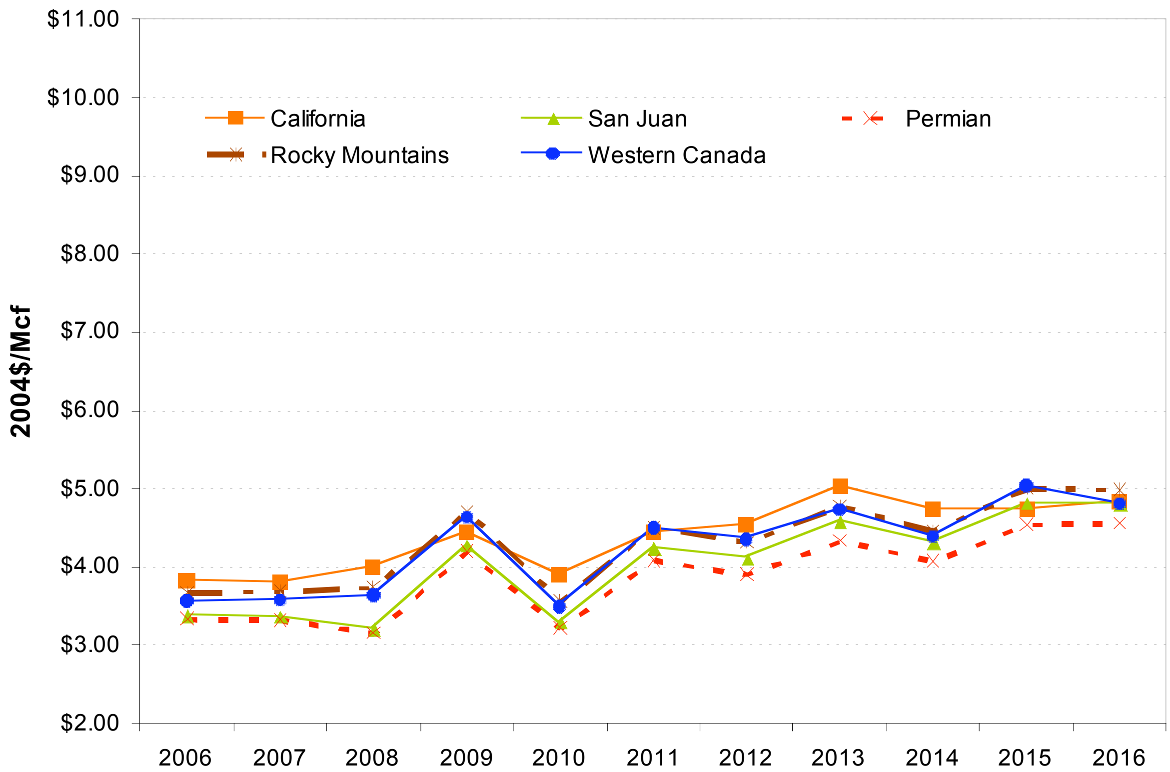
From 2006 to 2016, wellhead prices in the basins supplying natural gas to California are generally projected to increase, reflecting the increasing marginal costs to produce gas in those regions as resources are depleted. During several years over the forecast horizon, however, the upward price trend in those basins would be altered by market influences such as the introduction of large, new supplies into the market, or changes in natural gas demand. Figure 5-1 illustrates projected natural gas wellhead prices in the basins that supply natural gas to California.

A major change in assumptions in this revised case, causing a change in price trends reported in the preliminary case, is because of the potential of liquefied natural gas (LNG) terminals to expand over time, as demand grows on the continent. In the preliminary assessment, an assumption was made that LNG terminals would not expand beyond what is currently planned up to the year 2010. This assumption froze the LNG capacity in years beyond 2010, putting higher pressure on gas prices throughout the continent. In the revised assessment, these terminals are allowed to expand their capacity if it is economically viable. Hence the LNG capacity and resulting LNG flow increases in this case, compared with the preliminary case. This in turn provides for a lower price trend than what was observed in the preliminary case.

A second change that tends to work in the opposite direction is the availability of the Mackenzie and the Alaskan pipelines. Due to delays observed in the progress of the approval process, the availability of these two major pipeline projects has been pushed further into the future, with the MacKenzie pipeline slated to be in operation in 2013 and the Alaskan pipeline to be in operation in 2016. This change delays the potential to get cheaper northern frontier gas supplies into U.S. and Canada, thereby tending to increase prices in the 2010 to 2016 time frame. However, the change in

LNG assumptions is more pronounced, so overall prices in this revised case are lower.

Figure 5-1—Projected Natural Gas Basin Wellhead Prices



Source: California Energy Commission, Natural Gas and Special Projects Office

Energy Commission staff assumed the Cameron LNG import terminal in Lake Charles, Louisiana will begin operation in 2007, adding 1,500 MMcf per day of capacity to the North American natural gas market. The infusion of new supplies to the Gulf of Mexico is projected to cause wellhead prices to drop in supply basins throughout North America, including those supplying California. The effects would be most acute in the Permian Basin since it is the only supply source for California that would directly compete with LNG imports brought into the Gulf of Mexico.

Staff further assumes that, in the following year, Sempra Energy's Baja LNG terminal would go on-stream. The impact of this addition of new gas supplies in Baja Mexico would be mitigated in part because gas imported at Baja incurs transportation charges before reaching the U.S. border, and because some of that gas will be consumed within Mexico. Nonetheless, the addition of more LNG to the U.S. markets is forecast to temper the overall trend of increasing natural gas wellhead prices.

The Canadian MacKenzie Pipeline is expected to be in service in 2013, adding 1500 MMcf per day to the North American market, although most of those incremental supplies will be consumed in Alberta. The supply from Northern Canada increases to about 1800 MMcf per day by the end of the forecast horizon.

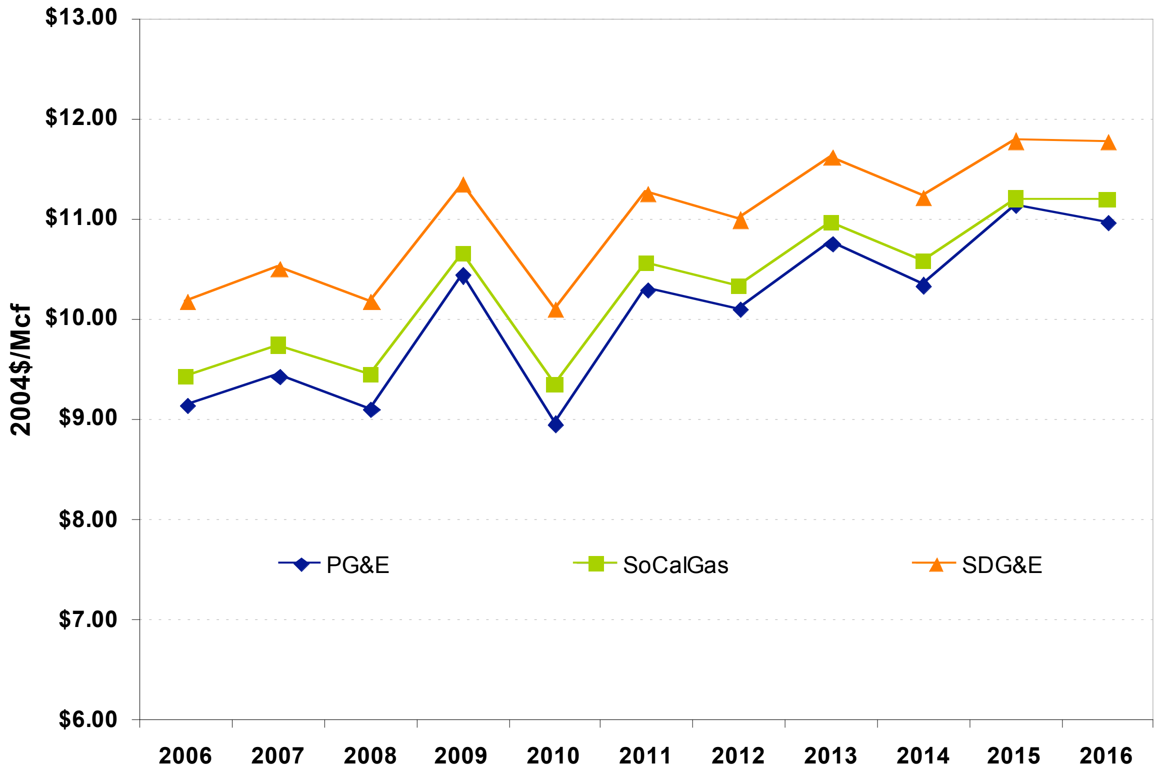
California End-Use Price Outlook

A number of pipeline expansions completed during 2002 to 2004, as well as regulatory changes for customers east of California, relieved constraints to California's access to regional supplies such as the Rocky Mountain and San Juan regions. As a result, California natural gas prices no longer tend to be out of step with the rest of the North American natural gas market, as they were during 2000 and 2001. Consequently, from 2006 to 2016, California's end-use natural gas prices mirror the trends of the overall national market. The following sections examine the end-use price outlook for each end-use sector in California's three major natural gas utility areas. Note that a proposal is pending before the California Public Utilities Commission (CPUC) to integrate the rates for Southern California Gas (SoCalGas) and San Diego Gas and Electric (SDG&E) customers; however, for purposes of this report, staff assumes that the current rate structure will remain in effect for the forecast period.

Natural Gas Price Projections for Residential Customers

California's residential customers pay the highest natural gas prices because of the cost and complexity involved in serving millions of residential customers in each utility service area. Over the next decade, modeling projects California's residential gas prices to fluctuate between $9.14 and $11.77 per thousand cubic feet (Mcf) of natural gas, depending upon the utility service territory. Residential customers in the SDG&E territory are expected to pay the highest natural gas prices because of the added costs to transport gas through the SoCalGas system. Presently, SDG&E does not have direct access to gas supplies, although it will once Sempra Energy's Baja LNG terminal begins operation. However, model projections suggest that deliveries via Mexico will not be enough to replace SDG&E's current reliance on the SoCalGas system for a portion of its supplies. Residential customers in the Pacific Gas and Electric (PG&E) service territory would pay the least for natural gas over the forecast horizon, slightly below what the same customer class would pay in the SoCalGas area. PG&E's lower prices reflect lower commodity costs and utility rates. The gap between PG&E and SoCalGas residential gas prices should narrow slightly over time, reflecting the projected increasing wellhead prices in Western Canada, which is a significant source of natural gas for northern California. SDG&E and SoCalGas do not have direct access to Canadian supplies. Figure 5-2 illustrates the projected residential gas prices in California over the next decade.

Figure 5-2—Price Projections for Residential Customers

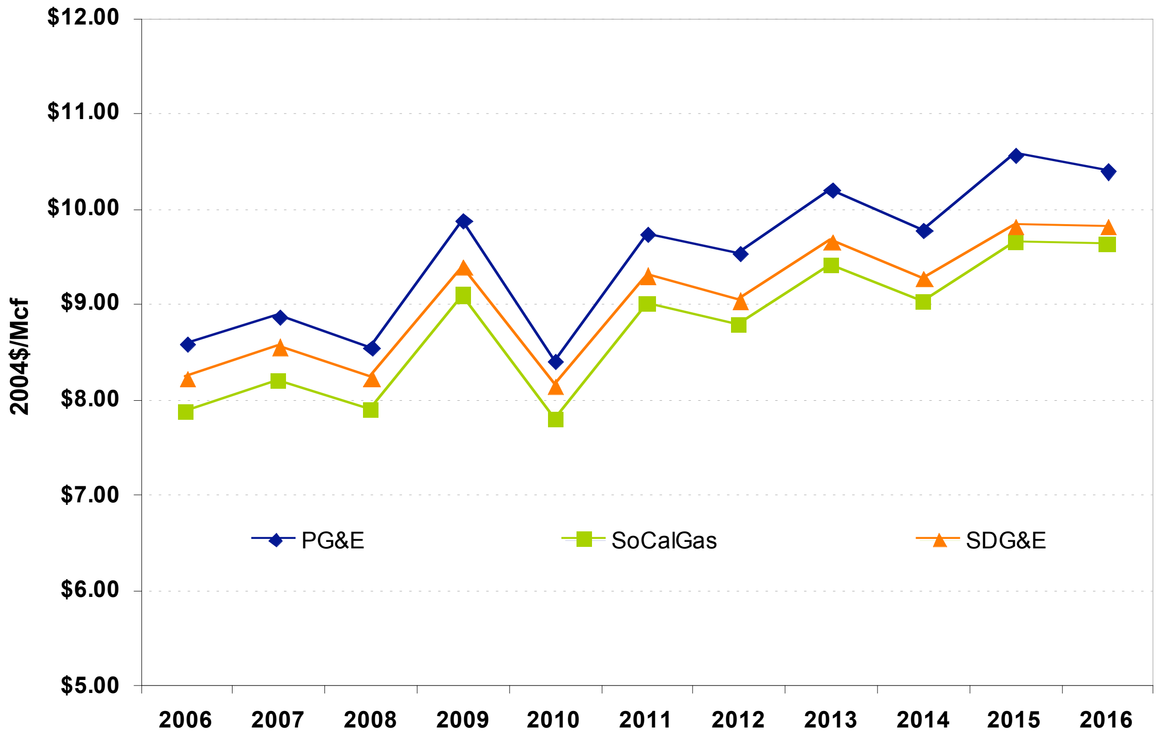


Source: California Energy Commission, Natural Gas and Special Projects Office

Natural Gas Price Projections for Commercial Customers

Over the forecast horizon, California's commercial customers are forecast to pay between $7.87 and $10.40 per Mcf for natural gas, depending upon the year and the service territory. In contrast to residential customers, commercial customers in the PG&E service territory are expected to pay more for natural gas than other commercial customers in the State based on CPUC rate cases. Through 2016, commercial customers in the SoCalGas service territory are forecast to pay the lowest natural gas prices, compared to similar customers in other gas utility service territories in California. Figure 5-3 shows the prices projected for commercial customers over the next decade.

Figure 5-3—Price Projections for Commercial Customers

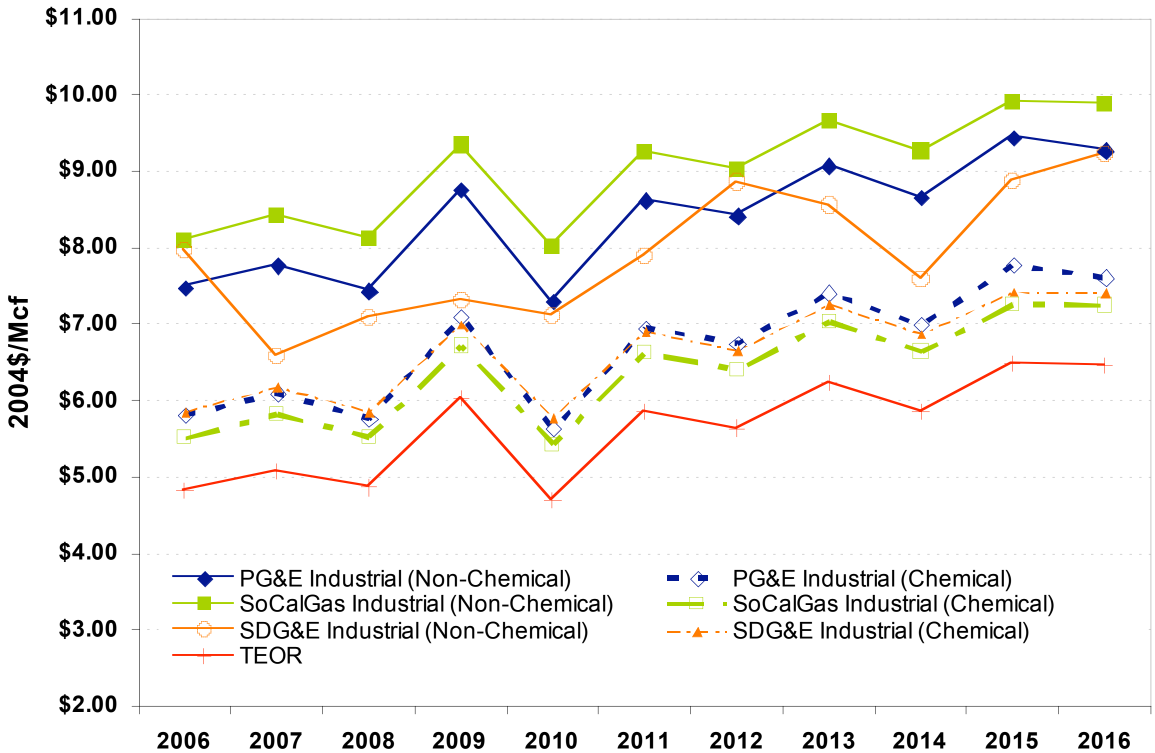


Source: California Energy Commission, Natural Gas and Special Projects Office

Natural Gas Price Projections for Industrial Customers

Natural gas prices for industrial customers follow the same trends as those for other California customers, but at a much lower price level. Industrial gas customers are far fewer in number than the residential and commercial customers served by each natural gas utility and tend to require large volumes of gas with little seasonal variation. Additionally, the larger volume or “non-core,” industrial customers purchase their own natural gas supplies, pipeline capacity, and storage services. All of these factors make it less costly for utilities to serve industrial customers, and are reflected in the lower transportation rates charged those customers. Differences in industrial price projections mainly reflect the differences in commodity costs. Thermally enhanced oil recovery (TEOR) customers pay the lowest price for natural gas because much of the gas they consume is taken directly off the large interstate pipelines, eliminating the need to pay the intrastate transportation charges when utility distribution pipelines are used. Figure 5-4 illustrates the projected prices for industrial customers (chemical and non-chemical) in California.

Figure 5-4—Price Projections for Industrial Customers



Source: California Energy Commission, Natural Gas and Special Projects Office

Natural Gas Price Projections for Electricity Generators

In California, thermal power plant operators using natural gas can be broadly broken into two categories: those served by a natural gas utility and those taking their fuel supplies directly from a source other than a utility, such as from an interstate pipeline or a local gas producer. As in the industrial sector, natural gas prices paid by electricity generators taking gas from California's three major natural gas utilities differ slightly based upon the transportation rates each utility charges and the mixture of supplies available to them.

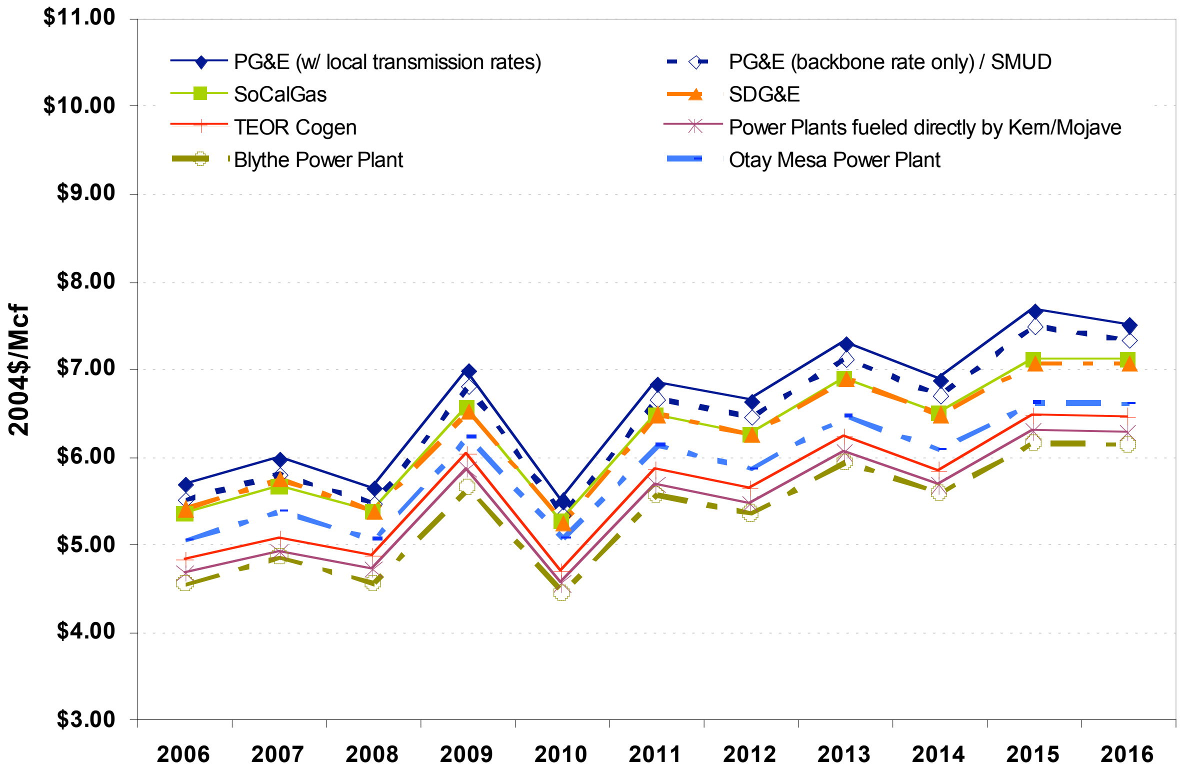
In the PG&E service territory, a further distinction is made for power plants that are either built after March 1, 1998, or take gas directly from PG&E's large-diameter, backbone pipeline system. As provided in the CPUC Decision 04-12-50, power plants that meet the above criteria pay only $0.05 per Mcf over the Citygate, or clearing house, price.[xix] This charge covers public purpose programs. Power plants built prior to March 1, 1998, or which take gas from the smaller pipe diameter distribution system, pay an additional $0.14 per Mcf local distribution charge, or

$0.19 per Mcf above the Citygate price. An exception to this rule is the Morro Bay Modernization and Replacement Power Plant Project, which receives a substantial discount on local distribution rates. For purposes of this study, the Energy Commission staff considered the effective rate that Morro Bay receives equivalent to the backbone-only rate. The original Morro Bay generating station, which has been operating since 1955, will be razed once the new units are completed.[xx] Additionally, the Sacramento Municipal Utility District (SMUD), a publicly owned utility (POU) located within the PG&E service territory, pays a slightly different transportation rate to bring gas to the power plants it owns. In the mid-1990s, SMUD purchased an equity position in PG&E's backbone pipelines. Provisions in the contract between PG&E and SMUD provide for a rate of about $0.03 per Mcf for up to 43 MMcf per day of flow on each of the two backbone pipeline paths. For combined flows above 85 MMcf per day, the backbone-only rate of $0.05 per Mcf is charged.

Currently, electricity generators in the SoCalGas and SDG&E areas pay virtually the same transportation rate to move gas through either utility's system, with power plant operators in the SDG&E service territory paying a few cents per Mcf more than those in the SoCalGas territory. The two utilities, which are both owned by Sempra Energy, are exploring the possibility of integrating their two pipeline rate structures.

The remaining power plant operators shown in Figure 5-5 bypass the utility pipeline systems, thus avoiding the transportation charges assessed on power plants taking fuel from the utilities. As a result, the natural gas prices for these operators are projected to be lower than those paid in the utility service areas. The lowest natural gas prices would be paid at power plants operating directly off the interstate pipeline systems, such as those located along the Kern/Mojave pipeline and at the Blythe Power Plant, which take gas directly from the El Paso southern system.

Figure 5-5—Price Projections for Electricity Generators



Source: California Energy Commission, Natural Gas and Special Projects Office

Chapter 6: Natural Gas Policy Options

Introduction

This chapter raises policy questions that the State of California must address to improve California's long-term natural gas demand, supply, infrastructure, and price position relative to national markets. Energy Commission staff has identified the concerns listed below based upon its analysis of these market conditions and the responsibility to help ensure a reliable supply of natural gas at reasonable prices to consumers. This analysis benefited from close collaboration with the California Public Utilities Commission (CPUC) staff. Input from various stakeholders that participated in public workshops sponsored by the California Energy Commission (Energy Commission) also contributed to the identification of issues and to their potential solutions. The Energy Commission staff seeks additional comment from all parties potentially affected by these concerns.

Policy Goal

The State of California's long-term policy goal for natural gas is succinctly stated as follows:

- To ensure a reliable supply of natural gas, sufficient to meet California's demand, at reasonable and stable prices and with acceptable environmental impacts and market risk.

The State's natural gas policy goal addresses the needs of natural gas consumers (reliable supplies at reasonable prices), the natural gas industry (stable prices with acceptable market risk), and the State of California (environmental protection and a healthy economy). This goal assumes that these factors will be balanced and does not identify how these factors will be weighted. For example, when balancing reliability, price, and market risk, consumers (or their regulated natural gas providers) may be willing to pay a slightly higher price than the minimum achievable in order to substantially reduce the risk of future price spikes or increase the reliability of future supplies.

The staff has interpreted the natural gas policy goal to mean that reliability of supply is the top priority, followed by reasonable and stable prices. These goals must be achieved in a manner consistent with environmental and public health and safety protection requirements. Market risk analysis and risk mitigation are important strategies that consumers and providers use to achieve their individual goals, and can complement the actions the State might take. Since the State's infrastructure and access to supplies are currently adequate due to several recent and expected pipeline and storage facility additions, Energy Commission staff does not have an immediate concern regarding reliability. Although the State needs to take additional action to ensure its long-term supply reliability, it does not have to take these actions now. Staff is concerned, however, about the availability of natural gas supplies at reasonable prices. Therefore, this chapter focuses on natural gas price reduction and actions the State can take to reduce prices, and therefore energy bills, for consumers.

Background Context: Current Market Conditions

The assessment of long-term natural gas policy concerns provided in this chapter highlights several policy choices that the State needs to consider. These choices must be considered in the context of California's current natural gas demand, supply, infrastructure, price, and market situation. The Energy Commission staff has summarized its observations of current market conditions, below. Much of this information is documented in the Energy Commission's Natural Gas Assessment Update, February 2005, and in the above chapters, and has been discussed at various public workshops held by the Energy Commission, including the July workshop on the Preliminary Reference Case.

Demand

- Nationally, natural gas demand is exceeding domestic supply, and the supply/demand deficit is growing each year.
- Californians are becoming more energy efficient, with the average California household now using less than half of the natural gas it used in 1975.
- Although Californians are continuing to use electricity more efficiently, total electrical demand is slowly growing, increasing the demand for natural gas used as a fuel for power plants.
- Natural gas is capturing a larger share of the total energy demand for electricity generation in the U.S. and is the dominant fuel in California.
- The staff expects California's total natural gas demand to increase slightly for several years as the State economy recovers from its earlier slump, then to increase only very slightly in future years.
- The largest driver of seasonal natural gas demand is weather, with temperature causing large swings in gas heating and electric cooling loads in winter, and with snowfall levels affecting hydropower availability in the summer.
- The largest drivers of the industrial and commercial sector natural gas demand are business cycles and energy prices.

Supply

- Marginally adequate supplies of natural gas are available to California for the next ten years, on an annual average basis, assuming California consumers are willing to pay enough to attract those supplies to the State.
- California production appears to have peaked and to be slowly declining.
- U.S. production is relatively flat and is not expected to increase on pace with demand.

- Drilling activity for new supplies in North America is at or near record levels.
- The cost to produce new gas supplies is increasing.
- New gas wells are being depleted at faster rates than before.
- More of the nation's new production is dedicated to replacing declining, older production, so that less new production is available to meet demand growth.
- Renewable resources are potentially very large but production is uncertain since technological advances are needed to increase production.
- Increasing natural gas imports on a national basis is a critical supply strategy identified by the U.S. Department of Energy (DOE) to ensure that future supply and demand are balanced.
- Imports from Canada are not likely to grow enough to meet U.S. needs.
- DOE expects liquefied natural gas (LNG) imports to the U.S. to grow substantially and become a significant part of the nation's total gas supply portfolio.
- Uncertainty in natural gas demand for electric generation in neighboring states creates uncertainty in the reliability of gas supplies to California.

California's natural gas quality standards currently limit the use of some in-state and imported (LNG and domestic) sources if they are not processed to meet current standards.[xxi]

Infrastructure

- California currently has adequate pipeline infrastructure within its boundaries to move gas to load centers, on an annual average basis.
- Adequate interstate pipeline infrastructure exists from adjacent states to the northern California border through 2016, on an annual average basis, assuming announced pipeline modifications are completed.
- Adequate interstate pipeline infrastructure exists from adjacent states to the southern California border through 2016, on an annual average basis, assuming announced pipeline modifications are completed.
- Natural gas pipeline and/or natural gas storage infrastructure may not currently be adequate to meet extreme, infrequent winter peak daily demands. While staff has not specifically analyzed extreme peak day demand during the winter and summer time frame, unusually high peak gas demand resulting from a combination of situations can cause tightness in the gas market. Staff will consider the impact of extreme peak winter and summer gas demand conditions in subsequent reports.
- The determination of pipeline and storage infrastructure capacity needs is based upon rules that allow curtailment of power plant customers when supply shortages occur.

- Opportunities may exist for infrastructure additions to relieve occasional regional congestion, increase reliability, and increase market efficiencies.

Price/Markets

- Natural gas wellhead and market prices have increased dramatically in the past two years and are likely to increase further.
- Short-term natural gas market prices are highly volatile and much more volatile than in the past.
- California has recently been paying from $0.25/mcf to $1.00/mcf less for its natural gas supplies than most other states due to moderate demand, sufficient infrastructure, and ample storage.
- Severe weather in other areas of the U.S. dramatically increases demand and prices in those areas and impacts prices in California since most of North America functions as an interconnected pricing market.
- Many infrastructure projects (interstate pipelines, private storage facilities, and LNG import terminals) are financed with private capital, not with capital from California's investor-owned utilities (IOU).
- Many in-state pipelines and storage facilities developed by IOUs are financed through their customers' rates, while private facilities are built with their own funds and charges are recovered in user fees.

Natural Gas Policy Issues

Having reviewed the available information, the Energy Commission staff identified important policy issues that need both resolution and immediate action to help restore California and its natural gas consumers to a healthier long-term future. While these issues focus on a longer-term perspective, their resolution may provide benefits in the short term as well. These issues complement actions being considered by the CPUC in its Order Instituting Rulemaking 04-01-025, which covers short- and mid-term issues, rates, and rules of utility regulation.

The overarching theme for the policy issues detailed below can be summarized as follows:

- Are there additional, cost-effective actions California could take to both reduce consumers' prices below expected levels and manage the risk of potentially higher natural gas prices, while maintaining adequate reliability and meeting environmental and public health and safety requirements?

As mentioned previously, this report focuses on price reductions to California consumers. In the natural gas arena, California is closely tied to the North American market. Demand, supply, and infrastructure factors throughout North America establish prices. As a result, California often has little direct control over market prices. For example, California natural gas wholesale prices spiked in February 2003 due to extreme weather conditions in the Northeast at a time when California's own demand was very moderate. Ideally, all states would implement cost-effective energy efficiency measures so that available supplies could exceed demand. However, that is not the situation today. Therefore, California needs to focus on those actions within its control that can help California consumers.

Many Californians are familiar with the electricity markets and California's dominance because of its size. However, several significant differences between the electricity and natural gas markets affect the ability of the State to take actions to reduce prices. These differences are:

- California is not the price leader for the natural gas market.
- California must import approximately 85 percent of its natural gas to meet its needs, resulting in the importation of natural gas supplies through interstate pipelines from sources that are hundreds of miles away.
- The interstate pipelines are regulated by the federal government, are operated as common carriers, and are supported by long-term capacity contracts from consumers.
- Natural gas production was deregulated many years ago. Prices for these supplies rise and fall as a result of overall national market conditions.
- California residential consumers pay current market prices for their natural gas supplies since the natural gas IOUs pass through their fuel costs to consumers each month.
- Natural gas supplies are normally purchased now with shorter-term contracts.

These differences require California policy makers to examine these two energy markets differently and emphasize the importance of evaluating potential California policy actions in both a state and national context.

Consumers can help reduce their cost of natural gas by investing in energy efficiency measures which reduce their total consumption. The State can also pursue additional supplies that come directly to California and are not tied to national pricing benchmarks. These options are tied to long-term supply availability, and even if these options do not lower prices they will provide greater stability and lower volatility to price trends compared with current market trends.

California as a whole can also benefit from:

- Increases in its domestic natural gas production.
- Development of supplemental natural gas supplies.
- Development of alternative energy sources that reduce overall energy (electricity and natural gas) demand.

- Attention to timely infrastructure additions to ensure supplies can continue to be reliably delivered without causing localized congestion.

Financial hedging can also help manage short-term natural gas price volatility. The major natural gas IOUs in California have already been granted this authority by the CPUC.

Possible actions should also be directed to areas where they will be most effective. Actions that help reduce peak demand are more effective than actions that only address average, year-round usage, since peak usage reductions save natural gas molecules and also limit the need for additional infrastructure. California now has two natural gas peak seasons. The traditional winter peak, California's largest, is driven by heating demand during the coldest months. California also has a second, smaller peak season during the summer, driven by the fuel demand of gas-fired, thermal power plants that run to meet the electric air conditioning demand. These twin peak demands mean that California should pursue measures that primarily help reduce either the winter heating demand or the summer cooling demand, or both. For example, more thermally efficient buildings help insulate occupants against both the winter cold and the summer heat, reducing consumer energy demands in both periods. Alternatively, solar water heating primarily helps reduce summer demand since that is when the sun shines the most.

Since over one-third of California's total natural gas demand is dedicated to fueling its electricity generation system, California should consider additional actions in the electricity sector that provide benefits to the natural gas system and its consumers. For example, more efficient air conditioners will save electricity during the peak electricity season, also reducing the natural gas fuel requirements for power plants.

The following section helps focus discussion on some of these issues and potential actions.

Natural Gas Issues

Demand Issues

1. How will greater investments in energy efficiency and related programs affect natural gas demand and prices, and should the State establish higher savings goals?

2. Are there any remaining cost-effective opportunities in California to achieve significant, increased energy efficiencies in the power generation sector?

3. Are there any remaining cost-effective opportunities in California to achieve significant, increased energy efficiencies in the commercial sector, specifically involving refrigeration and lighting?

4. Are there any remaining cost-effective opportunities in California to achieve significant, increased energy efficiencies in the industrial sector, specifically using combined heat and power?

5. Are there any remaining cost-effective opportunities in California to achieve significant, increased energy efficiencies in the residential sector, specifically using advanced solar water heating?

6. How will even greater investments in renewable energy for electricity generation and related programs affect natural gas demand and prices, and should the State establish higher goals?

7. How can the State ensure that its goals for energy efficiency and renewable energy are aggressive without risking that they will not be met, resulting in an unplanned increase in the future demand for natural gas?

8. Are there viable clean fuels that can allow fuel switching capability for electric generators and large industrial consumers to temporarily reduce their natural gas demand during periods of constrained supply, and should the State encourage this strategy?

9. Are there additional costs or air emissions associated with burning such clean fuels by electric generators or industrial customers?

10. Are there actions California can realistically take to achieve natural gas demand reductions and/or energy efficiency increases in other U.S. states?

Supply Issues

1. If current efforts to resolve the domestically produced and imported natural gas quality issue are successful, will those efforts result in significant additional supplies for California, and should California's natural gas specifications be revised?

2. Should the State take additional actions to provide incentives for increased production of its natural gas resources, consistent with its environmental protection goals?

3. Are there opportunities to significantly increase supply from the development of domestic biogas?

4. Are there opportunities to significantly increase natural gas supply from the gasification of other energy sources?

5. How can the natural gas research and development program help develop supplemental natural gas supplies?

6. Does LNG offer enough benefits to California to outweigh its potential negative impacts, and should the State adopt a policy recommending the direct import of LNG into California?

7. Should the State act as an enabler/facilitator and establish government-to-government relationships with natural gas supply states and countries to help ensure that enhanced supply availability and deliverability benefits both parties?

8. Should the State seek to further diversify natural gas supply sources currently available to it in order to allow market competition to drive prices down?

9. Are there additional actions the State can take to increase the amount and diversity of natural gas supplies available to California?

Infrastructure Issues

1. How should the State determine the need for new infrastructure? Should the State increase the "slack capacity" minimum requirement to account for extreme peak days or other factors affecting system deliverability risk?

2. Does the State need additional intrastate pipelines to resolve deliverability and/or congestion issues?

3. Should the State require California's electric utilities to obtain firm interstate pipeline capacity rights or firm storage capacity rights to serve their gas requirements?

4. Is there a need for additional storage capacity or increases in withdrawal capacity at existing storage facilities?

5. Can a new LNG import terminal fulfill the functional equivalent of a new interstate pipeline?

6. Does the lack of natural gas storage capacity east and north of California threaten the physical reliability of natural gas deliveries to California during times of supply shortages or extremely high demand?

Price/Market Issues

1. Will higher natural gas prices significantly impact the State's industrial sector, compared with other states, and potentially result in a significant impact on California's economy?

2. Have higher natural gas prices had a significant, detrimental effect on the California economy through reduced purchasing power by consumers?

3. Can California take additional actions to cause wholesale natural gas prices available to California or prices of natural gas delivered to California to decrease further below the national benchmark?

Natural Gas and Electricity Interface Issues

Background

As the integrated analysis of the western natural gas and electricity systems becomes more sophisticated, the complexity of issues grows involving interconnection between the natural gas system and the electricity system, both generation and transmission. Since natural gas has become a dominant component of the State's electricity supply system, this interconnection deserves additional analytical attention.

Issues

- **Does the communication protocol between natural gas and electric parties during normal market operations need adjustment?**

  The North American Energy Standards Board (NAESB) is currently examining an interrelated set of questions dealing with natural gas electric generation communication. At the heart of this issue is its "Energy Day" concept, designed to resolve the mismatch in timing between the Electric Day and Gas Day market nomination and commitment cycles. This issue is mitigated in part in the West due to the time zone differentials between the national gas market hub and major western regional electricity demand centers. However, the western states may still need to make some additional adjustments to ensure that they can solicit and guarantee fuel commitments during all nomination cycles.

- **Is the coordination protocol between natural gas and electricity system operators during periods of extremely high demand or supply shortages adequate to ensure system reliability?**

  The experience in the Northeast during winter 2003-04 demonstrates that the reliability of both the electricity system and the natural gas system can be jeopardized during times of extreme stress. In this instance, the severe temperature caused extreme stress, but natural or man-made factors could also cause the same result. The reliability threat was a function of poorly developed communication, market rules, and procedures between the natural gas and electric generation system operators, and between each system operator and its respective market participants. Further examination of the potential causes of extreme stress in the West and integrated natural gas and electric generation system responses is needed to identify what measures, if any, should be considered to ensure these systems still provide reliable service to customers.

- **Should the State require a guarantee of firm fuel delivery for firm electric supply?**

  The CPUC is currently developing electricity procurement rules to ensure adequate electricity resources throughout the year. These electricity resource adequacy rules do not require that gas-fired generation has fuel lined up months in advance. The State can obtain fuel through a mix of short-term and longer-term contracts, supplemented by financial hedges. Physical access to the fuel includes securing the molecules, securing transmission access for those molecules through either interstate pipeline capacity contracts or natural gas storage contracts, and securing access to the distribution system. These contract and access mechanisms need to address both firm and non-firm commitments. An integrated analysis is needed to determine whether individual gas management strategies can be implemented in aggregate and if the financial market approach can assure physical delivery, or whether gas constraints might exist in real time.

- **What are the limits to the interchangeable nature of natural gas and electricity when significant regional shifts in energy supply flows are needed?**

  The western energy market is large and highly interdependent due to a web of electric transmission lines and natural gas pipelines providing fuel for the thermal power plants. Western energy system operators have the ability to make regional shifts in how that energy is provided. For example, thermal power plants in the Southwest could take fuel from the natural gas system in Arizona to generate electricity to meet an electricity market demand in Los Angeles. Alternatively, the same natural gas could be delivered farther west to fuel thermal power plants in southern California, which could then meet electric demand in Los Angeles, avoiding the need for electric transmission from Arizona to Los Angeles. However, the ability to shift regionally between fuels and power plants is limited by the electric transmission and natural gas pipeline systems. These inter-fuel and inter-regional limits need to be defined both to explore opportunities for economic improvement and determine the maximum flexibility system operators have during times of moderate and extreme stress. The issue of limits is complicated by energy market and physical system realities that allow western natural gas supplies to move east, making them unavailable to any western sub-region.

- **Is the more volatile nature of power plant fuel demand causing unacceptable impacts to natural gas system operations?**

  The natural gas system was designed for delivery of molecules at “city gates” to meet a slowly fluctuating demand. With almost all new electric generation additions in California and the Southwest fueled by natural gas, this demand sector has increased significantly and has become a larger proportion of the total gas demand. In addition, some power plants, due to rapid ramp up and down in fuel consumption, impose a significantly different demand pattern on the natural gas system than historically experienced. A particular concern may arise when numerous power plants suddenly come on line, causing a rapid draw on the interstate pipeline network and potentially threatening the reliability of the natural gas system as pipe pressure drops. California's large storage facilities partially mitigate this concern, but the potential issue is more prominent in the Southwest. Further analysis would determine whether the issue presents a widespread potential impact, whether any immediate protective action is necessary, and whether addressing the issue from a broad western states perspective is appropriate.

- **What are the impacts of the quality/interchangeability of non-traditional natural gas supplies on traditional natural gas end users, and are they acceptable?**

  LNG developers are proposing import terminals on the West Coast of North America. Without processing, these natural gas supplies are potentially incompatible with historical U.S. and western gas quality standards and could cause operational problems with thermal power plants and other end users. Although California has been investigating this issue and may adopt modifications to its natural gas quality standards that will protect thermal power plants and other end users, it has yet to do so. Given the interconnected pipeline system, this concern about quality standards may also affect other western states.

Endnotes

[i] U.S. Department of Energy, Energy Information Administration website, “Total Consumption,” “Volume delivered to consumers,” 2004. The value was multiplied by (1000/365) to convert the value from MMcf to Bcf per day, http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[ii] Historical data obtained from the U.S. Department of Energy, Energy Information Administration, *Natural Gas Annual, 1996*, “Census Division Summaries”, pages 70-87, September 1997.

[iii] State of California, Department of Finance, Population Projections by Race/Ethnicity for California and Its Counties 2000–2050, Sacramento, California, May 2004. http://www.dof.ca.gov/HTML/DEMOGRAP/DRU_Publications/Projections/P1.htm

[iv] U.S. Census Bureau, Population Division, Projections Branch, Information & Research Services Internet Staff (Population Division), *Table 6: Interim Projections: Total Population for Regions, Divisions, and States: 2000 to 2030*, Created: April 21, 2005, Last Revised: April 21, 2005 at 11:48:54 AM. http://www.census.gov/population/projections/PressTab6.xls

[v] U.S. Department of Energy, Energy Information Administration, *Natural Gas Annual, 2003*, Table 16, “Natural Gas Delivered to Consumers by State and Sector, 1999-2003”, December 22, 2004. Value was divided to 365 to derive MMcf per day. http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/table_016.pdf

[vi] Statistics Canada, CANSIM table 052-0001, *Projected population for Canada, provinces and territories, July 1, 2000-2026, annual*.

[vii] Same as 4, above.

[viii] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook, 2005*, data for “Figure 35. Average annual growth rates of real GDP and economic factors, 1995-2025”, Report #: DOE/EIA-0383(2005), January 2005. http://www.eia.doe.gov/oiaf/aeo/excel/figure35_data.xls

[ix] Same as 5, above.

[x] Canadian National Energy Board, *Canada’s Oil Sands: Opportunities and Challenges to 2015*, May 2004. http://www.neb-one.gc.ca/energy/EnergyReports/EMAOilSandsOpportunitiesChallenges2015/EMAOilSandsOpportunities2015Canada2004_e.pdf

[xi] Same as 10, above.

[xii] Canadian National Energy Board, *Canada’s Energy Future: Scenarios for Supply and Demand to 2025*, Table A3.7, Demand, Supply Push, Alberta, July 23, 2003. http://www.neb-one.gc.ca/energy/SupplyDemand/2003/English/SupplyDemandAppendices2003_e.pdf

[xiii] California Energy Commission website, *2004 Database of California Power Plants*, updated July 1, 2004. http://www.energy.ca.gov/database/POWER_PLANTS.XLS

[xiv] U.S. Department of Energy, Energy Information Administration website, last modified April 18, 12:01:09 PDT, 2005. http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/diablo.html

[xv] California Energy Commission website, Energy Commission Media Office Power Plant Fact Sheet, updated June 22, 2005, http://www.energy.ca.gov/sitingcases/FACTSHEET_SUMMARY.PDF
[xvi] California Energy Commission, Natural Gas Market Assessment, Document No. 100-03-006, August 2003.
[xvii] The supply chapter uses the term Tcf, or trillion cubic feet, since the amounts discussed are very large. In other chapters, this report uses the term MMcf, or million cubic feet. This report will also use the term Bcf, or billion cubic feet, where appropriate. As a reminder, 1000 MMcf = 1 Bcf and 1000 Bcf = 1 Tcf.
[xviii] The Energy Commission is assuming for modeling purposes of this report that only a Baja-based LNG facility will be built on the West Coast; however it is understood that there may well be other LNG terminals built on the West Coast.
[xix] PG&E defines the Citygate as “any point at which the backbone transmission system connects to the local transmission and distribution system.” http://www.pge.com/pipeline/library/doing_business/glossary.shtml#C
[xx] Same as 13, above.
[xxi] The California Air Resources Board (CARB), the CPUC, the Division of Oil, Gas, and Geothermal Resources, and the California Energy Commission have been conducting an investigation into this matter. The CARB is planning a technical workshop on its standards in August 2005. The CPUC has a proceeding to investigate the need to potentially modify its standards. The four agencies are working together to ensure energy supplies can be increased in a manner that does not cause any significant air quality impacts and does not jeopardize public health and safety requirements.

APPENDIX A: Demand Methodology

Kenneth B Medlock III, Ph.D.
Research Fellow in Energy Studies,
James A Baker III Institute for Public Policy
Rice University

Data used for input to determine demand in NARG are derived from published statistics at the Energy Information Administration (EIA), the National Oceanic and Atmospheric Administration (NOAA), the US Bureau of Economic Analysis (BEA), the US Census Bureau, and offices internal to the California Energy Commission. Demand is forecast regionally for five end-use sectors (residential, commercial, non-chemical industrial, chemical industrial, and power generation). In all sectors except power generation, estimates of the elasticity of demand with respect to weather, gas price, oil price, income, industrial production, and population are obtained through econometric analysis of historical data spanning the time period 1986-2000. The estimates were obtained from the Modeling Subgroup of the National Petroleum Council's recently published study "Balancing Natural Gas Policy" (2003). For the power generation sector, a demand forecast in Western States for use in the NARG model was generated by successive iteration with the power model used by the Electricity Analysis Office of the California Energy Commission. EIA projections from the *Annual Energy Outlook 2005* where used in the remaining states.

A Note on Elasticity

With regard to the estimation of the elasticity of demand for natural gas, simultaneous estimation (the method used herein) enables a distinction between, say, income and price effects. This is important because, for example, any demand projection that is not sensitive to price will overstate the effect of income growth.

Consider the income elasticity of natural gas demand. The income elasticity is defined as the percentage change in energy demand given a one percent change in income holding all else constant, or

$$\varepsilon_Y = \frac{\%\Delta NG}{\%\Delta Y} = \frac{dNG}{dY} \cdot \frac{Y}{NG}$$

where Y denotes the income and E denotes energy. One must use caution, however, when applying this definition of elasticity. It is not sufficient to simply divide the percentage change in natural gas demand by the percentage change in income for a given time period. This approach ignores the affect that other variables may have on demand and leads to erroneous, statistically biased results. To illustrate, recall that the income elasticity of natural gas demand is the percentage change in natural gas demand given a one percent change in income, *holding all else* *constant*. Allowing natural gas demand to be a function of income, price, and possibly some other set of variables, $NG = f(Y, P, \ldots)$, then, in general, the total derivative of natural gas demand is given as $dNG = \frac{\partial NG}{\partial Y} dY + \frac{\partial NG}{\partial Y} dY + \ldots$. If we hold all factors but income constant, this equation reduces to $dNG = \frac{\partial NG}{\partial Y} dY$. We can then multiply both sides by $\frac{1}{dY} \cdot \frac{Y}{NG}$ to yield

$$\frac{dNG}{dY} \cdot \frac{Y}{NG} = \frac{\partial NG}{\partial Y} \cdot \frac{Y}{NG}.$$

The left-hand side of this equation is by definition the income elasticity of energy demand, but we only arrive at this result *when all variables except income are held constant*. It is a simple matter to show that if all other variables are not held constant then there will be a remainder term on the right-hand side of the above equation (i.e.- the term in brackets below)

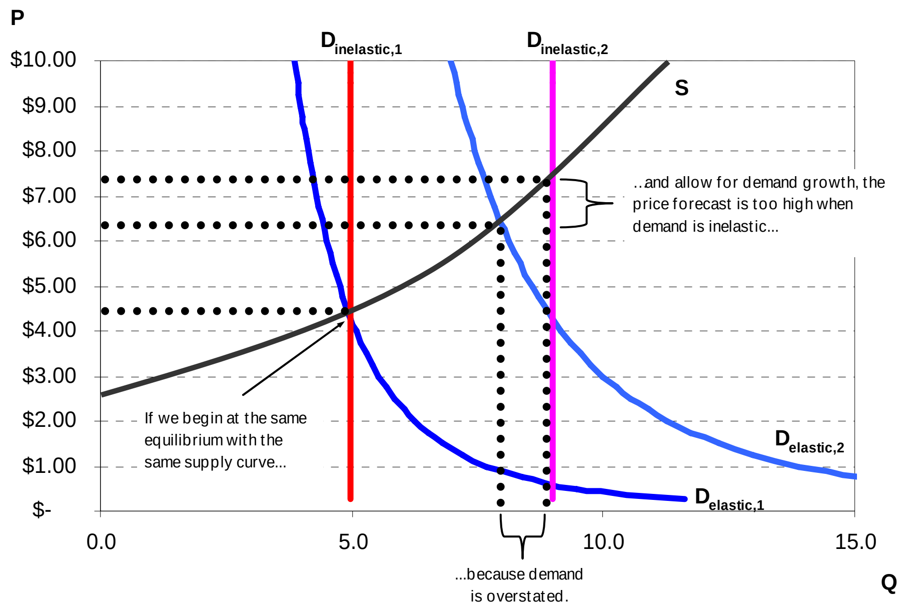
$$\frac{dNG}{dY} \cdot \frac{Y}{NG} = \frac{\partial NG}{\partial Y} \cdot \frac{Y}{NG} + \left\{ \frac{\partial NG}{\partial P} \cdot dP \cdot \frac{1}{dY} \frac{Y}{NG} + \ldots \right\}.$$

If, therefore, we seek an estimate of income elasticity, we cannot ignore the other relevant variables as it introduces a bias similar to the term in brackets.

For a numerical example, consider the following. If natural gas consumption has been increasing at 2% per year for 10 years, and income has been increasing at 3% per year for the same time period, a naïve approximation of income elasticity would be 0.67 $(= 2\%/3\%)$. However, if we consider that price may have been changing during the last 10 years, then our naïve estimate is biased. Specifically, if price had been falling, then, given a downward sloping demand curve, an income elasticity of 0.67 is an overestimate, and can lead to serious problems when forecasting future demand. *Therefore, when modeling energy demand it is important to recognize that many variables simultaneously influence energy use.*

For a graphical example of this concept, consider Figure 1. As indicated, income growth will tend to shift the demand curve horizontally to the right. If demand is not sensitive to price it is referred to as “price-inelastic” and is represented as a vertical line. If demand is sensitive to price, it is referred to as “price-elastic” and is represented as a downward sloping line. We see in Figure 1 that the income effect, while similar in the cases of both elastic and inelastic demand, results in a lower price when we have price-elastic demand compared to price-inelastic demand. This “price-effect” also works to increase demand when a new source of supply, such as liquefied natural gas (LNG) or Alaskan natural gas delivered via pipeline, is introduced. For example, if LNG can be provided to a market area at a price below that which has been realized historically, we would graphically represent this as an outward shift of the supply curve. The price suppressing effect of LNG, however, will be muted somewhat by the increase in demand that is realized by lower prices.

Figure 1 – Elastic vs. Inelastic Demand

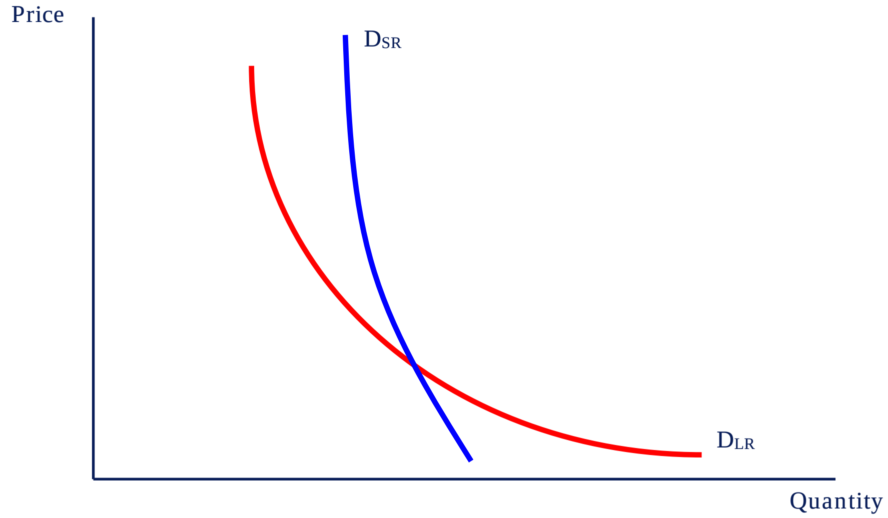


The price elasticity of energy demand is defined as the percentage change in energy demand given a one percent change in price holding all else constant, or

$$\varepsilon_P = \frac{\%\Delta NG}{\%\Delta P} = \frac{dNG}{dP} \cdot \frac{P}{NG}$$

where P denotes the price of natural gas. This measures the influence of natural gas price on energy demand, and bears mention here because the long and short run effects of changes in natural gas prices can be difficult to disentangle. In general, energy demand is predicated on ownership of an energy-using capital good, the owner's decision as to the energy efficiency of the capital good, which is made when the capital is purchased, and utilization of the capital good. Once an energy-using capital good has been purchased, the capital utilization decision will dictate the responsiveness of energy demand to price in the short run, assuming the short run implies that capital and technology are fixed so that the consumer cannot 'trade-up' to higher energy efficiency. In the long run, however, the consumer is free to turn over capital equipment in favor of higher energy efficiency. Thus, the long run response to price involves a decision on both capital utilization rates and energy efficiency. The resulting effect on demand responsiveness to price can be illustrated as in Figure 2. In general, we see that the long run responsiveness in demand to higher prices is greater than in the short run, as consumers can adjust capital stocks accordingly. *The estimation methodology applied herein utilizes a Koyck lag* *specification in order to differentiate between the short and long run elasticity with respect to all relevant variables.*

Figure 2 – Long run versus short run demand elasticity



In estimating demand by end-use sector, we must obtain suitable data and choose the appropriate econometric specification. In each end-use sector, various specifications of demand were tested, and variables with no statistical explanatory power were sequentially dropped from the analysis until a suitable functional form was obtained. Accordingly, residential and commercial sector demand is taken to be a function of income, population, weather, and the price of natural gas. Industrial demand, in both the chemical and non-chemical sectors, is taken to be a function of industrial production, the price of natural gas, and the price of crude oil. Population data is obtained from the U.S. Census Bureau, natural gas demand data, natural gas price and oil price data are all obtained from the U.S. EIA. Income and industrial production data are obtained from the U.S. Bureau of Economic Analysis and the Federal Reserve Bank, and heating degree day data are obtained from NOAA.

The parameters for each of the demand functions (see below) are estimated using a dynamic panel specification. Standard estimation procedures (such as ordinary least squares) applied to a model using dynamic panel data may be inconsistent due to correlation between the lagged endogenous variable and the error term.[1] Therefore, a suitable alternative must be chosen. We apply two-stage least squares

---

[1] For background in the estimation of dynamic panel data models see, among others, Matyas and Sevestre (*The Econometrics of Panel Data: Handbook of Theory and Applications*, Kluwer Academic Publishers, 1992), Balestra and Nerlove ("Pooling Cross Section and Time Series Data in the Estimation of a Dynamic Model: The Demand for Natural Gas," *Econometrica* 34, 1966), and Hsaio (*Analysis of Panel Data*, Cambridge University Press, 1986). One applied study of considerable interest is that of Baltagi and Griffin ("Pooled estimators vs. their heterogeneous counterparts in the context of dynamic demand for gasoline," *Journal of Econometrics* 77, 1997). They evaluate the out-of-sample forecast performance of a number of estimators that have been proposed for a dynamic panel data model applied to a very well researched field, gasoline demand.

(2SLS) regression to estimate the parameters in the demand equations, using as instruments for the lagged endogenous variable present and lagged values of the regressors.

In forecasting demand, the model equates demand and supply in each period by adjusting price. Thus, price is endogenous, but all other variables in the demand functions are taken to be exogenous. As a result, forecasts of those variables are required prior to each model run. It should be noted that variations in the assumed forecasts for the exogenous variables are an important component of scenario analysis.

Residential Demand

Residential demand for natural gas, $q^*_{res,i,t}$, is assumed to be a function of population, $pop_{i,t}$, natural gas price, $p_{i,t}$, GDP, y_t, and weather, $hdd_{i,t}$. More specifically, we assume residential demand can be given as

$$q^*_{res,i,t} = A_{res,i}\, pop_{i,t}^{\alpha_1}\, p_{i,t}^{\alpha_2}\, y_t^{\alpha_3}\, hdd_t^{\alpha_4}$$

where *i* denotes the region and *t* denotes the time period, and the term $A_{res,i}$ is a region-specific constant term. Residential demand within a region is thus assumed to be a function of population, price and weather within that region, as well as national income. We can take the natural logarithm of both sides of the above equation and assume a Koyck lag adjustment mechanism of the form

$$\left(\ln q_{res,i,t} - \ln q_{res,i,t-1}\right) = \gamma\left(\ln q^*_{res,i,t} - \ln q_{res,i,t-1}\right) \text{ where } \gamma = (0,1]$$

to yield

$$\ln q_{res,i,t} = b_{res,i} + \beta_1 \ln pop_{i,t} + \beta_2 \ln p_{i,t} + \beta_3 \ln y_t + \beta_4 \ln hdd_{i,t} + (1-\gamma)\ln q_{res,i,t-1}$$

where the term $b_{res,i}$ is a region-specific intercept. We assume a lag adjustment mechanism in order to differentiate between the long and short run impacts of changes in demand induced by changes in the independent variables. Such lags may be generated by capital stock turnover, habit-persistence, etc. The mechanism allows that adjustment to the long run be instantaneous if the parameter γ, which is referred to as the speed-of-adjustment coefficient, is equal to 1. The parameters β_i are estimated directly and are the short run elasticities of demand with respect to population, price, income and weather, respectively. The long run elasticities, α_i, can be recovered by dividing β_i by γ.

The estimated coefficients, or elasticities, have the appropriate sign ($\beta_1, \beta_3, \beta_4 > 0$ and $\beta_2 < 0$). This tells us that an increase in population, a decrease in the price of natural gas, an increase in income, or an increase in heating degree days will have a positive influence on the quantity of gas demanded in the residential sector. (See Table 1 for a summary of the parameter estimates.)

Commercial Demand

Commercial demand for natural gas, $q^*_{com,i,t}$, is also assumed to be a function of population, $pop_{i,t}$, natural gas price, $p_{i,t}$, income, y_t, and weather, $hdd_{i,t}$. Thus, commercial demand is assumed to be determined by the same factors as residential demand. Allowing for a Koyck adjustment mechanism to distinguish between long and short run effects results in the following equation describing commercial demand

$$\ln q_{com,i,t} = b_{com,i} + \beta_1 \ln pop_{i,t} + \beta_2 \ln p_{i,t} + \beta_3 \ln y_t + \beta_4 \ln hdd_{i,t} + (1-\gamma)\ln q_{com,i,t-1}$$

where the term $b_{com,i}$ is a region-specific intercept. As before, the parameters β_i are estimated directly and are the short run elasticities of demand with respect to population, price, income and weather, respectively. The long run elasticities, α_i, can be recovered by dividing β_i by γ. Note, however, that despite the similarities in functional form, the estimated elasticities in the commercial sector need not be the same as those in the residential sector (and indeed they are not).

The estimated coefficients, or elasticities, have the appropriate sign ($\beta_1, \beta_3, \beta_4 > 0$ and $\beta_2 < 0$). This tells us that an increase in population, a decrease in the price of natural gas, an increase in income, or an increase in heating degree days will have a positive influence on the quantity of gas demanded in the commercial sector. (See Table 1 for a summary of the parameter estimates.)

Industrial (Chemical/Non-Chemical) Demand

The National Petroleum Council Demand Sub-group went to extensive effort to model industrial demand by component. Specifically, demand was separated into Industry Group, End-use, and Region. (The reader is referred to “Balancing Natural Gas Policy” (2003) for more detail on the methodology used by the NPC.) In effort to honor the detailed analysis done by the Demand Sub-group, the Modeling Sub-group used a collection of outputs from the Industrial Demand Sub-module to estimate elasticity. The data were aggregated into two broadly defined industrial sectors – Chemical and Non-chemical. Then, model generated forecasts of price and demand along with the associated oil price and industrial production forecasts were used to estimate the elasticity of demand in each sector with respect to each of the variables.

Industrial demand (both chemical and non-chemical) for natural gas, $q^{*}_{ind,i,t}$, is assumed to be a function of industrial production, ip_t, natural gas price, $p_{i,t}$, and oil price, $poil_{i,t}$. (It should be noted here that although the functional forms are the same, the parameter estimates are distinctly different across each sector.) More specifically, we assume industrial demand can be given as

$$q^{*}_{ind,i,t} = A_{ind,i} ip_t^{\alpha_1} p_{i,t}^{\alpha_2} poil_{i,t}^{\alpha_3} .$$

Again, we can take the natural logarithm of both sides of the above equation and assume a Koyck lag adjustment mechanism to yield

$$\ln q_{ind,i,t} = b_{ind,i} + \beta_1 \ln ip_t + \beta_2 \ln p_{i,t} + \beta_3 \ln poil_{i,t} + (1-\gamma)\ln q_{ind,i,t-1}$$

where the term $b_{ind,i}$ is a region-specific intercept. As before, the parameters β_i are estimated directly and are the short run elasticities of demand with respect to industrial production, natural gas price and oil price, respectively. The long run elasticities, α_i, can be recovered by dividing β_i by γ.

The estimated coefficients, or elasticities, have the appropriate sign ($\beta_1, \beta_3 > 0$ and $\beta_2 < 0$). This tells us that an increase in industrial production, a decrease in the price of natural gas, or an increase in the price of oil will have a positive influence on the quantity of gas demanded in the industrial sector. (See Table 1 for a summary of the parameter estimates.)

Parameter estimates and NARG model execution of the demand methodology

The parameter estimates along with standard errors and a goodness-of-fit measure are summarized in Table 1. Note that the parameter estimates are interpreted as elasticities since the data where transformed into natural logarithms prior to estimation.

Table 1 – Parameter estimates and standard errors

	SECTOR			
	Residential	**Commercial**	**Industrial**	**Chemicals**
Own Price(t,i)	**-0.2270**	**-0.2104**	**-0.0919**	**-0.2903**
standard error	*0.0234*	*0.0284*	*0.0242*	*0.0681*
Cross Price(t,i)			**0.0251**	**0.0734**
standard error			*0.0227*	*0.0227*
GDP(t)	**0.1559**	**0.4000**		
standard error	*0.0330*	*0.0645*		
Industrial Production(t)			**0.0368**	**0.2522**
standard error			*0.0171*	*0.0967*
Heating Degree Days(t,i)	**0.5175**	**0.2913**		
standard error	*0.0314*	*0.0391*		
Population(t,i)	**0.7807**	**0.1776**		
standard error	*0.0623*	*0.0667*		
Q(t-1,i)	**0.2398**	**0.4658**	**0.4467**	**0.6836**
standard error	*0.0426*	*0.0731*	*0.0077*	*0.0107*
R^2	**0.9327**	**0.9568**	**0.9958**	**0.9937**

In order to use the estimated elasticities from the NPC version of NARG, it was first necessary to recalibrate the region-specific constant term to match the regional aggregation present in the CEC version of NARG. For each sector and region, this is done by setting the constant term so that the resulting demand estimate matches the historical value of demand for that sector and region. This is done for several years of data, and an average is taken for forecasting purposes. To reiterate, the calibration chooses the constant term so that, given the parameter estimates in Table 1, predicted demand equals actual demand. Or, for example, in the residential sector in region *i*, we have for 1997 the following calibrated constant term $b_{res,i}$,

$$b_{res,i} = \ln q_{res,i,1997} - \left(\beta_1 \ln pop_{i,1997} + \beta_2 \ln p_{i,1997} + \beta_3 \ln y_{1997} + \beta_4 \ln hdd_{i,1997} + (1-\gamma)\ln q_{res,i,1996}\right)$$

where such a calculation would be made for all years for which there is historical data available (1998-2004). Then, the average calibrated constant term is used to forecast 2005 and all subsequent years. (Note that there is little variation in the calibrated constants from year to year, and all are reasonably close to the values estimated by the NPC.) Similar calculations are also made for the commercial and industrial sectors.

Demand forecasts in each sector are then generated for a “reference” set of prices. The resulting “reference demand” forecasts are loaded into the NARG model along with the reference prices, the price elasticity and the parameter describing the impact of lagged demand. NARG then forecasts demand based on the internally-solved price, which is based on market balance. Therefore, the demand forecast generated by the model will differ from the reference forecast to the extent that the model-solved price differs from the reference price.