CALIFORNIA ENERGY COMMISSION

CALIFORNIA NATURAL GAS ANALYSIS AND ISSUES

STAFF REPORT

NOVEMBER 2000
P200-00-006

STATE OF CALIFORNIA ENERGY COMMISSION 1975 2000

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CALIFORNIA ENERGY COMMISSION

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California
Natural Gas Market Analysis
And
Issues

November 21, 2000

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Key Observations and Conclusions

The substantial North American natural gas resources can meet the nation s demand for at least the next 50 years, at current consumption levels.

California imports about 85 percent of natural gas used in the state.

The physical capacity of interstate pipelines appears adequate, when used in conjunction with in-state storage capability. Local constraints can still be a problem.

Current high natural gas prices are a short-term phenomenon.

Low natural gas prices over the last few years reduced drilling activity, causing wellhead production capability to lag behind growing demand. Today s higher natural gas prices have spurred increased drilling activity in known gas fields. As these new wells start producing natural gas, prices should decline to long-term market equilibrium levels.

Current high electricity prices are substantially above the incremental cost increase attributable to recent natural gas price increases.

Summer natural gas demand is higher owing to increased electricity generation as a result of reduced electricity imports.

Normally, winter peaking demand leads to tight natural gas supplies. This summer, gas demand for electric power generation has also led to tight supplies in some areas within California.

EXECUTIVE SUMMARY

As part of a continuing, comprehensive analysis of natural gas markets in the continental U.S., Canada, and Mexico, the California Energy Commission prepares long-term forecasts of natural gas demand, supply availability, and market equilibrium prices. For California, the Energy Commission estimates the retail prices for each sector consuming natural gas in the state over a twenty-year forecast horizon. From a long-term perspective, with the proved reserves and potential resources that can be economically developed, current demand levels can be satisfied for a period of over 50 years. Results of this analysis will be published in the Energy Commission s *Natural Gas Market Outlook, 2000-2020*. The intent of the long-term analysis is to support key energy policy analysis on issues such as early warnings of the need for new, or expansion of existing, natural gas pipelines and fuel dependency concerns.

Over the past six months, natural gas prices at the wellhead have far exceeded the price levels suggested by long-term market fundamentals. Prices at the California border have also been at record levels, considerably higher than any other part of the country. For instance, the natural gas price at the Topock border crossing (Arizona to California), where gas from the southwest producing regions enter the state, was \$4.40 per MMBtu in June 2000 compared to prices of about \$2.40 per MMBtu a year ago. Further, following the explosion of the El Paso natural gas pipeline segment in New Mexico on August 19, 2000, prices rose an additional \$2.00 per MMBtu reaching about \$6.40 per MMBtu. The cost of natural gas to the state is nearly \$15 million more per day than in June 2000 and nearly \$30 million per day higher than a year ago. In 1999, total natural gas expenditures averaged about \$18 million dollars per day. While summer prices far exceeded long-term price trends, supply and demand expectations for the coming winter have already pushed California border prices above \$10.00 per MMBtu.

The path to current price levels began several years ago. Very low natural gas prices over the past decade prompted gas producers to reduce investment in drilling for new supplies. The resulting slower growth rate in developing and producing natural gas is one of the primary reasons for the current high natural gas prices. As demand continued to rise this summer, growth driven by increased use of natural gas for power generation and temporary limits on gas production capability (as opposed to a limit of natural gas resources) has pushed prices higher. Long-term supplies remain abundant relative to current and projected demand. Nevertheless, as a result of high prices, natural gas producers have increased their drilling efforts, and in the next one to three years as more producing wells come on-line, prices should ease, trending towards previous levels. In the interim, high natural gas prices can be a serious burden for natural gas consumers.

Growth in demand for power generation in California s neighboring states has consumed much of the surplus generating capacity that once provided high levels of cheap imports of electricity. This is forcing California to rely more on in-state generation than in the recent past. Since most summer peak electricity generation in California is met by natural gas fueled power plants, natural gas demand has risen to very high levels. The combination of reductions in electric imports, increased national competition for natural gas supply, and current high demand for both commodities, has led to higher electricity and natural gas prices in the U.S. and particularly within California. The market price for electricity has reached record high levels, even in off-peak demand hours. High wholesale electricity prices allow generators to recover the costs of high natural gas prices, leading to a willingness on the part of the generators to pay the higher natural gas prices.

Very high demand for electricity due to extreme air conditioning loads combined with limitations on transmission lines into the San Diego region has given rise to periodic curtailments of interruptible electric customers this summer. The power generators within this region have been running at high operating loads, requiring more natural gas than ever before. The start of delivering natural gas to Mexico in June 2000 has compounded the problem. Several times, the pipeline capacity to deliver natural gas into the San Diego region has approached maximum possible levels, resulting in the potential need for natural gas curtailments. Fortunately, during the summer, natural gas curtailments were not necessary. However, if the natural gas market continues to be as tight in the future, natural gas curtailment is a significant possibility in the San Diego region. Early indications of this situation were observed November 14 to 15, 2000.

Rising energy costs and maintaining reliability in energy supply are significant concerns for many Californians. Changes in market fundamentals are affecting the way decisions are made by participants. Unlike the long-term contracts and regulated environment of the past, today s restructured electricity market and soon-to-be restructured natural gas market are changing the way energy transactions occur. Short-term contracts and spot market transactions increase the volatility in market clearing prices, as observed in today s market.

This paper presents the fundamentals of the natural gas market to put current conditions in a larger context. It also identifies actions being taken or that should be taken by industry and government to address the situation and offers actions to take to prepare for this winter, when natural gas use for residential and commercial space heating normally drives demand to the highest levels.

Key Issues

From an analytical perspective there are several key issues that should be identified and addressed:

> **Status of Core and Noncore Storage:**
> Natural gas storage should normally be filled by November 1, 2000, the normal start of the winter heating season. One critical concern is whether utilities will be able to store sufficient gas to meet wintertime core demand, mainly residential and small commercial customers, in light of last summer s gas withdrawals to meet high electricity demand.

To what extent will actions of noncore customers--industrial and power generators--electing to play the winter spot market rather than obtaining storage, impact natural gas supply and price?

Interstate Pipeline Capacity:
El Paso Energy has contracted for a large portion of El Paso Natural Gas Co. pipeline capacity. If this capacity is not fully utilized, either by El Paso Energy or otherwise made available to the market, reduced pipeline import capacity will affect California prices.

What are the impacts of new electric power plants that secure gas directly from interstate pipelines that serve California (new power plants in the state and in neighboring states) on utility system reliability?

Regulatory Actions:
The state and federal regulatory actions stimulate the utilities to add the necessary pipeline capacity to be able to receive and deliver increased amounts of natural gas needed to meet long-term market requirements.

How can the curtailment rules and methods be improved to minimize disruptions in service during peak gas demand conditions?

Electricity Markets:
Natural gas is a valuable commodity in California because, in most instances, there is no other alternative fuel. During the past decade, large gas consumers became more reliant on natural gas. Up until recently, economics have been favorable for using natural gas.

How should the current electricity market be restructured to minimize disruptions in service during peak gas demand conditions?

Remedies and Recommendations

Market Responses:
The natural gas market has responded to the current situation in several ways:

A primary cause for the tightness in production capability was the decreased drilling activity lowering natural gas production capability. The average for the past ten years was 454 rigs drilling for natural gas, recently dropping to 371 in April 1999. With an increase in the gas price, drill rig utilization has reversed. The count is now up to 813 as of the first of September, signifying an increase in future wellhead production.

Several new natural gas pipeline proposals are being considered to enhance supply deliverability to the state.

Government response:
The California Energy Commission and the California Public Utilities Commission (CPUC) need to take immediate steps to ensure that information is made available to all participants and to

take quick action to alleviate current problems. Following are actions that should be taken by the Energy Commission and the CPUC.

California Energy Commission will:

- Prepare well-documented, reliable, and objective short- and long-term natural gas market assessments to anticipate market aberrations and allow time for corrective actions. The natural gas and electric utilities are no longer making these assessments. With input and critique from the utilities and other industry participants, the Energy Commission will provide this service.
- Develop natural gas demand, supply and price forecasts from a short-term perspective (one to three years), in addition to the present long-term analysis. This will include seasonal demand estimates and in-state and out-of-state pipeline needs assessments.
- Collect, analyze and disseminate historical data.
- Enhance participation in state and federal regulatory proceedings, providing the benefits of the Energy Commission s analysis.

California Public Utilities Commission should:

- Consider an Order Instituting Investigation (OII) to examine the current situation of higher-than-normal prices and possible delivery constraints on natural gas pipelines in the state.
- Review natural gas utility curtailment rules. Make adjustments to the rules as needed to meet current and evolving natural gas market conditions.
- Expedite the regulatory process for approving in-state pipeline capacity additions for transmission and distribution. Current processes are time intensive. The CPUC s process for in-state pipeline capacity additions could range from two to three years in regulatory phase alone. This slows the ability for pipeline companies to meet fast-changing market conditions.
- Develop a strategy to mitigate the loss of oil as a back up fuel to natural gas fired electricity generation. Concerns over emissions have led to almost exclusive use of natural gas in thermal power plants in California. The natural gas supply system, however, was designed under the assumption that power plants could use fuel oil when natural gas supplies were tight. Oil burning is no longer an option. Consequently, an important safety valve to relieve pressure on the natural gas system has been eliminated. Both increased in-state natural gas storage capacity and interstate pipeline delivery capacity are likely needed to compensate for the loss of the oil burning option.

NATURAL GAS MARKET ANALYSIS

Introduction

The California Energy Commission conducts a comprehensive analysis of the natural gas market in the U.S., Mexico, and Canada. The result is a 20-year forecast of supply availability and prices for each market sector consuming natural gas in California. This analysis includes resource evaluation, pipeline capacity needs, natural gas demand and wellhead prices, and costs of transportation and distribution. The intent of this long-term analysis is to support long-term investment decisions such as new power plants and addition of new, or expansion of existing, natural gas pipelines. The following is a brief summary of California s natural gas pipeline system, reliability of this system with regard to demand, and current prices and their short-term outlook. The short-term price outlook will be updated about the middle of each month and posted on the Energy Commission s web site at www.energy.ca.gov.

Natural Gas Resource Base

North America has a huge natural gas resource base. This resource base includes proven reserves that are ready to be produced, and an estimate of resources that could be developed and produced economically. With an estimated 975 trillion cubic feet (Tcf) in the U.S. (including nearly 160 Tcf of proven reserves) and 417 Tcf in Canada, this resource base can provide affordable natural gas supplies to serve the nation for the next 50 years at current demand levels.

In addition to these resources, the natural gas industry is moving to develop and bring to market the large resource base located at Alaska s North Slope and the Canadian fields located in the Beaufort Sea and McKenzie Delta regions. It is anticipated that, in six to ten years, 1,000 to 2,000 million cubic feet per day (MMcfd) in supply could be flowing to the U.S. from these regions, benefiting California and other regions.

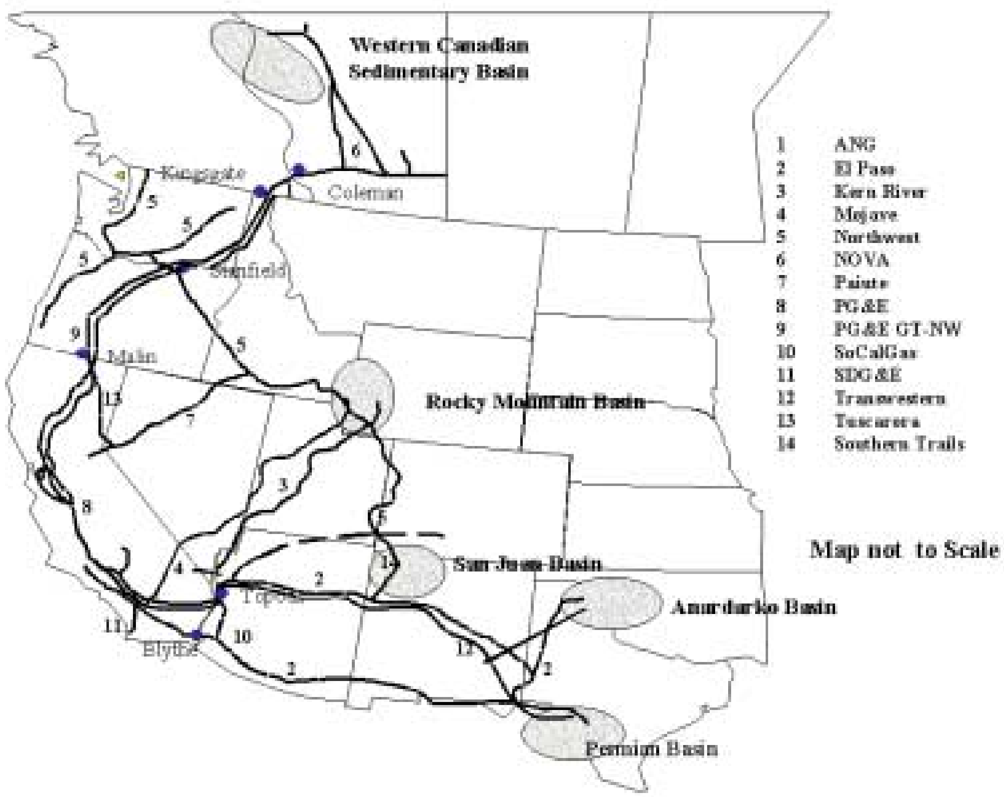
Liquefied natural gas (LNG) is another economic natural gas supply source. LNG imports in recent years have been gradually building. In 1998, the U.S. received on average 234 MMcfd. There are four LNG re-gasification facilities located on the East Coast with a present operational capacity of 1,235 MMcfd. While only two of the facilities are currently functioning, plans are being made to bring the others into operation. When this happens up to 2,565 MMcfd in LNG imports will be possible. Currently liquefaction facilities are being constructed in Trinidad and Venezuela to provide LNG to compete in the U.S. market.

In addition to the sources mentioned above, there are other unconventional natural gas resources that will take many years to develop the technology to produce. Natural gas hydrates is one such unconventional source, consisting of gas molecules frozen between water molecules. Gas is also found in geopressured brines, underground salt-water reservoirs with large quantities of natural gas dissolved in the liquid. It is yet uncertain what the potential is for each of these unconventional resources, but it is thought to be many, many times greater than the present 975 Tcf we are relying on today.

Overview of California Natural Gas Supply and Demand

The inter- and intra-state pipeline system in California has been very reliable for the past decade. Figure 1 displays the major natural gas pipelines in the western U.S. region and the supply regions that serve the California natural gas market. Specific information on each of the pipelines that directly serve California is found in the attachment to this paper.

Figure 1

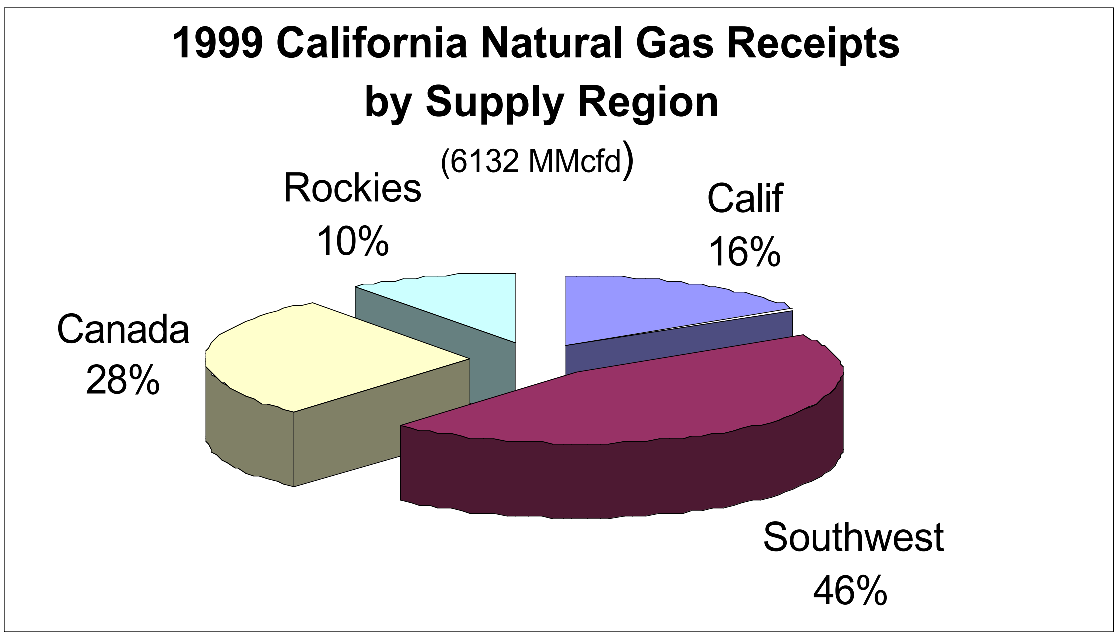


As early as 1989 the Energy Commission s long range forecasts indicated that new interstate pipeline capacity would be needed to serve California in the mid to late 1990s. By the end of 1993, three new pipelines had been built. These pipelines increased capacity to deliver natural gas to California from the Rocky Mountain, San Juan, and Western Canadian Sedimentary basins through three separate pipelines.

The Energy Commission s long-term analysis indicates that to meet average daily conditions, more interstate pipeline capacity will be needed to transport natural gas from these supply regions within the next five years. Several projects are on the drawing boards. Questar, a pipeline that operates in the Rocky Mountain region has received the approval of the Federal Energy Regulatory Commission (FERC) to convert the Four Corners Pipeline to transport natural gas rather than crude oil. The pipeline extends from the San Juan Basin to Long Beach, California. The pipeline is expected to be operating in late 2001. In late 2000, Kern River will be filing an application with the FERC to expand its capacity by 125 MMcfd, to be operational in spring 2002. It is possible that another request for expansion will be filed by Kern River mid-2001 for a yet undisclosed capacity amount. Finally, El Paso purchased the All American Pipeline, a crude oil pipeline. It extends from Santa Barbara, California to Texas. The plans are to convert the pipeline to transport natural gas to the California border. Capacity in this line would be in the area of 100 MMcfd.

The importance of an adequate and reliable interstate pipeline system is evident from the fact that the state imports nearly 85 percent of its natural gas from outside the state. Figure 2 displays the market shares of natural gas supplies from various supply sources for the year 1999.

Figure 2



The natural gas market has more recently been influenced by higher gas demand. Figure 3 displays market shares for the major sectors that consumed natural gas during 1999. The core sector consists of customers receiving bundled services from the utility and includes residential, commercial and small industrial users. The noncore sector usually procures its own natural gas and transportation services and includes large commercial and industrial users. The electric generation sector consists of noncore customers who use natural gas for electricity generation. The nonutility sector includes customers that bypass the utility system. Natural gas consumption is fairly well divided between the major market sectors in the state, namely, the residential, commercial, industrial and electricity generation sectors.

Figure 3

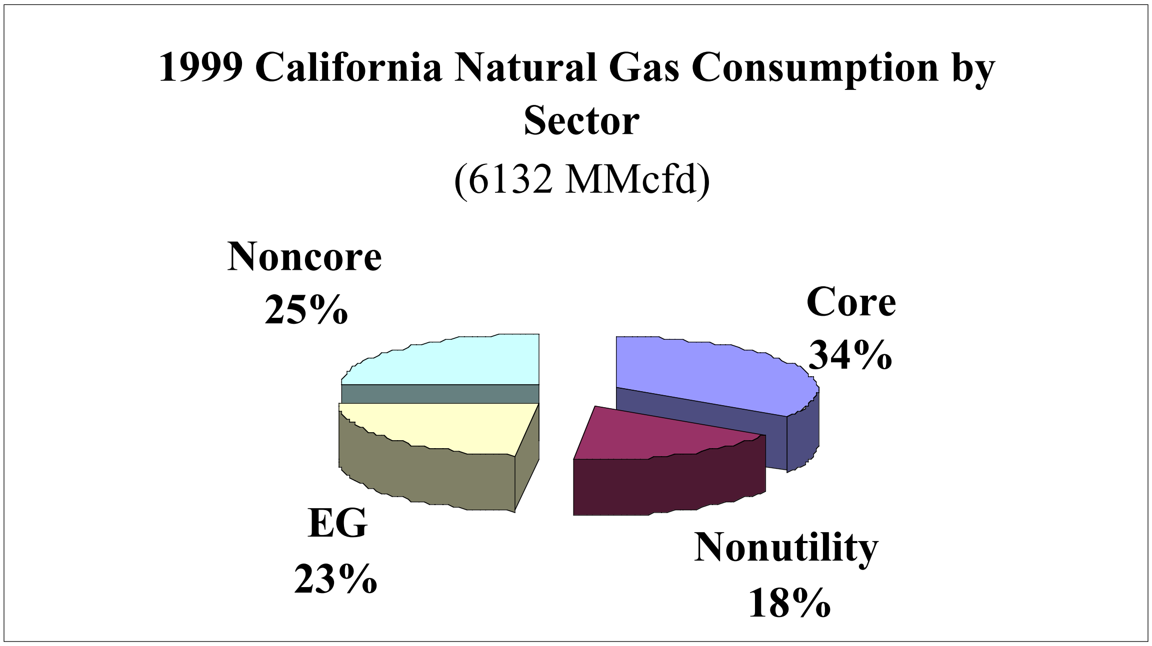
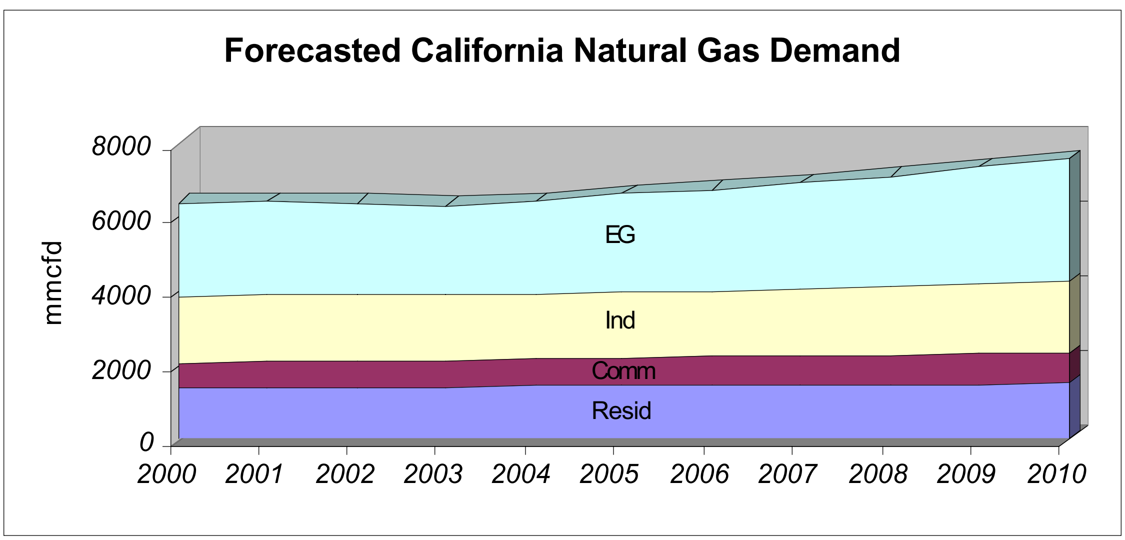


Figure 4 displays California s forecasted natural gas demand. The State s natural gas use over the next decade will increase from 6,400 MMcfd in 2000 to 7,500 MMcfd by 2010. While residential, commercial, and industrial sectors grow gradually over the period, the demand for gas to meet electric generation is driving the forecast.

Figure 4



The annual average natural gas demand growth for electric generation is expected to be about 2.5 percent. This growth in natural gas demand by electric generation mirrors the annual average increase in electricity needs. In the short-term, more efficient generation should displace electric generation from the older, less efficient units. By 2003 the net annual demand for electric generation will bottom out at 2,400 MMcfd then rise to 3,300 MMcfd by 2010. This estimate could change if, over the next five years, current trends in in-state generation continue, resulting in higher natural gas demand for in-state power generation.

Figure 4 depicts a healthy growth in natural gas consumption for the State. The Energy Commission s past analysis has centered on assessing the long-term trends in the natural gas market. Increasing demand for electricity is raising some levels of concern about the adequacy of the utility and interstate pipeline capacity to deliver needed natural gas supply to California. In particular, peak summer demand will continue to grow. Winter peak demand for space heating is also increasing. When coupled with continued reliance on natural gas for electric generation, there is the potential that the pipeline capacity to deliver gas to California electricity generators and to other customers within the state may be stretched on days of peak demand. This gives rise to questions regarding the reliability of the natural gas infrastructure and its adequacy to serve the state s peak demand. These issues are discussed in the following section.

Reliability of the California Natural Gas System

As discussed above, the natural gas infrastructure in California has been adequate for over a decade. This section discusses the current ability of each of the natural gas utilities in the state to deliver natural gas to its customers.

San Diego:

In the San Diego area, the natural gas infrastructure is approaching the limits of its capability to deliver natural gas. For example, on a cold day in January 1999, natural gas demand in the San Diego Gas and Electric (SDG&E) service area almost exceeded the delivery capacity. In addition, during the summer of 2000, SDG&E, on several occasions, barely met its customers gas demand without curtailing service. The situation in San Diego is compounded by the fact that since June 2000 SDG&E started delivering natural gas to Mexico to meet power generation gas demand at the Rosarito Beach facilities.

The SDG&E service area is at the end of a very long pipeline system. The only links to natural gas supplies are two pipelines from SoCal Gas, with no physical gas storage capability within the region. Hence the flexibility to meet peak demand is limited. Besides supply entering its system, SDG&E can draw upon a small amount of natural gas it can store in its pipeline system by increasing the compression in the pipeline. If that were not adequate, then service would need to be curtailed to some of its natural gas customers. Although SDG&E can maintain a supply of gas in underground storage facilities located in the SoCal Gas service area, that gas must flow through the same constrained pipeline system, pushing delivery facilities to their limits during peak periods.

Recognizing the potential for summer time curtailment, SDG&E petitioned the California Public Utilities Commission (CPUC) to change its curtailment rules. In summer 2000, it asked to be able to curtail the firm service it had agreed to provide to the Encina, South Bay and Rosarito power plants without interrupting service to its residential, commercial and industrial customers. These power plants all have the capability to burn residual fuel oil.

Although too late to be useful this summer, this petition could lead to policy that may be needed in the near future. After receiving comments from various parties, the CPUC Energy Division, on September 14, 2000, issued a proposed resolution denying the petition.[1] If adopted by the CPUC, the resolution would rule that [i]n the event a curtailment of gas transportation is necessary due to system capacity restraints, SDG&E shall be required to curtail the Rosarito plant first and only during each and every curtailment until adequate capacity is built to support the Rosarito load. In the event the total capacity utilized by the Rosarito plant at the time a curtailment is called is not adequate to support the necessary required reduction, the remaining amount of load to be curtailed will be taken from the remaining power plants on a pro rata basis, simultaneously.

In addition, the proposed resolution states that [t]he Commission shall open an Investigation (OII) into the activities of Sempra Energy, SoCal Gas and San Diego Gas and Electric with regard to the planning of the SDG&E gas transmission system and the providing of service to the Rosarito plant. The proposed resolution was to be considered at the October 5, 2000 CPUC business meeting. However, prior to the meeting, SDG&E withdrew the petition.

As a result of the withdrawal, the staff proposed resolution is nullified. Existing curtailment rules remain in effect, i.e., large industrial and power generation customers, including the Rosarito power plant, will be equally subject to curtailment on a rotating basis. At its business meeting on October 19, 2000, the CPUC will consider an OII into the planning of SoCalGas' and SDG&E's gas transmission system and transmission service to the Rosarito Power Plant and various matters related to transmission capacity.

Southern California Gas Company:
Currently, the SoCal Gas service area has flexibility to meet its natural gas customer needs. But during the past couple of years, the company has had to depend more often and for longer periods of time on its storage to meet summer natural gas demand. This is because its supply receipt points are operating at maximum capacity during this time and more gas is needed to meet customer needs. Major net gas injections had been delayed until September and October to insure storage is ready to meet winter demand that begins on November 1st. SoCal Gas should evaluate the need to expand intrastate pipeline receipt capability. As indicated on the pipeline map shown in Figure 1, expansion options would be at Wheeler Ridge (supply from PG&E, Mojave/Kern River and California production in the San Joaquin Valley), Topock (supply from El Paso) and Needles (supply from Transwestern). The Topock receipt point is always running full and may be the most appropriate location for capacity reinforcement.

1 CPUC Energy Division Resolution G-3297

Alternatively, the addition of interstate pipeline capacity can alleviate some concerns in the SoCal Gas service area. Both Southern Trails and Kern River pipeline system operators have proposed to provide natural gas delivery service into the Los Angeles Basin. The completion of these proposed projects potentially would increase the supply flexibility in the area, reducing the need for SoCal Gas to add new receipt capacity, and thus increasing competition. Each of the pipeline projects could deliver both to SoCal Gas and directly to noncore consumers.

Pacific Gas and Electric Company:
PG&E has adequate storage to meet its gas requirements for its residential, commercial and small industrial customers. However, with only seven billion cubic feet (Bcf) available for the growing electric generation sector, PG&E s storage is rather inadequate to meet its noncore customer needs. The industry acknowledges this problem and steps are being taken to rectify it. The newly constructed, privately owned gas storage facilities are being developed. To date, 14 Bcf is available at Wild Goose storage field. Additional storage facilities will soon be developed near Lodi.

Another problem looming for PG&E is future capability of the PG&E Gas Transmission line to make gas deliveries at Malin to PG&E. There are a number of new natural gas-fired power plants being sited along the PG&E Transmission pipeline in Oregon and Washington. These new facilities will draw directly from the interstate pipeline. Without the addition of new pipe capacity in Oregon and Washington, PG&E s natural gas supply from PG&E Gas Transmission will be correspondingly reduced. For example, current deliveries of Canadian gas at Malin, Oregon on very cold winter days are limited to about 1,600 MMcfd, about 200 MMcfd below pipeline capacity. The reduction is due to increased demand on the upstream portion of the interstate pipeline. As PG&E winter peak gas demand increases, additional gas transmission capability may be needed to meet peak winter day requirements.

Winter Natural Gas Curtailment for Electric Generators

The present natural gas utility delivery system was neither designed nor built to meet 100 percent of the natural gas demand 100 percent of the time. During the winter, demand reaches its peak when residential and commercial heating loads are high. A gas utility s available supply (including that drawn from storage) could be lower than its customers needs. In this situation, the gas utility curtailment rules provide that large customers (including power plants) would be the first to have natural gas service curtailed.

In the past when gas was unavailable, power plants had the capability to burn fuel oil. They stored over a month s supply of fuel oil in a ready-to-use mode. This, however, is no longer the case. Due to environmental and air quality requirements, only a few of the older power plants in California still have dual-fuel capability[2].

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[2] Recently, the ISO Dual Fuel Study Group recommended that reserving gas storage was preferable to directing generating units to maintain fuel oil-burning capability to ensure electric generation could operate during times of gas curtailment to ensure the reliability of electric supply in the Los Angeles Basin.

The current concern is that natural gas utilities may need to curtail natural gas service to power plants on a cold winter day with high heating load. This has the potential to degrade electric service reliability. The ISO determines when electric curtailments are required and instructs the electric utilities to implement their curtailment plan. However, the natural gas utilities determine the timing and implementation of natural gas curtailment.

On cold winter days, the gas utility curtailment rules require, if necessary, the curtailment of natural gas service to electric generators, even though they no longer have alternative fuel burning capability. When an order from the gas utility to reduce gas consumption occurs, the generator correspondingly will need to reduce its generation levels. Consequently, supply of electricity would be reduced and possibly lead to the ISO asking for the curtailment of electric service.

In December 1998, Northern California experienced a series of very cold days and natural gas supplies were beginning to run short due, in part, to increased gas demand in the Pacific Northwest, which reduced the amount of gas delivered to California at its northern border by 200 MMcfd. To meet its commitments to firm supply customers, PG&E issued a call on its option to purchase gas from one of its large customers based on contractual agreements. Even with this additional supply, PG&E was forced to reduce natural gas service to 80 of its customers over a three-day period. While no natural gas service to central electric generation facilities was curtailed, several cogeneration facilities were forced to leave the gas utility system for a period of time.

During the same cold spell, one of the nuclear electric generation units was down at the Diablo Canyon power plant. The combination of natural gas curtailment and electricity generation capacity shortage forced the ISO to issue a Stage Two Emergency. This required PG&E to initiate voluntary interruption of its electric service to several of its electricity customers.

With all new electricity generation facilities dependent on natural gas, the PG&E December 1998 situation may become more commonplace in the future if corrective measures are not taken. Integrated electric and gas supply and demand analysis is needed. The growing reliance on natural gas for power generation may imply that coincident demand for electricity and gas should be determined, electric generation and transmission line capacity evaluated, and gas supplies and pipeline needs assessed. The natural gas industry should be informed of these results so that they can make the necessary system adjustments.

Beyond this information and analysis, natural gas curtailment regulations need to be reviewed in light of the changing natural gas market. The impacts of such curtailment cross several regulatory boundaries. Coordinated efforts between the CPUC, the ISO, the Energy Commission, the California Air Resources Board (CARB), and Air Pollution Control Districts (APCD), as well as the utilities and customers should be established. Each of these entities has a responsibility or interest when natural gas service is interrupted. The CPUC regulates the utilities and as such is responsible for overseeing the rules the utilities operate under. The ISO is concerned about the potential loss of generation capacity and the resulting impact on electric system stability during very cold weather conditions. CARB and APCDs are concerned with power plant emissions. Utilities have to administer the rules, and other parties may be directly impacted by the rule administration.

To meet the growing gas demand in California, new pipeline and storage capacity will be needed to insure that no curtailment occurs to customers that have elected firm gas capacity. The above regulatory agencies may need to adjust their processes to be more responsive to market dynamics, providing gas utilities with the ability to add more receiving, transmission and delivery capacity. Currently, gas utilities need to include their revenue estimates for major expansions in their Performance Based Rate proceedings before the CPUC, a two-year process. Following this, they must meet environmental requirements by preparing an Environmental Impact Report before construction can begin. From start to finish it could be over five years before a project would be in place. In general, these regulatory agencies may examine how other agencies process capacity additions to complete the regulatory review more efficiently. At FERC, it takes 18 months for regulatory review plus a couple of months for construction. That process requires a minimum of about two years from filing to project operation.

In conjunction with reinforcing storage and pipelines with new capacity, a decision on how to best meet the natural gas peaking requirements in the state needs to be made. Should the current curtailment philosophy of striving to meet only the residential, commercial and small industrial customers on the designed peak day[3] continue? Or, should the design criteria be expanded to meet a higher demand load?

Since alternative fuels are generally not an option, system upgrades will be needed to insure adequate firm gas supply during periods of peak natural gas demand. Peak duration of use may be short and the upgrade may not be needed for extended periods. Cost recovery then becomes a problem. Utilities need a method to recoup their investment costs. What are the alternatives to make the utility whole after making the investment? Who should pay for the capacity? Should the peak users for whom it was designed pay? Or, should all the ratepayers share in the costs? Costs could be allocated on some basis to all the ratepayers. Alternatively, peak demand charges, paid monthly to insure firm service, could be used for the utility to receive a reasonable return on their investment in peak capacity expansion. Time of use payments is one more option. However, this method would not provide timely utility investment recovery, since payments would be sporadic and uncertain.

In carrying out its responsibility for the reliability of the electric system in California, the ISO completed an August 1999 report[4] on the need for options to insure that there was adequate fuel for electric generation during peak winter natural gas demand periods. The fear was that, in the event of severely cold weather, there might not be enough natural gas for power generation to

[3] A design peak day consists of a cold temperature that has been experienced and an estimated demand that would be expected if the temperature were to reoccur. Each gas utility designs for different adverse peak day temperatures.

[4] *Dual Fuel Capability Requirements*, Memorandum from Kellan Fluckiger, August 19, 1999.

preserve the reliability of the electric system in certain areas of the State. The report spoke to the need of maintaining limited amounts of fuel oil burning capability at dual fueled generation facilities located in the PG&E and SDG&E service areas. In the SoCal Gas service area, it was determined fuel oil use would not be necessary as natural gas could be withdrawn from storage.

To ensure system reliability, the report recommended that the following facilities maintain limited dual fuel capability for use when gas is curtailed:

- Potrero Unit # 3 (207 MW in the city of San Francisco)
- At least 220 MW in the greater San Francisco Bay area (at either Pittsburg or Contra Costa facilities)
- Humboldt Units #1 and #2 (100 MW on the North Coast)
- Encina Units #1 through #5 (876 MW in San Diego)
- South Bay Units #1 through #4 (693 MW in San Diego).

Additionally, the report recommended that sufficient natural gas be kept in storage to meet 670 MW of peak generation to service the Los Angeles Basin for one three-day period.

Short-Term Natural Gas Prices

There is an abundant natural gas resource base to serve the nation that is available at reasonable price levels. From time to time market conditions cause prices to either rise above or fall below normal market-clearing long-term price trends. When wellhead deliverability exceeds demand, for example, natural gas prices become soft and tend to drop below the expected long-term trend. Conversely, when wellhead deliverability is exceeded by demand, natural gas prices will rise above the long-term trend.

In competitive markets, price increases are not uncommon. Weather conditions, unexpected disruptions, and natural events may all contribute to upward pressure on prices. As a result, price fluctuations are anticipated and market participants usually take appropriate actions to mitigate such price or supply excursions. However, these temporary price spikes may generate high levels of concern throughout the market. Such is the current situation in North America, and particularly in California, as we prepare for the winter season.

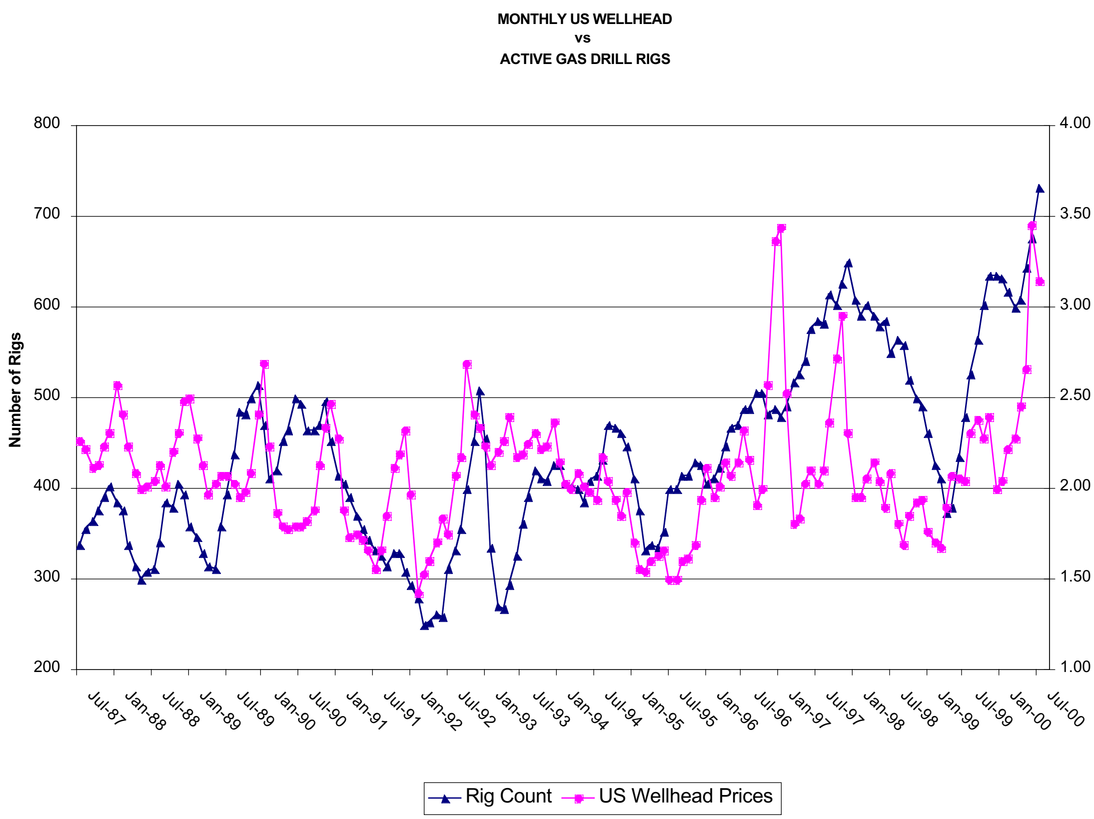
Natural gas spot prices far exceed the Energy Commission s long-term cost-based price trends. California, as well as the rest of the nation, is experiencing abnormally high natural gas prices this year. During the year 1999 the average wellhead or commodity cost for natural gas was about $2.00 per MMBtu. Since the first of the year, natural gas commodity prices at the California border have increased, rising to about $4.30 per MMBtu in June/July 2000. Following the El Paso Pipeline rupture in mid-August, natural gas prices delivered to the California border peaked for a short time at over $7.00 per MMBtu, before retreating to $6.40 per MMBtu. Supply and demand expectations for the coming winter have already pushed California border prices above $10.00 per MMBtu.

Several factors contributed to the current price levels. First, increasing natural gas demand, particularly in power generation, has apparently outstripped production growth. This is because natural gas prices over the past decade have been at low levels. The low prices have not provided the economic incentive for producers to replace natural gas that has been produced with new reserves.

This is illustrated in Figure 5. During the past decade, natural gas wellhead prices have not supported drilling activity. Over the last 10 years, monthly active rigs drilling for natural gas averaged only 454 rigs, which is not sufficient to meet incremental demand. Many in the industry feel that 600 to 800 active drilling rigs are necessary to sustain wellhead deliverability. Because average wellhead prices fell below $2.00 per MMBtu, active rig count dropped to 371 in April 1999. After that point, average wellhead prices in the U.S. began to climb and drilling activity followed. By September 2000, active rig count had risen to 813.

It normally takes from several months to a year before the wellhead supply may be brought to market after the drilling occurs. With sustained higher rig activity, natural gas wellhead deliverability should be in balance with demand in two to three years. At that time, natural gas prices should return to the long-term market clearing prices. In the mean time, high natural gas prices are to be expected.

Figure 5



A second factor contributing to the current level of natural gas prices is the lack of an economic fuel alternative. In California, oil burned for power generation is restricted to only a few power plants and only under the most extreme conditions. In other parts of the U.S., even though natural gas prices have increased, minimal switching to other fuels has occurred because prices for alternate fuels, such as fuel oil and distillates, have also risen to comparable levels. ICF Consulting, however, believes that recent high natural gas prices are the result of high oil prices, not other factors such as increased gas demand for electric power generation, wellhead gas deliverability, or natural gas storage issues[5]. Most analysts believe that natural gas and oil prices have decoupled, because gas markets are driven by gas-on-gas competition. However, ICF notes that its computer modeling of market dynamics indicates that tight gas supplies have caused gas prices to reach parity with oil prices at the burner tip, and prices have again coupled. Recent Henry Hub natural gas prices and UK Brent crude oil prices do appear to track one another[6]. Further, NYMEX futures prices for Henry Hub natural gas and New York Mercantile Exchange futures prices for light sweet crude oil (Cushing, OK) have a fairly strong correlation between October 2000 to September 2002[7]. Commission staff has not yet investigated these issues further.

Finally, with the loss of one of El Paso s pipelines in the August 2000 rupture, California deliveries dropped by 400 to 700 MMcfd. This reduction forced SoCal Gas to withdraw more gas than normal from storage to meet customer needs. The reduction in delivery coupled with the knowledge that the supply drawn from storage would need to be replaced before winter season apparently pushed gas prices to $7.00 per MMBtu at the California border.

California has been paying a premium well above the basis for its natural gas supplies. The term basis is the difference in price for natural gas when it enters a pipeline from a producing area and its price when it arrives at its destination.[8] Normally the basis is the cost added for pipeline transportation. For most of the U.S., this is the case. However, for California prior to the El Paso rupture, the basis was about a $1.00 per MMBtu over the cost to transport. After the El Paso pipeline rupture on August 19, 2000, the basis to California jumped to $2.00 or more over transport costs. This $2.00 jump in prices is costing California ratepayers approximately $15 million per day. Additionally, the increase in natural gas prices at the California border following the El Paso rupture added another $15 million to California s daily cost. So, the current high natural gas prices seen at the state s border has cost consumers about $30 million per day more than last year. The typical bill for natural gas on an average day in 1999 was about $18 million per day.

What has been the reason for the large basis spread for gas delivered to California? The CPUC partially attributed the cause to the awarding, earlier this year, of a huge block of firm capacity on

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5 Oil & Gas Journal Online, September 27, 2000.
6 Oil & Gas Journal, September 25, 2000, page 79.
7 Energy Commission staff analysis, October 13, 2000.
8 If the price for gas entering a pipeline is $2.00 per MMBtu and its delivered price is $2.50 per MMBtu, its basis would be $0.50 per MMBtu.

the El Paso pipeline system to a sister company, El Paso Merchant Energy. The CPUC contends that El Paso Merchant, a natural gas marketer, is trying to control and raise gas prices by withholding some of that capacity from the market[9].

Natural gas is a valuable commodity in California because, in most instances, there is no other alternative fuel. During the past decade, large gas consumers became more reliant on natural gas. Up until recently, economics have been favorable for using natural gas. Gas deliverability to the state became plentiful when new interstate pipeline capacity was added during the early 1990s[10]. This led to a surplus delivery capacity to California and lower natural gas prices due to increased competition to serve California. Additionally, air pollution control districts, with the intent of reducing air emissions, promulgated rules that either directly required the sole use of natural gas or set emission limits that pushed towards the use of only natural gas.

Peak day demand is now beginning to approach interstate pipeline delivery capacity to California and the California utilities ability to receive supply from the interstate pipelines. An indication of this was SoCal Gas recently having insufficient summer time receiving capacity to meet peak summer day gas demand. Instead, SoCal Gas relies on storage to meet peak demand. If summer demand for natural gas is above normal or supply is interrupted, as in the El Paso rupture, SoCal Gas may be unable to re-inject sufficient quantities of natural gas into storage to meet winter demand.

While the utilities will eventually fill the storage for their core customers, regardless of the prices paid today, they are not obligated to store any natural gas to cover other users such as industrial and electricity generating customers. If these interruptible customers do not purchase natural gas for storage to meet their winter needs, the probability of winter curtailments, under situations of gas supply shortages, increases. Additionally, their reliance on flowing pipeline natural gas rather than from storage during peak demand conditions could have the effect of increasing natural gas prices.

A secondary issue with gas demand in the state is in regard to electric generation. California imports a significant amount of electricity from the neighboring states. This year, California has had to rely more on in-state generation than in the recent past. Thus natural gas demand for generation has risen to higher levels, exacerbating the tight situation in the state s natural gas market. Being short in both electric imports and natural gas supply when demand for both commodities has been high has led to higher electricity and natural gas prices.

Natural Gas Price Outlook

In the past, staff prepared natural gas price forecasts based on long-term economics. These forecasts rely on natural gas resource costs that provide market-clearing prices. Short-term phenomena cause a deviation from the anticipated long-term price trends. These phenomena

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9 Federal Energy Regulatory Commission filing (RP00-241), April 2000.

10 With the completion of the Kern River, Mojave, and PG&E-GT pipelines.

include changes in supply and demand due to price changes. Demand changes, for example, are changes in consumption because of price changes or consumers switching their energy use to other fuels. Supply changes could include new pipelines, additional storage facilities, and pipeline capacity modifications.

To account for the recent run up in natural gas prices from short-term phenomena, staff computed a short-term price forecast and used a transition period to move to the long-term. Figures 6 and 7 show natural gas price forecast for electric generating customers. The price forecast looks at the three utilities in California: PG&E, SoCal Gas, and SDG&E[11]. The short-term begins in September 2000 and ends in March 2003. The transition period starts on April 2003 and ends at August 2003. The long-term forecast continues until 2020[12], but the focus here will be until December 2005.

The short-term portion of the forecast correlates the utility s historic prices with the natural gas futures market prices. Futures contracts sold on the New York Mercantile Exchange (NYMEX)[13] provide the foundation of the gas price outlook for the forecast beginning in August 2000 and ending in March 2003. Futures market prices illustrate the gas market s current perceptions and concerns about supply and demand. These parameters can change often. An example of a change would be the El Paso pipeline explosion lowering supply expectations and increasing prices.

In 2003, the forecast transitions from the short-term to the long-term. It is assumed that in about 32 months, most constraints in the gas market decrease significantly. For April through July 2003, prices are interpolated using the average short-term prices for January to March 2003 and subtracting the average long-term prices for August through December 2003. In 2004 and 2005, annual long-term prices are interpolated, based on gas consumption and utility revenues, to determine these monthly prices.

Winter 2000-2001 Natural Gas Prices and Beyond

For this winter, average monthly natural gas prices for utility electric generation may peak at about $6.00 per million British thermal units (MMBtu). Residential customers may face monthly peak prices of about $9.00 to $10.00 per MMBtu because they face higher costs of transmission and distribution. Recently, these costs typically range between $4.00 and $4.50 per MMBtu.

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11 Because of the recent California Public Utilities Commission ruling (Decision 00-04-060), SoCal Gas and SDG&E electric generating customers face the same natural gas transportation rate. Based on the forecast assumptions, the electric generating customers also face the same natural gas prices.

12 A complete description of the long-term forecast can be found in the *2000 Natural Gas Market Outlook, 2000-2020*.

13 The price of a futures contract reflects the current market consensus of commodity price expectations in the future for the following 36 months. The futures price incorporates information about present and future supply and demand of natural gas. The Henry Hub natural gas futures contract is based on delivery of gas to the Henry Hub gas processing plant in southern Louisiana.

The electric generation natural gas price forecasts for the three in-state utilities are displayed below. Figure 6 shows prices for the PG&E utility area and Figure 7 illustrate the prices for SoCal Gas and SDG&E. Residential natural gas prices should follow similar price paths with the addition of transmission and distribution costs.

As seasonal demand likely falls after the heating season, prices should decrease also. Compared to winter 2000-2001 prices, the 2001-2002 winter peak monthly prices should moderate as expected new supplies come to market. As the price forecast moves toward the end of the short-term, prices may range from $3.00 to $4.00 per MMBtu for electric generators.

An examination of historical price behavior and futures market prices suggests current price movements are temporary. There is no reason to believe that prices will remain at their current levels. Drilling activity has climbed to its highest levels in fifteen years. Drilling activity is mainly a response to current high prices and expectations of short-term prices above long-term price trends. This will produce new supplies within one to three years, further adding downward pressures on natural gas prices. The huge natural gas resource base, much of it still untapped, clearly indicates supplies are abundant and that the current higher-than-normal prices will not remain at present levels. Consequently, prices should return to their long-term trends.

During the second and third quarters of 2003, the price forecast transitions from short-term to the long-term. With more supplies becoming available, price expectations fall back to normal long-term trends. Price growth typically increases mainly from overall demand growth. Monthly prices for gas used in electricity generation should range from $2.20 to $3.50 per MMBtu.

Figure 6

PG&E Electric Generation Natural Gas Price Forecast

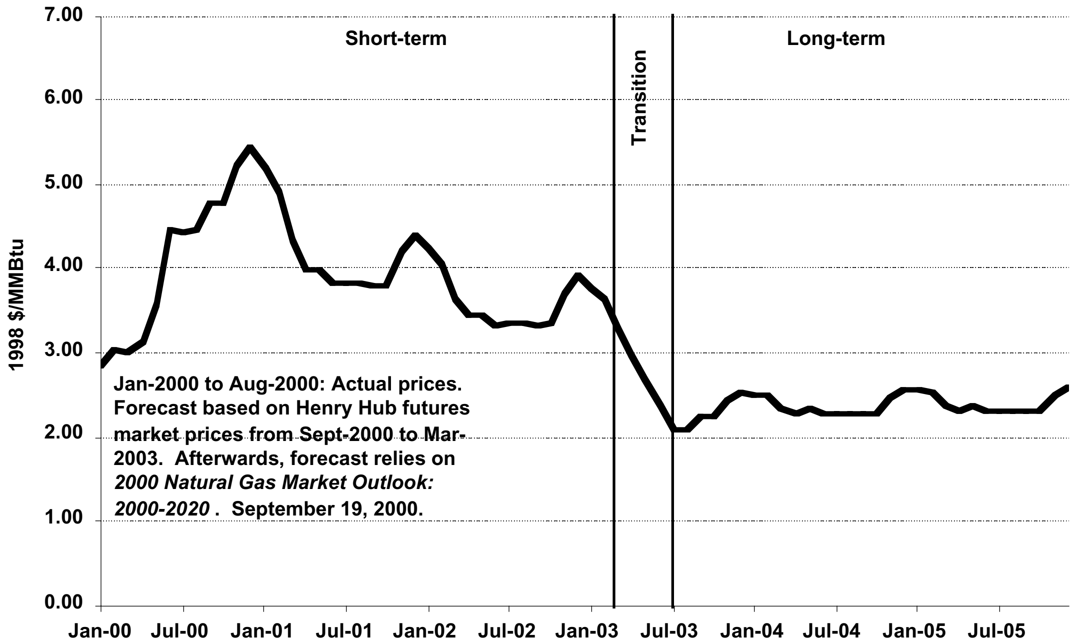
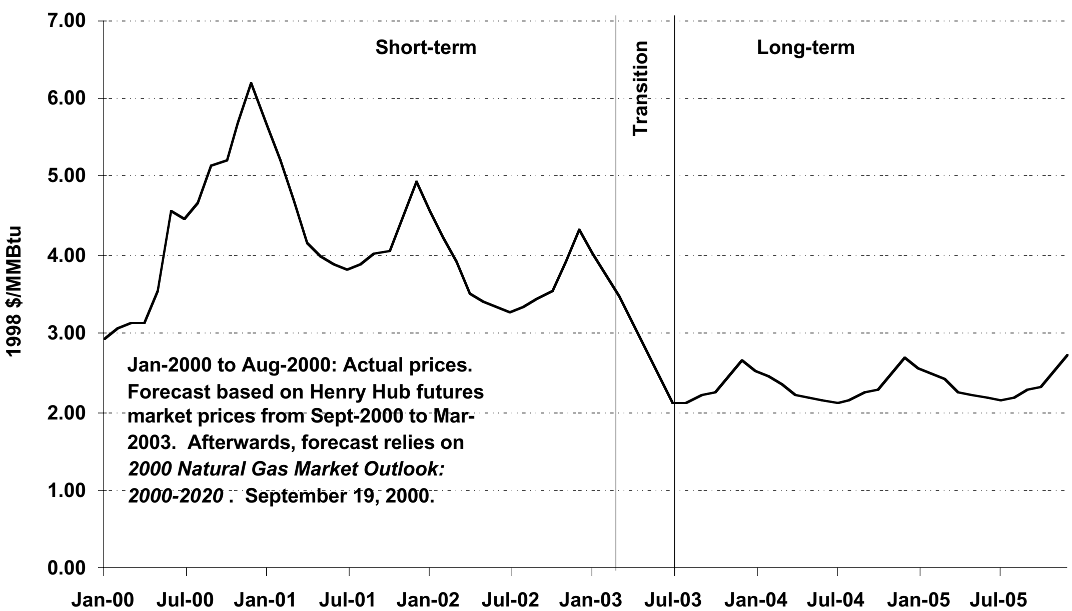


Figure 7

SoCal Gas and SDG&E Electric Generation Natural Gas Price Forecast



Conclusions

Four major conclusions can be derived from this natural gas market analysis:

The substantial North American natural gas resources can meet the nation s demand for at least the next 50 years, at current consumption levels.

The physical capacity of interstate pipelines appears adequate, when used in conjunction with in-state storage capability. Local constraints can still be a problem.

Current high natural gas prices are a short-term phenomenon.

Low natural gas prices over the last few years reduced drilling activity, causing wellhead production capability to lag behind growing demand. Today s higher natural gas prices have spurred increased drilling activity in natural gas fields. As these new wells start producing natural gas, prices should decline to long-term market equilibrium levels.

Attachment

Four major interstate pipelines now deliver natural gas to California (Table 1). Canadian supplies enter California at Malin, Oregon via the PG&E Gas Transmission —North West (NW) system. The gas flows into the PG&E utility s main long-distance or backbone transmission lines from the north. Current capacity to receive natural gas at Malin is 1,833 MMcfd.

TABLE 1
INTERSTATE PIPELINE CAPACITY AND UTILITY TAKEAWAY CAPACITY (MMcfd)

Interstate Pipelines and Delivery Capacity to California		Takeaway Capacity at California Border		
Pipeline	Delivery Capacity	Mojave	PG&E	SoCal Gas
PG&E GT — NW	1,833		1,855	
El Paso	3,530	400	1,140	1,990
Transwestern	1,065			750
Kern River	700			
Wheeler Ridge Receipt Point				600
Total	7,128	400	2,995	3,340

Notes:

- PG&E GT - NW delivery capacity to California is impacted by its gas flow into the Tuscarora system. Tuscarora can take deliveries up to 112 MMcfd from PG&E GT - NW at Malin, reducing California deliveries by up to the same amount.
- PG&E may receive up to 1,140 MMcfd from a combination of El Paso, Transwestern, Kern River, and Mojave deliveries.
- Mojave receives its supply from El Paso and Transwestern.
- Through Wheeler Ridge SoCal Gas receives gas from California production, Kern River, Mojave and PG&E.
- Not listed, but direct deliveries are made by Kern River, Mojave, and from California production to industrial, electricity generation and EOR facilities.

Southwest supplies from the San Juan, Permian, and Anadarko Basins are delivered to the PG&E, SoCal Gas, and Mojave systems at Topock, Needles, and Ehrenburg along the Arizona-California border. The northern part of the El Paso system delivers gas from the San Juan basin to California at Topock and also by moving gas to the south along the Havasu Crossover, to Ehrenburg. Natural gas from the Permian basin, moving on El Paso s southern system, with a capacity of 1,210 MMcfd, is delivered at Ehrenburg. Approximately 750 MMcfd of gas flowing through the Transwestern pipeline system moves gas into the SoCal Gas system at Needles. Since the expansion of the Transwestern system in 1992, another 315 MMcfd of gas can also flow through Topock. No additional intrastate capacity was added to accommodate the expanded Transwestern capacity.

Rocky Mountain supplies enter the State via the Kern River pipeline system. Approximately 700 MMcfd of capacity is available to California with the effective California border point located at Wheeler Ridge in the lower San Joaquin Valley. The Wheeler Ridge receipt point can take gas not only from Kern River but also from Mojave and PG&E systems for delivery into the SoCal Gas service area. Flow at Wheeler Ridge equals 600 MMcfd. Additional supplies on Kern River and Mojave can be delivered to a number of Enhanced Oil Recovery producers and electric generators located in Kern and San Bernardino counties. PG&E can also receive natural gas from Kern River and Mojave pipelines at an interconnect located near Daggett, California.

In addition to the gas supply coming from other states and Canada, California also relies on in-state production for about 15 percent of its total gas consumption. Of the 989 MMcfd produced in California in 1999, only 48 percent was delivered by natural gas utilities. The remainder was either consumed at or near the point of production, or delivered for utilization by a nonutility pipeline network.