

# NATURAL GAS INFRASTRUCTURE

**DOCKET**

**09-IEP-1J**

DATE \_\_\_\_\_

RECD. MAY 07 2009

**W. William Wood Jr.**

*Electricity Analysis Office  
Electricity Supply Analysis Division  
California Energy Commission*

*Presented at:*  
California Energy Commission  
Sacramento, California  
May 14, 2009

**DRAFT STAFF PAPER**

## **DISCLAIMER**

This paper was prepared by a California Energy Commission staff person. It does not necessarily represent the views of the Energy Commission or the State of California. The Energy Commission, the State of California, its employees, contractors and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this paper; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This paper has not been approved or disapproved by the California Energy Commission nor has the California Energy Commission passed upon the accuracy or adequacy of the information in this paper. This paper has not been approved or disapproved by the full Commission.

May 2009

CEC-200-2009-004-SD

## Acknowledgements

Contributing to the paper were the following:

James Fore: Attachment 3, Ten Pipelines Outside California

Paul Deaver: Attachment 4, Proposed Natural Gas Storage

Mary Ann Miller: Technical Editor

Catherine M. Elder: Technical Review

Ross Miller: Technical Review

Please use the following citation for this report:

Wood Jr., W. William. 2009. *Natural Gas Infrastructure*. California Energy Commission. CEC-200-2009-004-SD



## Preface

Eighty-seven percent of California's natural gas supply is delivered by pipelines that extend deep into Canada, the Rocky Mountains, and the U.S. southwest production areas. Adequate delivery pipelines and utility receiving capacity are needed to ensure the state has supply to meet its needs at competitive prices. This became apparent during the 2000–2001 energy crisis. Interstate pipes delivering natural gas to California were running at or near capacity for more than a year. The utilities' receiving and local transmission delivery systems and storage operations were taxed to their limits. Because there were no supply options available, California had to buy its natural gas supply at scarcity prices. And the state paid the price. In 2001, natural gas cost California \$19.4 billion, more than double the price paid for similar amounts in the years just before to the crisis.

During and after the crisis, California bought an insurance policy in the form of increased interstate pipeline delivery capacity, utilities improved their receiving ability, and the utility and independent storage owners enhanced their storage operations to meet future high-demand day conditions. The result has given California utilities the flexibility to choose supply sources in their day-to-day operations, forcing the production areas to compete for a share of the state's natural gas market.

The investment has paid off. The flexibility from having extra infrastructure, coupled with supplies from lower-priced production areas, helps shield the state from the brunt of price volatility. Since California is part of an international natural gas market that includes Canada, the United States, and Mexico, when there is a disruption in one area, ripples though the rest of the market. California is not immune to the ripples, but the ripples are much smaller now when they reach the state. Prices of natural gas at the state's border are among the lowest in the nation, with current prices considerably less than the Henry Hub price.

This paper examines whether the state still has sufficient natural gas infrastructure to meet possible worst case conditions during the next 10 years.

# Table of Contents

	Page
<b>Acknowledgements.....</b>	<b>i</b>
<b>Preface.....</b>	<b>iii</b>
<b>Abstract.....</b>	<b>vi</b>
Introduction.....	1
Issues .....	2
Interstate Pipelines .....	2
California Production.....	5
Storage.....	5
Winter Peak Day Supply and Demand .....	6
Limited Statewide Supply .....	6
Statewide Winter Peak Day Demand .....	11
Supply and Demand Balance.....	13
Impact of Renewable Energy on Natural Gas Infrastructure.....	15
Proposed New Infrastructure .....	18
Pipeline Projects.....	18
Storage Projects.....	21
Impact on Limited Supply Estimates by Proposed Infrastructure Additions .....	22
Conclusions .....	23
<b>ATTACHMENT 1: Statewide Winter Highest Day Sendout.....</b>	<b>1-1</b>
<b>ATTACHMENT 2: Summer Statewide Peak Day Demand .....</b>	<b>2-1</b>
<b>ATTACHMENT 3: Ten Pipelines Outside California.....</b>	<b>3-1</b>
<b>ATTACHMENT 4: Proposed Natural Gas Storage .....</b>	<b>4-1</b>
Sacramento Natural Gas Storage.....	4-1
Fresno Natural Gas Storage .....	4-1
Lodi Gas Storage Expansion .....	4-1
Arizona Natural Gas Storage.....	4-1

## List of Figures

	Page
Figure 1: 2007 California Natural Gas Receipts by Source .....	1
Figure 2: Natural Gas Resource Areas and Pipelines.....	4
Figure 3: Statewide California Winter Highest Day Sendout .....	11
Figure 4: Short-term Winter Peak Day Demand and Supply.....	14
Figure 5: Long Term High Winter Demand and Supply .....	15
Figure 6: California Statewide Summer High Sendout.....	16
Figure 7: Malin and Southern California Border Price Comparison with Henry Hub .....	21

## List of Tables

	Page
Table 1: California Natural Gas Storage Facilities .....	6
Table 2: Limiting Supply Capacity to Deliver Natural Gas to California Customers MMcf/d.....	8
Table 3: Impact of Proposed Infrastructures on California .....	22
Table 3-1: Proposed Pipeline Projects .....	3-2

## Abstract

This report reviews potential natural gas supply capacity available to meet statewide short-term peak demand and higher demand that may occur throughout a winter with combined cold and dry weather conditions. The paper compares the supply capacity with several demand forecasts extending through to 2020. A number of issues and uncertainties are discussed, including whether winter and summer peak-gas demand may continue to grow at current rates, how suddenly and by how much daily natural gas demand may change as renewable generation is added to the electric resource mix, whether the Pacific Northwest and California natural gas market could support both an Oregon liquefied natural gas (LNG) terminal and a Rockies pipeline, to what degree shale supply may further displace southwest production such that more southwest or Rockies natural gas becomes available to California, and what role LNG from Costa Azul and/or another future facility located in the southern part of the state may play in California's future supply mix.

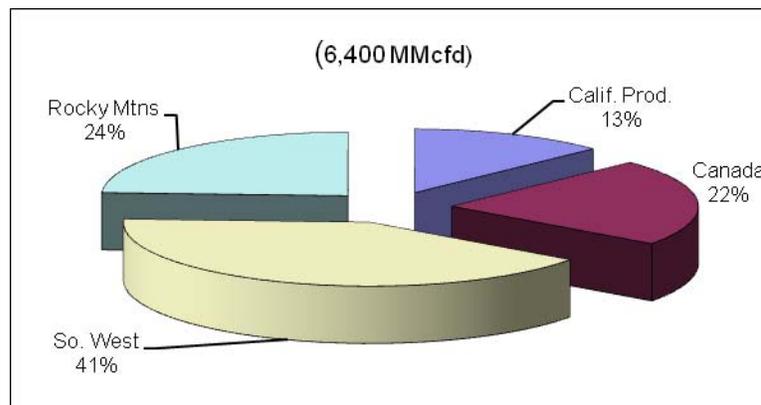
**Keywords:** California natural gas supply, liquefied natural gas (LNG), natural gas infrastructure, *California Gas Report (CGR)*, peak gas demand, winter peak demand, PG&E, SoCal Gas, SDG&E, natural gas storage, interstate pipelines, natural gas receipts, California production, storage, renewable resources, natural gas infrastructure, pipeline projects, storage projects, Rocky Mountains, shale

## Introduction

The adequacy of California's natural gas infrastructure is uncertain. California has more than 10 million customers, mostly residential, in the natural gas market. The state's average daily consumption in 2007 was approximately 6,400 MMcf/d (million cubic feet per day).

California is the second largest natural gas consuming state in the United States, just behind Texas, and depends on 87 percent of its natural gas from out-of-state supplies. Market shares of supply from the various basins have shifted over time. Twenty years ago, the southwest provided nearly 60 percent of the state's supply, California produced 20 percent, and the rest came from Canada and other basins. **Figure 1** depicts sources of recent natural gas supplies to the state. As existing producing regions mature and new resources are developed, it is only natural that new pipelines will be built and supply shares will shift.

**Figure 1: 2007 California Natural Gas Receipts by Source**



Source: Pipeline and Utility Filings with the California Energy Commission

During the past few years, California experienced access to favorably-priced natural gas in part from the location of producible natural gas reserves in the West and the ability to transport that gas to the large California market more economically than to other markets. Moreover, California supported construction of transportation capacity in excess of the quantity of gas it consumes. This helped assure continued competitive access to natural gas supplies.

Will this situation prevail in the future? Will California continue to have sufficient pipeline and storage capacity? This paper addresses those questions and identifies issues that might affect that capacity and potentially impact natural gas prices in California. In particular, the report observes the growing markets in other states that when combined with certain pipeline reconfigurations may reduce the amount of natural gas available to California via the state's regular pipeline corridors.

## Issues

In its analysis staff has reviewed the state's current supply, transport, and storage facilities; supply and demand; and proposed new infrastructure projects. During this appraisal staff identified and discussed the following issues in the report:

- Will California be able to rely on the Mojave Pipeline for instate deliveries under high demand conditions?
- Will supply at Ehrenberg be reliable during future summer months due to the increased power generation served by El Paso Natural Gas's southern system?
- Are the gas utilities too optimistic about the high winter demand forecast?
- Will new infrastructure be necessary during the next 10 years?
- Will the increased reliance on renewable energy require changes in the state's natural gas infrastructure?
- Will additional pipeline capacity to California result in additional benefits of gas-on-gas competition for the state or will California customers be competing with each other at the supply centers?
- Would the market support both a liquefied natural gas (LNG) terminal and a pipeline from the Rockies to Malin, Oregon?
- A Kern River Pipeline expansion would benefit Southern California, but would it affect Northern California?
- To what extent should California rely on natural gas supply from the Costa Azul terminal?
- Could expansion of the Rockies Express Pipeline result in higher natural gas prices in the region?
- Will shale development in the Mid-Continent, East Texas, and the Gulf Coast regions result in additional natural gas availability to the state from the Permian Basin and Rockies?

### *Interstate Pipelines*

Five interstate pipelines bring gas to California from Canada, the Rocky Mountains, and production areas in the southwestern part of the United States. These pipelines deliver natural gas to both utilities and non-utility customers inside and outside California. In the near future, California could also receive natural gas from an LNG facility located at Costa Azul, Mexico.

Gas Transmission-Northwest pipeline (GTN) carries Canadian natural gas; El Paso, Transwestern, and Questar's Southern Trails transport southwest gas; and the Kern River pipeline system moves Rocky Mountain production to market. Except for Southern Trails, each of these pipelines serves other customers before reaching California. **Figure 2** shows the pipeline locations.

In addition to these five pipelines, there are two additional pipelines that "pass through" California to serve other markets. These are the Tuscarora Pipeline, which delivers natural gas received from GTN at Malin to the Reno area, and the North Baja Pipeline, which receives gas from El Paso at Ehrenburg for delivery to Mexico near Yuma, Arizona.

The Mojave Pipeline and El Paso's Line 1903 are special cases. Mojave is considered an interstate pipeline, but only transports gas received from El Paso and Transwestern at the California-Arizona border. Originally, the pipeline was built to serve thermally enhanced oil recovery and other industries in the lower San Joaquin Valley and in the Mojave Desert. El Paso's Line 1903 is a converted crude oil pipeline that extends from Daggett, California, to Ehrenburg, Arizona.

The two pipelines now work together to deliver southwest and Rocky Mountain gas to Ehrenburg/Blythe. Nearly all of Mojave's capacity is used to carry southwest supply to Daggett, where the natural gas is delivered to the El Paso's Line 1903. Kern River is also delivering supply into Line 1903. From Daggett, Line 1903 carries the supply to Ehrenburg. At that point, the gas may flow south on the North Baja Pipeline, west to California on Southern California Gas Company (SoCal Gas)'s southern system, or east on El Paso's Southern System.

Effectively, this gives Mojave two possible delivery points: The current one in California into the Kern Mojave Pipeline, and the other at Ehrenburg. *Will California be able to rely on the Mojave pipeline for in-state deliveries during high demand periods?* All of its capacity would be available to the state if the deliveries of natural gas were into the Kern Mojave system. At Ehrenburg, the natural gas could move west to SoCal Gas, south to Mexico by way of the North Baja Pipeline, and east on El Paso's Southern System. Because of the multiple delivery points the certainty of how much supply would be available for California consumption is unclear.

This arrangement has enhanced the use of the Mojave pipeline system. In the past it operated at about half of its capacity, but now is running closer to its 400 MMcf/d capacity. Current impacts on California is the loss of about 200 MMcf/d that Mojave used to deliver to industry and an additional 100 MMcf/d that the Kern River pipeline is now delivering to Line 1903.

California utilities have two interconnects with Mexico. SoCal Gas delivers to Mexicali, and, in the past, San Diego Gas & Electric Company (SDG&E) has delivered to the Tijuana area at Otay Mesa for power plant use. Flows through Otay Mesa may be reversed to allow natural gas to be transported north from Mexico to the SDG&E service territory.

Figure 2: Natural Gas Resource Areas and Pipelines



Source: 2008 California Gas Report

## *California Production*

The state's infrastructure has few limits on the quantity of California production it can receive. However, instate natural gas production has been declining over time; the downward trend may continue from the current 825 MMcf/d to possibly 700 MMcf/d by 2020.

Slightly more than 50 percent of California's production flows to satisfy non-utility needs. The remaining natural gas is received by SoCal Gas and Pacific Gas & Electric Company (PG&E). Several new pipelines have been proposed to improve the state's infrastructure. These are discussed in "Proposed New Projects" section.

## *Storage*

Storage is an important piece of California's natural gas infrastructure. Without it, the supply pipelines would have to increase in size to meet winter demand, leaving a huge investment standing idle during half of the year. Storage fields are basically depleted natural gas fields that have had injection and withdrawal wells already drilled, and compression and processing equipment added to cleanup extracted natural gas. Natural gas is withdrawn from storage during periods of high demand, such as in the winter for space heating and in the summer for power generation. The injection season spans from spring to fall when overall demand is low. Pipeline capacity is then available for bringing supply of natural gas to refill the storage facilities.

Another way to use the storage facilities is to hedge natural gas prices. Utilities can buy natural gas when the price is low, put it into storage, and then sell or use it when prices rise. **Table 1** summarizes the storage facilities in California.

SoCal Gas has some cycling capabilities while the independent, non-utility Lodi and Wild Goose facilities have good cycling abilities. Each may withdraw and inject several times throughout the year and may also hold the same delivery levels as volumes of gas in storage are extracted. SoCal Gas indicates that it may maintain up to 2,225 MMcf/d<sup>1</sup> withdrawals throughout all levels of storage. PG&E, on the other hand, is limited in its ability to cycle and needs the whole storage injection season to refill its fields. As PG&E's natural gas in storage is depleted, its withdrawal capacity diminishes.

Several new storage projects are under review by the California Public Utilities Commission. These are discussed in "Proposed New Projects" section.

---

<sup>1</sup> 2008 *California Gas Report*, page 90.

**Table 1: California Natural Gas Storage Facilities**

	<b>Year Depleted Field Converted to Storage</b>	<b>Working Storage Bcf (Billion cubic Feet)</b>	<b>Maximum Injection Rate MMcf/d</b>	<b>Maximum Withdrawal Rate MMcf/d</b>
PG&E				
Los Medanos	1980			220
McDonald Island	1958			1,210
Pleasant Creek				56
PG&E Total		98	400	1,486
SoCal Gas				
Aliso Canyon	1972			1,904
Goleta	1941			409
Honor Rancho	1975			1,023
Playa Del Rey	1942			409
SoCal Gas Total		122	1,117	3,745
Independent Storage				
Lodi		22	400	500
Wild Goose	2000	24	480	450
Independent Total	1999	36	880	950
State Summary		256	2,397	6,181

Source: California Energy Commission staff

## Winter Peak Day Supply and Demand

Staff has used supply and demand data from the *2008 California Gas Report (CGR)* and from filings the utilities and pipelines made with the California Energy Commission for this section. The discussion has been divided into two parts: Limited Statewide Supply and Statewide Winter Peak Day Demand.

### *Limited Statewide Supply*

Because an interstate pipeline has a certain delivery capacity, it does not mean that all that capacity is available to California. Each pipeline serving California has firm delivery contracts not only for California customers but also for customers upstream from California. Because of these upstream commitments, not all of a pipeline’s capacity is available for delivery to the state. During low demand periods there is “slack” or unused capacity that may be used by those who may need it. Slack capacity disappears when all shippers use their firm capacity during periods of very high demand.

Although the utilities have firm capacity contracts with the interstate pipelines, often these do not match up at individual delivery points or utility pipelines. For instance, PG&E’s Baja

Path may transport 1,140 MMcf/d, but it has firm contracts on Kern River, El Paso, Transwestern, and Southern Trails pipeline systems that total much more than the Baja Pipeline may carry.

**Table 2** shows the limited natural gas supply capacity to meet California customer needs for both short-term and long-term demand periods. The Limited Supply Capacity levels represent those minimum receipts/deliveries that occur when interstate upstream demand is high. In such a case, a pipeline's capacity is derated, and gas in storage has to be used to maintain natural gas supply to consumers over a long period. The Receiving Summary represents utility pipeline receiving capacity available to meet short-term demand and with storage operating at rated high withdrawal levels.

Both delivery capacity and utility receiving capacity are provided. One of the two will be a limiting factor on the reliable supply that may be obtained from that receipt point for each delivery point.

Supply points include interstate pipelines, California production, and storage withdrawal.

### **Pipelines and Production**

Interstate pipelines and California production have the current capacity to supply California consumers up to 10,110 MMcf/d. California utilities and non-utilities have the ability to receive only 9,330 MMcf/d. However, because of upstream demand and utility multiple receiving points, the state can rely only 7,810 MMcfd of supply from pipelines and native production.

For instance, GTN has the capacity to deliver 2,100 MMcfd at Malin and PG&E may receive a like quantity. Because of upstream contract commitments in the Pacific Northwest, however, PG&E uses only 1,850 MMcf/d. for supply planning purposes.

**Table 2: Limiting Supply Capacity to Deliver Natural Gas to California Customers MMcf/d**

Supply Point	Delivery	Receiving					Limiting Supply Capacity
	Firm	PG&E	SoCal	Non-utility	Summary	Peak Supply	
<b>Malin GTN</b>	2,100	1,850			1,850	1,850	1,850
<b>Topock/Needles</b>							
El Paso	1,680	1,140	540		1,680	1,680	1,680
Transwestern	1,150		800		800	650	650
So. Trails	120	40	80		120	120	120
Mojave	400						
<b>Ehrenberg/Blythe</b>							
El Paso South	1,710		1,210		1,210	1,210	1,210
Mojave/Line 1903	400						
<b>Kern River</b>	1,750	675	965	1,000	2,640	1,500	1,500
<b>California Production</b>	800	120	460	450	800	800	800
<b>Pipeline and Production</b>	10,110	3,825	4,055	1,450	9,330	7,810	7,810
<b>Storage</b>							
PG&E	1,500	1,500			1,500	1,500	400
SoCal Gas	2,225		2,225		2,225	2,225	1,100
Lodi	500	500			500	500	300
Wild Goose	450	450			450	450	320
<b>Storage Summary</b>	4,675	2,450	2,225		4,675	4,675	2,120
<b>Summary</b>	14,785	6,625	6,280	1,450	14,005	12,485	9,930

Source: 2008 California Gas Report  
Utility and pipeline filings with the California Energy Commission

At the Needles/Topock receiving points, adjustments to El Paso and Transwestern capacity have been made. El Paso capacity has been dropped by 400 MMcfd because Mojave is no longer delivering to California, but to El Paso Line 1903 for export out of the state. The assumption is that current contracts require deliveries to continue to Ehrenberg.

Transwestern has just completed a 500 MMcf/d lateral pipeline to Phoenix, Arizona, without adding any new mainline capacity. Effectively that lateral pipeline drops winter delivery capacity to California to 650 MMcf/d. These reductions limit the natural gas supply that may be received at Needles/Topock.

Delivery capacity to Ehrenberg/Blythe is substantially higher than SoCal Gas's ability to receive. But at this point, supply of natural gas is also distributed to the North Baja Pipeline for delivery to Mexico and may also flow east on El Paso's southern system.

There is a concern regarding deliveries of natural gas by El Paso at Ehrenberg. *Will supply at Ehrenberg be reliable during future summer months due to the increased natural gas demand for power generation off El Paso's southern system?* Along El Paso's southern system, more than 10,000 MW of natural gas fired power plants have been built. These plants may consume up to 1,600 MMcf/d, with demand swings of up to 500 MMcf/d. This demand could stress the 2,000 MMcf/d pipeline capacity to meet all demand, leading El Paso to issue operational flow orders that would limit the quantity of natural gas each customer would receive from the southern system. Under these conditions all demand for natural gas may not be met. These power plants are able to ramp up in a very short time. If all plants do so at the same time, the pipeline may be stressed to meet all the demand, possible leading to an "unstable" supply for California.

Kern River pipeline also makes upstream deliveries in Utah and Nevada that effectively reduce its ability to deliver full capacity to California. The overall flowing ability is reduced to about 1,500 MMcf/d, but during a cold period deliveries may be less than 1,500 MMcf/d. Non-utility customers in California receive about 1,000 MMcf/d from Kern River with PG&E and SoCal Gas receiving the remaining 500 MMcf/d.

More than half of California's 800 MMcf/d production of natural gas is distributed to non-utilities. The rest is taken by PG&E and So Cal Gas.

Several important observations from the analysis to this point become obvious. The first is that it is important to understand the differences between pipeline delivery and utility receiving capacities. There are limiting factors for each and, if not taken into consideration, may lead to faulty conclusions about what future supply may really be in a high demand scenario.

Secondly, to get a full picture of supply, pipeline capacity needs to be reviewed on a statewide basis, not a utility basis. There are many mutual receiving points which each utility relies on for their supply of natural gas. There is also an instance of one utility transporting natural gas for another utility that masks the reliable transport capacity. A good example is the PG&E's Baja Path moving several hundred million cubic feet per day for delivery to SoCal Gas. This affectively reduces the pipeline delivery capacity to PG&E customers.

## Storage

The supply of natural gas available from storage is highly variable. It depends on the current natural gas storage levels and the anticipated length of the withdrawal period. California storage operations may provide up to 4,675 MMcf/d during peak day demand. However, in a prolonged high demand period, extending from November through March, withdrawal would be limited to less than half, or approximately 2,120 MMcf/d. This

assumes that storage is full at the beginning of the period and that there is a continued injection of gas during the off peak hours.

Under normal winter operating conditions, PG&E withdraws 240 MMcf/d. This represents the average withdrawal rate for the winter months. If conditions warrant, the company can withdraw up to 500 MMcf/d for few days at a time. On peak days or when temperatures drop below normal, PG&E might extract up to 1,500 MMcf/d. Noticeably, on December 16, 2008, PG&E experienced its historically highest natural gas demand day, reaching 4,479 MMcf/d. Besides pipeline supply, PG&E drew 1,200 MMcf/d of natural gas from its storage, and the independent Wild Goose and Lodi added 1,096 MMcf/d.<sup>2</sup>

SoCal Gas reports that its firm winter storage withdrawal is 2,225 MMcf/d, a level which SoCal Gas is able to maintain throughout the winter months. Normally, SoCal Gas withdraws approximately 1,500 MMcf/d, but can increase up to 3,000 MMcf/d for periods when demand is high. During the past 10 years, SoCal Gas has experienced two days when daily demand was in excess of 5,000 MMcf/d. The most recent occurred on December 17, 2008, which led to net withdrawals of 2,650 MMcf/d from storage.<sup>3</sup> As with PG&E, the remaining need was fulfilled directly by pipelines.

This analysis has looked at storage in two ways. Most of the time storage is viewed as a source of supply to meet a peak-day demand. And normally that would be the case. But as was learned during the 2000-2001 energy crisis, storage was a valuable tool in meeting the extended period of high natural gas demand that the state experienced. Therefore, when evaluating storage additions, their value as a tool to meet demand for extended periods must be taken into account. This evaluation has more significance at a regional than at a local level.

**Supply for High Demand.** Pipeline supply and storage summaries are provided in **Table 2**. Two possible scenarios are presented in the table. The first, called “Peak Supply,” represents the peak day sendout of gas to customers that would be available to meet a short-term daily demand need. Under this scenario all the storage capability, coupled with flowing pipeline supply, would be available to meet a high peak demand 12,845 MMcf/d.

The second, “Limited Supply Capacity,” would represent the quantity of natural gas that would be available to meet a long-term high demand case, similar to what occurred during the 2000-2001 energy crisis. In this scenario the flowing supply from pipelines and production would be available, but gas in storage would be used to meet the long-term demand. Under these conditions supply would be limited to 9,330 MMcf/d

Without changes in infrastructure, only two options could raise the level of natural gas supply. First, a lower demand in the Pacific Northwest would allow more gas to flow to Malin, Oregon. Second, part, or all, of the Mojave Pipeline supply would be delivered to the

---

<sup>2</sup> PG&E's *PipeRanger*.

<sup>3</sup> *SoCal Gas Envoy*.

Kern River/Mojave pipeline system rather than to Ehrenberg, via El Paso’s Line 1903. Together these two options could add up to 650 MMcf/d to the pipeline and production summary in **Table 2**.

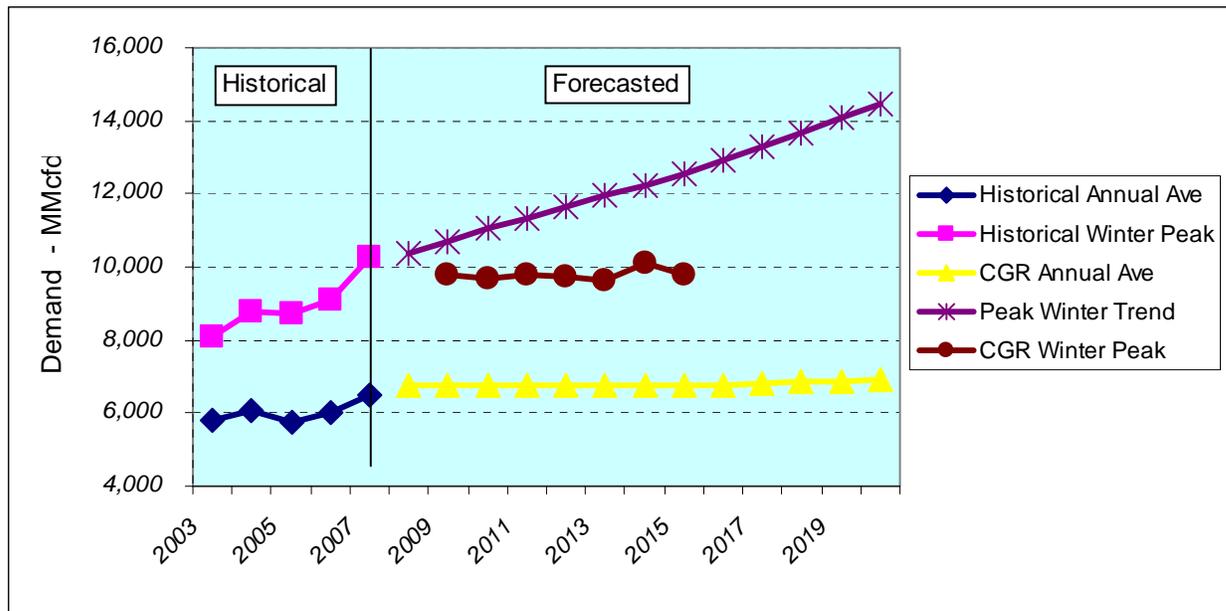
## Statewide Winter Peak Day Demand

Winter demand is driven by heating requirements, principally in the residential and commercial sectors. The need for natural gas for power generation is greatly reduced during the winter, representing about 14 percent of winter demand. Industrial sector varies little from season to season.

To define statewide winter peak day demand, staff included utility and non-utility service sectors. A statewide winter peak demand does not represent the combination of the highest sendout that each utility and non-utility would service. Seldom, if ever, would these occur for all utilities and non utilities on the same day; rather, it represents the combination of higher demands on a single day.

For the first time, the CGR provides historical information on the highest day sendout for the summer and winter. The CGR also provides summer and winter peak day sendouts for each utility and statewide annual average sendout for cold year and dry hydro conditions. This information for the winter is presented in **Figure 3**.

**Figure 3: Statewide California Winter Highest Day Sendout**



Source: 2008 California Gas Report and California Energy Commission Staff

The figure shows five demand trends. “Historical Annual Ave” is the average statewide sendout for each year.<sup>4</sup> “Historical Winter Peak” is the historical statewide winter highest day sendout.<sup>5</sup> This would be representative of the short-term peak demand.

The “CGR Annual Ave” is the forecasted statewide annual average for a cold day and dry hydro conditions.<sup>6</sup> To derive future winter peak day requirements, the utilities forecasted demand for three years --2010, 2015, and 2020, and Commission staff made straight-line interpolations of these forecasts for the years in between. As shown in **Figure 3**, the gas utilities in the CRG have forecasted a flat high winter day demand (CGR Winter Peak), hovering around 10,400 MMcf/d. This forecast includes the utility sum plus the Energy Commission’s annual average non-utility demand forecast. It represents the highest winter peak day demand. Note that the flatness is seems to be completely contrary to the past five year’s historical trend where peak demand has been higher than the previous year. No discussion in the CGR relates the causes of the rising historical peaks, nor does it explain what conditions suddenly would change the historical winter peak day growth pattern to being flat in the future. This leads to the question of whether *the gas utilities are being too optimistic about the high winter demand being flat.*

Finally, note in particular how **Figure 3** shows that the relationship between the historical annual average and the historical peak are growing apart. The 2007 actual statewide peak demand was 10,300 MMcf/d. A preliminary estimate of 10,600 MMcf/d for the 2008 statewide winter high demand indicates that the trend continues. Each of these levels of natural gas demand is higher than the 2000-2001 state wide winter peak day, which reached 9,900 MMcf/d. To take this historical growth pattern into account, staff developed the “Peak Winter Trend.” This simply extends into the future the statewide historical statewide winter highest day sendout trend using a simple regression analysis.<sup>7</sup> While the Peak Winter Trend does not have the same weight of a forecast, it does present the potential future results from the continuation of unexplained market forces that have been causing winter high peak day to grow in the past several years. It could also be used to indicate an upper bound to future winter peak day demand.

The escalation in historical winter peaks experienced since 2003 seems to imply that the simple growth in the number of residential customers would have had a greater impact on winter peak demand than the increased use of renewable fuels for electricity generation or other programs to reduce demand. A simple look at average historical residential use may help explain this. Forty years ago the average home used about 120 Mcf per year. Because of the state’s conservation and appliance standards, the average residential use has flattened to

---

<sup>4</sup> 2008 California Gas Report, pages 22-26.

<sup>5</sup> 2008 California Gas Report, page 27.

<sup>6</sup> 2008 California Gas Report, page 18.

<sup>7</sup> Data for the five demand trends are provided in Attachment 1.

47 Mcf<sup>8</sup> during the recent years. Demand growth in the intervening years from the addition of more homes was offset by the reduction in the average residential home use. As the average home use has flattened out, it would seem the addition of new housing stock would lead to annual increases in winter peak demand growth.

Data for the **Figure 3** are provided in Attachment 1.

### *Supply and Demand Balance*

Staff reviewed the high winter peak demand given **Figure 3** in two ways. In the first, demand may reach or exceed the abnormal peak day levels. These conditions may last for a day or two and may be associated with several additional days of high demand. On a short-term basis, the utilities and pipelines have options that may be employed to meet the higher needs. Flowing supply from pipelines and production may be balanced with storage operations to meet the high demand. Staff calls this the “Short-term Winter Peak Day Demand.” Associated with this demand would be the Peak Supply given in **Table 2**.

**Figure 4** is the same as **Figure 3** except in this instance staff has defined **Figure 4** to represent the short-term winter peak day demand. That is what the CGR Winter Peak forecast represents. The peak supply has been added to compare demand with supply. For the forecasted period the CGR conditional estimate for short-term winter peak demand remains flat, hovering in the area of 10,000 MMcf/d. This is well below the 12,485 MMcf/d peak supply that could be available, as shown on **Table 2**. Under these circumstances, current pipeline and storage would have the potential to be adequate to meet all short-term winter peak demand during the foreseeable future.

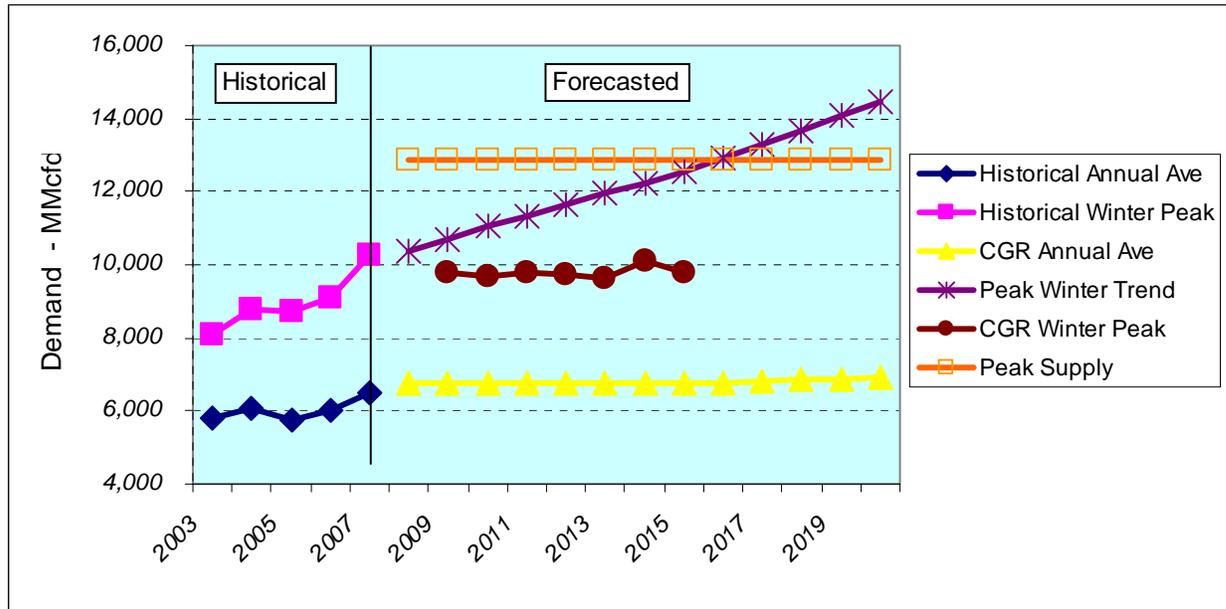
On the other hand, should the short-term winter peak demand continue to follow the historical trend, short-term peak demand could grow more than 14,000 MMcf/d. Peak supply to meet this level of demand, as shown by the Peak Winter Trend on **Figure 4**, would be exceeded by 2016. After that point it would be necessary to add some combination of new storage and pipeline infrastructure to meet the short-term peak demand.

The second high- demand period is of greater concern. High-demand levels occur for an extended period, which could include all of the five winter months. Under those circumstances, the pipelines and utilities have fewer supply options to meet the extended demand period. The state’s natural gas system could be strained to meet all demand. As in the 2000-2001 energy crisis, pipeline flows would be at or near maximum, and there would be few options for manipulating storage operations. In this analysis staff is calling this condition a “Long- Term High Winter Demand” period lasting for up to 150 days.

---

<sup>8</sup> [http://energyalmanac.ca.gov/naturalgas/residential\\_natural\\_gas\\_consumption.html](http://energyalmanac.ca.gov/naturalgas/residential_natural_gas_consumption.html)

**Figure 4: Short-Term Winter Peak Day Demand and Supply**



Source: 2008 California Gas Report and California Energy Commission Staff

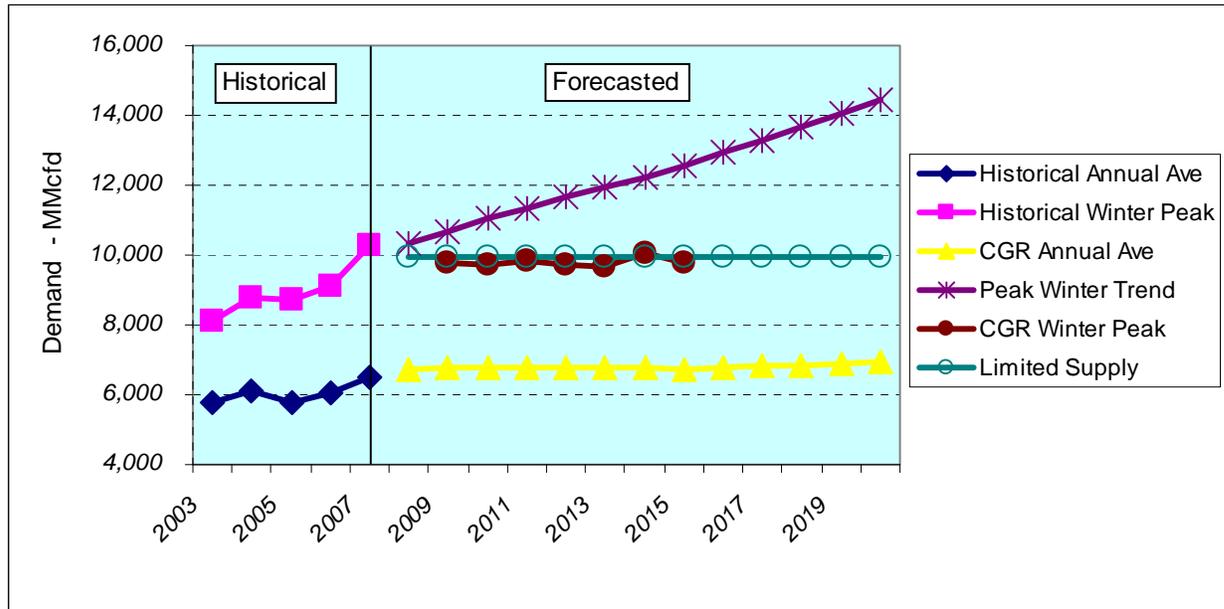
In **Figure 5** the forecasts illustrate of a long- term high winter demand. The limited supply of 9,930 MMcf/d, taken from **Table 2**, has been overlain on the figure. With the current infrastructure the figure indicates the limited supply would be uncomfortably close to the CGR Winter Peak demand case. This would be similar to the condition the state faced during the 2000-2001 energy crisis. To avoid the perils of the energy crisis, additional infrastructure must soon be added.

For illustrative purposes, staff has included the Peak Winter Trend. While there is no forecast that substantiates this trend, it is presented as a reminder that demand forecasting is only a tool to look into the future. It is always wise to look to the past to see how well the forecast fits with history.

Several important observations from the analysis to this point become obvious. The first is that it is important to understand the differences between pipeline delivery and utility receiving capacities. There are limiting factors for each and if not taken into consideration may lead to faulty conclusions about what future supply may really be in a high- demand scenario.

Staff is not implying that long- term high demand would occur continuously for the study period. Instead, the implication is that should such a demand level occur during the next 10 years, there is the potential that it will be fall between the two forecasted demand levels shown on **Figure 5**.

**Figure 5: Long-Term High Winter Demand and Supply**



Source: 2008 California Gas Report and California Energy Commission

The supply and demand analysis provides several insights to future infrastructure needs. But those needs are dependent on what high demand is being evaluated. As a planning tool, *should the short-term winter peak or a prolonged high winter demand be used for considering what future level of infrastructure may be needed?* Each approach provides a different answer. To meet a short-term winter peak, current pipeline and storage facilities seem to be adequate. This has been the case for the past several years. But analysis of a prolonged high winter demand period, similar to the 2001-2002 energy crisis, indicates that current supply and storage facilities will be barely adequate. How often would an event as the 2000-2001 energy crisis occur? The natural gas price tag for not planning for a siege of high winter demand was more than \$19 billion in 2001, more than double the price paid for similar amounts in the years just before the crisis.

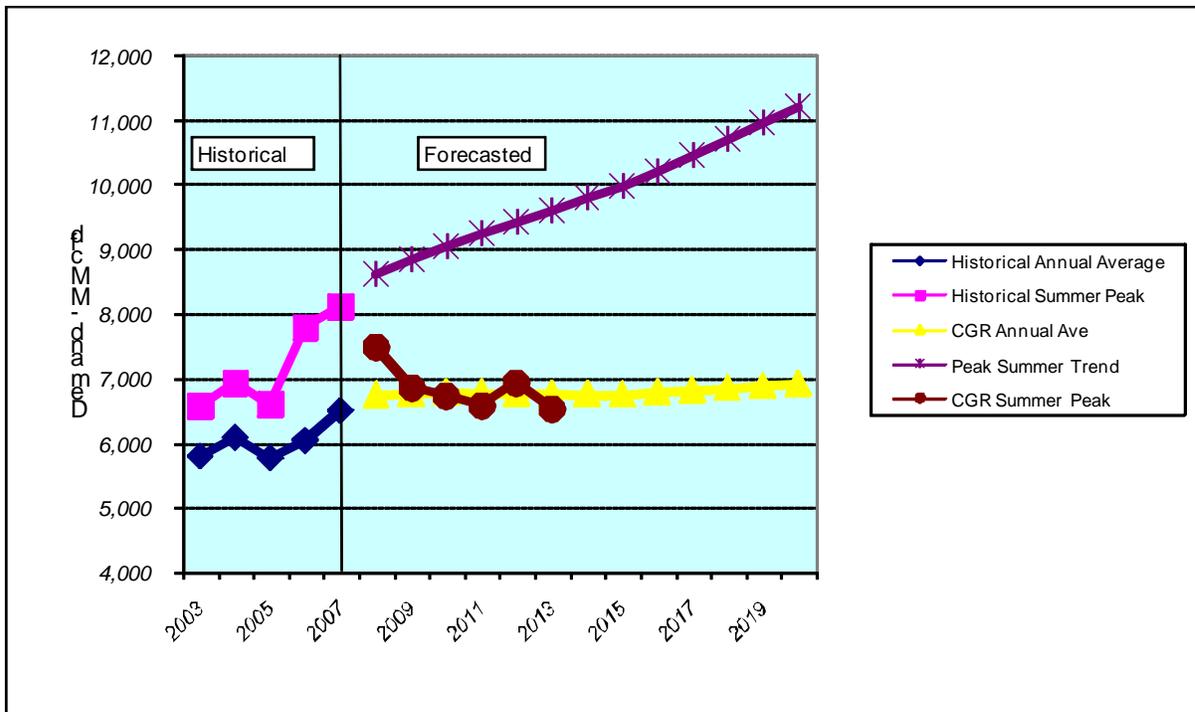
### ***Impact of Renewable Energy on Natural Gas Infrastructure***

The state is shifting to renewable energy sources to provide a larger share of the electricity generated to meet California's needs. Does the addition of alternative energy technologies "strand" the current natural gas infrastructure<sup>9</sup> due to a decline in natural gas consumption for power plants, or does renewable lend to the need for additional pipelines and storage? *Will the increased reliance on renewable energy require changes in the state's natural gas infrastructure?*

<sup>9</sup> Stranded infrastructure costs result when costs exceed the amount that can be recovered through an asset's sale

**Figure 6** shows historical and forecasted natural gas use during summer peak days.<sup>10</sup> Note first that since 2003 summer peak high natural gas demand has grown from 6,500 MMcf/d, up to a peak of approximately 8,800 MMcf/d in 2007. Second, relative to the historical peak, the CGR projects a 1,200 MMcf/d drop in summer peak-day natural gas use during the next few years. The CGR is unclear in explaining what assumptions are causing the drop, but is likely the result of a combination of electricity conservation programs lowering peak period demand, lower more efficient heat rates for the marginal gas-fired units as new generators, including combined heat and power, are added and existing less efficient units retired, refurbished, or dispatched less, and renewable energy technology generation added to the electric resource mix.

**Figure 6: California Statewide Summer High Sendout**



Source: 2008 California Gas Report and California Energy Commission

The CGR Summer Peak natural gas demand forecast is presumably developed by the utilities using electricity production cost dispatch modeling. Such modeling relies upon a number of assumptions, each of which introduces uncertainty. The forecast raises at least three questions: If the electrical peak demand forecast itself is rising; if more gas-fired generation has to be used to meet that peak; and how does the seasonal availability and intermittency of renewable generation is added to meet the Renewables Portfolio Standard target affects summer average and peak day generation gas demand.

<sup>10</sup> Attachment 2 provides the data used and the sources of the data.

Unless they are paired with onsite energy storage technologies, renewable generation technologies are not dispatchable to follow load and may not be available to meet peak day requirements. Solar thermal and photovoltaic generation better matches load than does wind generation. To insure reliable service during peak demand periods, natural gas fired generation will be needed to meet peaking requirements, provide load following and backup services for the renewable generation, and provide base load services.

Natural gas currently meets about 33 percent of the state's electricity requirements. While older units have heat rates in excess of 10,000 Btu per kwh, the newer combined cycle facilities operate at approximately 7,500 Btu per kwh. Peaking units are less efficient and, depending on the age of the unit, will use 50 to 100 percent more gas per MWh than a new combined-cycle unit.

Which type of unit would be used to supplement the renewable generation? The type of generation would affect the need for natural gas. For example, a 40 percent loss of renewable generation would be equivalent to an increase of 480 MMcf/d in combined cycle fuel use. Since the peaker requires 60 percent more fuel, on average, gas demand would increase by 770 MMcf/d. Whatever the marginal gas-fired unit, because of the changes mentioned above, it is likely to be more efficient than those historically observed, and on which the trend line is based.

To meet incremental summer peak-day demand, the gas utilities have a number of tools. One might be supply flowing in on the interstate pipelines. Note that it takes three to four days for gas to reach California from out-of-state production areas. Accordingly, flowing supply will not be the solution on a short-term peak day basis.

A second tool to meet this need is underground gas storage. The independent storage facilities with their high withdrawal and cycling capability are well-positioned to provide this service. A third could be the ability to back down summer storage injections. PG&E has traditionally relied on this method to help meet summer peak requirements. Power plants can consume gas that otherwise would have been injected into storage.

The gas utilities also have in place what are known as balancing requirements. The balancing rules allow some amount of tolerance for nominations to reflect changed gas requirements or for a customer to consume what is immediately needed and make up the difference later.

Finally, incremental demand for gas on a hot day does not occur suddenly. Heretofore, an understanding of the weather forecast, combined with the ability to adjust injections into or withdrawals from storage and balancing flexibility, has allowed gas-fired generators to rapidly increase their consumption without major difficulty for the gas utilities.

Whether that will continue as peak- day demand rises or as intermittent generation is added is unclear. Renewable energy sources and natural gas infrastructure will be the subject of an Energy Commission workshop scheduled for June 29, 2009.

## Proposed New Infrastructure

The natural gas market is never stagnant and always dynamic. New resources are continually being found and developed; pipelines, LNG facilities, and new storage fields are proposed, and some are actually built. Twenty years ago, industry players were excited about techniques that had been found to produce coal bed methane. Today shale is drawing the attention.

During the late 1970s, when natural gas supplies were low and customers were facing curtailments of service, LNG terminals were seen as a new source of supply to meet the nation's growing demand for natural gas. Price deregulation occurred, domestic resources were found to meet the need, and for many years those LNG terminals sat idle. More recently, it appeared that natural gas supply would not keep pace with demand, and the industry looked again to LNG. New facilities were built, but in the meantime domestic production of natural gas has increased and demand has waned.

### *Pipeline Projects*

At least three new pipelines or expansions have been proposed over the last few years to serve California. Detailed descriptions of these pipelines are found in Attachment 3. The following discusses the impacts these projects may have on California.

#### **Pacific Northwest**

Industry developers are ready to operate or are proposing several new supply sources that will indirectly deliver natural gas to California. In the Pacific Northwest, potential importers are proposing several LNG terminals. Additionally, at least two pipelines have been proposed to deliver natural gas produced in the Rocky Mountains to the GTN pipeline in Oregon that eventually would carry the gas to California.

None of the projects in the Pacific Northwest would offer additional receiving capacity to California at Malin, unless PG&E were to also expand its Redwood Path (Line 400/401). As indicated earlier in this paper, PG&E has existing capacity on Line 400/401 that will go unused due to upstream demand. Any new supply at Malin can therefore use that currently idle capacity. Such supply could also replace declining Canadian production or even displace supply from Canada, depending on how the economics unfold.

Normally, the Rockies' supply of natural gas to California takes a netback price, as exemplified by Kern River supply trading at the Southern California border index. San Juan basin gas has traditionally set the border price. For PG&E, lower Canadian prices sometimes pull the PG&E Citygate index below the Southern California price. It is not clear how new supply at Malin, Oregon, would affect PG&E Citygate prices.

Building both an LNG terminal and a Rocky Mountain pipeline would cause supply and price competition. The market is limited and supply from Canada, LNG and the Rockies' gas would be competing for share of a limited market.

### Kern River

In response to the proposed Rocky Mountain projects to the Pacific Northwest, Kern River has countered by proposing to increase its flowing capacity to California. It is clear that a *Kern River expansion would benefit Southern California but would it help Northern California?* This proposal would increase supply of natural gas to California, increase price competition in Southern California and would compete with supply from the Southwest.

The greatest benefit would be to SoCal Gas enhancing its supply options. The increase in capacity would add supply to SoCal Gas's receipt points with the Kern/Mojave systems, thereby improving the utility's receiving and supply capabilities.

Potentially there would be no new supply effects to PG&E's service area, unless it either increases its flowing capacity on the Baja Path (Line 300 A&B) downstream from Kern River Station or PG&E reduces delivery to SoCal Gas via Wheeler Ridge.

It is unclear what would be the price effects from a Kern River expansion. There would be increased competition, but shippers on the Kern River pipeline have been price takers, following the price at the Southern California border. One possible outcome could be that that suppliers bringing gas from the southwest would lower the price to meet the new competition. If so, possibly Kern Rivers shippers would follow suit.

### California LNG

The construction of the Costa Azul LNG Terminal was completed last year and is still awaiting the first deliveries of natural gas for commercial use. It has received several cargos of liquefied gas to test the facility. *To what extent should California rely on natural gas supply from the Costa Azul liquefied natural gas terminal?* As described in staff paper *Liquefied Natural Gas Uncertainty Issues*, LNG is available in world markets, but suppliers are able to sell their LNG to higher priced Asian markets.

Imports of natural gas from Costa Azul would not add to the state's delivery or receiving capacity without a natural gas flow reversal of the Otay Mesa international delivery point near San Diego. If that line flow were reversed, capacity would be limited to about 400 MMcf/d. Without major changes to the SDG&E system and potential modifications to SoCal Gas' southern system, there is no feasible method of transporting the natural gas from Costa Azul to the SoCal Gas territory.

One of the potential alternatives is to reverse the flow on the TGN and North Baja pipeline system to transport gas eastward. Once the gas reaches Ehrenberg it can flow back west into SoCal Gas, north bound on the bi-directional Line 1903, or east on El Paso's southern system towards Phoenix.

Any excess LNG supply would add to California's supply mix. Under normal conditions, this would lead to price competition for market share. But realizing that LNG is a price taker (It doesn't set price) and the present reluctance of international cargos to deliver LNG to the West Coast of the United States, it is unclear what kind of impact the Costa Azul facility will have on future supply and price of natural gas.

There are other LNG terminals currently proposed to serve directly the SoCal Gas service area. It is not clear whether one or more of these facilities would be operational during the next 10 years.

### The Rocky Mountains

The Rocky Mountain supply region has gained a substantial share of the California natural gas market over the years. The reason is that the Rockies gas has long sold at a discount to Henry Hub<sup>11</sup>, which is the benchmark for spot natural gas price in the United States. The Rockies region is "land locked" with production levels being higher than pipeline capacity to move the production to the consumer markets.

Project developers have advanced several proposals to expand and construct new pipelines that would increase the export capacity of natural gas out of the Rockies to the east. *Could expansion of existing and building of new pipelines out of the Rockies Express result in higher natural gas prices in the region?* These projects would change the market dynamics, impacting the supply and price of natural gas available to the California market. To the extent that these projects reduce natural gas available to the California market, border prices may increase.

The production of natural gas from shale and other unconventional resources has added greatly to the nation's supply. California has benefited from natural gas production from coal beds and tight formations in the Rockies. But, *what about natural gas from shale development in the mid-continent, east Texas and the Gulf Coast?* It appears that California is already feeling the effects of gas from shale production. El Paso has noticed up to five percent more southwest natural gas production out of the Permian Basin moving west.<sup>12</sup> This gas is being displaced from moving to eastern demand markets because the increased production from shale formations in those regions. New shale gas in the east could further displace southwest production making more of the southwest supply available to California. It is also possible that shale deposits further east of the United States could displace the Rockies supply expected to move eastward via the Rockies Express pipeline and other similar pipelines.

Historically, California border prices of natural gas at Malin, Oregon, have been lower than at Southern California. In addition, California prices have also been lower than the natural

---

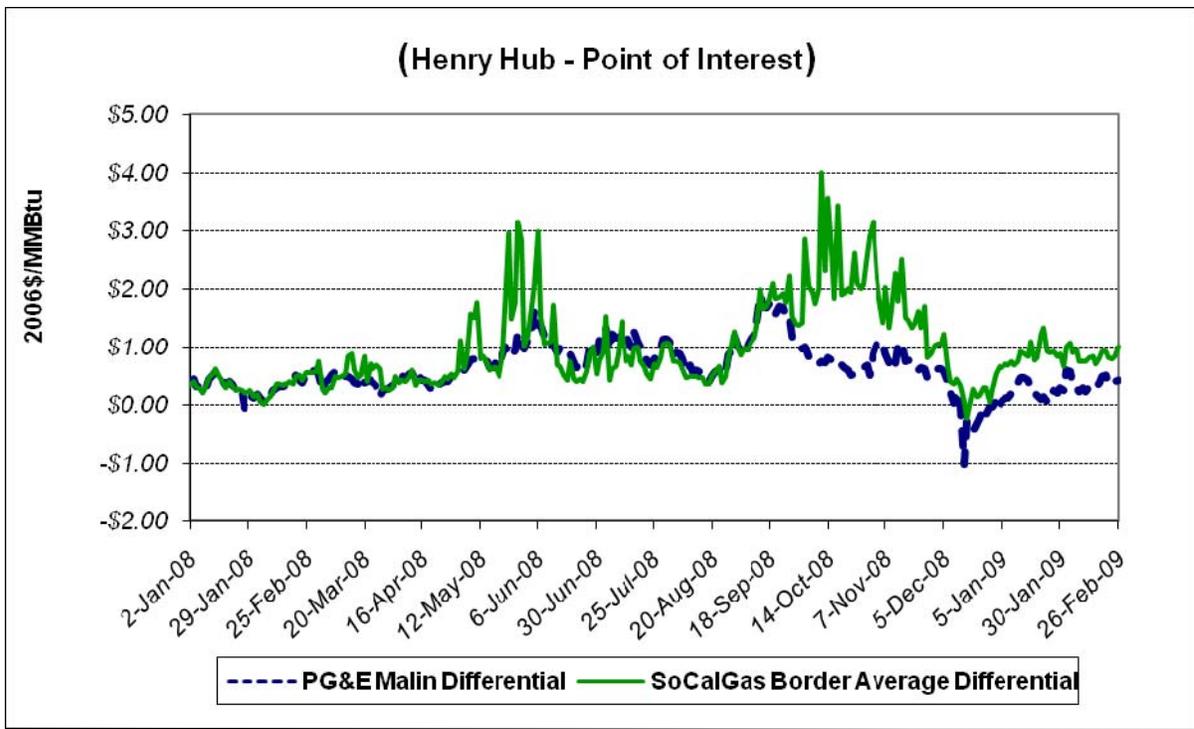
<sup>11</sup> A natural gas pipeline located in Erath, Louisiana, Henry Hub is owned by Sabine Pipe Line LLC and has access to many of the major gas markets in the United States.

<sup>12</sup> El Paso Web Cast, *Fourth Quarter 2008 Financial & Operation Update*, Feb. 26, 2009.

gas prices at Henry Hub. **Figure 7** shows the price differentials between Henry Hub and the two California border points since January 2008. California prices continue to be lower than Henry Hub, but there has been a price shift between the border prices. In early 2008 border prices were about the same, but since mid-2008 the Southern California price of natural gas has been lower than the price at Malin. The only apparent reason for the lower prices in Southern California is the displaced southwest gas now flowing to California.

It is unclear how new pipelines flowing east from the Rockies and increased production from shale gas in the east will impact California border prices.

**Figure 7: Malin and Southern California Border Price Comparison with Henry Hub**



Source: Natural Gas Intelligence

### Storage Projects

There are three underground natural gas storage projects under review in California. These include the expansion of the existing Lodi facility and the additions of new facilities near Fresno and Sacramento. All of these ventures lie in the PG&E service area and would help meet peak summer and winter demand. Together the three would add 1,050 MMcf/d in withdrawal capability.

There is also an additional underground proposed storage project in Arizona. This facility would take advantage of several salt domes in western Arizona. Their operation would help El Paso manage the summer swings in demand from power generation and meet winter peak day demand along the western end of its southern system. California supply at Ehrenberg would be more stable with the building of the Arizona storage facility.

More information for these projects is found in Attachment 4.

## Impact on Limited Supply Estimates by Proposed Infrastructure Additions

**Table 3** summarizes the impacts the proposed infrastructure will have on increasing natural gas supply to California. The potential increase to meet winter peak-day requirements would be approximately 1,745 MMcf/d. This would increase the state’s short-term peaking capability to 14,200 MMcf/d. As indicated in **Figure 3**, this capability would be enough to meet the CGR Winter Peak, although new additional infrastructure would be necessary to meet the Peak Winter Trend by 2020.

**Table 3: Impact of Proposed Infrastructures on California**

	<b>Current Limited Supply</b>	<b>Future Limited Supply</b>	<b>Change</b>
<b>Northern California</b>			
GTN/PG&E	1,850	2,000	150
Sacramento Storage		200	200
Fresno Storage		650	650
Lodi Storage	500	700	200
Summary	2,100	3,550	1,200
<b>Southern California</b>			
Kern River	1,500	1,675	145
Otay Mesa		400	400
Summary	1,500	2,075	545
<b>Total</b>			<b>1,745</b>

Source: California Energy Commission

The limiting supply capability to meet the long term high winter demand would be increased to 11,600 MMcf/d. As indicated by the increase in **Table 3**, these proposed pipeline and storage modifications would be sufficient to meet the CGR Winter Peak

demand through 2020. But more complementary infrastructure is necessary after 2012 to meet the Peak Winter Trend.

## Conclusions

Several important observations from the analysis become obvious. First, it is important to understand the differences between pipeline delivery and utility receiving capacities. There are limiting factors for each and if not taken into consideration may lead to faulty conclusions regarding the future supply of natural gas in a high-demand scenario.

Second, to get a full picture of supply of natural gas, pipeline capacity needs to be reviewed on a statewide basis, not a utility basis. There are many mutual receiving points that each utility relies on for supply of natural gas. And there is an instance of one utility transporting supply for another utility that masks the reliable transport capacity. For example, PG&E's Baja Path transports several hundred million cubic feet per day for delivery to SoCal Gas territory. This affectively reduces the pipeline delivery capacity to PG&E customers.

This staff analysis has examined storage in two ways. Most of the time storage is considered as a source of supply to meet natural gas demand on a peak-day, which normally would be the case. But, as was learned during the 2000-2001 energy crisis, storage was a valuable tool in meeting unusually high levels of natural gas demand for an extended period. Therefore, when evaluating storage additions, their value as a tool to meet demand for extended periods must be taken into account. This evaluation has more significance at a regional than at a local level.

The supply and demand analysis provides several insights to future infrastructure needs. But those needs are dependent on what high demand is being evaluated. As a planning tool, *should the short-term winter peak or a prolonged high winter demand be used for considering what future level of infrastructure may be needed?* Each approach provides a different answer. To meet a short-term winter peak, current pipeline and storage facilities seem to be adequate. This has been the case for the past several years. But analysis of a prolonged high winter demand period, similar to the 2001-2002 energy crisis, indicates that current supply and storage facilities will be barely adequate. How often would an event like the 2000-2001 energy crisis occur? The natural gas price tag for not planning for a siege of high winter demand was more than \$19 billion in 2001, more than double the price paid for similar amounts of natural gas in the years just before to the crisis.

Renewable resources will play a greater role in meeting the state's need for electricity. It is unclear how these new additions will impact the operation the utility systems. But it is apparent that underground storage of natural gas will play an important role in providing quick response to electricity generation peaking plants.

Project developers have proposed several new supply and storage projects that would benefit California. These projects combined would provide approximately 1,700 MMcf/d of

additional natural gas to the state. These new supply sources of natural gas would be necessary to meet a prolonged high winter natural gas demand, add flexibility to the system, and help hedge against high natural gas prices.

While some features of the natural gas infrastructure are already under development, there are some key uncertainties including:

- To what extent would natural gas demand growth in upstream markets further limiting California's supply access via existing infrastructure?
- Will winter and summer natural gas peak demand in California continue to grow at current rates?
- How would the addition of renewable technologies to the electric resource mix impact California natural gas market operations?
- Would the Pacific Northwest and California natural gas markets support both an Oregon LNG terminal and a Rockies pipeline?
- What additional natural gas storage might be constructed or expanded in California?
- To what extent would new and existing pipelines transporting Rockies natural gas to the East impact supply and price of natural gas in the California market?
- Will natural gas produced from shale deposits displace Rockies and southwest-produced gas that currently flows to the eastern part of the country so that such gas becomes available to California?
- What role would LNG from Costa Azul and possibly from a new facility off the Southern California coast play in California's future natural gas supply mix?
- What additional pipelines bringing gas from the Rockies can be constructed to the West Coast?

# ATTACHMENT 1: Statewide Winter Highest Day Sendout

Statewide Winter Highest Day Sendout MMcfd					
Year	Historical Annual Ave	Historical Winter Peak	CGR Annual Ave	Peak Winter Trend	CGR Winter Peak
2003	5,791	8,085			
2004	6,087	8,777			
2005	5,763	8,729			
2006	6,041	9,104			
2007	6,507	10,291			
2008			6,744	10,349	
2009			6,764	10,694	9,771
2010			6,784	11,040	9,704
2011			6,777	11,342	9,809
2012			6,770	11,644	9,726
2013			6,762	11,945	9,650
2014			6,755	12,245	10,080
2015			6,748	12,545	9,777
2016			6,782	12,922	
2017			6,816	13,303	
2018			6,850	13,687	
2019			6,884	14,074	
2020			6,918	14,464	

**Source:** Historical Annual Average: 2008 CGR pg 22-26  
 Historical Winter Peak: 2008 CGR page 27  
 CGR Ave: 2008 CGR page 18 with interpolation  
 Peak Winter Trend: Continued historical summer peak trend  
 CGR Winter Peak: 2008 CGR pgs 48 & 91, plus Staff Final Natural Gas Assessment, Table J-4

## ATTACHMENT 2: Summer Statewide Peak Day Demand

Summer Statewide Peak Day Demand MMcfd					
	Historical Annual Average	Historical Summer Peak	CGR Annual Ave	Peak Summer Trend	CGR Summer Peak
2003	5,791	6,568			
2004	6,087	6,937			
2005	5,763	6,602			
2006	6,041	7,789			
2007	6,507	8,124			
2008			6,744	8,613	7,495
2009			6,764	8,832	6,866
2010			6,784	9,052	6,728
2011			6,777	9,236	6,591
2012			6,770	9,419	7,236
2013			6,762	9,603	6,535
2014		-	6,755	9,785	
2015		-	6,748	9,968	
2016			6,782	10,212	
2017			6,816	10,458	
2018			6,850	10,706	
2019			6,884	10,956	
2020			6,918	11,208	

**Source:** Historical Annual Average: 2008 CGR pg 22-26  
Historical Summer Peak: 2008 CGR page 27  
CGR Ave: 2008 CGR page 18 with interpolation  
Peak Summer Trend: Continued historical summer peak trend  
CGR Summer Peak: 2008 CGR pgs 48 & 91, plus Staff Final Natural Gas Assessment, Table J-4

## ATTACHMENT 3: Ten Pipelines Outside California

There are several proposals to expand and construct new pipelines that would increase the takeaway capacity of natural gas out of the Rockies. These projects could impact the supply and price of natural gas available to the California market. The natural gas basins in the Rockies are a major source of California's natural gas supply. In 2007, the Rockies accounted for 24 percent of the natural gas consumed in the state.

The lack of pipeline capacity carrying natural gas to the markets in the eastern part of the country has resulted in natural gas from the Rockies selling at a discount to Henry Hub, the benchmark for spot natural gas price in the United States. Any additional takeaway capacity sending natural gas eastward will have an impact on California's natural gas market.

There are currently eight pipeline projects to either expand the capacity of existing pipelines or construct new pipelines to increase the takeaway capacity of gas from the Rockies. Three of the proposed projects would increase the amount of gas available to western states. The Ruby and Sunstone pipelines are proposals that would interconnect with TransCanada GTN pipeline that delivers gas to Washington, Oregon and California from Canada's Western Sedimentary Basin. The Kern River Expansion would increase gas deliveries out of the Rockies serving Utah, Nevada, and California. Some other infrastructure changes for transporting gas from the Rockies to the east include the completion of the eastern portion of the Rockies Express Pipeline, along with several new pipelines to serve the Mid-Continent gas market. Some of these projects are competing for customers in the same market; so, it is possible that not all of the proposed projects listed in **Table 3-1** will be completed.

El Paso Corporation's Ruby pipeline would extent from the Opal Hub in Wyoming terminating at a Malin, Oregon, interconnect. This pipeline would deliver gas from the Rockies to serve California, Northern Nevada, and back fill into the Oregon and Washington markets. The proposed pipeline has an initial design capacity of up to 1, 300 MMcf/d.

The Sunstone pipeline, proposed by TransCanada and Williams, would also serve the West Coast. This pipeline would commence at the Opal Hub in Wyoming to an existing interconnect between Williams Northwest Pipeline and TransCanada GTN System at Stanfield, Oregon. The Sunstone pipeline initial capacity is slated to be 1,200 MMcf/d.

**Table 3-1: Proposed Pipeline Projects**

<b>Pipeline Project</b>	<b>Company</b>	<b>Capacity (MMcf/D)</b>
<b>Supply Natural Gas to the West Coast</b>		
Kern Expansion	Kern	145 Expansion/Total 1,900
Ruby	El Paso	1300
Sunstone	Williams/TCPL/Sempra	1200
<b>Supply Natural Gas to the Mid-Continent, Mid-Atlantic, and New England States</b>		
Bison	TransCanada	405
Pathfinder	TCPL	1200
Alliance/Questar	Alliance/Questar	1300
Chicago Express	KinderMorgan	1200
Grasslands Expansion	Williston Basin Pipeline	40 Expansion/Total 180

Source: Energy Information Administration

The Kern River pipeline from Wyoming to the California border serves Utah, Nevada, and California. Kern River plan to upgrade some above-ground facilities that will increase capacity on the pipeline by 145 MMcf/d. When the expansion is completed the pipeline will have a capacity of 1,900 MMcf/d.

There are other pipelines that have been proposed to move natural gas out of the Rockies to markets in the upper Mid-Continent, Mid-Atlantic, and New England states. These proposals include expansion of existing pipelines along with new pipeline systems out of the Rockies.

Alliance Pipeline Incorporated and Questar Overthrust Pipeline Company have proposed the Rockies Alliance Pipeline to transport natural gas from Wyoming to the Chicago and upper Mid-Continent markets. The initial capacity for this pipeline is expected to be 1,300 MMcf/d with possible expansion to 1,700 MMcf/d.

KinderMorgan Energy Partners and Natural Gas Pipeline Company have proposed building a pipeline to serve the Chicago market. This pipeline referred to as the Chicago Express Pipeline project would move gas from Wyoming to the Joliet Hub in Illinois. The Chicago Express Pipeline currently calls for a design capacity of 1,200 MMcf/d.

TransCanada Corporation has proposed the Pathfinder Pipeline to also carry natural gas from Wyoming to the Chicago market. The Pathfinder Pipeline would have an initial capacity of 1,200 MMcf/d, with a proposed ultimate capacity of 2,000 MMcf/d. The pipeline would carry gas from Wyoming tying into the Northern Border Pipeline. The Northern Border Pipeline transports natural gas from the Western Sedimentary Basin to the Chicago and Mid-Continent markets.

Some developers have proposed future expansions of the Pathfinder pipeline to Noyes, Minnesota and Emerson, Manitoba, where Rockies gas can then be shipped to eastern markets using the Great Lakes Gas Transmission system and TransCanada's Canadian Mainline system.

There is also the Grasslands Pipeline project. The Grasslands Pipeline transport gas from the Powder River Basin in northeastern Wyoming to western North Dakota, where it connects with the Northern Border Pipeline. Grasslands proposal is an above-ground pipeline expansion that would increase the pipelines capacity by 40 MMcfd. The pipeline is currently at 138 MMcf/d.

Completion of the Rockies Express pipeline will result in a takeaway capacity of 1,800 MMcf/d. Associated with the Rockies Express pipeline are several infrastructure additions for interconnections that will be move gas from this pipeline by other interstate and local distribution companies serving customers in the Mid-Continent, Mid-Atlantic and New England states. In the future, This, in the future, could lead to an additional takeaway capacity for the Rockies Express.

# **ATTACHMENT 4: Proposed Natural Gas Storage**

## **Sacramento Natural Gas Storage**

The Sacramento natural gas project will use the depleted dry Florin gas field to store natural gas in the Sacramento region. This depleted natural gas reservoir is located approximately 3,800 feet underground and has an initial working storage of 8 Bcf. The facility, which is independently owned, is currently in the permitting phase and is expected to be operational sometime in 2009. Injection rate could be up to 100 MMcf/d, and withdrawal could reach up to 200 MMcf/d. Cushion gas remains in the field, leftover from past production. The facility will be able to completely cycle 3.2 times per year.

## **Fresno Natural Gas Storage**

Gill Ranch Storage, LLC, and PG&E are developing a new underground storage facility near Fresno. This project will use depleted, sandstone natural gas reservoirs located more than 5,000 feet underground. This new facility will provide 20 Bcf of initial working gas storage and 650 MMcf/d of firm withdrawal. This project is expected to be completed in 2010.

## **Lodi Gas Storage Expansion**

Lodi Gas Storage will add an additional 12 Bcf of working gas storage capacity and could provide an additional 100 MMcf/d of firm injection and 200 MMcf/d of firm withdrawal capabilities. Lodi Gas Storage went into commercial operation in 2008. This expansion would bring the total working storage of Lodi up to 34 Bcf.

## **Arizona Natural Gas Storage**

El Paso Corporation's Western Pipeline Group is developing four storage facilities in Eloy, Arizona, which is about 40 miles southeast of Phoenix. These four new facilities, which are underground salt caverns, could have a working gas storage capacity of approximately 3.5 Bcf. The new facilities will be able to deliver 350 MMcf/d of natural gas.

The first storage facility is expected to be in service in mid-2010, while the remaining three facilities could be in service in 2011-2012. These facilities could serve nearby residential customers and power plants. California supply at Ehrenberg would be more stable with the building of the Arizona facilities.