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Abstract

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. To ensure the state has enough natural gas supply to meet its needs at competitive prices, adequate delivery pipelines and utility receiving capacities are needed. 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 few supply options available, California had to buy its natural gas at scarcity prices. In 2001, natural gas cost California $19.4 billion, more than double the price paid for similar amounts in the years just before the crisis.

During and after the crisis, California bought an insurance policy in the form of increased interstate pipeline delivery capacity, improved receiving ability, and enhanced utility and independent 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 flexibility of 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, 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 than before. Prices of natural gas at the state's border are among the lowest in the nation. During the first seven months of 2009 prices were considerably less than the price at Henry Hub.

This report examines whether the state still has sufficient natural gas infrastructure to meet demand in abnormal conditions during the next 10 years.

Keywords: California natural gas supply, liquefied natural gas (LNG), natural gas infrastructure, *California Gas Report* (CGR), peak day demand, winter peak demand, Pacific Gas and Electric (PG&E), Southern California Gas (SoCalGas), Sand Diego Gas & Electric (SDG&E), natural gas storage, interstate pipelines, natural gas receipts, netback price, price taker, California production, storage, renewable resources, open season, pipeline projects, storage projects, Rocky Mountains, shale.

Executive Summary

This report identifies issues that might affect natural gas capacity and potentially impact natural gas prices in California. In particular, the report observes that growing markets in other states, when combined with certain pipeline reconfigurations, may reduce the amount of natural gas available to California via the state's regular pipeline corridors.

Should all the proposed storage projects go forward, it may be difficult to effectively use all the storage capacity in Northern California. First, the total gas extracted from all storage facilities may exceed Pacific Gas and Electric's maximum transmission and local delivery capabilities, possibly reducing receipts from interstate pipelines. Second, simultaneous use of all the injecting capability in storage facilities to place gas into storage and also meet its retail and electric generation customers needs may strain Pacific Gas and Electric's summer backbone or mainline capacity.

Interstate pipelines have a nameplate rating capacity, which represents the upper bound on the pipeline's transport levels. However, that does not mean that all capacity will be used to transfer natural gas to California. Each pipeline serving California has firm delivery contracts not only for California but also for customers in other states. Because of these upstream commitments, not all of a pipeline's capacity may be available for gas delivery to the state. Three factors may limit how much out-of-state gas supply California can rely upon: the interstate pipeline's capacity to delivery natural gas to California, California's ability to receive natural gas from the pipelines, and the upstream demand that interstate pipelines serve before reaching California.

Reliable pipeline capacity is a supply that the state may firmly rely on from out-of- state sources. It is based on both the capacity to deliver and capacity to receive. In addition, reliability must also take into account the natural gas reductions in pipeline delivery because of upstream demand. Any of these conditions will diminish the reliability of natural gas supply to the state. This report finds that it is important for state policy makers to take into account upstream contracts, which will limit how much natural gas is delivered to state consumers.

CHAPTER 1: Pipelines and Storage Infrastructure

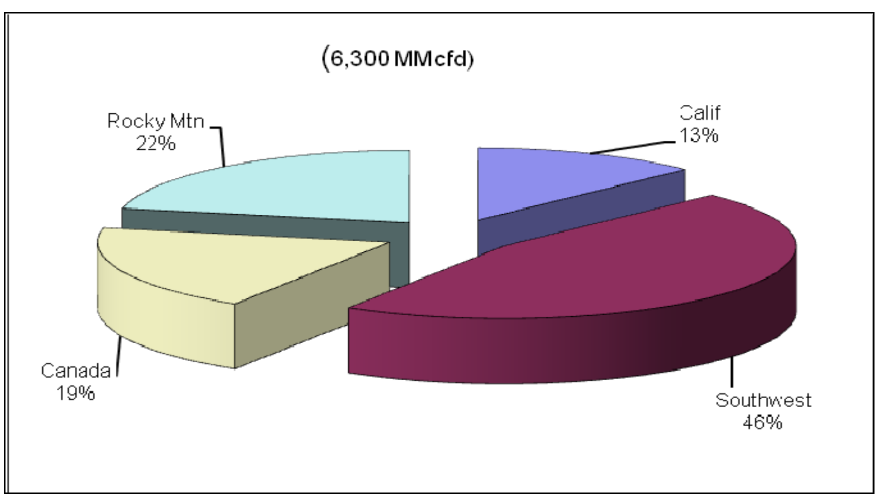
Introduction

California Public Utilities Commission (CPUC) Decision 06-09-039 directs Pacific Gas and Electric and Southern California Gas companies to maintain intrastate natural gas backbone transmission systems sufficient to serve all system demand on an average day in a 1-in-10 cold and dry hydroelectric year. Furthermore, the same decision indicates that the utilities must file an advice letter every even-numbered year indicating that they hold adequate backbone transmission capacity and have sufficient slack capacity. In their comments to a preliminary draft of this staff report, the utilities claim that they are complying with the CPUC criteria when planning intrastate pipeline and storage capacity infrastructure. However, more extreme weather conditions can strain the utilities' systems during long-term peak demand events.

California has more than 10 million customers, mostly residential, in the natural gas market. The state's average daily consumption in 2008 was approximately 6,300 million cubic feet per day (MMcfd).

California is the second-largest natural gas consuming state in the United States, just behind Texas, and receives 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: 2008 California Natural Gas Receipts by Source



Source: 2009 California Gas Report

During the past few years, California accessed favorably priced natural gas from reserves in the West that interstate pipelines were able to transport more economically to the large California market 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 report addresses those questions and identifies issues that might affect that capacity and potentially impact natural gas prices in California. In particular, the report observes that growing markets in other states, when combined with certain pipeline reconfigurations, may reduce the amount of natural gas available to California via the state's regular pipeline corridors.

In this analysis, staff reviews the state's current natural gas supply, transport and storage facilities and proposed new infrastructure projects. In addition, staff analyzes the reliability of natural gas supply, compares natural gas demand to reliable supply, examines current CPUC guidelines for slack capacity, and discusses possible impacts of intermittent renewable technologies on the gas system. Staff specifically identifies and discusses 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 (El Paso) southern system?
- Does the CPUC's reserve margin criterion for transmission capacity adopted in CPUC D. 06-09-039 use the appropriate planning criteria? 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?

In this chapter, staff discusses existing interstate pipelines, proposed new pipelines and expansions, liquefied natural gas prospects in the state, California production of natural gas, and existing and proposed natural gas storage facilities.

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 March 2010 California started receiving over 100 MMcfd of 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 California markets. 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 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, Nevada area, and the North Baja Pipeline, which receives gas from El Paso at Ehrenberg 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 Ehrenberg, Arizona.

The two pipelines now work together to deliver southwest and Rocky Mountain gas to Ehrenberg/Blythe. Nearly all of Mojave's capacity is used to carry Southwest supply to Daggett, where the natural gas is delivered to El Paso's Line 1903. Kern River is also delivering supply into Line 1903. From Daggett, Line 1903 carries the supply to Ehrenberg. At Ehrenberg, the natural gas could move west to SoCalGas, 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.

Effectively, this gives Mojave two possible delivery points: the current one which delivers to California customers off Kern Mojave Pipeline, and the other at Ehrenberg. Staff has learned from El Paso that the contracts to Line 1903 via Mojave are firm and California should not rely on receiving major supply from Mojave for the foreseeable future.[1]

These contract arrangements have 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 MMcfd capacity. Current impacts on California are the loss of about 200 MMcfd that Mojave used for delivery to industry, and an additional 100 MMcfd that Kern River pipeline is currently delivering to Line 1903.

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

Proposed Pipeline Projects

The natural gas market is never stagnant. 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 encouraged about new techniques to produce coal bed methane. Today shale is drawing the attention of gas exploration and development companies.

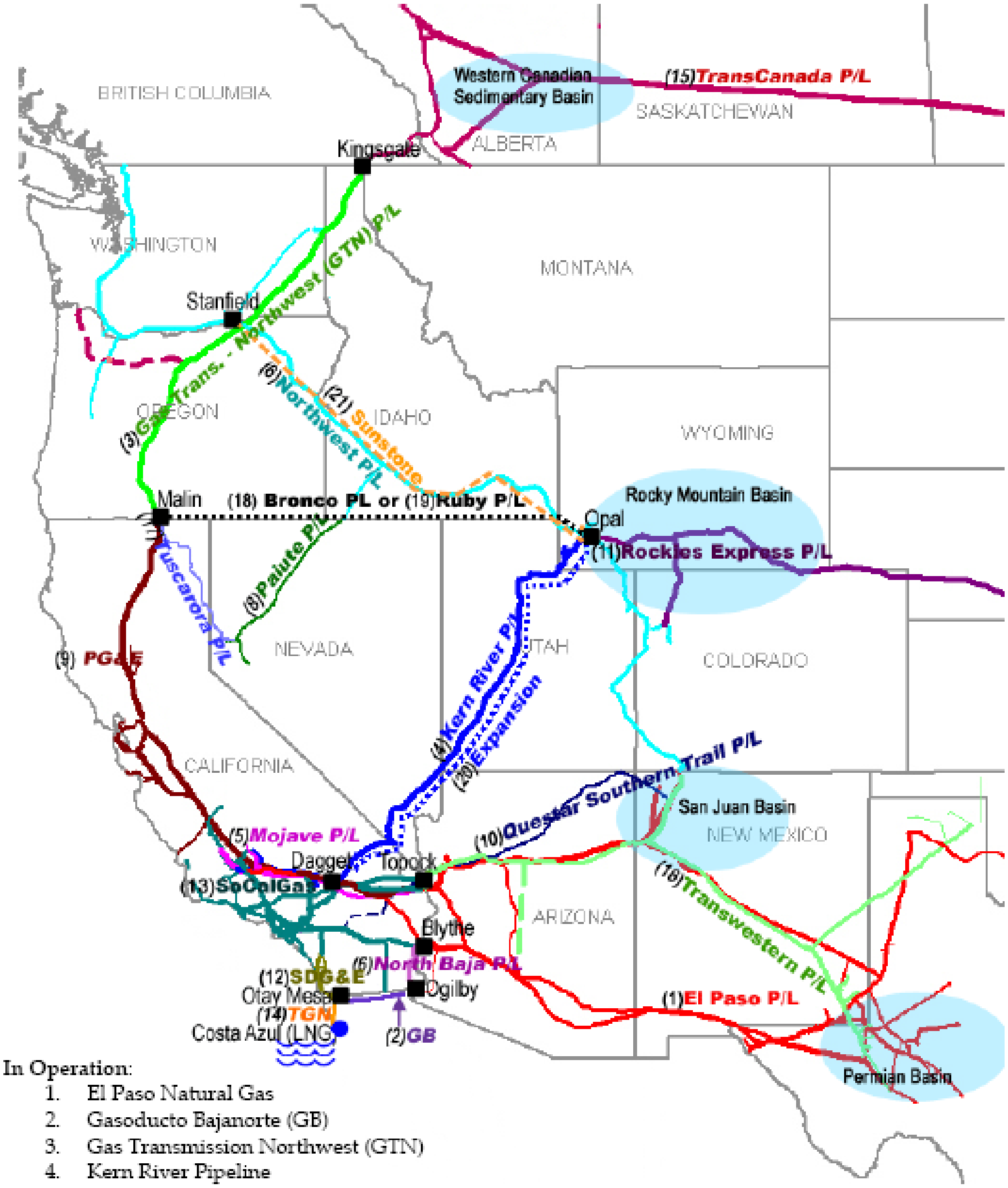
At least three new pipelines or expansions have been proposed over the last few years to serve the Pacific Northwest and California. Detailed descriptions of these pipelines are found in **Appendix A** of this report. The following discusses the impacts these projects may have on California.

Pacific Northwest

Industry developers 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.

1. Staff conversation with Wayne Tomlinson, El Paso’s consultant, May 14, 2009.

Figure 2: Western Natural Gas Resource Areas and Pipelines



In Operation:

1. El Paso Natural Gas
2. Gasoducto Bajanorte (GB)
3. Gas Transmission Northwest (GTN)
4. Kern River Pipeline
5. Mojave Pipeline
6. North Baja Pipeline
7. Northwest Pipeline
8. Paiute Pipeline
9. Pacific Gas Electric Company
10. Questar Southern Trail Pipeline
11. Rockies Express (REX)
12. San Diego Gas &Electric Company
13. Southern California Gas Company
14. Transportadora de Gas Natural (TGN)
15. TransCanada Pipeline
16. Transwestern Pipeline
17. Tuscarora Pipeline

Proposed:

18. Bronco Pipeline
19. Ruby Pipeline
20. Kern River Expansion
21. Sunstone Pipeline

Source: *2008 California Gas Report*

The new supply projects in Oregon would impact supply received in California at Malin from GTN. Each of the Oregon projects could also replace declining Canadian production or even displace supply from Canada, depending on how the economics unfold. However, not all projects would increase supply to California. For example, natural gas demand in the GTN leg between Stanfield and Malin now averages 300 MMcfd, with levels approaching 500 MMcfd during the winter.[2] Without mainline capacity expansion on GTN above its present 2,100 MMcfd capacity, any new supply entering the GTN system at or upstream from Stanfield would not increase supply to California above 1,850 MMcfd.

On the other hand, new supply sources, such as the Ruby Pipeline and the Coos Bay LNG project in Oregon, would deliver natural gas directly to Malin, Oregon with no upstream diversion to serve other markets. These projects have the potential to fully fill the PG&E pipeline at Malin.

Normally, the Rockies' supply of natural gas to California takes a *netback price*,[3] 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 price[4] index below the Southern California price. Although it is not clear how new natural gas supply at Malin, Oregon, would affect PG&E Citygate prices, it is possible that new gas supplies at Malin could displace a higher-priced natural gas.

Building both an LNG regasification terminal in Oregon and a pipeline bringing gas from the Rockies would cause supply and price competition. The Pacific Northwest market is limited in size, and gas supply from Canada, LNG, and the Rockies would be competing for share of a limited market.

Kern River

The Kern River Gas Transmission Company has several expansion projects on the books. The first of these is a mainline expansion that would directly increase deliveries to California utilities by 145 MMcfd in 2010. PG&E would receive 95 MMcfd, and SoCalGas would receive the remaining 50 MMcfd.

In May 2009, PG&E held an *open season* to find out if the market would support an expansion of its Baja Path.[5] A portion of the expansion capacity would have required receiving gas at an interconnection at Arvin, near Kern River Station, to take advantage of low-cost Southwest natural gas supplies. Kern River had also proposed an Arvin

2. Lippman Consulting, Inc. database.

3. Netback price is the price a natural gas producer receives net of transportation, taxes, and other charges.

4. PG&E Citygate price is a virtual point representing the price of all the natural gas supply delivered into the PG&E system. It maybe visualized as a point located in the San Francisco Bay Area.

5. An open season period is a period when a developer of a natural gas storage facility or a pipeline offers the capacity and considers all users on an equal basis.

interconnect project to enlarge its system to support PG&E's proposed Baja Path expansion. In the open season, there was interest in the 30 MMcfd of PG&E's Baja Path capacity that was available at all receipt points, but there was not interest in capacity with only the Arvin receipt point. Neither Kern River nor PG&E is considering the Arvin interconnection or a Baja Path expansion with an Arvin interconnection point.

Kern River is currently moving forward with its 266 MMcfd Apex Project, which is designed to meet natural gas power plant needs in the Las Vegas area. It would not provide any new supply to California. The expected service date for this project is November 2011.

It is unclear what would be the price effects from the Kern River expansions. There would be increased competition, but shippers of gas on the Kern River pipeline have been price takers, following the price at the Southern California border. It is possible that suppliers bringing gas from the Southwest would lower the price to meet the new competition. If so, Kern River's shippers might follow suit.

California LNG

The construction of the Costa Azul LNG terminal was completed in May 2008. It has received several cargos of liquefied gas to test the facility. Commercial cargos started arriving early in 2010, with deliveries to California in excess of 100 MMcfd beginning in March 2010. California waits to see to what extent it can rely on natural gas supply from the Costa Azul LNG terminal.

As described in staff report *Liquefied Natural Gas Uncertainty Issues,* LNG is available in world markets, but suppliers are able to sell their LNG to higher priced Asian and European markets.

Imports of natural gas from Costa Azul could add to the state's supply mix in two ways. First, up to 800 MMcfd (400 MMcfd on a firm basis) could be received at the Otay Mesa international delivery point near San Diego. However, the Otay Mesa receipt point does not itself add to the state's receiving capacity, and the combined firm receipt capacity of Otay Mesa and Ehrenberg is limited to 1,210 MMcfd. The costs to increase the SDG&E and SoCalGas receipt capacity and system upgrades would be prohibitively expensive, and no expansion of this capacity is currently planned.

If supply of gas from Costa Azul reaches levels above Baja California demand of about 350 MMcfd, the excess could also be moved north and east to Ehrenberg by reversing the flow on the TGN and North Baja pipelines. Once the gas reaches Ehrenberg, it can flow west into SoCalGas, north bound on the bidirectional Line 1903, or east on El Paso's southern system toward Phoenix.

Any excess LNG supply delivered to Ehrenberg 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 effect the Costa Azul facility will have on future supply and price of natural gas.

Price impacts for the three months since regasified LNG reached California in March 2010 have been mixed. Price differentials between Henry Hub and the Southern California have fluctuated between a positive $ 0.24 per MMBtu to a negative $0.26 per MMBtu.

If LNG from Costa Azul, regardless of quantity or destination, enters the market, it will displace marginal supplies and thus potentially lower natural gas prices. Even if LNG stays in Mexico, it will free up natural gas that is currently imported from the United States.

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

Production

Although California produces natural gas, most of the natural gas that California consumes comes from outside the state. Of this gas, the Rocky Mountains region currently provides substantial amount. The rest comes from the Western Canadian Sedimentary Basin (WCSB) in Alberta and Saskatchewan, the San Juan Basin in the Southwest, and the Permian Basin in Western Texas and New Mexico. Most recently, however, increasing gas production from shale formations around the country is indirectly affecting the state's natural gas supplies and prices.

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 MMcfd to possibly 700 MMcfd by 2020. Although no details have been publicly released, Occidental Petroleum recently announced significant discoveries of oil and natural gas in the Bakersfield area. This could alter natural gas production in the state.

Slightly more than 50 percent of California's production flows to satisfy non-utility needs. SoCalGas and PG&E receive the remaining natural gas supply.

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 Rockies gas has long sold at a discount to Henry Hub,[6] 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 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 Eastern part

6. 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.

of the United States. These projects would change the market dynamics, impacting the supply and price of natural gas available to California. 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. Formations are considered tight when the pores containing natural gas are closed off and not allow the gas to flow freely to a well bore without special well development techniques.

Shale Gas Development

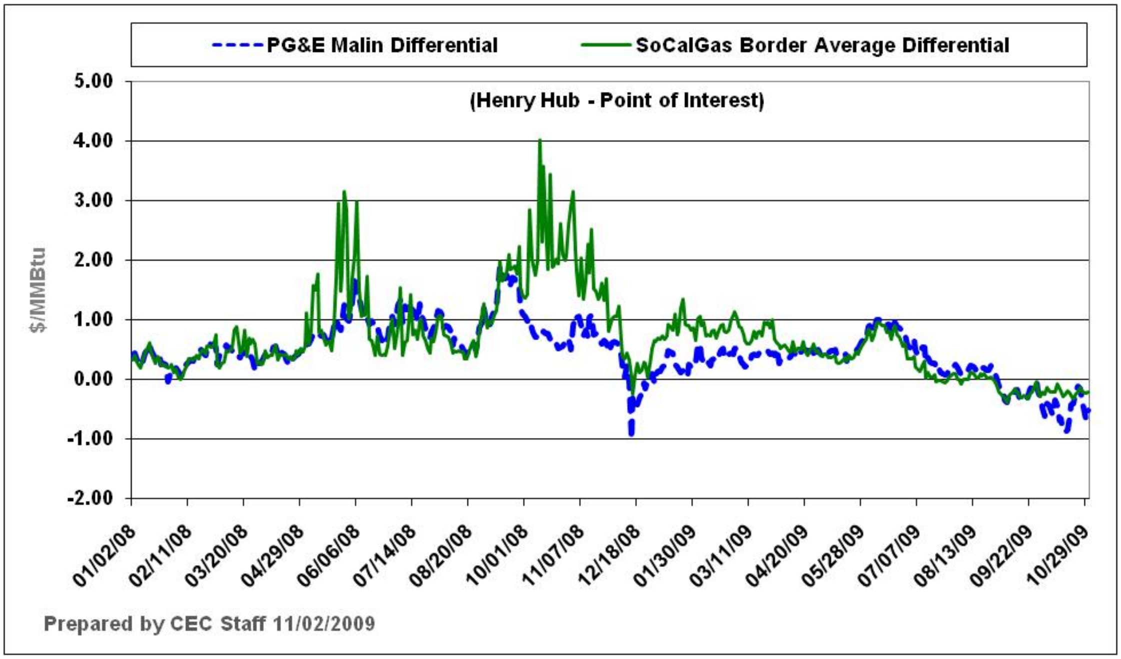
California is already feeling the price and supply effects of new natural gas from shale production. El Paso's officials have noticed up to 5 percent more Southwest natural gas production out of the Permian Basin moving west.[7] This natural gas is being displaced from moving to demand markets in the eastern part of the United States because of the increased production from shale formations in those regions. In addition, 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 in Pennsylvania and New York 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 gas prices at Henry Hub. **Figure 3** shows the price differentials between Henry Hub and the two California border points since January 2008. Recently, however, natural gas prices in Southern California have reversed the trend and are now higher than Henry Hub prices. It is uncertain if this price shift is only temporary or a long-term trend in basis differentials.

It is unclear at this time how new pipelines flowing east from the Rockies and increased production from shale gas in the East will affect future California border prices.

7. El Paso Web Cast, Fourth Quarter 2008 Financial & Operation Update, Feb. 26, 2009.

Figure 3: Malin and Southern California Border Price Comparison With Henry Hub



Source: Natural Gas Intelligence

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 capital investment standing idle during half of the year. Storage fields are mostly depleted natural gas fields with injection and withdrawal wells, as well as compression and processing equipment to clean up the extracted natural gas. Utilities and non-utilities withdraw natural gas 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 to transport natural gas to refill the storage facilities.

Storage facilities can also be used 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 increase. **Table** 1 summarizes the storage facilities in California.

PG&E's storage fields have the ability to cycle small quantities of gas through the year. The utility needs most of the injection period to fill its storage to meet winter demand. PG&E has indicated that it may maintain a 1,451 MMcfd withdrawal rate through the winter.[8]

8. Don Petersen, PG&E, at the Natural Gas Working Group Meeting, Sacramento, June 4, 2009.

Although SoCalGas has good natural gas cycling capabilities, the independently owned, non-utility Lodi and Wild Goose facilities have better 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. SoCalGas indicates that it can maintain up to 2,225 MMcfd[9] of gas withdrawals throughout all levels of storage.

Proposed Storage Projects

There are seven underground natural gas storage projects either approved or under review in California. These include the expansion of the existing Lodi and Wild Goose facilities. SoCalGas has approval from the California Public Utilities Commission (CPUC) to increase its storage and injection capacity. New projects include the Gill Ranch near Fresno, the Sacramento Storage development, the Central Valley storage project located near Williams, and the Tricor Ten Section Hub close to Bakersfield. All but the Tricor Ten Section project come under the CPUC's jurisdiction. Tricor is seeking approval from the Federal Energy Regulatory Commission (FERC).

Northern California has the greatest share of the new storage developments. Should all the projects become operational, PG&E's service area would have more than 5,000 MMcfd in storage withdrawal and 2,335 MMcfd in injection capacity. With this amount, it may be difficult to effectively use all the storage capacity. First, the extraction rate may exceed PG&E's maximum transmission and local delivery capabilities, possibly reducing receipts from interstate pipelines. Second, PG&E's summer *backbone,* or mainline capacity, maybe strained when simultaneous used to meet the needs of both its retail and electric generation customers as well as the injecting capability to place natural gas into storage. PG&E's backbone capacity, including Silverado capacity, is about 3,300 MMcfd.[10] For the last several years, the summer monthly flow has ranged from 2,000 MMcfd to as high as 2,800 MMcfd with an average of 2,500 MMcfd.[11] Historical storage withdrawals would add an average of 250 MMcfd.

9. 2008 California Gas Report, page 90.

10. Silverado represents the capacity to receive supply from California production.

11. CEC Form 1308 Schedule 2 filed by PG&E.

Table 1: California Natural Gas Storage Facilities

Area	Working Capacity Bcf	Maximum Injection Rate MMcfd	Maximum Withdrawal Rate MMcfd
Northern California			
Current Storage Facilities			
PG&E	97.6[12]	385	2,067
Lodi Gas Storage[13]	34	550	750
Wild Goose	29	450	700
Subtotal	160.6	1,385	3,517
Proposed Storage Projects			
Wild Goose	21	200	500
Gill Ranch	20[14]	450	700
Sacramento	8	100	200
Central Valley	5.5	200	200
Subtotal	54.5	950	1,600
No. California Total	215.1	2,335	5,117
Southern California			
Current Storage Facilities			
SoCalGas	133.1	850	3,195
Proposed Storage Projects			
SoCalGas	7	145	
Tricor Ten Section	22.4	800	1,000
Sub total	29.4	945	1,000
So. California Total	162.5	2,123	4,760
California Summary			
Current	293.7	2,235	6,712
Proposed	83.9	1,895	2,600
California Total	377.6	4,130	9,312

Source: California Energy Commission staff
Proposed natural gas storage sponsor websites
Richard Meyers, California Public Utilities Commission Regulatory and Natural Gas Infrastructure, May 14, 2009
Don Petersen and Bob Cowden, PG&E, at the Natural Gas Working Group Meeting, Sacramento, June 4, 2009, and emails during March 2010.
David Bisi, SoCalGas and Herb Emmrich, SoCalGas and SDG&E emails during March 2010.

The Tricor Ten Section Hub has the potential to serve both PG&E and SoCalGas, shippers on Kern and Mojave pipelines, and the non-utility customers located in the lower San Joaquin

12. Does not include PG&E's portion of the Gill Ranch storage project.

13. Includes both the Lodi and the Kirby Hills sites.

14. Includes 4.9 Bcf of storage for PG&E with an injection rate of 63 MMcfd and a withdrawal rate of 164 MMcfd.

Valley. Natural gas supply would be provided by the Kern River pipeline system, thus the project falls under FERC's jurisdiction for approval.

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 demand on a winter peak day along the western end of its Southern system. California supply at Ehrenberg would be more stable with the building of the Arizona storage facility; however, this project is having difficulty receiving approval due to brine disposal issues.

CHAPTER 2: Reliable Statewide Natural Gas Supply

As indicated earlier, California receives about 13 percent of its natural gas supply from internal domestic production, while the remainder flows through interstate pipelines to California from out-of-state resources. Normally supply is discussed with regard to how much a utility may receive from pipelines and instate production, or how much interstate pipeline capacity flows to the state. However, this chapter introduces the concept of reliable natural gas supply.

Because an interstate pipeline has a nameplate delivery capacity, it does not mean that all that capacity will be used to transfer natural gas to California. Each pipeline serving California has firm delivery contracts not only for California but also for upstream customers in other states. 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.

The utilities have mainline backbone pipelines that transport supply from the various interstate pipelines into their distribution systems. Often the sum of individual delivery point capacities does not match with the utility backbone capacities. For instance, PG&E's Baja Path may transport 1,060 MMcfd, but Kern River, El Paso, Transwestern, and Southern Trails pipeline systems combined may deliver up to 3,215 MMcfd, exceeding what the Baja Pipeline may carry.

Having the ability to receive natural gas supply from a number of sources is important. First, it provides the utility and its customers the flexibility to receive supply from the cheapest sources, fostering price competition. Second, it gives the opportunity to swap, trade, or displace supply from one area with another, adding supply flexibility. Finally, having multiple supply sources offers options to backup pipeline curtailments or lack of supply from a production area.

Table 2 provides information on current and proposed California supply sources. It also displays pipeline delivery capacity and utility/non-utility receiving capacity.

Pipelines and Production

Interstate pipelines and California producers have the current capacity potential to supply California consumers up to 9,785 MMcf of natural gas a day. California utilities and non-utilities have the ability to receive 9,755 MMcfd. These are basically the same capacity levels. As **Table 2** indicates, in some instances the state's receiving capacity is equal to the pipeline delivery capacity; in others, it is either less or more than the pipeline delivery capacity. Additionally, out-of-state upstream demand and contractual commitments may also limit the supply a pipeline may deliver to the state, which is reliable supply.

Table 2: California Reliable Pipeline Supply – MMcfd

Supply Point	Delivery Potential	Receiving PG&E	SoCal	Non-utility	Summary	Reliable Supply
Current Pipeline & Production						
Malin	2,100	1,850	-		1,850	1,850
Topock/Needles						
El Paso	1,680	1,140	540		1,680	1,680
Transwestern	1,225	400	800		1,225	710
So. Trails	120	40	80		120	120
Ehrenberg						
El Paso So	1,710	-	1,210		1,210	1,210
Mojave/Line 1903	400					
Kern River	1,750	675	965	1,000	2,640	1,500
California Production	800	120	460	450	1,030	800
Subtotal	9,785	4,225	4,055	1,450	9,755	7,870
New Pipeline Projects						
At Malin	300	300			300	300
Kern River	145	95	50	-	145	145
Subtotal	445	395	50	-	445	445
Sum Pipeline and Production	10,230	4,620	4,105	1,450	10,200	8,315

Source: *2008 California Gas Report*

Utility and pipeline filings with the California Energy Commission

To meet high demand for extended periods it is necessary to know how much natural gas the state could rely upon. The reliable supply to meet these conditions from out-of-state sources would be based on either nameplate capacity to deliver, reduced by upstream demand, or California's capacity to receive. One of these two will be a limiting factor on what will be considered a reliable supply. **Table 2** indicates current reliable supply would be 7,870 MMcfd from pipelines and domestic production. New pipeline projects would add 445 MMcfd in capacity, increasing reliable supply up to 8,315 MMcfd.

GTN has the capacity to deliver 2,100 MMcfd at Malin, and PG&E could receive a similar quantity. However, because of the upstream 250 MMcfd contract commitments in the Pacific Northwest, PG&E may rely on only 1,850 MMcfd for supply planning purposes. Since 2007 PG&E has received in excess of 1,850 MMcfd a number of days in the spring and summer, but not during the winter months. The Coos Bay LNG facility and the Ruby Pipeline project, which would directly deliver to Malin, could increase reliable natural gas supply from Malin to 2,150 MMcfd. The other LNG projects on the Columbia River would only add to the supply mix, but not to the reliable supply to California.

At the Needles/Topock receiving points, staff adjusted El Paso capacity because Mojave is no longer delivering to California but to El Paso's Line 1903 for export out of the state. Staff dropped El Paso's reliable capacity by 400 MMcfd from 2,080 MMcfd to 1,680 MMcfd. However, staff is assuming that El Paso's current contracts to deliver gas at Ehrenberg will continue as indicated in **Table 2**.

The Transwestern pipeline was also adjusted downward from 1,225 MMcfd. Transwestern has just completed a 500 MMcfd lateral pipeline to Phoenix, Arizona, without adding any new mainline capacity. Currently 350 MMcfd of the lateral is under contract for winter delivery to Phoenix. In addition, Transwestern also has 165 MMcfd winter delivery contracts to Southwest Gas for use in the Reno area. These delivery commitments limit the reliable amount of natural gas supply that Transwestern can deliver at Needles/Topock during the winter to 710 MMcfd.

El Paso South and Mojave/Line 1903 delivery capacity of 2,110 MMcfd at Ehrenberg/Blythe is substantially higher than SoCalGas' ability to receive (1,210 MMcfd). At this point, however, El Paso also provides natural gas to the North Baja Pipeline for delivery to Mexico. The gas may also flow east on El Paso's Southern system either directly or as a displacement.

Staff is concerned about El Paso's future natural gas deliveries at Ehrenberg during 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 MMcfd and are able to ramp up rapidly with demand swings of as much as 500 MMcfd. This demand could stress the 2,110 MMcfd pipeline capacity, requiring El Paso to issue operational flow orders that would limit the quantity of natural gas each customer would receive from the Southern system leading to an "unstable" supply for California. However, one of the proposed Arizona storage projects, if constructed, would help alleviate the problem.

Southern Trails is a small pipeline that delivers Rocky Mountain production to California. Currently it has no delivery points other than to California. The supply split between PG&E and SoCalGas is based on historical utility receipts from the pipeline.

Kern River pipeline makes upstream deliveries in Utah and Nevada that effectively reduce the pipeline's delivery capacity to California. Although California's utility and non-utility receiving capacity is 2,640 MMcfd, reliable supply from Kern River is limited to approximately 1,500 MMcfd. Furthermore, natural gas deliveries may be even lower than 1,500 MMcfd during cold periods. Overall, non-utility customers in California receive approximately 1,000 MMcfd from Kern River, and while the utilities have a combined 1,640 MMcfd of receiving capacity, they have access only to the remaining 500 MMcfd. Noticeably, utility receipts have actually been declining for the past couple of years, while non-utility deliveries have been increasing. Kern River, however, is in the process of adding 145 MMcfd of new delivery capacity to California utilities, which would increase Kern River's reliable supply of natural gas to California to 1,645 MMcfd.

It is important to understand the differences between pipeline delivery capacity and utility and non-utility receiving capacities. Failure to take limiting factors for each category into consideration may lead to faulty conclusions regarding the actual available supply of natural gas in a high natural gas demand scenario. Furthermore, a complete assessment of future natural gas supply must consider utility and non-utility pipeline capacity within the state. Each utility relies for its supply of natural gas on many mutual receiving points. Utilities also transport natural gas for other utilities, which may mask the transporting utility's reliable transport capacity. For example, PG&E's Baja Path is moving several hundred million cubic feet per day of natural gas for delivery to the SoCalGas system. However, PG&E has indicated that these are "as available" contracts and are used only when PG&E has unused capacity. These "as available" flows are low during the winter months and not available to SoCalGas system; therefore, these flows cannot be considered as part of SoCalGas' reliable natural gas supply.

CHAPTER 3: Long-Term High Demand and Reliable Supply

California utilities and non-utilities need to plan for two high-demand situations to ensure they have reliable supply of natural gas. Both situations would most likely occur during the winter months. The first would be a short-term cold snap that may last for a couple of days to a week. The second would be a prolonged period of high demand, occurring during the winter's cold months with an extended period of severe drought.

Short-term peak demands have gradually grown over the past few years, reaching up to 10,000 MMcfd on a statewide basis.[15] Increasing winter space heating requirements, coupled with some moderate drought conditions, account for these short-term, high-demand periods that may last for a couple of days. Given existing pipeline capacity, coupled with storage, these demands are easily met by the current system.

Planning for cold and dry-year conditions is challenging, particularly if they are similar to what occurred during the energy crisis of 2000-2001. Throughout the winter, the utilities were faced with meeting both the residential and commercial space heating needs and demand for natural gas power generation that mirrored summertime demand levels. Winter natural gas demand for electricity generation during the crisis reached between 2,500 and 3,000 MMcfd, which is approximately 1,500 MMcfd above normal winter demand.

While demand above 10,000 MMcfd has not occurred for more than a few days in the past under dry-year conditions in the winter time, it would indicate what could occur for an extended winter cold period. Some mitigating factors could help avoid what happened during the energy crisis of 2000-2001. For the past nine years, additional pipeline delivery and receiving capacity and storage facilities have been added, and more are underway or proposed. The state's pipeline and storage infrastructure is in better condition that it was in 2000-2001. However, some of the reliable pipeline supply capacity has also been lost because Mojave switched delivery points and Transwestern built the Phoenix lateral.

Noticeably, drier-than-normal hydro conditions of the past few years have increased natural gas demand for electricity generation. Furthermore, as the state moves to more reliance on renewable electricity generation that might not be available during the winter due to seasonal wind patterns, the need for more natural gas for power generation will increase during those cold months.

Under a long-term, high natural gas demand scenario, as long as demand remains below reliable pipeline supply levels, the pipelines and utilities would be able to act normally. There should be no pressure on supply that would drive price above normal winter levels. However, if natural gas demand exceeds reliable supply, storage facilities would be working overtime to meet demand, and the market would have to shift to meet the

15. 2009 CGR, page 15.

increased demand. Utilities and non-core customers would seek additional supply to meet their demand, and scarcity prices would prevail. Marketers and others would be attracted by the higher prices. Any pipeline slack capacity would be pressed into service, and supply that normally could have been delivered elsewhere would come to California – up to the interstate delivery capacity or utilities' receiving capacity.

Under these circumstances, it is likely that shippers on the Mojave system would decide to drop off their gas into the state at Daggett, Wheeler Ridge, and Krammer Junction rather than to Line 1903. Likewise, deliveries to the state from Kern River and Transwestern would be expected to increase. GTN and El Paso at Topock and Ehrenberg would already be flowing at capacity. Without some enhancements to the SoCalGas mainline Southern system or debottlenecking the SDG&E pipeline system, LNG would be only a small component of the supply mix and could not add any additional delivery capacity to California.

It is difficult to foresee what the overall price impact such a scenario would have on California consumers. Total natural gas costs, including commodity, transport and distribution, were approximately $8 billion prior to the energy crisis but increased up to $19 billion during the crisis, due to much higher commodity prices. Because the commodity price for natural gas has more than doubled in the past 10 years over pre-energy crisis prices, California now pays approximately $20 billion,[16] the same as during the crisis. Would natural gas costs react in a similar manner as they did during the energy crisis? Would California be facing a near $40 billion price tag for its natural gas in a long-term, high demand scenario?

To meet a cold winter and dry hydro scenario, the CPUC instituted a reserve margin criterion in Decision 06-09-039. The measure is called *slack capacity.* The utilities must now have sufficient mainline or backbone capacity to meet a 1-in-10 cold year and dry hydro conditions to meet all natural gas demand on their systems. The crisis years 2000–2001 were more severe than the 1-in-10 criteria.

Slack capacity is measured by comparing a utility's mainline or backbone-pipeline capacity with its annual natural gas demand. The purpose is to determine whether there is a sufficient margin or reserve capacity to meet unexpected high demand periods.

The CPUC adopted broad, general criteria for new pipeline capacity. Following the curtailments in the late 1980s, the CPUC concluded that *slack capacity* of 10 percent in the near term and up to 20 percent in the long term (based on cold-year forecasts) would support the unbundled gas service structure, foster competition (gas-on-gas and pipeline-to-pipeline), and achieve a higher level of reliability of gas service in California.[17]

In 2006, the CPUC again examined the slack capacity concept. As a result of the proceedings, the CPUC ordered PG&E and SoCalGas to "plan and maintain intrastate

16. http://energyalmanac.ca.gov/naturalgas/annual_gas_costs.html

17. CPUC Decision 90-02-016

natural gas backbone transmission systems sufficient to serve all system demand on an average day in a one-in-ten cold and dry-hydroelectric year." Utilities were also directed to continue using the 10 percent and 20 percent backbone-slack capacity guidelines.[18]

Staff has prepared an estimate of what the state's slack capacity would be in **Table 3**. In this case, the reliable supply capacity of 8,315 MMcfd in **Table 2**, which includes California production and current and proposed pipeline, was used rather than the backbone capacities. This accounts for upstream demand the interstate pipelines must serve, non-utility demand and interstate pipeline delivery points where each of the utilities may have one or more receiving options.

In the CPUC method, each of the utilities reviews its backbone capacity separately. This potentially ignores the possibility that the utilities would be relying on the same interstate delivery capacity, and also could ignore upstream demand the interstate pipelines are also obligated to serve.

Staff used three demand forecasts to estimate slack capacities through 2020. The first was produced by the California Energy Commission staff in support of the *2007 Integrated Energy Policy Report* and represents average year temperatures and hydro conditions. The other two were developed by the utilities and published in the *2008 California Gas Report (CGR)*. One represents demand under average conditions and the other portrays demand in a cold winter and dry-hydro year. All three of the forecasts include both utilities' demand and non-utility demand, as estimated by the Energy Commission staff.

The slack capacity values in each of the three cases fall within the 15 to 20 percent range. These factors are consistent with CPUC guidelines when the interstate pipeline capacity proposed additions are included. They are also indicative of pipeline slack capacity levels that would be needed to reduce price impacts should high demand levels occur.

An estimated slack capacity of 15 to 17 percent indicates the possibility that by 2020 the utilities could be considering adding more infrastructure than is currently being proposed.

If the proposed interstate projects were not built, the 7,870 MMcfd figure in **Table 2** must be used to derive the slack capacities. Energy Commission staff's slack capacity values, as described in **Table 4**, using the Commission staff demand estimates**,** start at 16 percent and drop 5 percentage points by 2016. In such a case, the utilities should be looking at construction of additional pipeline capacity to maintain competition and a high level of reliability.

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18. CPUC Decision 06-09-039

Table 3: Application of CPUC Backbone Slack Capacity/Guidelines Based on 8,315 MMcfd in Reliable Supply

	CEC Normal		CGR Normal		CGR Cold and Dry	
Year	Demand MMcfd	Slack Cap Percent	Demand MMcfd	Slack Cap Percent	Demand MMcfd	Slack Cap Percent
2010	6,626	0.20	6,200	0.25	6,784	0.18
2011	6,575	0.21	6,195	0.26	6,777	0.19
2012	6,776	0.19	6,190	0.26	6,770	0.19
2013	6,735	0.19	6,184	0.26	6,762	0.19
2014	6,804	0.18	6,179	0.26	6,755	0.19
2015	6,858	0.18	6,174	0.26	6,748	0.19
2016	6,991	0.16	6,206	0.25	6,782	0.18
2017	6,998	0.16	6,237	0.25	6,816	0.18
2018	7,035	0.15	6,269	0.25	6,850	0.18
2019	7,072	0.15	6,300	0.24	6,884	0.17
2020	7,107	0.15	6,332	0.24	6,918	0.17

Source: California Energy Commission Normal Capacity – California Energy Commission, Natural Gas Market Assessments Report, Final Staff Report, Appendix J, Dec. 2007.

CGR Normal and CGR Cold and Dry – 2008 California Gas Report

Table 4: Application of CPUC Backbone Slack Capacity/Guidelines Based on 7,870 MMcfd in Reliable Supply/(Proposed Interstate Projects Are Not Built)

	CEC Normal		CGR Normal		CGR Cold and Dry	
Year	Demand MMcfd	Slack Cap Percent	Demand MMcfd	Slack Cap Percent	Demand MMcfd	Slack Cap Percent
2010	6,626	0.16	6,200	0.21	6,784	0.14
2011	6,575	0.16	6,195	0.21	6,777	0.14
2012	6,776	0.14	6,190	0.21	6,770	0.14
2013	6,735	0.14	6,184	0.21	6,762	0.14
2014	6,804	0.14	6,179	0.21	6,755	0.14
2015	6,858	0.13	6,174	0.22	6,748	0.14
2016	6,991	0.11	6,206	0.21	6,782	0.14
2017	6,998	0.11	6,237	0.21	6,816	0.13
2018	7,035	0.11	6,269	0.20	6,850	0.13
2019	7,072	0.10	6,300	0.20	6,884	0.13
2020	7,107	0.10	6,332	0.20	6,918	0.12

Source: California Energy Commission Normal Capacity – California Energy Commission, Natural Gas Market Assessments Report, Final Staff Report, Appendix J, Dec. 2007.

CGR Normal and CGR Cold and Dry – 2008 California Gas Report

CHAPTER 4: Impact of Renewable Energy on Natural Gas Infrastructure

Renewable energy sources are providing a larger share of the electricity generated to meet California's needs. An important question to consider is whether the addition of alternative energy technologies may strand some of the current natural gas infrastructure[19] as natural gas consumption for power plants declines. Or, conversely, might the addition of intermittent renewable energy technologies to the electric system require additional pipelines and storage?

Since 2003, summer peak natural gas demand has grown from approximately 6,500 MMcfd to 8,800 MMcfd in 2007. The increase is attributed to low-hydro generation rather than growth in electricity demand. Drought conditions can have an impact on natural gas demand for power generation during the winter months. Relative to the historical peak, the *2009 CGR* projects a 1,200 MMcfd drop in summer peak-day natural gas use during the next few years. The *CGR* does not explain what assumptions cause the decrease, but they may be a combination of less consumption because of the economic recession, electricity conservation programs, more efficient heat rates for the marginal gas-fired units, retirement of less efficient units, and renewable energy technology generation additions to the electric resource mix that displace conventional gas generation.

The utilities use electricity production cost dispatch models to develop the *CGR* summer peak demand forecast. Such modeling relies upon a number of assumptions, each of which introduces uncertainty to the results in at least two important areas: 1) declining demand for natural gas when electricity peak demand forecast itself is rising and more gas-fired generation has to be used to meet that peak demand, and 2) the ways in which renewable generation's seasonal availability and intermittency of renewable generation affects summer average and peak-day gas demand.

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

Natural gas currently meets over 40 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 units operate at approximately 7,500 Btu per kWh. Peaking units are less efficient and, depending

19. Stranded infrastructure costs result when costs exceed the amount that can be recovered through an asset's sale.

on the age of the unit, will use 50 to 100 percent more gas per MWh than a new combined cycle unit.

The need for additional natural gas depends on the type of unit used to supplement the renewable generation. For example, a 40 percent loss of renewable generation would be equivalent to an increase of 480 MMcfd in combined cycle fuel use. If a peaker unit is backing up renewable generation, on average the unit requires 60 percent more fuel, or approximately 770 MMcfd.

To meet incremental summer peak-day demand, the gas utilities and non-core customers have a number of options. One option might be the natural gas flowing in the interstate pipelines. However, natural gas takes three to four days to reach California from out-of-state production areas. Therefore, transporting natural gas in the pipelines from far away cannot be a solution for a short-term peak demand occurrence but can be used on a long-term basis. A second tool to meet this short-term 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 option could be the ability to reduce summer storage injections. Utilities and marketers could redirect natural gas that otherwise would have been injected into storage to power plants for immediate combustion.

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 they will continue to use that option as peak-day demand rises or as intermittent generation is added is unclear at this point.

CHAPTER 5: Conclusions

Several important observations from this report have 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, they 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 on a utility basis. There are many mutual receiving points that each utility and non-utility customer relies on for supply of natural gas. And there are instances 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 on an as-available basis for delivery to SoCalGas territory. This effectively reduces the pipeline delivery capacity to PG&E customers. Should PG&E call back that capacity for its use, then SoCalGas customers have lost natural gas supply.

Otay Mesa is a point where Costa Azul regasified LNG may enter into California. Because of a constriction in the SoCalGas Southern pipeline system, this point of entry does not add any receiving capacity to the state. Flowing supply at Ehrenberg and Otay Mesa in combination may reach only 1,210 MMcfd. Costa Azul therefore adds only natural gas to the supply mix.

Northern California is getting the greatest share of the new storage developments. Should all the projects become operational, PG&E would have more than 5,000 MMcfd in storage withdrawal and 2,512 MMcfd in injection capacity. Should every one of the storage projects go forward, there may be difficulties to effectively use all the storage potential. First the extraction rate may exceed PG&E's maximum transmission and local delivery capabilities, possibly reducing receipts from interstate pipelines. Secondly, simultaneous use of all the injecting capability would start to strain PG&E's summer backbone or mainline capacity in meeting its retail and electric generation customers. PG&E's backbone capacity is 3,300 MMcfd and for the past several years summer consumption has ranged from 1,500 MMcfd to as high as 2,600 MMcfd. In the final instance, market prices will determine if it is more cost effective to withdraw gas from storage or bring in interstate supplies.

Staff introduced the concept of reliable pipeline supply. This is a supply that the state may firmly rely on from out-of-state sources that is based on nameplate capacity to deliver and capacity to receive. In addition, reliability must take into account the natural gas reductions in pipeline delivery due to upstream demand. Any of these conditions will diminish the reliability of natural gas supply to the state. **Table 2** in Chapter 2 indicates that the reliable pipeline supply, including California production, is currently 7,870 MMcfd and is projected to grow to 8,315 MMcfd, after taking into account supply from new pipeline projects.

As long as demand for pipeline supply remains below the reliable supply, there should be little if any price impacts on the state. However, if demand increases to the point that pipeline supply approaches or is higher than the reliable supply, utilities and non-core customers would seek additional natural gas to meet their demand; in that case, scarcity prices would prevail. It is unknown what the cost impact would be to the state, but during the 2000–2001 energy crisis the total cost of natural gas jumped from around $8 billion to $19 billion. A similar incidence happened in 1976–1977 when a prolonged drought occurred in the West. Fuel oil was used for power generation purposes to make up for the lack of natural gas. As a result, there were no natural gas price implications. However, that fuel-switching capability no longer exists, and the consequences of a similar event will have different results today.

Staff applied the CPUC backbone-slack capacity guidelines on a statewide basis, using three demand scenarios. The reliable pipeline supply and California production were used in lieu of the backbone capacity. The slack capacity factors were within the CPUC guidelines, ranging from 20 percent in the near term to 15 percent at the end of the study period. However, these results indicate that by 2020 the utilities and interstate pipelines should be planning more additions to the natural gas infrastructure than the ones currently proposed.

Renewable resources will play a greater role in meeting the state's need for electricity. It is unclear how these new additions will affect the operation of the utility systems. But it is apparent that underground storage of natural gas will play an important role supplying gas for electricity generation during peaking demand periods. Because of the increasing injection needs in the PG&E service area, PG&E's backbone capacity may be strained to meet both summer demand and storage injection. PG&E and the independent storage operators will have to watch carefully how injection and extraction are scheduled.

Project developers have proposed several new supply and storage projects that would benefit California. Pipeline projects would add 445 MMcfd in new flowing supply to the state. Another 2,800 MMcfd in peaking supply would be available from new storage facilities. All the new supply sources of natural gas would be necessary to meet quick response to electricity generation peaking plants, add flexibility to the system, and help hedge against high natural gas prices.

APPENDIX A: 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 affect 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 2008, the Rockies accounted for 22 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 the 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 A-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 MMcfd.

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 MMcfd.

Table A-1: Proposed Pipeline Projects

Pipeline Project	Company	Capacity (MMcfd)
Supply Natural Gas to the West Coast		
Kern Expansion	Kern	145 Expansion/Total 1,900
Ruby	El Paso	1300
Sunstone	Williams/TCPL/Sempra	1200
Supply Natural Gas to the Mid-Continent, Mid-Atlantic, and New England States		
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 plans to upgrade some above-ground facilities that will increase capacity on the pipeline by 145 MMcfd. When the expansion is completed, the pipeline will have a capacity of 1,900 MMcfd.

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 MMcfd with possible expansion to 1,700 MMcfd.

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 calls for a design capacity of 1,200 MMcfd.

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 MMcfd, with a proposed ultimate capacity of 2,000 MMcfd. 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 transports 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 MMcfd.

Completion of the Rockies Express pipeline will result in a takeaway capacity of 1,800 MMcfd. Associated with the Rockies Express pipeline are several infrastructure additions for interconnections that will 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, these infrastructure additions could lead to an additional takeaway capacity for the Rockies Express.

APPENDIX B: Proposed Natural Gas Storage

SoCalGas Expansion Project

CPUC Decision D.08-12-020 provided for SoCalGas to increase its working storage by 7 Bcf and injection capacity by 145 MMcfd. Working storage will increase 1 Bcf per year from 2010 through 2015 by adding more wells and increasing liquids removal. Another 1 Bcf will be added in 2010 by adding a small amount of compression. Injection capacity will be increased by upgrading compression at the Aliso Canyon Storage field. The new injection service will be available by 2013.

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 in the permitting phase. Injection rate could be up to 100 MMcfd, and withdrawal could reach up to 200 MMcfd. Cushion gas remains in the field, leftover from past production. The facility will be able to completely cycle 3.2 times per year. Because of siting delays staff assumed that this project would not be available during the study period. The facility is expected to be operational in September 2010.

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 700 MMcfd of firm withdrawal capacity. There are no environmental concerns, and the CPUC approved the project in January 2010. This project is expected to be completed in August 2010.

Lodi Gas Storage Expansion

Lodi Gas Storage added an additional 12 Bcf of working gas storage capacity in 2009 with an additional 100 MMcfd of firm injection and 200 MMcfd of firm withdrawal capabilities. Lodi Gas Storage first went into commercial operation in 2002. This expansion brought the total working storage of Lodi up to 34 Bcf.

Central Valley Gas Storage Project

Nicor, Inc., is proposing to develop a new natural gas storage field near Colusa. The Central Valley Gas Storage project would use two depleted natural gas reservoirs that are 2,200 feet beneath the surface. It would have working storage of up to 8 Bcf and have a 200 MMcfd injection and withdrawal capacity. A 14-mile pipeline would tie the project into PG&E's Redwood Path near Delevan. Nicor applied to the CPUC for a Certificate of Public Convenience and Necessity in August 2009. An environmental impact report (EIR) has been prepared and is being reviewed. It is anticipated the project would be fully operational by the second quarter of 2011.

Tricor Ten Section Hub

Tricor is reactivating the Ten Section depleted oil and natural reservoir as a storage field. Ten Section is located about 10 miles southwest of Bakersfield. The plan is to have up to 22.4 Bcf in working storage with a maximum 1,000 MMcfd withdrawal rate and an 800 MMcfd maximum injection rate.

From 1977 through 1982, PG&E and SoCalGas operated the field for natural gas storage. The project's location has easy access to Kern River and Mojave interstate pipelines. On June 1, 2009, Tricor began a nonbinding open season. Tricor applied to the Federal Energy Regulatory Commission (FERC) on June 12, 2009, for an authorization to construct and operate their natural gas storage project certificate to serve the Kern River/Mojave pipeline system. According to Tricor's application, the facility initially will interconnect with the jointly owned Kern River/Mojave interstate pipeline. In addition, however, the facility will be in close proximity to, and may later seek to interconnect with PG&E and SoCalGas, giving the Tricor storage hub a combined, lateral surrounding option of more than 4 Bcf. Tricor hopes to have the project operational by January 2012.

Arizona Natural Gas Storage LLC

The Arizona Natural Gas Storage Project (ANGS) will consist of multiple salt caverns and pipeline infrastructure to be constructed on a multi-phased basis. The caverns will be created in the bedded salt structure formation located in the Picacho Basin near Eloy, Arizona.

On December 15, 2009, FERC accepted ANGS's request for approval to use the pre-filing procedures and establish a pre-filing docket (PF10-3-000). Upon receipt of required permits, ANGS will proceed with the development of the project with a currently projected in-service target of 2012/2013 and a working gas capacity of 20 Bcf.

Picacho Peak Natural Gas Storage LLC

Picacho Peak Gas Storage, LLC, is developing up to 8 Bcf of high-deliverability natural gas storage in underground salt caverns located north of the town of Eloy, Arizona. The first cavern is expected to be operational in 2013 and the second in 2015. Open season was completed in March of 2010.

Picacho Peak facilities will tie into two interstate pipelines and local power plants. Picacho Peak will seek authority to construct and operate from the FERC, which will offer market-based rates, customized storage capacity, and hub services to its customers.